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BEFORE THE ARIZONA CORPORATION COMMISSION

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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 TEHREON, TO APROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND TO AMEND DECISION NO. 67744.

DOCKET NO. E-01345A-05-0816

STAFF'S NOTICE OF FILING TESTIMONY

Staff hereby provides notice of filing its Direct Testimony in this Docket. An original and thirteen copies are submitted of the Prefiled Direct Testimony of Matthew J. Rowell, Barbara E. Keene, Jerry D. Anderson, Jerry D. Smith, James R. Dittmer, Michael L. Brosch, Ralph C. Smith, David C. Parcell, John Atonuk and William R. Jacobs. Staff is providing a disk from Jerry D. Smith containing confidential information and several pages from James R. Dittmer containing confidential information to Administrative Law Judge Farmer, the Commissioners, their Executive Aides and to those parties who have entered into a Protective Agreement with Arizona Public Service Company.

RESPECTFULLY SUBMITTED this 18th day of August, 2006.

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Arizona Corporation Commission
DOCKETED

AUG 18 2006

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(REDACTED VERSION)
DOCKET NO. E-01345A-05-0816

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ARIZONA PUBLIC SERVICE COMPANY FOR A
HEARING TO DETERMINE THE FAIR VALUE OF
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AND REASONABLE RATE OF RETURN THEREON,
AND TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP SUCH RETURN, AND TO AMEND DECISION NO. 67744

August 18, 2006

BEFORE THE ARIZONA CORPORATION COMMISSION

JEFF HATCH-MILLER
Chairman
WILLIAM A. MUNDELL
Commissioner
MARC SPITZER
Commissioner
MIKE GLEASON
Commissioner
BARRY WONG
Commissioner

IN THE MATTER OF APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, AND TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, AND TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND TO AMEND DECISION NO. 67744	DOCKET NO. E-01345A-05-0816

DIRECT

TESTIMONY

OF

MATTHEW J. ROWELL

CHIEF ECONOMIST

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

AUGUST 18, 2006

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ATTACHMENT

EXECUTIVE SUMMARY

Staff is recommending that the Commission not adopt APS' proposed Environmental Improvement Charge for the following reasons:

- The EIC would collect revenues from ratepayers based predominantly upon estimated rather than incurred costs.
- The EIC appears to be unique.
- The EIC would include costs that will not be incurred for several years beyond the Test Year.
- The EIC would include funding for projects before they are mandated to be installed on APS' system.
- Regulatory mandates typically build in construction lead times to provide industry sufficient time to comply with mandated regulatory requirements.
- The EIC is derived based upon multiple year revenue requirements that increase the complexity of auditing the charge in the context of future general rate cases and annual EIC reset proceedings.
- The effect of the EIC on APS' interest expense is unclear.
- The annual reset of the EIC could be implemented without Commission approval under APS' proposal.
- The EIC does not address the fundamental financial challenges that APS has identified.
- The environmental impact of implementing the EIC is unclear.

I. INTRODUCTION

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

A. My name is Matthew J. Rowell. I am the Chief Economist at the Arizona Corporation Commission ("ACC" or "Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. What is your position at the Commission?

A. I am the Chief of the Telecommunications and Energy section of the Commission's Utilities Division.

Q. Please describe your education and professional background.

A. I received a BS degree in economics from Florida State University in 1992. I spent the following four years doing graduate work in economics at Arizona State University where I received a MS degree and successfully completed all course work and exams necessary for a Ph.D. My specialized fields of study were Industrial Organization and Statistics. Prior to my Commission employment I was employed as a lecturer in economics at Arizona State University, as a statistical analyst for Hughes Technical Services, and as a consulting research analyst at the Arizona Department of Transportation. I was hired by the Commission in October of 1996 as an Economist II. I was promoted to the position of Senior Rate Analyst in November of 1997 and to Chief Economist in July of 2001. In my current position, I am responsible for supervising nine professionals who work on a variety of telecommunications and energy matters.

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

A. This testimony addresses Arizona Public Service Company's ("APS" or "Company") proposal to establish an Environmental Improvement Charge ("EIC"). Testimonies submitted by APS witnesses Messrs. Edward Z. Fox and Gregory A. DeLizio address the environmental expenditures forecast for APS over the next several years and the technical functions of the EIC, respectively.[1] Staff's testimony addresses the appropriateness of the EIC proposal as discussed in testimonies sponsored by Messrs. Fox and DeLizio.

II. SUMMARY OF TESTIMONY AND RECOMMENDATIONS

Q. Briefly summarize your Environmental Improvement Charge ("EIC") testimony.

A. Staff recommends that the Commission reject the Environmental Improvement Charge filed by APS. The stated purpose of the EIC is to establish an adjustment mechanism that would provide recovery of substantial capital investment in environmental controls for APS' coal generation facilities.[2] APS originally estimated that environmental improvement changes to the Cholla Power Plant will cost approximately $135 million through the year 2009. In response to Staff Data Request MJR 3-5, APS updated the number to approximately $160 million and also identified six additional Cholla Plant environmental improvement projects estimated to cost approximately $83 million for a combined total of $243 million. APS states that it will recalculate the EIC and update the Direct Testimony of Mr. Edward Z. Fox. The updated data will be addressed by Mr. Gregory A. DeLizio in his Rebuttal Testimony. It should be noted that the updated $160 million in estimated capital expenditures only include mandated projects according to APS.[3] The Company maintains that the acceleration and scale of environmental expenditures have reached a point where an adjustment mechanism is necessary to timely recover the cost of implementing and maintaining environmental improvements.[4]

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[1] Gregory A. DeLizio (GAD), p.3, lines 7-10
[2] EZF, p.2, lines 1-4
[3] APS' response to Staff Data Request MJR 3-5
[4] Edward Z. Fox (EZF), p.2, lines 22-26

Staff believes that APS has not demonstrated that the traditional test year rate base method is insufficient to deal with upcoming environmental requirements. Although many programs have been and likely will be promulgated regarding environmental improvement projects, APS endeavors to go beyond basic compliance.[5] The Company expresses a desire to be proactive and stay ahead of the regulatory curve when it comes to protecting the environment.[6] On the surface, APS' approach seems noble, but Staff will present testimony that supports following a more prudent and traditional path. This course is supported by the realities that deadlines associated with APS' mandated future environmental improvements are uncertain. Actual project completion dates may be amended or delayed[7]. Furthermore, regulatory mandates typically build in reasonable lead periods to allow industry time to comply with mandated environmental improvement projects.[8] Staff's testimony will also address the issues of accounting for rate base and expenses that would have to be removed from general rate case filings if the proposed EIC were authorized by the Commission. In general, Staff does not support collecting funds from Arizona ratepayers, including interest, before costs have been incurred. Staff will also address issues pertaining to recovery of out of test year costs,[9] industry practices, and EIC provisions proposed by APS.

III. DERIVATION OF THE EIC

Q. Can Staff provide an example of how the proposed EIC is derived?

A. Yes. Staff has developed Table 1 to help explain the derivation of the proposed EIC and illustrate how difficult it could be to keep track of EIC-related expenses. Although APS updated actual and estimated capital expenditures from $135 million to approximately

[5] EZF, p.4-5, lines 22-2
[6] EZF, p.6, lines 3-6
[7] Staff Data Request MJR 3-1
[8] APS' response to Staff Data Request MJR 3-5
[9] For example, a maximum amount of only $3.6 million (2.25 percent) of the updated $160 million in Cholla-related environmental improvement projects could have occurred during the Test Year in this rate case.

$243 million, the updated revenue requirements and resultant EIC kWh rate are not expected to be available until Mr. DeLizio updates and files them with his Rebuttal Testimony.[10] However for the purposes of Table 1, the revenue requirement process is expected to remain unchanged after Mr. DiLizio updates the data and files it with his Rebuttal Testimony.

Table 1

Rate Base and Revenue Requirement Derivation

2004-2007 EIC 1 (GAD-WP1, pp.10-12)

(Unit 1 Baghouse only)

($x1000)

YEAR	(A) Projected Capital Expenditures[1]	(B) AFUDC[2]	(C)= (A)+(B) Rate Base	(D) Revenue Requirement[3]
2004	$373	$11	$384	Not Applicable
2005	$3,147	$188	$3,335	Not Applicable
2006	$15,571	$1,094	$16,665	Not Applicable
2007	$3,038	*	$3,038	$2,808
Totals	**$22,129**	**$1,293**	**$23,422**	**$2,808**

*2007 = plant in service year; therefore AFUDC is replaced with a revenue requirement.

(1) See Work Paper EZF-WP9.

(2) AFUDC is accumulated at an 8.73% rate (Schedule D-1, p. 1) that is applied monthly to rate base (Work Paper GAD-WP1, p. 10). (The 8.73% rate includes APS' requested 11.50% cost of equity.)

(3) A 1.6407 revenue conversion factor (Schedule C-3) is included in the $2,808 Revenue Requirement (RR). The RR is shown in Work Paper GAD-WP1, p. 2 and in Attachment 1.

[10] APS' response to Staff Data Request MJR 3-5

Q. What is the purpose of Table 1?

A. The purpose of Table 1 is to summarize revenue requirements associated with Project EIC 1 used, in part, to develop the EIC kWh rate proposed for Calendar year 2007 (Work Paper GAD-WP1, p. 2), and to illustrate the complexity of the process used in developing EIC revenue requirements as illustrated in Attachment 1. In an attempt to simplify explaining the derivation of the EIC revenue requirement, Staff focused on the <u>Cholla Unit 1 Baghouse Project</u> (EIC 1) proposed to begin in the year 2007. Staff chose this project as its example simply because it represents the first data entry on Work Paper GAD-WP1, p.2.

Q. Please continue your discussion of Table 1.

A. Column (A) in Table 1 contains an excerpt of data contained in Work Paper GAD-WP1 and Work Paper EZF-WP9. Column (A) is the starting point for developing EIC rates because it lists projected capital expenditures for EIC-related projects as reported by APS.

Q. What is the purpose of Column (B) in Table 1?

A. The purpose of Column (B) is to reflect allowance for funds used during construction ("AFUDC") charges in the years 2004-2006. APS booked the referenced 2004-2006 capital expenditures under construction work in progress ("CWIP") and accumulated the AFUDC as shown in Table 1. The clearest illustration of how the data in Column (B) is derived is contained in Work Paper GAD-WP1, p.10. For example, the $188,000 shown in Column (B) for 2005 is the sum of the twelve AFUDC entries listed on p. 10 of Work Paper GAD-WP1. (It should be noted that manually adding the twelve entries equals $192,000. The difference is due to rounding.)

Q. What is the purpose of Column (C) in Table 1?

A. The purpose of Column (C) is to show a $23,422,000 match with total CWIP/AFUDC shown on Work Paper GAD-WP1, p.12.

Q. What is the purpose of Column (D) in Table 1?

A. The purpose of Column (D) is to show a $2,808,000 match with the revenue requirement shown on Work Paper GAD-WP1, p. 2. The derivation of the approximate $2.8 million revenue requirement is shown on Work Paper GAD-WP1, p.12. Staff has also included Attachment 1 to its Testimony to provide an example of the actual calculations used to develop the revenue requirement for January, 2007.

Q. Has Staff prepared any other tables to help in understanding the nature of the proposed EIC?

A. Yes. Staff also prepared Table 2.

Table 2

Summation of Annual Revenue Requirement

2010* EIC 1 (GAD-WP1, p.15)

(Unit 1 Baghouse only)

($x1000)

Expenses		Annual Revenue Requirement
Interest		$507
Equity Return (Grossed-Up)		$2,124
Depreciation		$936
Property Taxes		$324
O&M		$600
Total		**$4,491**

*2010 = first year to include all expense categories included in Annual Revenue Requirements for EIC 1.

Q. What is the purpose of Table 2?

A. The purpose of Table 2 is to illustrate that the proposed EIC is a "fully loaded" revenue collection mechanism, which includes expenses that are typically and appropriately recovered through rates authorized in a general rate case. Since the revenue requirement process is the same as the methodology described in Table 1, Staff does not address the derivation of the revenue requirements shown in Table 2. The source of the data contained in Table 2 can be found on p. 15 of Work Paper GAD-WP1. Staff's objective with Table 2 is to show revenue requirements far enough in the future to identify all expenses proposed by APS to be included in the EIC. Table 2 focuses on the Cholla Unit 1 Baghouse Project (EIC 1) for the same reasons as discussed under Table 1 and to be consistent with Table 1. The year 2010 was chosen for this illustration because it is the first year in which all Cholla Unit 1 Baghouse expenses are identified by APS.

The annual revenue requirement comes to$4,491,000, also shown in Table 2 and Work Paper GAD-WP1, pp. 2 and 15. Table 2 expenses such as a return on equity grossed-up to cover taxes, depreciation and property taxes are expenses that normally are recovered under the evidentiary processes embodied in general rate cases.

IV. EXPERIENCE IN OTHER JURISDICTIONS

Q. Please discuss the Cambridge Study and its relevance to the EIC being proposed by APS in this rate case.

A. In May 2006, Cambridge Energy Research Associates ("CERA") provided Staff with a preliminary overview of a study being developed to identify methods of recovering costs incurred in installing coal plant environmental improvement projects across the United States. The study is incomplete at this time, but it includes survey responses from 22 states (including Arizona). Respondents represent greater than 81 percent of the listed

MW winter coal generation capacity in the country. A follow-up call to CERA confirmed the relevancy of the data to APS' EIC. The completed study will be available in the near future according to CERA. CERA represented that the Commissions they were aware of either had no surcharges for environmental improvements to coal plants or only allowed surcharges designed to recover expenses that were *actually incurred* in implementing environmental improvement projects. Additionally, in the majority of cases such surcharges are replaced once the utility comes in for a general rate case. In other words, environmental surcharges currently only exist until incurred expenses can be rolled into a general rate case to be recovered through base rates. None of the survey respondents operate under a provision that allows for a "pre-collection" of funds before costs are incurred. The EIC contrasts with industry standards in that the EIC allows for the collection of revenues based upon projected rather than incurred costs.

Q. Has Staff reviewed the NARUC Study[11] of State Incentives included with Mr. Fox's Testimony?

A. Yes. Staff did review the NARUC report on state level incentives for the installation of pollution control equipment. Like the CERA report discussed above, this NARUC study was focused on coal fired power plants. The NARUC study contained responses to a survey obtained from 15 states. None of the 15 responding states has implemented a cost recovery mechanism for environmental improvement projects that is similar to the EIC proposed by APS. The NARUC report cited Wisconsin as a state that has been particularly innovative in the area of financing environmental improvements because of legislation enacted in 2003. However, the legislation enacted in Wisconsin calls for a bond financing scheme that is quite different from APS' proposed EIC.

[11] *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).

V. OTHER FACTORS SUPPORTING STAFF'S RECOMMENDATION

Q. Does Staff have additional reasons for its position on the EIC?

A. Yes. APS' responses to Data Requests MR 1-5 and MR 1-6 indicate that APS will continue to book EIC-related projects as increases to rate base for tax purposes. This conclusion is based upon APS' statement that environmental investments which are capitalized will be subject to property taxes. Therefore, a part of property taxes associated with plant would be recovered through base rates and another part would be recovered through the EIC. Each year when APS applies to reset the EIC, it would be Staff's responsibility to verify that the property taxes are allocated appropriately in order to avoid double recovery. The complexity of this task would be compounded should a true up be required between estimated and actual expenses.

APS' responses to Staff Data Requests MR 1-5 and MR 1-6 indicate that, for tax purposes, EIC-related plant will continue to be booked as capitalized plant. It appears that APS would have to create a parallel track for the accounting of EIC-related projects. APS states that the benefits of the EIC approach are the timely recovery of these expenses, sooner implementation of environmental improvements and annual recovery of these capital projects.[12] Unfortunately, under APS' approach Arizona ratepayers would be pre-funding projects that could be constructed later than expected, and at different costs than were originally projected. APS' revisions to the EIC discussed in its response to Staff Data Request MJR 3-5 is an example of why Staff is concerned about using estimated data to fund environmental improvement projects. The updated capital expenditures for the Cholla Plant are $160 million, an increase of $25 million over APS' original proposal. Furthermore, APS identified six additional EIC-related projects that must be added to the EIC. The additional projects are estimated to add approximately $83 million to the

[12] APS' response to Staff Data Request No. MJR 6-1

updated $160 million, for a total of approximately $243 million.[13] In other words, project costs increased $108 million, or 80 percent, in six months compared to data filed by APS on January 31, 2006. Staff recognizes that APS includes a true-up mechanism in the EIC, including interest, but the reality is that APS would construct EIC-related plant using ratepayers - not investors or bond financed - money up front. Staff queried APS about the need for creating pre-construction funds for planned voluntary emissions reduction projects.[14] APS acknowledged that pollution control bonds have been used in the past to finance environmental pollution control projects. It was also acknowledged that pollution control bonds are less costly than taxable financing, but as pointed out by APS, the interest on these bonds is passed along to ratepayers. It is not clear to Staff that the EIC will result in interest expense savings because the proposed EIC includes a provision to pass along an interest expense component to ratepayers. Attachment 1 clearly shows that the EIC interest component is based upon the cost of long term debt (similar to the cost of pollution control bonds). Also, the true-up mechanism adds another interest component to the EIC. At this time Staff can not determine with any certainty that total interest charges will be less under the EIC compared to interest charges incurred with pollution control bonds. Additionally, under the proposed EIC, APS' ratepayers would not receive the tax benefit of pollution control bonds.

Q. The above answer refers to interest expense related to the proposed true up mechanism. Please explain.

A. APS is proposing to include interest as a part of any under or over collection identified in the true-up process.

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[13] APS' response to Staff Data Request No. MJR 3-5, Attachment APS 10399
[14] Staff Data Request No. MJR 6-1

Q. Some parties to this case may view the EIC as a mechanism that is conceptually similar to customer advances for construction. Do you agree with this analogy?

A. No. There are significant differences in concept and application between customer advances for construction ("CAC") and the EIC proposed by APS. In many cases, CACs are refundable, and the FERC has established Account 252 to accommodate a refund provision. Even in cases where non-refundable contributions are made by or on behalf of customers for customer-initiated plant projects, the contribution is usually based on the difference between the embedded investment and estimated incremental revenue per customer, and the estimated cost of the project. These allowances traditionally remove or substantially offset depreciation, O&M and property tax expenses. There is no offset to these expenses in the EIC. Additionally, CACs are generally paid within a short time period of when the related construction expenditures are made.

Q. What other factors contributed to Staff's recommendation that the Commission reject the EIC proposed by APS?

A. Staff is concerned about three additional aspects of the proposed EIC: 1) collecting revenues from customers based on estimated data; 2) the EIC creating the need for a more complex auditing process; and, 3) the potential for billing customers for EIC-related expenses without Commission approval.

1. <u>Estimated Data</u>

Under APS' proposal EIC collections would begin in January 2007 based upon costs that would not have been incurred until, at the earliest, sometime during 2007. Furthermore, the collections would be based largely upon estimated data. Nearly all of the originally reported $135 million in capital expenditures is based upon estimated, rather than actual, capital expenditures (Work Paper GAD-WP1, p.59). Even after capital expenditures were updated to approximately $243 million, estimated costs still represent 97 percent of total costs (APS' response to Data Request MJR 3-5, Attachment APS 10399). And as discussed earlier in Staff's Testimony, estimated costs for the Cholla Plant increased 80 percent in as little as six months from the January, 2006 filing date. Accurately estimating the cost of environmental improvement projects is, at best, an inexact science.

2. <u>Auditing</u>

Another factor influencing Staff's recommendation that the Commission reject the proposed EIC is that Staff would be required to audit EIC-related fund balances by project. For example, none of the originally reported $135 million in capital expenditures should be included in Test Year rate base. APS provided what initially appeared to be a validation of this conclusion by Staff in its response to Staff Data Request MJR 3-4. As a follow up, APS was asked to corroborate that the referenced project costs are not included in the Test Year AFUDC portion of Cost of Service rate base (Staff Data Request MJR 6-4). APS responded that $66,000 of the referenced project costs is included in the Test Year AFUDC portion of Cost of Service rate base. The "double counted" $66,000 rate base/CWIP is de minimis in this rate case. However, the issue is the introduction of yet another rate base revenue producing component, which increases the complexity of tracking plant-driven revenue requirement requests in future rate cases. Furthermore, the EIC would remove eligible environmental improvement plant from general rate case review and constraints. For example, cost recovery of these expenses would be passed on to ratepayers without regard to Test Year constraints.

Q. Verifying APS' Power Supply Adjustor ("PSA") revenues and expenses appears to be a manageable task. Why would the EIC be any different?

A. Verifying APS' PSA revenues and expenses is a manageable project because closing figures from month 1 provide a continuous and verifiable audit trail for month 2. Auditing the EIC will be a far more complex process, because general rate cases are not monthly events and the "double counted" $66,000 mistake discussed above could be compounded into millions of dollars and multiple projects between general rate cases.

3. **<u>Billing The EIC Without Commission Approval</u>**

According to Attachment GAD-2, p.2, Staff would have to review the proposed EIC annually after March 15, 2008 when APS files for the reset of the EIC. In the absence of Commission approval before July 1 of the applicable billing period, APS will automatically start billing customers the proposed EIC as though it had been approved by the Commission. Staff believes that it is inappropriate to implement customer charges without Commission approval. A subsequent true-up mechanism does not properly address the issue of possibly passing on charges to ratepayers that are incorrect and higher than they should be. Even if the Commission decides to reject Staff's recommendation and approve the EIC, this automatic approval provision of the EIC should be removed.

Q. Has Staff considered the financial impact of rejection of the EIC on APS?

A. Yes. Staff is well aware of the financial issues APS is currently confronting. However, APS has identified customer growth and increased fuel costs as the primary drivers behind their current need for a rate case.[15] APS projects that capital investments in the amount of approximately $1.4 billion[16] will be needed to expand its transmission and distribution facilities to serve its native load for the years 2007 through 2009. This amount dwarfs the

[15] See the direct testimony of APS witness Steven Wheeler.
[16] EZF, p.19, line 2

$243 million EIC. Since the EIC does not address the fundamental issues (as identified by APS) that are affecting APS' financial situation (customer growth and fuel costs) Staff does not believe that its rejection will place a significant financial burden on the company.

Q. Has Staff considered the environmental impact of rejection of the EIC?

A. Unfortunately, forecasting the environmental benefits of approval of the EIC would be a difficult task. APS has not provided estimates of the environmental benefit that could be associated with the EIC. Additionally, it does not appear as though APS or any other entity has attempted to calculate such benefits.[17]

Q. Please summarize Staff's recommendation.

A. The Commission should reject APS' request to implement the Environmental Improvement Charge for the following reasons:

- The EIC would collect revenues from ratepayers based predominantly upon estimated rather than incurred costs.
- The EIC appears to be unique. Staff is not aware of any jurisdiction that employs a mechanism with the same characteristics as the EIC.
- The EIC would include costs that will not be incurred for several years beyond the Test Year.
- The EIC would include funding for projects before they are mandated to be installed on APS' system.
- Regulatory mandates typically build in construction lead times to provide industry sufficient time to comply with mandated regulatory requirements.

[17] See response to MR 1-1(b)

- The EIC is derived based upon multiple year revenue requirements that increase the complexity of auditing the charge in the context of future general rate cases and annual EIC reset proceedings.
- The effect of the EIC on APS' interest expense is unclear.
- The annual reset of the EIC could be implemented without Commission approval under APS' proposal.
- The EIC does not address the fundamental financial challenges that APS has identified.
- The environmental impact of implementing the EIC is unclear.

Q. Does this conclude your Direct Testimony?

A. Yes, it does.

EIC 1 Cholla Unit 1 Baghouse
2005-2011
($000s)

GAD_WP1

	2007 January	2007 February	2007 March	2007 April	2007 May	2007 June	2007 July	2007 August	2007 September	2007 October	2007 November	2007 December
Capital Expenditures	253	253	253	253	253	253	253	253	253	253	253	253
Net Plant												
Beginning Balance (1)												
CWIP	20,637	20,890	21,143	21,397	21,650	21,903	22,156	22,409	22,662	22,916	23,169	23,422
AFUDC E/D based on Pre-Total	-	-	-	-	-	-	-	-	-	-	-	-
Total CWIP/AFUDC	20,637	20,890	21,143	21,397	21,650	21,903	22,156	22,409	22,662	22,916	23,169	23,422
Gross Plant in Service												
Accumulated Depreciation												
Net Plant in Service												
Tax Depreciation												
Cumulative Deferred Tax												
Rate Base												
Revenue Requirement												
1 Interest Expense	42	43	43	44	44	45	45	46	46	47	48	48
2 Return on Equity - Tax Gross Up	177	179	181	183	186	188	190	192	194	196	199	201
Depreciation	-	-	-	-	-	-	-	-	-	-	-	-
Property Taxes	-	-	-	-	-	-	-	-	-	-	-	-
O&M	-	-	-	-	-	-	-	-	-	-	-	-
Monthly Revenue Requirement	219	222	225	227	230	233	235	238	241	243	246	249
Annual Revenue Requirement												*2,808*

Cap. Expenditures	
2005	3,147
2006	15,571
2007	3,038
2008	-
2009	-
2010	-
2011	-

Depreciation Life	
Years	25

Monthly Tax Depreciation Rates	
2008	0.313%
2009	0.602%
2010	0.567%
2011	0.515%

O&M Expense	
Monthly	60

(1) $20,637 x [2.46%/12-months] = $42.31

(2) $20,637 x [6.27%/12-months] x 1.6407 = $176.91

ATTACHMENT 1

BEFORE THE ARIZONA CORPORATION COMMISSION

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

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND TO AMEND DECISION NO. 67744.	DOCKET NO. E-01345A-05-0816

DIRECT

TESTIMONY

OF

BARBARA KEENE

PUBLIC UTILITIES ANALYST MANAGER

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

AUGUST 18, 2006

TABLE OF CONTENTS

APPENDICES

EXECUTIVE SUMMARY
ARIZONA PUBLIC SERVICE COMPANY
DOCKET NO. E-01345A-05-0816

This testimony makes recommendations regarding funding for renewable resources, net metering, and green pricing tariffs. Those recommendations are the following:

1. The amount for renewables in System Benefits should continue to be $6,000,000.
2. The Environmental Portfolio Standard adjustor rate and caps should be increased to recover an additional $4.25 million for the EPS Credit Purchase Program.
3. The proposed net metering tariff, EPR-5, should be approved with the following modifications:
   a. A bi-directional meter should not be required.
   b. The limit on facility size should be increased to 100 kW.
   c. The participation of customers should not be limited by rate schedule.
   d. In the definition of Pilot Program, the phrase "with Commission approval" should be added to the end of the sentence that indicates that APS reserves the right to modify the rate schedule.
4. Green Power Block Schedule (GPS-1) and Green Power Percent Schedule (GSP-2) should be approved as proposed by APS.

This testimony also responds to Commissioner Mayes' July 17, 2006, letter regarding the Renewable Energy Standard and Tariff.

INTRODUCTION

Q. Please state your name and business address.

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

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

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

Q. As part of your employment responsibilities, were you assigned to review matters contained in Docket Nos. E-01345A-05-0816?

A. Yes.

Q. What is the subject matter of your testimony?

A. My testimony will address renewable energy for Arizona Public Service ("APS"); in particular, funding for renewable resources, net metering, and green pricing tariffs. This testimony also responds to Commissioner Mayes' July 17, 2006, letter regarding the Renewable Energy Standard and Tariff ("REST").

FUNDING FOR RENEWABLE RESOURCES

Q. What is the Environmental Portfolio Standard?

A. The Environmental Portfolio Standard ("EPS"), embodied in A.A.C. R14-2-1618, was approved by the Commission in 2001. The EPS requires load-serving entities to derive a portion of the retail energy they sell from solar resources or environmentally friendly renewable electricity technologies. The portfolio percentage increases annually. It was 1.00 percent in 2005 and became 1.05 percent in 2006, with at least 60 percent from solar resources.

Q. Did APS meet its EPS requirement in 2005?

A. No. According to APS' annual EPS report required under A.A.C. R14-2-1618(D), APS' total retail sales in 2005 totaled 26,477,551 MWh. Because the EPS requirement was 1.00 percent in 2005, APS was required to provide 1.00 percent of its retail sales from renewable resources. Therefore, the EPS target was 264,776 MWh (1.00 percent of 26,477,551 MWh). Since APS had 36,958 MWh from renewable resources in 2005, it met 14 percent of its 2005 EPS requirement (36,958 MWh = 14 percent of 264,776 MWh).

Q. What did APS do in regard to renewable resources in 2005?

A. During 2005, APS installed new solar generation capacity (both photovoltaic and solar trough); awarded contracts for wind, biomass, and biogas resources; provided off-grid solar services, continued its Solar Partners "green pricing" program; explored development of geothermal and manure resources; offered the EPS Credit Purchase Program; and purchased EPS credits from other providers.

Q. How is the EPS funded?

A. The costs of the EPS are recovered through the System Benefits Charge and through the Environmental Portfolio Surcharge, approved by Decision No. 63354 on February 8, 2001, and established as an adjustment mechanism by Decision No. 67744 (APS rate case settlement agreement). The surcharge is currently set at $0.000875 per kWh with monthly caps per service of $0.35 for residential customers, $13.00 for non-residential customers, and $39.00 for non-residential customers with demands of 3,000 kW or more.

Q. How much funding did APS have for renewable resources in 2005?

A. In 2005, APS received a total of $13,780,276 in revenue for renewable resources, including $7,320,775 through the EPS adjustor, $6,000,000 in System Benefits, $285,345 from its Solar Partners program, and $174,156 from off-grid revenue. During the test year, APS received $7,229,172 through the EPS adjustor. Total expenditures for renewable resources in 2005 were $14,039,708.

Q. What does Staff recommend regarding funding for renewables in the System Benefits Charge?

A. There is currently $6,000,000 for renewables in the System Benefits Charge. Staff recommends that the amount continue to be $6,000,000.

<u>**EPS Credit Purchase Program**</u>

Q. Please describe the EPS Credit Purchase Program.

A. APS began its EPS Credit Purchase Program in 2002. Through the program, customers install renewable energy systems on their properties, and APS reimburses them for a portion of the costs of the systems. APS can then use the renewable energy credits associated with the systems to help meet its EPS requirements.

Q. What needs to be done regarding funding for the EPS Credit Purchase Program?

A. Decision No. 67744 provided that renewable programs that directly involve APS retail customers must be submitted to the Commission for approval. When the Commission approved the EPS Credit Purchase Program in Decision No. 68668 (April 20, 2006), APS was ordered to increase its allocation for the program by an additional $4.25 million. Decision No. 68668 ordered that "any additional funds put into the credit purchase program by APS at the direction of the Commission shall be recovered in rates as part of APS' ongoing general rate case."

Q. How does Staff propose to handle the additional $4.25 million allocation in the rate case?

A. Staff recommends that the EPS adjustor rate and caps be increased to recover an additional $4.25 million. The increased rate and caps will be discussed in Staff rate design testimony to be filed on September 1, 2006.

NET METERING

Q. What is net metering?

A. Net metering allows customers to use their own generation to offset their consumption over a billing period. In effect, customers receive retail prices for the electricity they generate. Without net metering, the utility purchases the electricity that flows to the utility at its avoided cost for generating or acquiring electricity in the wholesale market. According to the U.S. Department of Energy Green Power Network, net metering is offered in more than 35 states.

Q. What has APS proposed in regard to net metering?

A. APS has proposed a new rate schedule EPR-5, Rates for Renewable Resource Facilities of 10 kW or Less for Partial Requirements.

Q. How are renewable projects currently compensated for electricity that flows to the utility?

A. Customers with those projects are compensated through the purchase rates included on EPR-2 (100 kW or less) or EPR-4 (10 kW or less). The purchase rates, updated annually, are the same on both schedules and are based on APS' estimated avoided energy costs. EPR-2 contains a monthly service charge.

Q. Please describe EPR-5.

A. EPR-5 would be a three-year pilot program for renewable resource generation facilities with a nameplate rating of 10 kW or less. A bi-directional meter would be provided to a customer. The customer would receive the full retail value of the energy component (charges assessed on a kWh basis) of its bundled Standard Offer Service Rate for the power fed into the system from the customer's generator. When the customer-owned generation output exceeds the customer's total usage in a given month, the customer would receive a kWh credit for the excess generation output on the next monthly bill. Any remaining kWh credit amount would be zeroed out in the customer's last bill of the calendar year or when the customer is shut off.

Eligible renewable resources would be those resources included in the EPS rules as may be modified. Retail rate schedules under the program would be limited to E-12, ET-1, ET-2, ECT-1R, and ECT-2 for residential customers and E-32 and E-32TOU for general service customers with monthly maximum demands of 20 kW or less. The pilot program would be capped at a total of 15 MW of capacity.

EPS funding would be used to recover the metering costs, billing system modification cost, and revenue loss associated with the program. According to APS' response to data request BEK 8-4, APS estimates the billing system modification cost to be about $848,500 and take about six to eight months to implement. Revenue loss would be calculated as the per kWh charges of the retail rate less APS' avoided fuel and purchased power cost.

Q. What does Staff recommend in regard to the proposed EPR-5?

A. Staff recommends approval of EPR-5 with modifications.

Q. What are Staff's proposed modifications to EPR-5?

A. The first modification is that a bi-directional meter not be required. Two standard meters (one measuring electricity going out and one measuring electricity coming in) could be used at lower cost than for a bi-directional meter. Per APS' response to data request BEK 8-2, the total installed cost for a bi-directional meter is $483.30 with maintenance cost of $15.97 per year. The installed cost of a standard meter is $102.63 and $1.18 per year for maintenance. Since one meter would already be in place, the savings from using two standard meters in place of a bi-directional meter would be $380.67 for each installed meter and $14.79 per year for maintenance of each meter.

In addition, the proposed EPR-5 contains a statement that "The Company" would provide a meter. APS should modify the statement to indicate that a meter would be provided but not imply that ratepayers would not be paying for it.

Q. Should APS recover "revenue loss" associated with the program through EPS funds?

A. Yes. APS should recover revenue loss associated with the program through EPS funds. This situation is analogous to when APS contracts to buy renewable energy in the wholesale market. The costs of the renewable energy that are below or at the market price of conventional generation are included in the calculations of the Power Supply Adjustor. APS is allowed to recover the amount above the market price of conventional generation through EPS funds.

Q. Does Staff agree with the method that APS proposes to use to calculate the revenue loss?

A. Yes. APS described the method of calculation in response to Staff's data request BEK 8-5. The lost revenues would be derived by applying the average kWh charges in the customer's otherwise applicable rate schedule to the kWh loss. The kWh charges would be for all services, including the EPS adjustor.

Q. Does Staff agree with the 10 kW limit on facility size?

A. No. Staff recommends that the limit on facility size be increased to 100 kW. This would allow larger projects to participate, while continuing to not allow a few projects to consume all of the funds.

Q. Does Staff agree with APS that only customers on specific rate schedules should be allowed to participate in the program?

A. No. Staff recommends that participation of customers should not be limited by rate schedule.

Q. Does Staff propose any other modifications to EPR-5?

A. Yes. In the definition of Pilot Program on EPR-5, APS indicates that it reserves the right to modify the rate schedule. The phrase "with Commission approval" should be added to the end of the sentence.

GREEN PRICING TARIFFS

Q. What is green pricing?

A. According to the U. S. Department of Energy Green Power Network, green pricing is an optional service that allows customers an opportunity to voluntarily support a greater level of investment in renewable energy technologies. Participating customers pay a premium on their electric bills to cover the incremental cost of the additional renewable energy. More than 600 utilities in the country offer a green pricing option.

Q. Does APS currently have a green pricing program?

A. Yes. APS has offered its Solar Partners Program (SP-1) since 1997. Through the program, customers pay a premium of $2.64 per month for a block of 15 kWh of solar energy. This equates to $0.176 per kWh in addition to the customer's current rate schedule.

Q. What has APS proposed in regard to green pricing?

A. APS has proposed freezing SP-1 and replacing it with two new rate schedules, Green Power Block Schedule (GPS-1) and Green Power Percent Schedule (GSP-2).

Q. Please describe GPS-1.

A. GPS-1 is similar to SP-1 in that customers would have the opportunity to buy blocks of electricity generated from renewable resources. The price would be $0.75 per month for each 25 kWh block. This equates to $0.03 per kWh in addition to the customer's current rate schedule. According to APS' response to Western Resource Advocates' data request WRA 1-1, the price represents the projected net cost of renewable energy above the cost of the conventional resource alternative. The renewable resources would include those resources eligible under the EPS rules as they are modified.

Q. Please describe GPS-2.

A. Under GPS-2, customers would choose a percentage of their electricity usage to come from renewable resources. There would be four options: $0.03 per kWh for 100 percent of the customer's service from renewable energy, $0.015 per kWh for 50 percent of the customer's service from renewable energy, $0.009 per kWh for 30 percent of the customer's service from renewable energy, and $0.003 per kWh for 10 percent from renewable energy. These prices would be in addition to the customer's current rate schedule. In effect, the prices all equate to $0.03 for a kWh of renewable energy.

Q. What does Staff recommend regarding GPS-1 and GPS-2?

A. Staff recommends that GPS-1 and GPS-2 be approved as proposed by APS.

RESPONSE TO COMMISSIONER MAYES' JULY 17, 2006 LETTER

Q. What did Commissioner Mayes request in her July 17, 2006, letter?

A. Commissioner Mayes requested that the parties to this Docket provide testimony on incorporating the Renewable Energy Standard and Tariff ("REST") into this case.

Q. What is the REST?

A. The proposed REST rules are intended to replace the current EPS rules. The Commission, in Decision No. 68566 (March 14, 2006), ordered that a rulemaking process begin for the REST rules.

Q. If the REST rules were to become effective, what would it mean for APS?

A. APS would have to comply with specific requirements regarding renewable resources.

Q. What are the requirements that APS would have to follow?

A. The requirements of the REST rules, in their present form, are the following:

1. APS would meet an Annual Renewable Energy Requirement by obtaining Renewable Energy Credits. A Renewable Energy Credit would be created for each kWh derived from an Eligible Energy Resource.

2. The Annual Renewable Energy Requirement would be calculated each calendar year by applying the applicable annual percentage in the following table to the retail kWh sold by APS during that calendar year.

Table 1
Annual Renewable Energy Requirement

Calendar Year	Annual Percentage of Retail kWh Sales
2007	1.50
2008	1.75
2009	2.00
2010	2.50
2011	3.00
2012	3.50
2013	4.00
2014	4.50
2015	5.00
2016	6.00
2017	7.00
2018	8.00
2019	9.00
2020	10.00
2021	11.00
2022	12.00
2023	13.00
2024	14.00
After 2024	15.00

3. A percentage of the above annual requirements would come from Distributed Renewable Energy Resources as shown in the following table. Half of the

Distributed Renewable Requirement would come from residential applications and the remaining half from non-residential, non-utility applications. No more than 10 percent would come from non-utility owned generators that sell electricity at wholesale to utilities subject to the EPS rules.

Table 2
Distributed Renewable Energy Requirement

Calendar Year	Distributed Percentage of Annual Renewable Energy Requirement
2007	5
2008	10
2009	15
2010	20
2011	25
After 2011	30

4. Eligible Energy Resources would be applications of the following technologies:
   a. biogas electricity generators;
   b. biomass electricity generators;
   c. hydropower facilities that were in existence prior to 1997 and have either a capacity increase or are used to firm or regulate the output of other eligible, intermittent renewable resources;
   d. new hydropower generators of 10 MW or less;
   e. fuel cells that use only renewable fuels;
   f. geothermal generators;
   g. hybrid wind and solar electric generators;
   h. landfill gas generators;
   i. solar electricity resources;

j. wind generators; and

k. Distributed Renewable Energy Resources.

5. Distributed Renewable Energy Resources would be applications of the following technologies that are located at a customer's premises:

a. biogas electricity generators;

b. biomass electricity generators;

c. geothermal generators;

d. fuel cells that use only renewable fuels;

e. new hydropower generators of 10 MW or less;

f. solar electricity resources;

g. commercial solar pool heaters;

h. geothermal space heating and process heating systems;

i. renewable combined heat and power systems;

j. solar daylighting;

k. solar heating, ventilation, and air conditioning;

l. biomass thermal systems;

m. biogas thermal systems;

n. solar industrial process heating and cooling;

o. solar space cooling;

p. solar space heating;

q. solar water heaters; and

r. wind generators of 1 MW or less.

6. For Distributed Renewable Energy Resources, one Renewable Energy Credit would be created for each 3,415 British Thermal Units of heat produced by technologies listed in number 5.l-q above.

7. Up to 20 percent of an Annual Renewable Energy Requirement could be met with Renewable Energy Credits derived from "manufacturing partial credits" if APS or an affiliate made a significant investment in a solar electric manufacturing plant located in Arizona or provided incentives to locate a solar electric manufacturing facility in Arizona. The credits would be equal to the nameplate capacity of the solar electric generators produced and sold in a calendar year times 2,190 hours.
8. Extra credit multipliers as included in the EPS rules would not be applicable for Eligible Renewable Energy Resources installed after December 31, 2005.
9. APS could ask the Commission to preapprove agreements to purchase energy or Renewable Energy Credits from Eligible Energy Resources.
10. APS would develop a customer self-directed renewable energy option.
11. APS would file annual reports.

Q. How would the EPS Adjustor rates be changed for APS to meet those requirements.

A. In response to Staff's data request BEK 12-3, APS has estimated that the rate and caps contained in the Sample Tariff (within the REST rules) would have resulted in revenue of about $28.52 million in 2005. The Sample Tariff consists of a monthly assessment of $0.004988 per kWh with monthly caps per service of $1.05 for residential customers, $39.00 for non-residential customers, and $117.00 for non-residential customers with demands of 3,000 kW or more. However, this rate and these caps would not be used for APS.

Q. Why would APS use a different rate and different caps than those contained in the Sample Tariff?

A. Paragraph 63 of the settlement agreement approved by Decision No. 67744 provides that any change in EPS funding requirements shall be collected from APS' customers in a manner that maintains the proportions between customer categories embodied in the current EPS surcharge. The proposed rate in the Sample Tariff would be 5.7 times the current rate, and the proposed caps would be 3 times the current caps. Maintaining the proportions between customer categories requires that the rate and caps be multiplied by the same number.

Q. How would the rate and caps be set so as to maintain the proportions between customer categories?

A. APS has estimated, in response to Staff's data request BEK 12-4, that multiplying the current rate and caps by 3.8 would result in a similar level of revenue ($28.59 million) and maintain the proportions between customer categories.

Q. How much of an increase over current EPS revenues would result from the changes to the rate and caps?

A. Complying with the proposed REST rules would require an increase of about $21.36 million over current EPS revenue.

Q. What would be the resulting rate and caps?

A. The rate would be $0.003325 per kWh with monthly caps per service of $1.33 for residential customers, $49.40 for non-residential customers, and $148.00 for non-residential customers with demands of 3,000 kW or more. The EPS Adjustor would be modified to incorporate this rate and these caps.

Q. Would there be any other cost recovery considerations?

A. Yes. The EPS adjustor would recover only the costs of renewable resources in excess of the market cost of conventional generation. In addition, APS could apply to the

Commission to increase its EPS funding as outlined in paragraph 64 of the settlement agreement approved by Decision No. 67744.

SUMMARY OF STAFF RECOMMENDATIONS

Q. Please summarize Staff's recommendations.

A. Staff's recommendations are as follows:

1. The amount for renewables in System Benefits should continue to be $6,000,000.
2. The EPS adjustor rate and caps should be increased to recover an additional $4.25 million for the EPS Credit Purchase Program.
3. EPR-5 should be approved with the following modifications:
   a. A bi-directional meter should not be required.
   b. The limit on facility size should be increased to 100 kW.
   c. The participation of customers should not be limited by rate schedule.
   d. In the definition of Pilot Program, the phrase "with Commission approval" should be added to the end of the sentence that indicates that APS reserves the right to modify the rate schedule.
4. GPS-1 and GPS-2 should be approved as proposed by APS.

Q. Does this conclude your direct testimony?

A. Yes, it does.

RESUME

BARBARA KEENE

Education

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

Additional Training

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

Employment History

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

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

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

Testimony

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Arizona Public Service Company Emergency Rate Case (Docket No. E-01345A-06-0009), Arizona Corporation Commission, 2006; testimony on bill impacts.

Publications

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

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

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

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

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

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

Reports

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

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

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

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

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

BEFORE THE ARIZONA CORPORATION COMMISSION

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

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND TO AMEND DECISION NO. 67744.)	DOCKET NO. E-01345A-05-0816

DIRECT

TESTIMONY

OF

JERRY D. ANDERSON

PUBLIC UTILITIES ANALYST

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

AUGUST 18, 2006

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EXECUTIVE SUMMARY
ARIZONA PUBLIC SERVICE COMPANY
DOCKET NO. E-01345A-05-0816

Staff's testimony addresses two main topics. First, it addresses Demand-Side Management ("DSM") at the Arizona Public Services Company ("APS" or the "Company") and how DSM programs are funded. Staff recommends that net lost revenue adjustments for DSM programs be disallowed and that the Company should be rewarded for DSM savings through a performance incentive. Staff does not oppose APS' proposal to accrue interest on the Demand-Side Management Adjustment Charge account balance. Secondly, Staff's testimony on APS' System Benefits Charge provides detail and specific recommendations regarding the System Benefits components. Staff recommends that the total of System Benefits should be $49,191,690.

INTRODUCTION

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

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

Q. Briefly describe your responsibilities as a Public Utilities Analyst.

A. In my capacity as a Public Utilities Analyst, I provide recommendations to the Commission on electric and gas rate filings, purchased power and fuel adjustment matters, Demand-Side Management ("DSM") programs, and other energy-related matters as assigned.

Q. Please describe your educational background and professional experience.

A. I graduated from Western Kentucky University, Bowling Green, Kentucky, receiving a Bachelor of Science degree with double majors in Economics and Business Management. My course of studies included classes in micro-economic price theory, macro-economic theory and business cycles, accounting, management, and data processing. I earned an MBA degree from Xavier University, Cincinnati, Ohio, with an area of concentration in multinational business. After working as a computer programmer for a major oil and refining company, I joined the Rate and Economic Research Department of the Cincinnati Gas & Electric Company (Cinergy/Duke Energy) where I applied my computer skills to rate research, load research, and load forecasting. I was promoted to a succession of more responsible positions over 15 years there and ultimately was named Economist in charge of all electric sales and load forecasting activities. In this position I was responsible for constructing econometric models of the regional economy for the purpose of forecasting electric system peak demands and sales by class of service for a three-state service territory. Since that time, I have served as a consultant and branch manager of two consulting firms, providing services to such clients as the State of Arizona and the Los Alamos National Laboratories, Los Alamos, New Mexico. More recently, I have held statistical analysis and computer system development positions in the government sector where I was involved with Y2K remediation efforts and interstate unemployment systems. In 2005, I was employed by the ACC as a Public Utilities Analyst. I have participated in various classes on general regulatory and utility issues, including the New Mexico State University's "Basics" class and the Michigan State University's "Camp NARUC" program. I am a member of the National Association for Business Economics.

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

A. I will address the System Benefits Charge ("SBC") in this rate case and the details of the Arizona Public Service Company ("APS or the "Company") DSM programs, both as a component of the SBC and in the broader overall perspective of APS DSM programs.

Q. Have you reviewed relevant portions of APS' filing in Docket No. E-01345A-0816 submitted by the Company in this case?

A. Yes, I have.

SUMMARY OF TESTIMONY AND RECOMMENDATIONS

Q. Briefly summarize how your testimony is organized.

A. My testimony is organized into two main sections. The first section discusses DSM programs at APS and how they are funded. The second section defines System Benefits and identifies each component of the System Benefits Charge in this case. In this section, I will discuss the DSM and low income components of the System Benefits Charge in some detail.

Q. Please summarize your recommendations regarding DSM.

A. Staff recommends that net lost revenue adjustments for DSM programs be disallowed and that the Company should be rewarded for DSM savings through a performance incentive. Staff does not oppose APS accruing interest in the Demand-Side Management Adjustment Charge ("DSMAC") account.

Q. Please summarize your recommendations regarding System Benefits Charge for APS.

A. Staff recommends that the System Benefits Charge be $49,191,690.

DEMAND-SIDE MANAGEMENT

<u>Current APS DSM Programs</u>

Q. What Commission-approved DSM programs did APS conduct during the test year?

A. According to semi-annual DSM reports filed with the Commission, APS conducted the following DSM programs during the test year:

1. Residential Existing Homes Heating, Ventilation, and Air Conditioning ("HVAC") Program (replaced by the Residential HVAC Efficiency Program)
2. Residential New Home Construction Program (replaced by the Residential New Construction Program)
3. Residential Consumer Products Program
4. Energy-Wise Assistance Program (replaced by the Energy-Wise Low Income Weatherization Program)

Q. Do you expect that these DSM programs in operation during the test year will continue in their present form into the future?

A. No. Various Commission decisions during and after the test year approved new DSM programs that will enhance or replace existing APS DSM programs or add to APS' DSM programs. These decisions require a significant expansion of DSM activities at APS. They are a result of Commission approval or interim approval, with modifications, of DSM programs APS proposed in its application for its Demand-Side Management Program Portfolio Plan ("Portfolio Plan") filed with the Commission on July 1, 2005, and its Energy Wise Low Income Weatherization program filed with the Commission on June 6, 2005. Both filings were in compliance with provisions of the Settlement Agreement between APS and the Commission in Decision No. 67744.

Q. Which specific Commission decisions brought about the change and expansion of DSM activities at APS during and after the test year?

A. Decision No. 68064, August 17, 2005, approved the Consumer Products Program. Decision No. 68488, February 23, 2006, granted interim approval for six non-residential DSM programs that were included in APS' Portfolio Plan. The six programs were approved with some modifications and are as follows:

1. Schools Program
2. Non-Residential Existing Facilities Program
3. Non-Residential New Construction and Major Renovation Program
4. Small Non-Residential Program
5. Non-Residential Builder Operator Training Program
6. Non-Residential Energy Information Services Program

Decision No. 68648, April 12, 2006, granted approval for two residential DSM programs that were included in APS' Portfolio Plan. The following two programs were approved with some modifications:

1. Residential New Construction Program
2. Residential HVAC Efficiency Program

Decision No. 68647, April 12, 2006, granted Commission approval of APS' Energy Wise Low Income Weatherization program which was modified and expanded to include a bill assistance component.

Q. Were the DSM programs included in the Portfolio Plan intended to intensify DSM efforts by APS as required in the Settlement Agreement?

A. Yes.

Q. Did some of the DSM programs approved after the test year replace programs that were in effect during the test year?

A. Yes. The Residential HVAC Efficiency Program expanded and replaced the earlier Residential Existing Homes HVAC Program. One of the primary differences in the two programs is that the newer program offers incentives to homeowners for equipment replacement, quality installation, maintenance, and repair by qualified contractors. The Residential New Construction Program expanded and replaced the earlier Residential New Home Construction Program. One of the primary differences between these programs is that the newer program offers incentives for builders to construct energy-efficient new homes. The Energy Wise Low Income Weatherization program is an expansion and modification of the Energy-Wise Assistance Program.

APS DSM Spending

Q. What has been the level of DSM spending during the periods following the Settlement Agreement contained in Decision No. 67744, April 5, 2005?

A. According to semi-annual DSM reports filed by APS, the following levels of DSM spending were recorded:

January – June, 2005	$ 953,501
July – December, 2005	$2,257,280

Q. What level of APS spending on DSM is required by the Settlement Agreement?

A. The Settlement Agreement requires at least $16 million to be spent on DSM per year.

Q. Is the $16 million per year spending requirement only for the years 2005 – 2007 or does it continue beyond 2007?

A. The $16 million annual spending requirement included in the Settlement Agreement remains in effect until the Commission acts to change or cancel it.

Q. Did APS meet the spending requirement imposed by the Settlement Agreement in 2005?

A. No. Because the Settlement Agreement was effective in April 2005, APS was obligated to spend only $10 million in 2005. However, this level of spending was not achieved in 2005 since most of the programs were not approved until 2006.

Cost Recovery for DSM Expenditures

Q. How does APS recover its costs for DSM programs?

A. The funding structure for DSM was established in the Settlement Agreement. The funding comes in both base rates and through an adjustor. According to the Settlement

Agreement, $10 million of DSM funding is included in base rates. The balance, a minimum of $6 million per year, is to be collected by an adjustor mechanism referred to as the DSMAC. A provision of the Settlement Agreement also states that if APS does not spend at least $30 million on approved DSM from 2005 through 2007, the unspent amount of the $30 million base rate allowance ($10 million per year) would be credited to the DSMAC account balance.

Q. How does the DSMAC work?

A. As approved in Decision No. 67744, the DSMAC is an adjustment mechanism consisting of an account where the costs for pre-approved DSM programs in excess of those prescribed to be in base rates are recovered. For example, DSM costs in excess of the $10 million to be included in base rates each year would be recorded in the DSMAC account. Such costs are to be recorded for each program by APS as the costs are incurred. By January 31 of each year, APS is to file data with Staff needed to set the per kWh DSMAC rate. APS is to document the costs placed in each DSM adjustment subaccount during the previous year and the revenue received from ratepayers through the per kWh charge during the previous year. The per kWh charge for the next year is to be calculated by dividing the account balance by the number of kWh used by customers in the previous year. General Service customers who are billed on a demand rate are to pay a per kW charge instead of a per kWh charge. To calculate the per kW charge, the account balance is to be first allocated to the General Service class based upon the number of kWh consumed by that class. General Service customers that are not demand billed are to pay the DSMAC adjustor rate on a per kWh basis. The remainder of the account balance allocated to the General Service class is to be divided by that kW billing determinant for the demand-billed customers in that class to determine the per kW DSM adjustor charge. The DSMAC adjustor rate is to be reset in this manner each year on March 1.

Q. What charges can be included in the DSMAC account?

A. Eligible DSM-related items in excess of the $10 million included in base rates may be included in the DSMAC account. This includes Commission-approved energy efficiency DSM programs, low income bill assistance, and a performance incentive.

Q. How are residential customers billed?

A. For residential customers, the DSMAC adjustment, as a charge per kWh, is combined with the Environmental Portfolio Standard ("EPS") adjustment and included on all customer bills as a separate line item labeled "Environmental Benefits Surcharge."

Q. Should the DSMAC account accrue interest?

A. Currently, the DSMAC account does not accrue interest. In the testimony of APS witness David J. Rumolo, pages 15-16, APS has proposed the inclusion of interest earnings on the unrecovered DSMAC account balance. Staff does not oppose the accrual of interest in the DSMAC account. Staff does not oppose APS' proposal that the balance in the DSMAC account should accrue the 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.

Q. What is Staff's position on APS' proposal for a proforma adjustment to test year data to recover net lost revenue resulting from DSM programs?

A. Staff recommends disallowance of APS' proposed $4,907,000 proforma adjustment for net lost revenue resulting from DSM programs.

Q. What is Staff's rationale for disallowance of the net lost revenue adjustment proposed by APS?

A. Staff's position is that APS should be compensated for its efforts to make DSM programs available and for the savings achieved by successful DSM programs through a performance incentive. A performance incentive and an adjustment for net lost revenues are two separate approaches to compensating the utility. Staff sees these techniques as mutually exclusive where you would allow one of the approaches or the other, but not both.

Q. Does the Settlement Agreement provide for the recovery of a performance incentive resulting from successful DSM programs?

A. Yes, it does.

Q. What are some of the advantages of the performance incentive?

A. The performance incentive is appealing because it is based upon a share of the actual net benefits accruing from approved successful DSM programs. As such, it is an incentive that rewards a utility's performance in conducting successful DSM programs. If money were spent on a DSM program that did not result in energy efficiency savings, there would be no performance incentive paid.

Q. Did APS propose a performance incentive in its Portfolio Plan of DSM programs?

A. Yes, it did. APS proposed a 90 percent/10 percent split between customers and the company respectively of the total net benefits accruing from approved DSM programs. It further proposed that the incentive be capped at 10 percent of the total amount of DSM spending, inclusive of the program incentive, and be reported in the semi-annual DSM reports filed with the Commission pursuant to Decision No. 67744. The Company further proposed that the incentive be determined for each reporting period based on the savings and net benefits reported for that semi-annual period.

Q. Does Staff concur with APS' proposal for a performance incentive?

A. Yes, conceptually it does. Staff recommends that the performance incentive be set at 10 percent of the net benefits from the energy efficiency achieved through approved DSM programs and that the performance incentive be capped at 10 percent of total DSM spending inclusive of the performance incentive.

Q. Would APS be guaranteed to collect $1.6 million in performance incentives (10 percent of the $16 million expected to be spent each year on DSM programs?

A. No. The $1.6 million would be the maximum performance incentive APS could collect annually based on DSM spending of $16 million per year. The actual performance incentive would be based upon actual energy efficiency savings achieved as a result of successful DSM programs.

Q. Should the net benefits be estimated from engineering calculations or should they be based upon savings factors measured by the Measurement, Evaluation, and Research contractor (MER)?

A. Net benefits of a DSM measure are defined as benefits minus costs associated with that measure. The benefits should be based upon actual measured savings resulting from before and after MER measurements where possible and where practical. For most prescriptive measures, the savings could be calculated by averaging a sample of actual measured usage for both standard and upgraded equipment for each energy-efficiency measure. For some prescriptive measures, such as replacement of a standard light bulb with a compact fluorescent light bulb, an engineering calculation may be more practical and would be acceptable. For large custom efficiency measures which are more unique, the savings should be based upon actual MER measurements both before the measure implementation and afterwards. The type of measurement and whether actual measurement is necessary or whether an engineering calculation would be acceptable will vary with the type of DSM measure.

Q. Should the averages of actual measured usage, for both standard and upgraded equipment, used to calculate savings for each measure be periodically updated?

A. Yes. The averages should be recalculated by the MER from usage samples for each prescriptive measure based on new measurements from the field no less frequently than every two years.

Q. Could engineering estimates be used to determine kW and kWh savings at lower cost than a monitoring program?

A. Engineering data can provide some guidance on savings, but data on actual experience, taking into account customer behavior and field performance of the measure, is essential. An example of customer behavior influencing kW and kWh savings is when the customer lowers a thermostat because the new air conditioner is more efficient and costs less to operate. Actual experience may be far different than engineering data would suggest. Another reason for using actual field measurement averages is that baseline usage as well as energy-efficient equipment usage is constantly moving toward increased energy efficiency over time. While it may be less expensive to rely on engineering estimates, such estimates could be providing kW and kWh savings numbers that are incorrect or not representative of Arizona's unique climate characteristics.

Q. Should the performance incentive accrue to the utility at the time the DSM expenditures are made and the measures are installed or over the life of the measures concurrent with the actual customer realization of the benefits?

A. Where it may be more theoretically correct to reward the utility as actual DSM savings accrue over the life of each measure installed, it is not practical to require the utility to wait up to 20 years to recover its performance incentive. Furthermore, the recordkeeping required to pay out a portion of savings each year over the life of each measure could be excessively costly and difficult for Staff to monitor. Staff recommends that APS should share in the benefits of the DSM measures as they are placed into service and expenditures are incurred. APS' Portfolio Plan application suggests that the performance incentive should be determined for each reporting period based on the savings and net benefits reported for that period. APS currently reports this information in each semi-annual DSM report, January – June and July – December. Staff recommends that APS include their request for a performance incentive payment in each semi-annual DSM report. The benefits during a measure's life minus the costs during the year the measure was installed equals the net benefits of that measure for that period.

Q. How should the DSM-related demand and energy savings be priced for comparison with the DSM cost in the calculation of net benefits?

A. APS' avoided cost should be used as the basis to assign a dollar value to DSM demand and energy savings.

Q. What specific calculations or methodology should be used to determine kW and kWh savings and to apply APS avoided costs to those savings to determine the net benefit of the DSM measures undertaken?

A. APS has not proposed a specific calculation or methodology. Determining the net benefits of DSM programs can be a technical and complex undertaking. Staff recommends APS submit its specific calculation and/or methodology for determining the net benefits of DSM measures and the performance incentive itself in its rebuttal testimony in this docket.

Q. Does Staff have nay additional recommendations regarding DSM?

A. Yes. Staff recommends that APS provide Staff with backup workpapers and input data substantiating numbers for net benefits and performance incentives included in its semi-annual DSM report. The backup information should be in sufficient detail to allow Staff to reproduce the numbers reported for net benefits and the performance incentive in the semi-annual DSM report.

Q. What information should be provided for Staff review?

A. The information provided to Staff should include the net benefit calculations and performance incentive dollar amount calculations for the total amount of the performance incentive reported. The calculations should be disaggregated such that the dollar amount of net benefits and performance incentive for each grouping of like individual measures within each DSM program are identifiable and, when added together, equal the total net benefits and performance incentive dollars requested for that DSM program. Major inputs should be provided along with documentation sufficient that Staff could reproduce the calculations. Inputs should include the numbers of like measures, the measure life, the avoided cost factors, discount rates used in present value calculations, kW and kWh savings and how they were derived, coincidence factors, actual cost data, line losses, and any other data required to duplicate the calculations.

Q. When should the information be provided to Staff?

A. APS should provide the information to Staff at the same time as APS files its semi-annual DSM reports.

SYSTEM BENEFITS CHARGE

Background on System Benefits Charges

Q. What are System Benefits?

A. A.A.C. R14-2-1601(41) defines System Benefits as "Commission-approved utility low income, demand-side management, Consumer Education, environmental, renewables, long-term public benefit research and development, nuclear fuel disposal and nuclear power plant decommissioning programs, and other programs that may be approved by the Commission from time to time."

Q. What is the System Benefits Charge?

A. A.A.C. R14-2-1608 requires each utility distribution company to file for Commission review nonbypassable rates or related mechanisms to recover the applicable pro-rata costs of System Benefits from all consumers located in the utility distribution company's service area. Utility distribution companies are to file for review of the System Benefit Charge ("SBC") at least every three years.

Q. Why were System Benefits Charges established?

A. The concept of System Benefits developed as a mechanism to preserve and promote the establishment and maintenance of renewables, DSM, and programs for low income customers. Investment in these programs and research into the reduction of long-term dollar and environmental costs through energy conservation and the development of renewable resources are an important function of public utility companies. When competition began to develop in the electric utility industry, however, there was concern that utilities would be forced through competition to concentrate on short-term results and lose its focus on important long-term objectives to promote conservation, the use of renewables, and some nuclear plant-related expenses. The System Benefits Charge was established to provide a mechanism that would ensure utilities could retain their focus on desirable long-term objectives without suffering an undue economic setback or competitive disadvantage. An important characteristic of the System Benefits Charge is that customers should continue to pay for system benefits even if they choose a different generation supplier; i.e. it is nonbypassable. The System Benefits Charge essentially re-classifies certain costs that are currently in rates to assure that important public benefits are not at risk. The charge is shown as a line item on customer bills.

System Benefits Components

Q. What are the components of APS' System Benefits Charge?

A. The System Benefit components and the amounts requested by APS and recommended by Staff are summarized in the following table:

System Benefits Components	APS Proposed	Staff Recommended
Demand-Side Management Programs	$10,000,000	$10,000,000
Low Income Programs (E-3/E-4 Rates)	$4,222,330	$4,372,330
Renewables	$6,000,000	$6,000,000
Palo Verde Power Plant Decommissioning	$18,901,703	$18,901,703
Independent Spent Fuel Storage Installation (ISFSI)	$10,177,404	$9,917,657
Total System Benefits	$49,301,437	$49,191,690

Q. Which portion of DSM expenses falls within the System Benefits Charge?

A. Only that portion of DSM expenses that are funded within base rates is included in the System Benefits Charge. The portion of DSM expenses that are funded through the DSMAC is outside the System Benefits Charge.

Q. What amount is Staff recommending to be included for DSM in the System Benefits Charge?

A. Staff recommends including $10,000,000 for DSM, the amount approved by Decision No. 67744.

Q. What amount is Staff recommending to be included for low income programs (E-3/E-4 Rates) in the System Benefits Charge?

A. Staff recommends including $4,372,330 for low income programs. This amount is $150,000 more than APS proposed. APS included $4,222,330 which represents the amount of discounts received by customers in the test year adjusted for the change in discount rates approved by Decision No. 67744. In response to Data Request JDA 9-7, APS indicated that there were also administrative and marketing expenses for both the E3 and E4 programs, including $87,847 in the test year plus a proforma adjustment of $62,153 to bring the level to $150,000 as approved by Decision No. 67744. APS states that these administrative and marketing expenses are for direct program promotion and marketing expenses only and do not include APS labor and overhead costs to administer the programs. Staff believes that it is appropriate to include the $150,000 in System Benefits.

Q. Which portion of renewables expenses falls within the System Benefits Charge?

A. Only that portion of renewable expenses that are funded within base rates is included in the System Benefits Charge. The portion of renewables expenses that are funded through the Environmental Portfolio Surcharge Adjustor is outside the System Benefits Charge.

Q. What amount is Staff recommending to be included for renewables in the System Benefits Charge?

A. Staff recommends including $6,000,000 in the System Benefits Charge for renewables. This amount is discussed in the Direct Testimony of Staff witness Barbara Keene.

Q. What amount is Staff recommending to be included for Palo Verde Power Plant decommissioning in the System Benefits Charge?

A. Staff recommends including $18,901,703 for Palo Verde Power Plant decommissioning, as proposed by APS.

Q. What amount is Staff recommending to be included for ISFSI in the System Benefits Charge?

A. Staff recommends including $9,917,657 for ISFSI. APS had included $10,177,404 for ISFSI. The proposed reduction of $259,747 is discussed in the testimony of Staff witness James R. Dittmer.

Total System Benefits

Q. What amount is Staff recommending for the total System Benefits Charge?

A. Staff recommends $49,191,690 for the total System Benefits Charge.

Q. Does this conclude your direct testimony?

A. Yes, it does.

BEFORE THE ARIZONA CORPORATION COMMISSION

JEFF HATCH-MILLER
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Commissioner
MIKE GLEASON
Commissioner
KRISTIN K. MAYES
Commissioner
BARRY WONG
Commissioner

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, AND TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, AND TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND TO AMEND DECISION NO. 67744	DOCKET NO. E-01345A-05-0816

DIRECT

TESTIMONY

OF

JERRY D. SMITH

ELECTRIC UTILITY ENGINEER

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

AUGUST 18, 2006

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EXHIBITS

EXECUTIVE SUMMARY
ARIZONA PUBLIC SERVICE COMPANY
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This testimony and the attached exhibits provide an analysis of the quality of service provided by APS for calendar years 2000 through 2005. It also provides a used and useful determination regarding capital improvements made in the rate case test year: 2005.

During the period of this quality of service assessment, APS experienced several transmission outages that resulted in interruption of service to distribution customers. In each instance APS notified and informed the Commission of its action and how it was managing restoration of service to customers. The scope of system improvements since the Westwing and Deer Valley Substation fires is vast and impressive to observe in the field. Major capital improvements have been made to remedy and mitigate the causes and effects of these events and to preclude a reoccurrence. Damaged equipment has been replaced and Type U transformer bushings are being replaced through out the APS system. Single points of failure for protection and control systems have been eliminated, fire mitigation measures have been implemented at various substations, and fire wall and oil cache basins are being established at appropriate substations.

The Summer 2004 transmission outages and Westwing and Deer Valley fires also have yielded positive effects for Arizona consumers. APS has implemented EPRISolutions, Inc. recommendations regarding 14 areas of maintenance and repair practices. As a consequence APS formed a Predictive Maintenance Team to focus on predictive and preventative maintenance activities to find and repair equipment prior to failure. APS has proactively resolved a significant number of equipment problems by using these diagnostic tools and intensifying its maintenance practices. Improved service to future generations of customers is more likely to occur as a result of these efforts.

All newly constructed and improved facilities observed during Engineering's site visits were found to be in compliance with NESC requirements. Sites that were visited that had capital improvements reported by APS for 2005 test year purposes were found to actually have been constructed and were operational. A sufficient sample of 2005 improvements were observed in the field and suggests a "used and useful" determination for 2005 test year capital improvements is warranted.

Engineering finds no reason to recommend consideration of quality of service mitigation measures as part of the pending APS rate case. However, Engineering does recommend that the Commission continue to monitor APS' quality of service as an integral part of required Biennial Transmission Assessments, through the Commission's existing outage reporting requirements, and via ongoing resolution of consumer complaints about APS service. Engineering further suggests that the Commission be particularly mindful of quality of service differences between the APS Metro Division and more rural service oriented APS divisions. It is for this reason that quality of service to the APS Southeast Division merits special scrutiny to assure service does not deteriorate and become problematic.

INTRODUCTION

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

A. My name is Jerry D. Smith. I am an Electric Utility Engineer employed by the Arizona Corporation Commission ("ACC" or "Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Please describe your educational background.

A. I graduated from the University of New Mexico in 1968 with a Bachelor of Science degree in Electrical Engineering. I received a Masters of Science degree in Electrical Engineering from New Mexico State University in 1977 majoring in power systems and electric utility management.

Q. Do you hold any special licenses or certificates?

A. I am licensed with the State of Arizona as a Professional Engineer - Electrical.

Q. Briefly describe your responsibilities as an Electric Utility Engineer.

A. I joined the Commission's Utilities Division Staff as an electric engineer in 1999. In my capacity as an Electric Utility Engineer, I have investigated the quality of service provided by electric utilities in Arizona and been responsible for three biennial transmission assessments regarding the reliability of existing and planned Arizona transmission facilities. During my employment at the Commission, I have investigated numerous system disturbances on behalf of the Commission. A 1999 blackout of Southern Arizona, a 2001 blackout of Gila Bend, and several extra high voltage ("EHV") disturbances occurring in 2003 and 2004 are among the system disturbances I have investigated. My most recent investigations were of the Westwing and Deer Valley Substation fires.

I chaired a series of Commission Distributed Generation workshops in 1999 and have participated in the revision of Arizona's electric retail competition rules. I have also inspected physical electric utility plant consisting of generation, transmission and distribution facilities. Such facility inspections were necessary to make a "used and useful" determination for rate case applications and to ascertain the level of security, safety, operational integrity, and maintenance exhibited by such facilities.

Q. Please describe other pertinent work experience.

A. I have over 27 years of experience as an engineer and manager in the electric utility industry. I was employed by the Salt River Project from 1968 through 1995. During that time I: 1) analyzed and planned transmission and distribution system improvements; 2) managed the design and consultation services required for retail customer projects; and 3) served as primary contact for local municipalities regarding siting of facilities and utilizing funds for aesthetic treatment of water and power facilities. I also performed ancillary functions such as development and management of capital improvement budgets; formation and modification of system planning, operational and maintenance policies, procedures and practices; and creation, modification and administration of new contribution in aid of construction charges and tariffs.

Q. Have you previously testified before this Commission?

A. Yes. I have extensive experience testifying before the Commission. I have testified on numerous occasions regarding quality of service to electric customers in the City of Nogales and Santa Cruz County. I was a Staff witness regarding the 2003 competitive wholesale power solicitations required by the Commission. I have provided testimony for over 35 power plant and transmission line applications for a Certificate of Environmental Compatibility. My experience filing engineering reports and providing testimony for the

Commission in rates cases is most applicable to this case. I have provided engineering reports and rate case testimony for Duncan Valley Electric Cooperative, Navopache Electric Cooperative, and the Arizona Public Service Company ("APS") and an Open Access Transmission Tariff ("OATT") case for Southwest Transmission Cooperative ("SWTC").

PURPOSE AND PREPARATION OF TESTIMONY

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

A. I am providing testimony concerning the security, safety, operational integrity, and maintenance status of APS's electric system. My testimony has a twofold purpose. It offers an assessment of the quality of service provided by APS to its customers. Secondly my testimony determines to what degree the test-year APS facilities are "used and useful."

Q. How have you prepared for your testimony?

A. I have reviewed information on file, issued data requests to APS, inspected APS's facilities and talked with APS personnel.

Q. When did you inspect APS's facilities?

A. I inspected APS's electric system during six consecutive days of site visits between July 24, 2006 and July 31, 2006. My observations are documented in the engineering report attached as Exhibit JS-1.

Q. What APS personnel have you talked with concerning this docket?

A. I have talked with Mr. Steve Bischoff, Mr. Stan Sierra, Mr. Pete Atwell, Mr. John Lucas, Mr. Dave Simonton, Ms. Jennie Vega, Ms. Angela Allison, and numerous field personnel during the course of my site visits to APS facilities.

Q. What documentation have you reviewed in preparing your testimony?

A. I have reviewed all rate application material filed by the applicant and numerous responses to Staff data requests. I also reviewed testimony and ACC engineering reports previously filed over the course of the last few years concerning other APS proceedings at the Commission. The ACC engineering report for this case is attached as Exhibit JS-1.

Q. Is your testimony herein based upon the aforementioned facility site observations, conclusions drawn from review of available documentation, information gathered by talking with applicant personnel and your educational background and work experience as a utility professional?

A. Yes it is.

FACILITIES CONSIDERED IN TESTIMONY

Q. Have you reviewed the APS application and testimony regarding facilities it proposes to include in rate base for this case?

A. Yes. I reviewed the respective rate schedules to ascertain what facilities I needed to make a used and useful determination for. This information was used to assist in my selection of facilities for a site visit.

Q. What other facilities are considered in your testimony?

A. I also visited other APS facilities to ascertain the on going status of maintenance, construction and repair practices contributing to the quality of service provided by APS. An outline of all APS facilities considered in my site visits is documented in Exhibit 2 of the ACC Engineering Report. A sampling of seven generating plants and 35 transmission and distribution substation facilities were visited.

JUSTIFICATION OF NEED FOR RECENT IMPROVEMENTS

Q. Briefly describe the fundamental justification of need for the many improvements being made by APS.

A. Major capital improvements were made to remedy and mitigate the causes and effects of the Westwing and Deer Valley Substation fires and to preclude a reoccurrence.

QUALITY OF SERVICE ASSESSMENT

Q. Please describe how you determined the quality of service being provided by APS to its customers.

A. Staff first considered trends in the APS reportable outage reports filed monthly with the Commission. Then actual APS distribution system reliability data was compared to the typical reliability indices for US utilities and APS system thresholds. Staff also considered the nature of customer complaints filed by APS consumers regarding quality of service. On this basis, Staff made an objective assessment of the quality of service being provided to APS distribution system customers. Finally, Staff coupled the above assessment with a physical inspection of a sampling of APS facilities.

Q. Have you determined if APS facilities are properly planned, designed, constructed, maintained and operated to achieve an appropriate level of reliable service to its customers?

A. Yes.

USED AND USEFUL DETERMINATION

Q. Please describe how you determined if the APS 2005 test year capital improvements were used and useful.

A. A used and useful determination requires a physical survey of new and improved facilities to assure completion of construction, validation that equipment is fully operational, and that the facilities meet National Electric Safety Code ("NESC") requirements per Arizona Administrative Code R14-2-208. Staff's used and useful determination of APS 2005 capital improvements was based upon inspection of a sampling of APS facilities and review and analysis of the company's response to data requests concerning its capital improvements. Choosing an appropriate sample of facilities to inspect was a fundamental requirement of Staff's used and useful determination. Staff's expertise was also critical in assembling criteria so a valid sample of facilities could be selected for field observation.

Q. Please summarize your observations of the site visits to APS facilities.

A. My observations and the results of my inspection of APS facilities are documented in my Engineering Report attached as Exhibit JS-1. In summary, my conclusions are:

- The scope of system improvements since the Westwing and Deer Valley Substation fires is substantial and impressive to observe in the field.
- Most of the electric transmission systems including substations were well maintained in terms of security in and around the substations, and of proper maintenance of equipment in the yard and in the switchgear rooms.
- Poor performing substations and distribution feeders are being maintained, refurbished and repaired in a logical and sound manner. Some of these improvements being made to the facilities serving tribal territories are effectively improving service.

- As recommended by APS Consultant EPRI Solutions, Inc., APS formed a Predictive Maintenance Team to focus on predictive and preventive maintenance activities to find and repair equipment prior to failure. Maintenance records looked at randomly during site inspections reflects the results of predictive maintenance.

Q. Have you determined if the capital improvements made by APS are "used and useful?"

A. Yes. All the electric facilities I observed during my six days of touring APS facilities were operational and well maintained. Therefore, I conclude the APS test year improvements are used and useful.

SUMMARY OF TESTIMONY CONCLUSIONS

Q. Please summarize the conclusions of your testimony.

A. Utility plant improvements constructed by APS in calendar year 2005 were appropriate and necessary to maintain reliable, efficient and cost effective service to its customers and the wholesale market. The justifications of need for such facilities were established before the Commission in prior proceedings. All utility plant contained in APS' rate application is "used and useful" in reliably delivering the energy needs of existing retail customers.

Q. Does this conclude your direct testimony?

A. Yes, it does.

ENGINEERING REPORT
UTILITIES DIVISION
ARIZONA CORPORATION COMMISSION

ARIZONA PUBLIC SERVICE COMPANY
RATE CASE
DOCKET NO. E-01345A-05-0816

STAFF'S QUALITY OF SERVICE ASSESSMENT
AND
USED AND USEFUL DETERMINATION

AUGUST 18, 2006

JDS:APSRateEngrRpt

STAFF ACKNOWLEDGMENT

This Engineering Report was prepared by the Arizona Corporation Commission Utilities Division ("Utilities Division") for use in the Arizona Public Service Company ("APS") rate case, Docket No. E-01345A-05-0816. It provides an analysis of the quality of service provided by APS for calendar years 2000 through 2005. It also provides a used and useful determination regarding capital improvements made in the rate case test year: 2005. The report documents an engineering assessment by Jerry Smith of the Utilities Division regarding these two matters.

Jerry Smith actively monitors quality of service matters for all Arizona utilities on an ongoing basis. His quality of service assessment of APS is based upon inspection of a sampling of APS facilities and review and analysis of the company's response to data requests concerning quality of service matters. Mr. Smith also documents the statistics of customer complaints filed with the Commission regarding quality of service matters.

A used and useful determination requires a physical survey of new and improved facilities to assure completion of construction, validation that equipment is fully operational, and that the facilities meet National Electric Safety Code ("NESC") requirements per Arizona Administrative Code R14-2-208. Mr. Smith has extensive industry experience regarding such investigations. His used and useful determination of APS 2005 capital improvements is based upon inspection of a sampling of APS facilities and review and analysis of the company's response to data requests concerning its capital improvements.

Jerry D. Smith
Electric Utility Engineer

JDS:APSRateEngrRpt

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PURPOSE OF ENGINEERING REPORT

This engineering report serves a two fold purpose. It documents a quality of service assessment of Arizona Public Service Company ("APS") performed by Utilities Division Engineering Staff ("Engineering"). Secondly it provides a used and useful determination of APS capital improvements for test year 2005 also performed by Engineering. The report is filed with the Arizona Corporation Commission ("Commission") in support of the Commission Staff's ("Staff") evidentiary record for the APS rate case, Docket No. E-01345A-05-0816.

FRAMEWORK OF QUALITY OF SERVICE ASSESSMENT

Engineering's quality of service assessment of APS covers the calendar years 2000 through 2005. It is based upon data collected via data requests of APS and site visits of a sampling of the worst performing APS facilities. A 2004 Biennial Transmission Assessment ("BTA") was performed in accordance with Arizona Revised Statute §40-360.02.G. A 2006 BTA is currently in progress. Each BTA determines to what degree the existing and planned transmission system facilities in Arizona adequately meet the energy needs of the state in a reliable manner. This assessment also incorporates findings of the Commission's investigation of the Summer 2004 transmission outages in Docket No. E-00000J-04-0522.

In addition, Engineering monitors quality of service matters for utilities in the state of Arizona in accordance with Arizona Administrative Code R14-2-208 which describes the provision of service required of electric utilities. APS routinely files a monthly summary report for all outages resulting in 1000 customer hours of service interruption. This quality of service assessment considers findings of the APS report filed in accordance with Commission Decision No. 67744 regarding quality of service to Tribal Territories.[1] Consumers also may opt to file a complaint regarding quality of service with the Commission's Consumer Services Section. This quality of service assessment considers the performance of APS in each of the aforementioned categories.

However, the Commission has adopted a North American Reliability Council ("NERC") definition of reliability for Engineering's use in the Biennial Transmission Assessment. Reliability is comprised of two components: adequacy and security. Adequacy is the ability of an electric system to supply the aggregate electrical demand and energy requirements of its customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements. On the other hand, security is the ability of an electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements. These components of reliability are very subjective, are not easily measured and leave much to interpretation. Nevertheless, this document does highlight several major transmission disturbances that have resulted in interruption of service to APS customers since 2000.

[1] Reliability Review of Electric Service to Tribal Territories, Arizona Public Service Company, October 5, 2005.

Many utilities use numerical indices as a measure of an average customer's distribution service reliability. Such reliability indices are typically computed on an annual basis. A utility may then set reliability targets based upon benchmarked data from its own system. The Institute of Electrical and Electronic Engineers ("IEEE") has adopted a standard definition for several reliability indices for electric distribution systems and established a national benchmark database via a 1995 IEEE survey of the electric utility industry. The most commonly used reliability indices are System Average Interruption Frequency Index ("SAIFI"), System Average Interruption Duration Index ("SAIDI"), and Customer Average Interruption Duration Index ("CAIDI"). All three reliability indices are defined in IEEE Standard 13-2003, *IEEE Guide for Electric Power Distribution Reliability Indices.*

SAIFI is the average number of interruptions experienced by customers per year. SAIDI is the average number of interruption minutes experienced by customers per year. CAIDI is the average duration of interruptions. Per Rural Utilities Service ("RUS") Bulletin 161-5, the RUS considers a SAIDI of five hours (300 minutes) or more per consumer as unacceptable except under very unusual circumstances, such as a natural disaster. The IEEE 1995 Survey established typical reliability index values for the electric utilities in the United States as displayed in the following table.

Table 1
Typical Reliability Index Values for US Utilities

Average	SAIFI	SAIDI	CAIDI
Top quartile	0.90	54	55
Second quartile	1.10	90	76
Average	1.26	117	88
Third quartile	1.45	138	108
Bottom quartile	3.90	423	197

APS has been using a one-minute "Sustainable Outage" threshold when collecting outage data. This yields a more conservative result than the IEEE five-minute threshold. This seems to be a sound practice since outages of transmission lines operated at 69 kV or higher tend to be shorter than five minutes but longer than 1 minute. Otherwise outages of transmission lines that result in interruption of service could be excluded from the reliability assessment data.

The lognormal distribution is used for electric distribution system reliability data. As such the arithmetic mean and standard deviation are used to estimate confidence levels for the collected data. IEEE 1366-2003 utilizes 2 and ½ standard deviations ("2.5β") above the statistical mean for establishment of a reliability indices threshold. APS, on the other hand, utilizes one standard deviation above the statistical mean for its reliability indices threshold. APS then utilizes this more conservative reliability threshold for contrasting the attributes of rural and urban distribution feeders in the following categories: 1) single transmission source vs. redundant transmission source and 2) overhead vs. underground distribution construction. The following table and Exhibit 1 depict how 2005 outages modified the APS reliability threshold first reported in its prior *Reliability Review of Electric Service to Tribal Territories* Report.

Table 2
APS System Reliability Threshold

	2002-2004*			2002-2005**		
System Attribute	**SAIFI**	**SAIDI**	**CAIDI**	**SAIFI**	**SAIDI**	**CAIFI**
Single Transmission	6.77	567.10	175.40	7.68	477.40	156.40
Redundant Transmission	3.03	189.60	147.90	3.33	158.80	140.50
Overhead Distribution	6.40	572.10	126.20	7.25	486.40	176.90
Underground Distribution	2.40	128.60	190.00	2.48	103.40	121.90

NOTES:
* APS Reliability Review of Electric Service to Tribal Territories, Docket E-01345A-03-0437, October 5, 2005.
** APS's response to Staff Data Request JDS 2-7, Docket No. E-01345A-05-0816

Engineering proposes to first consider trends in the APS reportable outage reports filed monthly with the Commission. Then actual APS distribution system reliability data will be compared to the typical reliability indices contained in Table 1 and Table 2. Engineering then proposes to consider the nature of customer complaints filed by APS consumers regarding quality of service. On this basis, Engineering can make an objective assessment of the quality of service being provided to APS distribution system customers. Coupled with a physical observation of a sampling of APS facilities, a determination can be made regarding the effectiveness of the various APS design, construction, maintenance, and repair practices.

FRAMEWORK OF USED AND USEFUL DETERMINATION

A used and useful determination requires a physical survey of new and improved facilities to assure completion of construction, validation that equipment is fully operational, and that the facilities meet National Electric Safety Code ("NESC") requirements per Arizona Administrative Code R14-2-208. This used and useful determination of APS 2005 capital improvements is based upon inspection of a sampling of APS facilities and review and analysis of the company's response to data requests concerning its capital improvements. Choosing an appropriate sample of facilities to inspect is a fundamental requirement in performing any valid used and useful determination. The investigator's level of industry experience is also critical in assembling criteria by which a valid sample of facilities is selected for field observation.

It was determined that a site visit of APS facilities was needed for both the quality of service assessment and the used and useful determination. However, APS has a large inventory of existing, new and upgraded facilities located state-wide. This made selection of a sample of facilities for field observation a necessity. APS' service area is segregated into five divisions: Metro, Northeast, Northwest, Southeast, and Southwest. Therefore, Engineering organized its field visits by APS Division and selected a reflective sample of generation, transmission and distribution facilities in each.

Exhibit 2 was compiled to facilitate a selection of APS facilities for a site visit. It lists the worst performing substation in each of the five APS Divisions for each year from 2003 through 2005. Similarly, it lists the three worst performing distribution feeders in each APS Division for each of the same years. It also lists the 2005 capital improvements constructed by APS in the form of new transmission lines (69 kV and above), distribution feeders, and new or upgraded substations. Finally, the Arizona power plants (except Palo Verde and Redhawk) owned and operated by APS and located in each APS Division are listed.

It was determined that by visiting all of the worst performing substations and about half of the new or upgraded substations listed in Exhibit 2 many of the worst performing distribution feeders would also be observed. Eastgate and Havasu were the only two worst performing substations not visited. The 2005 new and upgraded facilities selected for site visits were chosen primarily based upon improvements to correct previously poor performing sites or planned in response to scheduled maintenance discoveries. Capital improvements were afforded a higher visitation priority if they stemmed from implementation of recommendations filed with the Commission following the Summer 2004 outage events that lead to damaged equipment and a Westwing Substation fire. Redhawk and Palo Verde are the only APS solely or jointly owned and operated power plants in Arizona that were not included for visitation. Redhawk was inspected in 2002 by Electric Utilities Engineer, Prem Bahl, after it commenced commercial operation. An engineering report of that investigation was filed with the Commission. The Palo Verde Nuclear Generating Station was excluded because it has previously been visited and is part of an on going Commission investigation regarding unit outages that occurred in 2005.

During electric facility site visits Engineering generally ascertains: 1) facility security, 2) that proper safety and fire protection measures are employed, 3) all equipment have been constructed in compliance with NESC requirements, and 4) the operational status of facility. The site must be secure with proper height enclosures topped with either barbed wire or razor ribbon, and gate(s) and control house(s) are locked. Proper signage must be prominently displayed to inform the public that the facility poses an electric safety hazard. Existence of a formal employee safety training program and employee participation is established. Each site is observed to ascertain that it is a safe working environment. Employee adherence to safe operating practices is also observed in the field. Particular attention is given to fire extinction capability, proper separation of equipment or use of fire wall barriers, and existence of oil cache basins for transformers.

Confirmation that equipment exists in the field and is operational is a prerequisite for a used and useful determination. Therefore the operational readiness status of all onsite equipment is noted. Presence of a properly maintained substation DC battery supply is verified. Equipment maintenance needs are also observed and maintenance practices confirmed. Storage of damaged or non-useable equipment onsite is discouraged. However, onsite storage of equipment for future construction projects or staging of maintenance and repair activities at remote sites is an acceptable practice. Storage of a mobile or spare transformer at a remote substation is an example of this practice.

SITE VISITS AND FIELD OBSERVATIONS

Site visits were arranged and organized for each of the five APS Divisions. APS Northeast Division facilities were inspected on July 24, 2006. The Northwest Division was visited on July 25, the Southeast Division on July 26, and the Southwest Division on July 27. Two days, July 28 and July 31, were required to tour the Metro Division facilities. Jerry Smith was accompanied daily by two or three of the following APS personnel as he visited seven power plants and 35 substations over a period of six days. Power plant personnel were also interviewed at each of the power plants. The entourage visiting the Southeast Division and Southwest Division facilities was joined by local APS division personnel who graciously served as host.

Table 3
APS Personnel Accompanying Staff for Site Visits

	6/24	6/25	6/26	6/27	6/28	6/31
Jennie Vega		x		x	x	
Angela Allison	x		x			x
Pete Atwell	x	x				
John Lucas			x	x	x	x
Dave Simonton		x	x	x	x	

Engineering postulates that the substations and power plants sites visited and observations of transmission lines and distribution lines terminated at those same sites constitute a statistically valid sample of APS facilities. A complete set of photos taken during the site visits is provided as Appendix 1 on a compact disc ("CD"). Many of these photos depict security sensitive and critical infrastructure related information. Therefore the CD will be treated as confidential material in the filing of this report.

All sites visited were secure with enclosures of the proper height and were topped with either barbed wire or razor ribbon. Substations in rural settings were generally enclosed by chain link fences while those in urban settings were generally enclosed by masonry walls. All gate(s) and control house(s) were properly locked. Some facilities were protected by proximity alarms. The extra high voltage transmission substations and power plants utilize a security camera system to monitor the site. All but one power plant has personnel onsite 24 hours per day. A building is provided at the front gate of all but two power plants to house security personnel as needed. Proper signage was prominently displayed at each site to inform the public that the facility poses an electric safety hazard. A portfolio of photos depicting these observations is provided in Appendix 1. This collection of photos is labeled "Security Related."

The facilities visited included a spectrum of substations exhibiting a variety of traits. The substations varied in vintage from old to new and even included temporary installations pending selection of a permanent site. Substation designs ranged from wooden platform construction to high profile steel bus structures and low profile bus configurations. The primary voltage class of substations included 69 kV, 115 kV, 230 kV, 345 kV and 500 kV designs. There was a balanced mixture of rural and urban substations. Some substations had circuit breakers, motorized switches and control houses containing Supervisory Control And Data Acquisition ("SCADA") equipment, remote telemetry units, relays and communication equipment. Others simply had manual switches and fuses and no control house. Some substations had primary and/or secondary capacitors, reactors or voltage regulators for voltage control while others did not. A portfolio of photos depicting these observations is provided in Appendix 1 and is labeled "Vintage and Type."

The following capital improvements represent a significant portion of the corrective action taken by APS following the Summer 2004 transmission outages and Westwing and Deer Valley transformer fires. Examples of these capital improvements were observed during Engineering's site visits of APS facilities. Two portfolios of photos of such improvements observed during site visits been assembled in Appendix 1. These portfolios of photos are labeled "Post WWG Fire" and "Fire Mitigation."

1. Replacement of Type U bushings on transformers,
2. Use of Serveron units on bulk system transformers to monitor gas forming within a transformer,
3. Replacement of fire damaged transformers at Westwing and Deer Valley,
4. Installation of fire walls between transformers lacking suitable separation per IEEE Standards,
5. Placement of transformer cache basins with retaining walls or curbs for transformer oil containment,
6. Elimination of single points of failure for protection and control systems via the addition of new electronic relays to replace antiquated electro-magnetic devices, and
7. Implementation of fire mitigation measures at various substation sites.

The Commission's investigation of the Summer 2004 transmission outages and Westwing and Deer Valley fires documented an APS commitment to implement the EPRISolutions, Inc. recommendations regarding 14 areas of maintenance and repair practices. As a consequence APS formed a Predictive Maintenance Team to focus on predictive and preventative maintenance activities to find and repair equipment prior to failure. Vibration and acoustic monitoring and corona scanning are now used routinely as maintenance diagnostic tools. Visual inspections, thermal scanning, and Dissolved Gas Analysis ("DGA") and complete oil analysis of transformers have been increased. A regimented electric testing of substation transformers with expanded use of Doble test equipment, Sweep Frequency Response Analysis ("SFRA") and Leakage Reactance has been adopted by APS.

APS has proactively resolved a significant number of equipment problems by using these diagnostic tools and practices. Most of these equipment improvements listed below were observed during site visits to APS facilities. A portfolio of photos is provided in Appendix 1 that documents some of the equipment improvements benefiting from these extensive predictive maintenance practices. The portfolio of photos is labeled "New Maint Practices."

1. A 230 kV transformer was replaced at Pinnacle Peak Substation and Coconino Substation due to a DGA determining that the transformers were deteriorating internally.
2. A 230 kV transformer was replaced at Deer Valley Substation due to acoustic, vibration, and DGA determining that the transformer was deteriorating internally.
3. A new Deer Valley Substation 230 kV transformer was returned to the manufacturer due to a SFRA determining it was damaged during shipping from the manufacturer.
4. A 230 kV transformer at Cactus Substation was repaired following acoustic monitoring that discovered a nitrogen leak through the Current Transformer ("CT").
5. A 345 kV station post insulator was replaced at Preacher Canyon due to significant corona being detected by a corona camera.
6. A circuit breaker was replaced at Ocotillo due to a SF6 camera detecting a SF6 leak.
7. A 69 kV transformer was replaced at Jackson Street Substation due to internal damage detected by vibration analysis and SFRA.

All newly constructed and improved facilities observed during the site visits were found to be in compliance with NESC requirements. Sites that were visited that had capital improvements reported by APS for 2005 test year purposes were found to actually have been constructed and were operational. A sufficient sample of 2005 improvements were observed in the field and suggests a "used and useful" determination for 2005 test year capital improvements is warranted. However, several items were observed that merit some attention. The list provided below is viewed by Engineering as minor issues offering opportunities for improvement. These items are likely already on the utility's to do list. Failure to take corrective action in the near term could elevate Engineering's concern if quality of service from these facilities begins to deteriorate. A portfolio of photos of these items is provided in Appendix 1 with the label "Areas for improvement."

- Chino Wells Substation is an old substation with old equipment serving water pumps for Chino Wells. The station service transformers are not in service and have been abandoned in place. The substation transformers are old and showed signs of old oil leaks and have older Type U bushings. The substation is scheduled for replacement or refurbishment in the next few years.

- The Fairview generator and an emergency 69 kV tie at Sulphur Springs Valley Electric Cooperative's ("SSVEC") McNeal Substation are of inadequate capacity to restore full service to all of the Southeast Division for an outage of the APS Adams to Mural 115 kV line. This service area has the potential of exhibiting quality of service concerns comparable to that of Nogales and Santa Cruz County. In fact, the Southeast Division is APS' poorest service performance division over the last five years. A second 69 kV tie is being sought with SSVEC.

- A new transformer was constructed at Humbug in 2005 without an oil cache basin. The second unit already has asphalt curbing to assure containment of transformer oil spills. It is assumed that the construction activity may not have been completed or the cache basin may have simply been an oversight given the new focus of fire mitigation.

- Laguna Feeder #1 was rebuilt in 2005 as an underbuild on a 69 kV line on steel poles. The telephone lines previously in joint use on the old wood pole still remain in service with the poles topped above the telephone line. The wood poles are leaning in such a manner as to likely pose a public safety concern for road crossings. This is not an APS problem but is reflective of untimely relocation of joint use facilities on poles that are being removed and replaced.

- One 69 kV steel pole just north of Laguna Substation was observed to have experienced a hit and run vehicular accident. The base of the steel pole was severely crushed. The pole appears to be structurally sound but obviously needs replacement.

- Paulden Substation had a larger auger bit stored in an inappropriate location. It was placed in a position that could pose an obstacle for a vehicle's ingress to the site if occurring at night. Simply placing the auger bit adjacent to the substation fence would resolve this safety concern.

- The San Luis Substation control house has had a roof leak. A black garbage bag was suspended above electronic equipment on the top of a control rack to protect the equipment until the leak was resolved. The roof leak needs to be repaired and the plastic garbage bag removed to enable proper equipment ventilation void of moisture and to avoid the bag becoming a loose impediment in the control house.

TRANSMISSION ASSESSMENT

Engineering conducted the Commission's third biennial transmission assessment in 2004. Engineering investigated the ability of Arizona's transmission system to adequately deliver energy to the state's retail consumer markets as well as import energy from or export energy to the regional transmission grid with which it is interconnected. Adequacy of existing Arizona transmission lines and planned additions between 2004 and 2013 was determined and documented in a Staff report adopted by the Commission via Decision No. 67457.[2] The 2006 BTA is currently in progress but has not reached a point where findings of fact are available for inclusion in this analysis.

Engineering concluded in its third BTA that the electric industry in the State of Arizona had been very responsive to concerns raised in the Commission's first and second BTA. It further concluded that in general the existing and planned Arizona transmission system meets the load serving requirements of the state in a reliable manner. APS is a major transmission provider in the state of Arizona and therefore the conclusions derived from the Biennial Transmission Assessment are largely a reflection of the quality of transmission service provided by APS.

[2] Third Biennial Transmission Assessment 2004-2013, Docket No. E-00000D-03-0047, November 30, 2004.

However, the third BTA report continued to raise concerns about the adequacy of the state's transmission system to reliably support the competitive wholesale market emerging in Arizona. The third BTA conclusions were based upon the following findings:

- Very little long-term firm regional transmission capacity is available to export or import energy over Arizona's transmission system.
- There are transmission import constraints for five geographical load zones in Arizona: Phoenix metropolitan area, Tucson, Yuma, Santa Cruz County and Mohave County. Planned transmission enhancements will help mitigate such constraints in all but Mohave County.
- Transmission from Palo Verde to California is inadequate to allow all Palo Verde Hub generation full access to the California market under weak Arizona market conditions.
- Some new power plants have interconnected to Arizona's bulk transmission system via a single transmission line or tie rather than continuing Arizona's best engineering practice of multiple lines emanating from power plants.

During the period of this quality of service assessment, APS experienced four transmission outages that resulted in interruption of service to distribution customers. On July 1, 2003 the failure of a 230 kV circuit breaker at Pinnacle Peak substation resulted in APS and the Salt River Project ("SRP") interrupting service to 46,673 customers in the Phoenix metropolitan area to prevent cascading of the disturbance to other systems. Similarly on July 28, 2003, APS operating personnel took steps to shed local load by interrupting service to 119,348 customers in response to a 500 kV switching incident at the Hassayampa Switchyard that resulted in tripping of approximately 2600 MW of generation. On June 14, 2004 the Liberty to Westwing 230 kV line experienced a failure due to a fault not being cleared in a timely fashion. This event led to damage of transformers at Westwing which eventually caught fire on July 4, 2004. On July 20, 2004 failure of transformer bushings at Deer Valley Substation resulted in another transformer fire and led to interruption of service of 95,373 customers.

In each instance APS notified and informed the Commission of its action and how it was managing restoration of service to customers. The effect of these transmission events on APS' distribution reliability performance indices is discussed later in this report. APS management of and operational response to the Summer 2004 transmission outage events was the focus of an extensive Commission investigation.

DISTRIBUTION SYSTEM RELIABILITY INDICES

Engineering has reviewed data supplied by APS regarding its distribution system reliability indices for the years 2000 through 2005. APS provided outage statistics concerning Commission reportable outage events per Engineering's request. APS also provided SAIFI, SAIDI, and CAIDI data under a confidentiality agreement for its entire distribution system and for its five geographical regions: Metro, Northeast, Northwest, Southeast, and Southwest. This information is displayed respectively in tabular and graphical form in Exhibits 3 and 4. A summary of the reliability indices for the three worst performing feeders in each APS Division for 2003 through 2005 have been assembled as Exhibit 5. Exhibit 6 updates the summary of reliability indices for every APS feeder providing service to tribal territories from that previously filed with Commission. Exhibits 5 and 6 contain detailed information regarding specific substations and feeders and are therefore confidential. They have been filed as part of the confidential material in Appendix 1. All four of these exhibits form the basis for Engineering's summary analysis of APS distribution system reliability performance provided below.

The APS distribution system reliability indices are determined in large part by the performance of its Metro Division. The Metro Division is largely comprised of the Phoenix metropolitan area and is an urban service area representing approximately three quarters of the APS load. The Metro Division SAIFI, SAIDI and CAIDI reliability indices are the best of the five APS divisions for each of the last five years. The remaining four divisions are largely rural or small communities with limited distribution services whose operational character is more typical of rural distribution service. It is normal to expect such rural services to experience a greater number of service interruptions of longer duration due to: 1) longer length distribution feeders with aging distribution equipment due to slower growth patterns, 2) limited feeder switching capability among distribution substations, 3) remoteness of limited service personnel, and 4) geographic areas in which storm disturbances are more prominent.

The year 2005 was statistically not a good year for APS regarding sustained service interruptions to customers. The Commission requires that APS report outages resulting in 1,000 customer hours of service interruption. Exhibit 3 shows that the customer hours of interruption in 2005 was roughly three times that experienced in 2004. APS reports this 2005 increase is largely attributable to more extensive damage due to storm activity. Some of the outages occurred at times when the system was already in a state of reconfiguration for construction and maintenance activities. Customers served by APS Northwest Division facilities have been somewhat immune to the increased hours of outage over the last three years. The 2005 increase in reportable distribution outages predominantly affected Metro Division customers. On the other hand, the Southeast Division accounts for the majority of the 2005 increase in transmission reportable outages.

This phenomenon is partially explained by the reliability threshold statistics reported by APS in Exhibit 1. Customers served by overhead distribution feeders from a substation that has a single transmission line have about twice the number of outages and an outage duration of two to three times that of customers served by underground feeders from substations with redundant transmission lines. However, the customer average interruption duration remains comparable between the two groups of customers. This is the typical comparison of rural versus urban service. What is more significant in the Exhibit 1 data is that the reliability threshold in 2005 was reduced or improved over that reported for 2004. This implies that an improvement in the overall APS system reliability was achieved in spite of a 2005 increase in the incidence and duration of outages.

The actual APS reliability indices in Exhibit 4 have been compared to the IEEE typical industry indices listed in Table 1. Several conclusions can be drawn from this comparison. Over the last four years the number of interruptions of service per customer per year for the entire APS distribution system listed on page 4-1 of Exhibit 4 has correlated to the second quartile of U.S. utilities in Table 1. The average number of hours of interruption per year for the entire APS distribution system listed on page 4-2 of Exhibit 4 falls within the second quartile of U.S. utilities in Table 1 except in 2005 it drops to just below average. The CAIDI reliability indices for the entire APS system listed on page 4-3 of Exhibit 4 is in the second quartile of utilities except for the year 2002 when it is in the third quartile of U.S. utilities. These statistics imply that APS is managing its entire distribution system on a comparable par with the better utilities in the nation.

Exhibit 4 documents that the APS division exhibiting the weakest reliability indices is the Southeast Division. However, at no time have the Southeast Division reliability indices exceeded the reliability threshold levels depicted in Table 1. This portion of the APS system provides service to the communities of Douglas and Bisbee. Engineering is aware of an extreme transmission outage that caused a major blackout of much of Southern Arizona in 2001. That transmission outage accounts for the less reliable service to Southeast Division APS' customers in 2001. Engineering was first alerted to concerns regarding potential quality of service for the APS Southeast Division when it was investigating service complaints for Santa Cruz County in 1999. In 2000 the utilities serving Southeastern Arizona performed a regional study and presented results to the Commission. It concluded that restorative service to APS' Southeast Division following a 115 kV line outage was best accomplished with remote operational control of the APS Fairview generation and remote controlled equipment that enabled closing of two 69 kV ties with Sulphur Springs Valley Electric Cooperative substations and the addition of 69 kV capacitors for voltage control. Engineering believes it prudent for the Commission to continue to closely monitor quality of service in the APS Southeast Division given its system topology and quality of service history.

Only four feeders had a CAIDI performance level exceeding the 2005 reliability threshold in Table 1 from 2003 through 2005. Exhibit 5 documents that corrective system improvements have been made to resolve performance woes of each of the four feeders. The four feeders in question are Preacher Canyon #6, Pollack #2, Rainbow Valley #1 and Vicksburg #4. Similarly, Exhibit 6 reveals that over the time period of 2002 through 2005 only six feeders serving tribal territories had an average CAIDI exceeding the Table 1 reliability threshold. Only two of those feeders exceeded the threshold level in 2005: Caywood #1 and Valley Farms#6.

QUALITY OF SERVICE COMPLAINTS

The Commission provides the opportunity for consumers to file complaints regarding the quality of service received from utilities under its regulatory jurisdiction. Table 2 summarizes the nature of quality of electric service complaints filed with the Consumer Service Section regarding service from APS for calendar years 2000 through 2005.

Table 4 statistics indicate that quality of service complaints are predominantly related to outages or interruption of service. The largest number of outage complaints occurred in 2000. However, the largest percentage of complaints regarding outages occurred in 2005. That was a year in which the reliability indices previously discussed also reflected that APS customers experienced the largest number of average hours of outage per incident. APS experienced two major outages to its distribution system in the year 2001. Even so, its quality of distribution service overall was comparable to the better performing utilities in the nation.

The statistics provided by Table 4 also reveal the relationship of quality of service complaints to the total number of consumer complaints received from APS customers. The percent of total complaints about APS that are of a quality of service nature ranges between 5 and 12 percent. Engineering believes coupling these statistics with Consumer Services' experience in working with APS to resolve all complaints serves as an indication that the quality of customer service provided by APS is excellent.

Table 4
Quality of Service Compliant Summary[1]

Complaint Code	2000	2001	2002	2003	2004	2005
Defective equipment	3	0	0	0	2	4
Not working	5	3	3	0	1	3
Outage / interruption	37	30	11	17	23	65
Voltage	1	0	1	0	3	1
Engineering	0	0	0	0	0	1
Subtotal	46	33	15	17	29	74
Total Complaints	649	314	257	198	442	595
% Total Complaints	7.1 %	10.5 %	5.8 %	8.5 %	6.6 %	12.4 %

[1] Per Arizona Corporation Commission Consumer Service database.

STAFF CONCLUSIONS AND RECOMMENDATION

Engineering concluded in its second Biennial Transmission Assessment that in general the existing and planned Arizona transmission system meets the load serving requirements of the state in a reliable manner. APS is a major transmission provider in the state of Arizona. Therefore the conclusions derived from the Biennial Transmission Assessment are largely a reflection of the quality of transmission service provided by APS.

During the period of this quality of service assessment, APS experienced several transmission outages that resulted in interruption of service to distribution customers. In each instance APS notified and informed the Commission of its action and how it was managing restoration of service to customers. The scope of system improvements since the Westwing and Deer Valley Substation fires is vast and impressive to observe in the field. Major capital improvements have been made to remedy and mitigate the causes and effects of these events and to preclude a reoccurrence. Damaged equipment has been replaced and Type U transformer bushings are being replaced through out the APS system. Single points of failure for protection and control systems have been eliminated, fire mitigation measures have been implemented at various substations, and fire wall and oil cache basins are being established at appropriate substations.

The Summer 2004 transmission outages and Westwing and Deer Valley fires also have yielded positive effects for Arizona consumers. APS has implemented EPRISolutions, Inc. recommendations regarding 14 areas of maintenance and repair practices. As a consequence APS formed a Predictive Maintenance Team to focus on predictive and preventative maintenance activities to find and repair equipment prior to failure. APS has proactively resolved a significant number of equipment problems by using these diagnostic tools and intensifying its maintenance practices. Improved service to future generations of customers is more likely to occur as a result of these efforts.

All newly constructed and improved facilities observed during Engineering's site visits were found to be in compliance with NESC requirements. Sites that were visited that had capital improvements reported by APS for 2005 test year purposes were found to actually have been constructed and were operational. A sufficient sample of 2005 improvements were observed in the field and suggests a "used and useful" determination for 2005 test year capital improvements is warranted.

Poor performing substations and distribution feeders are being maintained, refurbished and repaired in a logical and sound manner. Only four feeders had a CAIDI performance level exceeding the 2005 APS reliability threshold from 2003 through 2005. Corrective system improvements have been made to resolve performance woes of each of the four feeders. Four feeders serving tribal territories exhibited an average CAIDI exceeding the reliability threshold level for 2002 to 2005. However, only two of those feeders actually exceeded the threshold in 2005. This signifies that improvements being made to facilities serving tribal territories are effectively improving service.

The system reliability indices for the APS distribution system for 2000 through 2005 imply that APS is managing its entire distribution system on a par with the better utilities in the nation. The APS division exhibiting the weakest reliability indices is the Southeast Division. This portion of the APS system provides service to the communities of Douglas and Bisbee. In no instance did the Southeast Division reliability indices exceed the APS reliability threshold.

Between 5 and 12 percent of annual complaints about APS are of a quality of service nature. Quality of electric service complaints filed with the Consumer Service Section regarding APS service for the years 2000 through 2005 are predominantly related to outages or interruption of service. APS experienced numerous major outages during the period of this quality of service investigation. Even so, APS quality of electric service overall was comparable to the better performing utilities in the nation. Given Consumer Services excellent experience with APS in resolving complaints, Engineering finds the quality of customer service provided by APS to be excellent.

Engineering finds no reason to recommend consideration of quality of service mitigation measures as part of the pending APS rate case. However, Engineering does recommend that the Commission continue to monitor APS' quality of service as an integral part of required Biennial Transmission Assessments, through the Commission's existing outage reporting requirements, and via ongoing resolution of consumer complaints about APS service. Engineering further suggests that the Commission be particularly mindful of quality of service differences between the APS Metro Division and more rural service oriented APS divisions. It is for this reason that quality of service to the APS Southeast Division merits special scrutiny to assure service does not deteriorate and become problematic.

APS System Reliability Threshold

	2002-2004*			2002-2005**		
System Attribute	**SAIFI**	**SAIDI**	**CAIDI**	**SAIFI**	**SAIDI**	**CAIFI**
Single Transmission	6.77	567.10	175.40	7.68	477.40	156.40
Redundant Transmission	3.03	189.60	147.90	3.33	158.80	140.50
Overhead Distribution	6.40	572.10	126.20	7.25	486.40	176.90
Underground Distribution	2.40	128.60	190.00	2.48	103.40	121.90

NOTES:

* APS Reliability Review of Electric Service to Tribal Territories, Docket E-01345A-03-0437,October 5, 2005

** APS response to Staff Data Request JDS 2-7, Docket No. E-01345A-05-0816

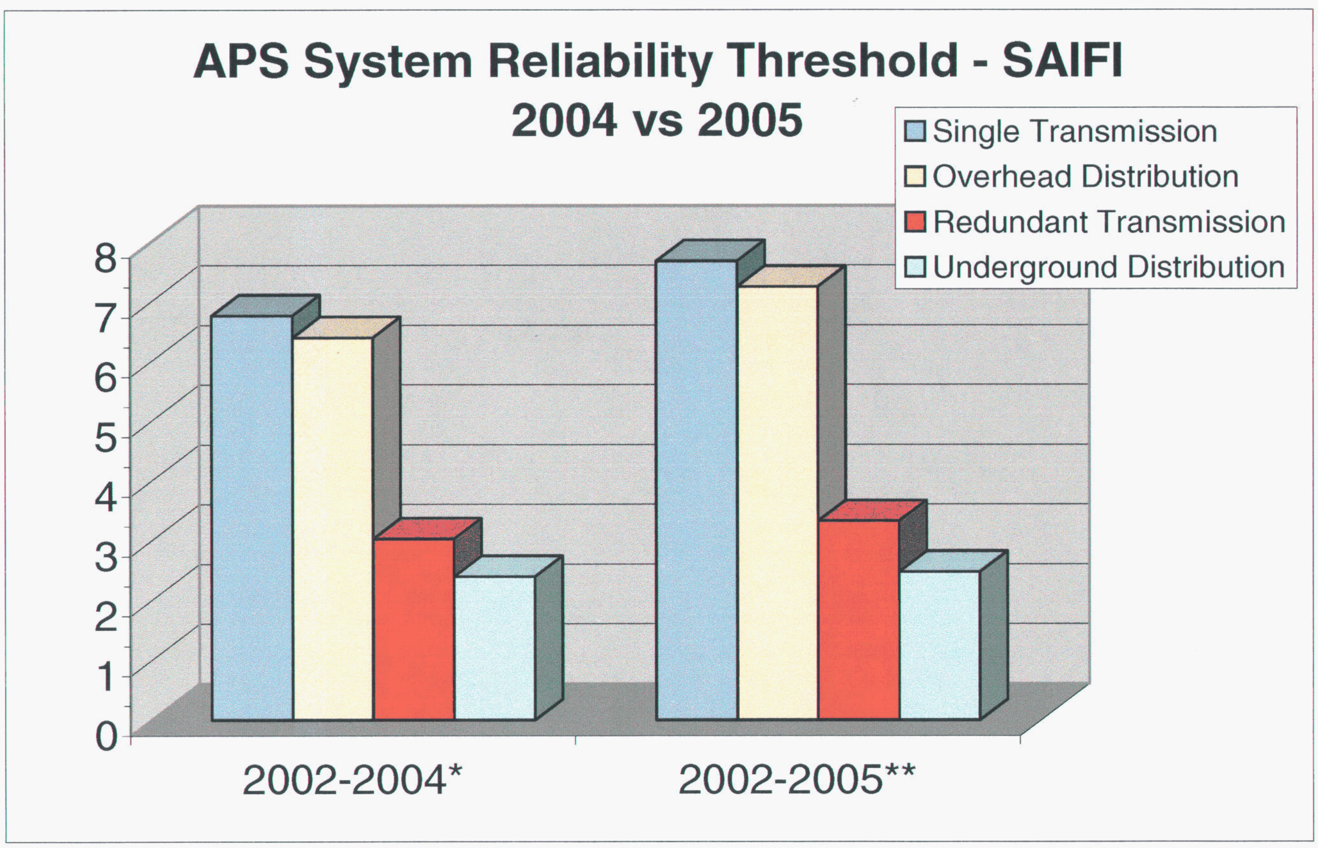
APS System Reliability Threshold - SAIFI

System Attribute	2002-2004*	2002-2005**
Single Transmission	6.77	7.68
Redundant Transmission	3.03	3.33
Overhead Distribution	6.40	7.25
Underground Distribution	2.40	2.48

NOTES:

* APS Reliability Review of Electric Service to Tribal Territories, Docket E-01345A-03-0437,October 5, 2005.

** APS response to Staff Data Request JDS 2-7, Docket No. E-01345A-05-0816



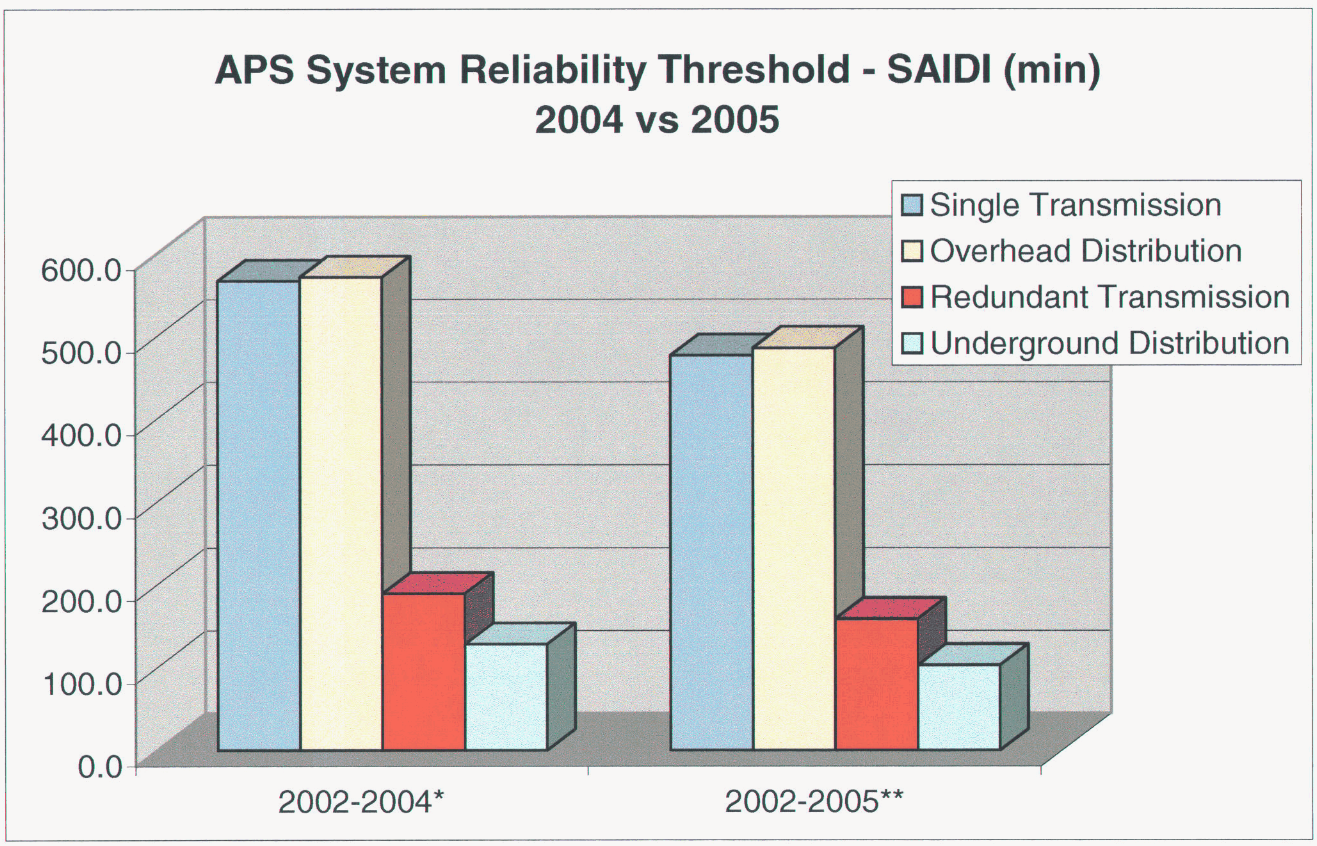
APS System Reliability Threshold - SAIDI (min)

System Attribute	2002-2004*	2002-2005**
Single Transmission	567.1	477.4
Redundant Transmission	189.6	158.8
Overhead Distribution	572.1	486.4
Underground Distribution	128.6	103.4

NOTES:

* APS Reliability Review of Electric Service to Tribal Territories, Docket E-01345A-03-0437,October 5, 2005.

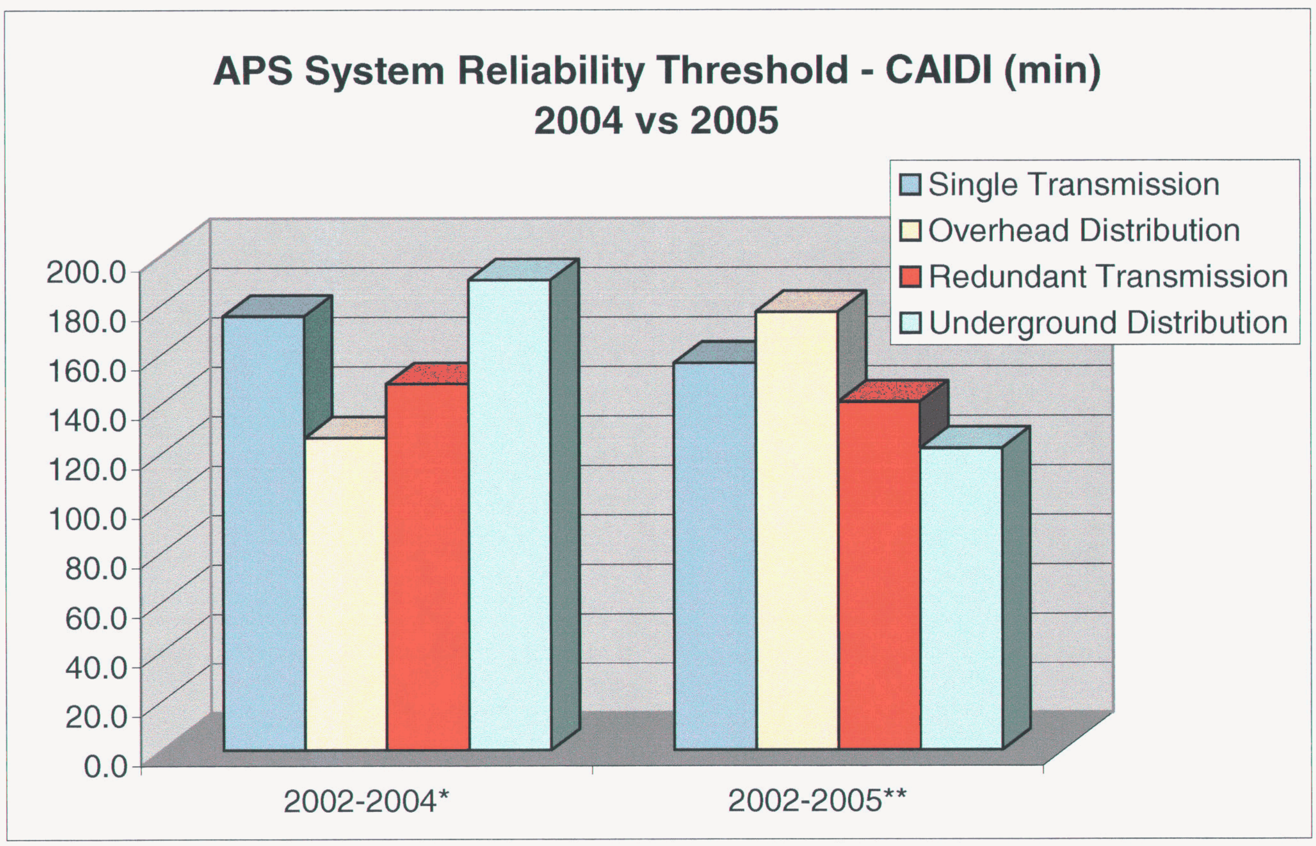
** APS response to Staff Data Request JDS 2-7, Docket No. E-01345A-05-0816



APS System Reliability Threshold - CAIDI (min)

System Attribute	2002-2004*	2002-2005**
Single Transmission	175.4	156.4
Redundant Transmission	147.9	140.5
Overhead Distribution	126.2	176.9
Underground Distribution	190.0	121.9

NOTES:
* APS Reliability Review of Electric Service to Tribal Territories, Docket E-01345A-03-0437,October 5, 2005.
** APS response to Staff Data Request JDS 2-7, Docket No. E-01345A-05-0816



Key APS Metro Division Facilties*

	Worst Performing		2005 Capital Improvements		
Year	Distribution Sub	Dist. Feeder	Dist. Feeder	New/Upgrade Subs	New Trans
2003	Desert Springs	Metro #4			
		Downing #2			
		Humbug #10			
2004	Deer Valley	Encanto #13			
		23rd Street #20			
		Sherman St #22			
2005	Humbug	HappyValleyTemp#4	Dysart #17	Gavilan Peak 230/69	Gavilan Pk-Dove Valley 69
		Indian Bend #10	Encanto #9	Stout, Polk, Oblerlin 69/12	Adobe-Stout 69
		Sherman St # 13	Filmore #19	Pyramid Pk 69/12	
			Lincoln W. #3	WWG 69/12	
			McDowell #9	DeerVly 230/69-upgrade	
			Meadowbrk #1	PPK 345/230 kV upgrade	
			Meadowbrk #21	Garfield, Shea 69/12upgrade	
			New River #2	Rock Spr 69/12 -upgrade	
			Shaw #15	Greenbrier 69/12 upgrade	
			Sherman #14	Lincoln W. 69/12	
			Sherman #17	Paradise 69/12	
			Sherman #22	Colter, Dysart 69/12	
			23rd Street #18	Surprise, Waddell 69/12	
				Humbug 69/12	

APS Generation within Division Boundry:	
Ocotillo W. Phoenix	

*Facilties visited highlighted in red

Key APS Northeast Dvision Facilites

	Worst Performing		2005 Capital Improvements		
Year	Distribution Sub	Dist. Feeder	Dist. Feeder	New/Upgrade Subs	New Trans
2003	Winslow	Preacher Canyon #6 Shumway #6 Shumway #2			
2004	Sandvig	Tusayan #14 Winona #1 Grand Canyon #1			
2005	Elden	Le Barron Hill #1 White Horse #1 Leupp Junction #1	Keems Cnyn #3 Keems Cnyn #5 Winslow #14 Woodruff #2	Matazal	Matazal -Tonto 69 Cholla-Keems Cnyn Flt Loc Blk Mesa-Tuba City Flt Loc Blk Mesa-Sandvig Flt Loc

APS Generation within Division Boundry:	
Cholla	

*Facilties visited highlighted in red

Key APS Northwest Division Facilties*

	Worst Performing		2005 Capital Improvements		
Year	Distribution Sub	Dist. Feeder	Dist. Feeder	New/Upgrade Subs	New Trans
2003	Dewey	Delano #1 Weston Wells #3 Delano #5			
2004	Dewey	Sturm Ruger #10 Bagdad Townsite #10 Pollock #2			
2005	Morristown	Pres.-ChinoWells#4 Aguila #1 Paulden #2	Delano #5 White Spar #12	Aguila 69/12 - upgrade Cottonwood 69/12-upgrade Poplar Wash 69/12	

APS Generation within Division Boundry:

*Facilties visited highlighted in red

Key APS Souheast Division Facilties*

	Worst Performing		2005 Capital Improvements		
Year	Distribution Sub	Dist. Feeder	Dist. Feeder	New/Upgrade Subs	New Trans
2003	Eastgate	San Pedro #14 Rainbow Valley #1 Toltec #4			
2004	Toltec	Aztec # 10 Coolidge #2 Coolidge #1			
2005	Boothill	Rainbow Valley #5 Why #1 Perryville #1	Coolidge #2 Don Luis #3	Boothill 115/21 kV- upgrade Buckeye - upgrade Pinal 115/69/21kV Hayes Gulch 69/21 kV	Pinal - Hayes Gulch 69 kV

APS Generation within Division Boundry:	
Saguaro Sundance Fairview	

*Facilties visited highlighted in red

Key APS Southwest Division Facilities*

	Worst Performing		2005 Capital Improvements		
Year	Distribution Sub	Dist. Feeder	Dist. Feeder	New/Upgrade Subs	New Trans
2003	Havasu	Quechan #26 Gila (DOE) #2 Quartzsite #2			
2004	32nd Street	YumaPalmsTemp#2 Laguna #1 Gila (DOE) #2			
2005	San Luis	Vicksburg #4 Utting #1 Planet #1	Quartzsite #6	Marine Air 69/12 - upgrade N. Gila 500/69	

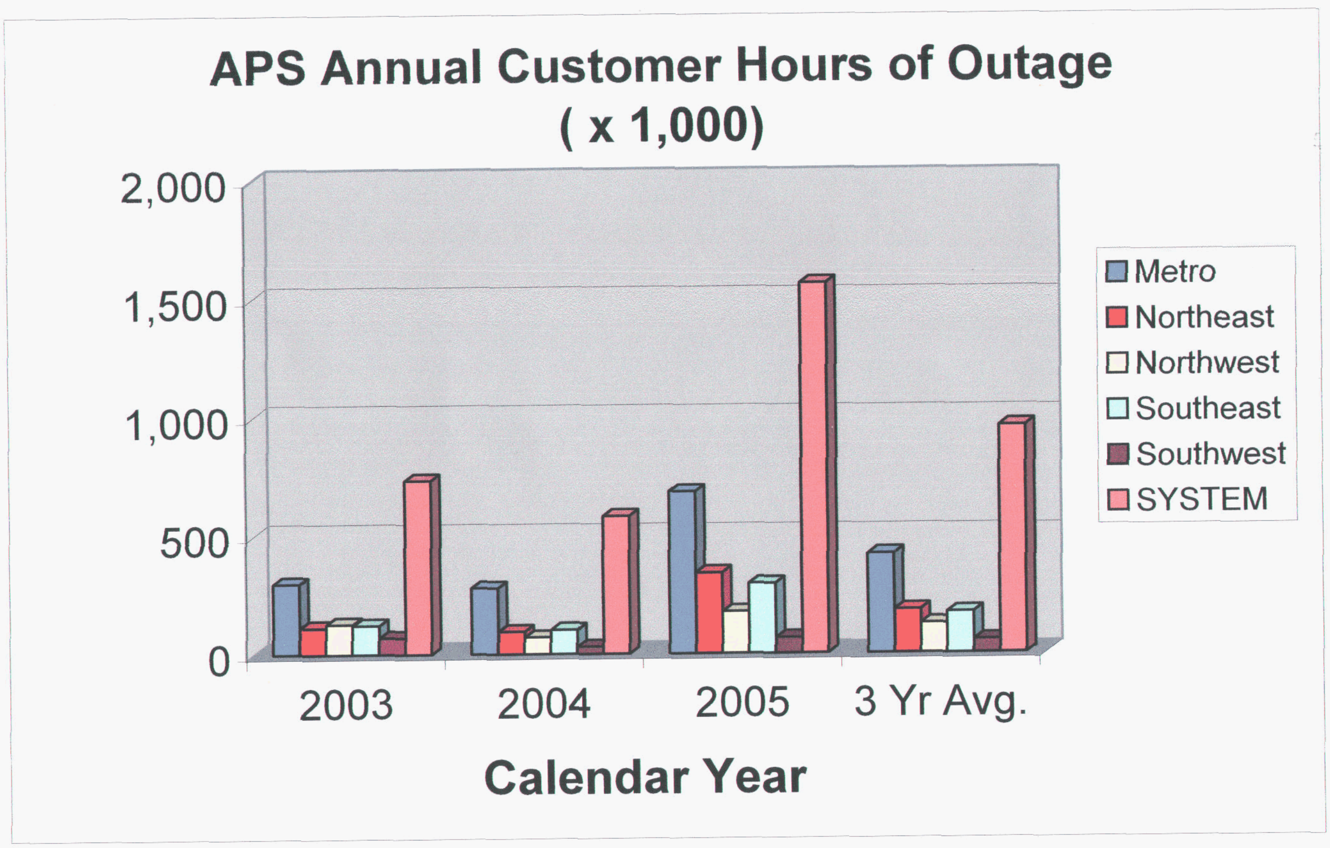
APS Generation within Division Boundry:	
Yucca	

*Facilties visited highlighted in red

Annual Customer Hours of Outage by APS Division*
(x 1,000)

	2003	2004	2005	3 Yr Avg.
Metro	299	280	684	421
Northeast	114	96	341	184
Northwest	128	71	177	125
Southeast	123	103	296	174
Southwest	71	31	67	56
SYSTEM	734	580	1,564	959

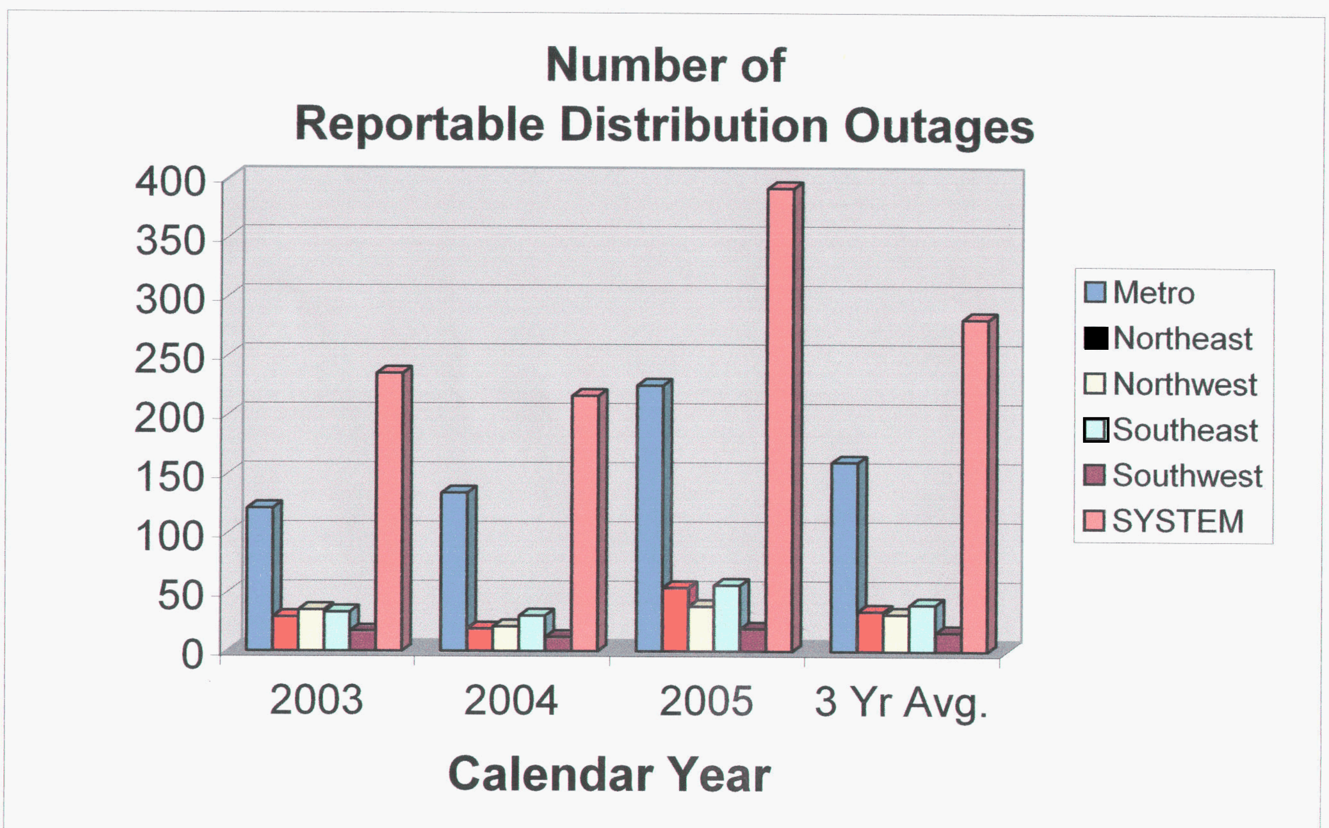
* per APS response to Staff Data Request JDS 2-1, Docket No. E-01345A-05-0816



Number of Reportable Distribution Related Outages by APS Division*
(ACC Reportable Outages = 1,000 Customer Hours or More)

	2003	2004	2005	3 Yr Avg.
Metro	121	134	225	160
Northeast	29	19	54	34
Northwest	35	21	38	31
Southeast	33	30	56	40
Southwest	17	12	19	16
SYSTEM	235	216	392	281

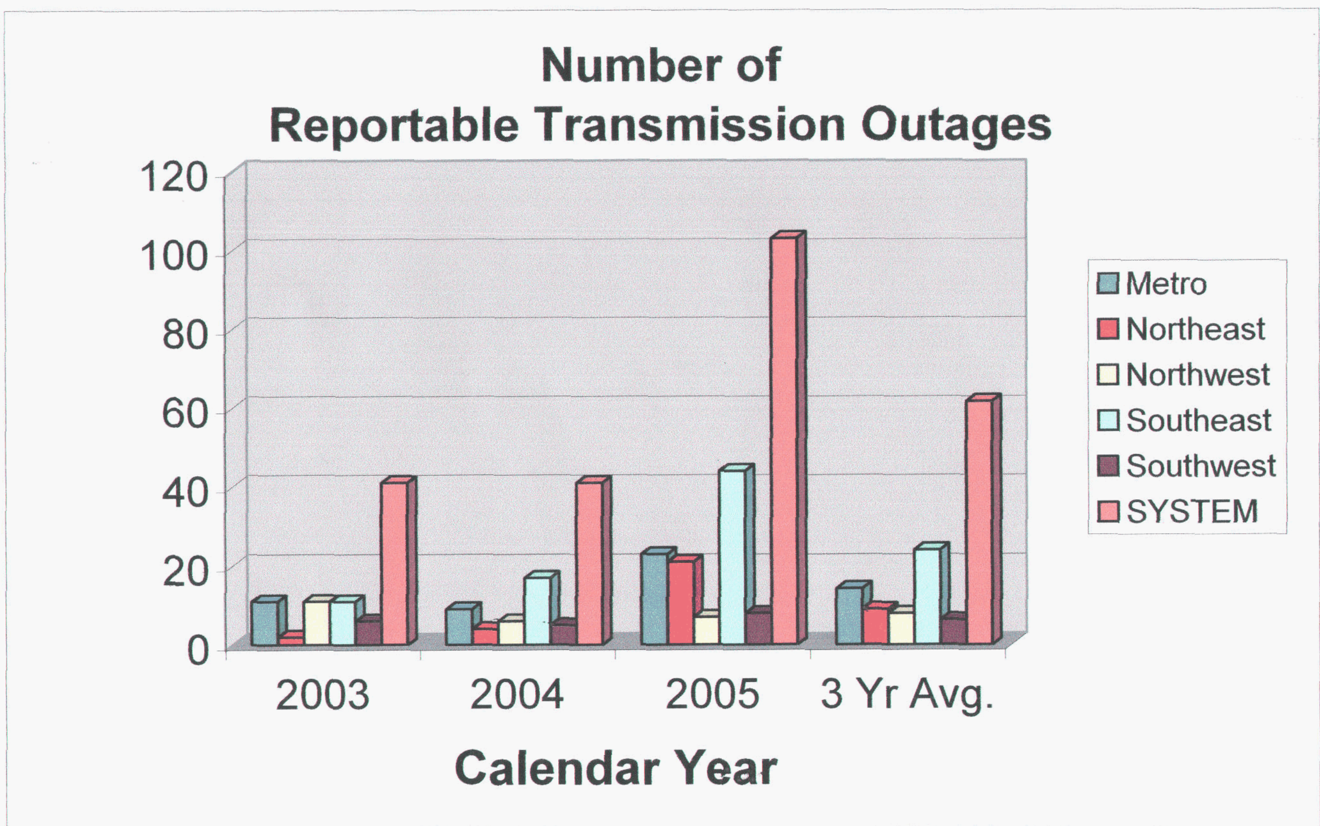
* per APS response to Staff Data Request JDS 2-1, Docket No. E-01345A-05-0816



Number of Reportable Transmission Related Outages by APS Division*
(ACC Reportable Outage = 1,000 Customer Hours or More

	2003	2004	2005	3 Yr Avg.
Metro	11	9	23	14
Northeast	2	4	21	9
Northwest	11	6	7	8
Southeast	11	17	44	24
Southwest	6	5	8	6
SYSTEM	41	41	103	62

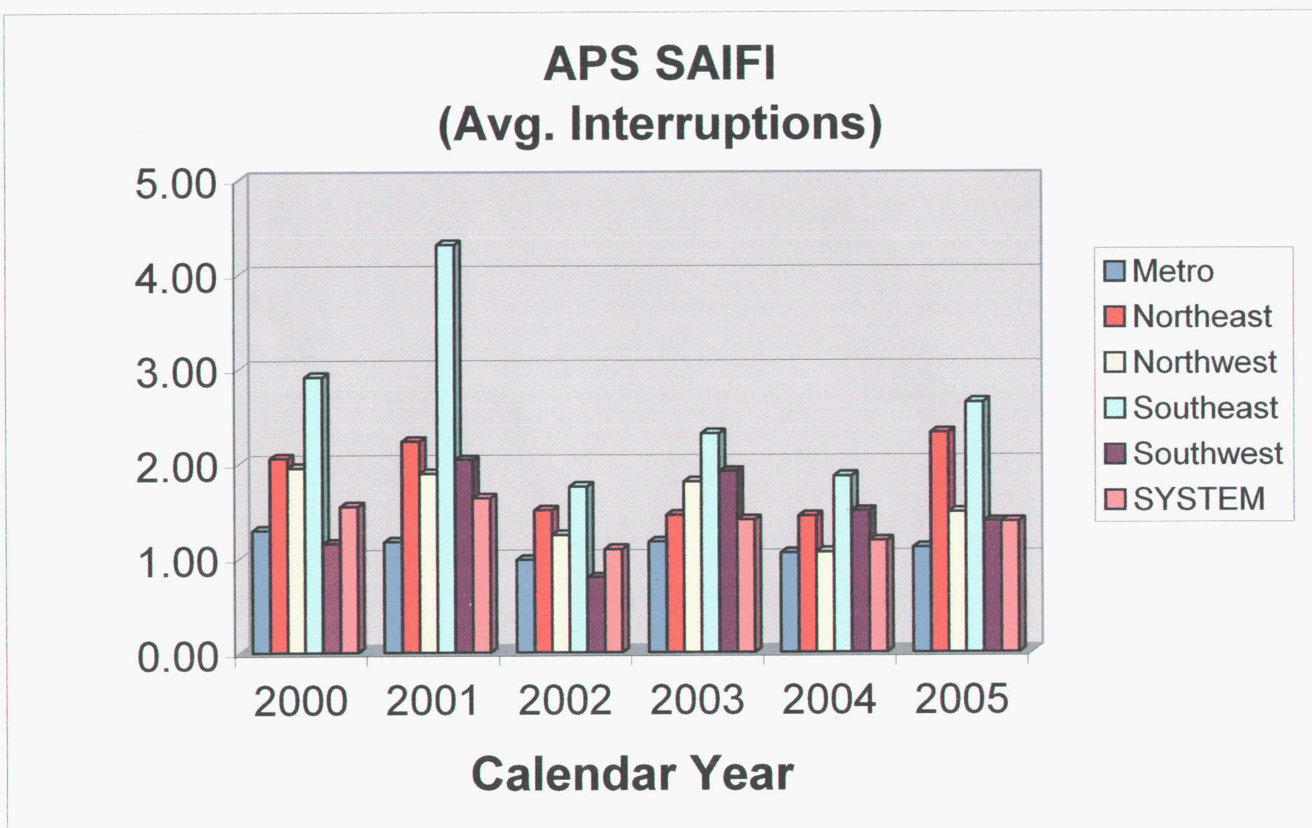
* per APS response to Staff Data Request JDS 2-1, Docket No. E-01345A-05-0816



SAIFI by APS Division* (Avg. Interruptions)

	2000	2001	2002	2003	2004	2005
Metro	1.29	1.17	0.98	1.17	1.05	1.11
Northeast	2.05	2.23	1.50	1.45	1.44	2.32
Northwest	1.95	1.89	1.24	1.80	1.06	1.48
Southeast	2.91	4.31	1.75	2.31	1.86	2.64
Southwest	1.15	2.03	0.79	1.91	1.49	1.38
SYSTEM	1.54	1.63	1.09	1.40	1.18	1.38

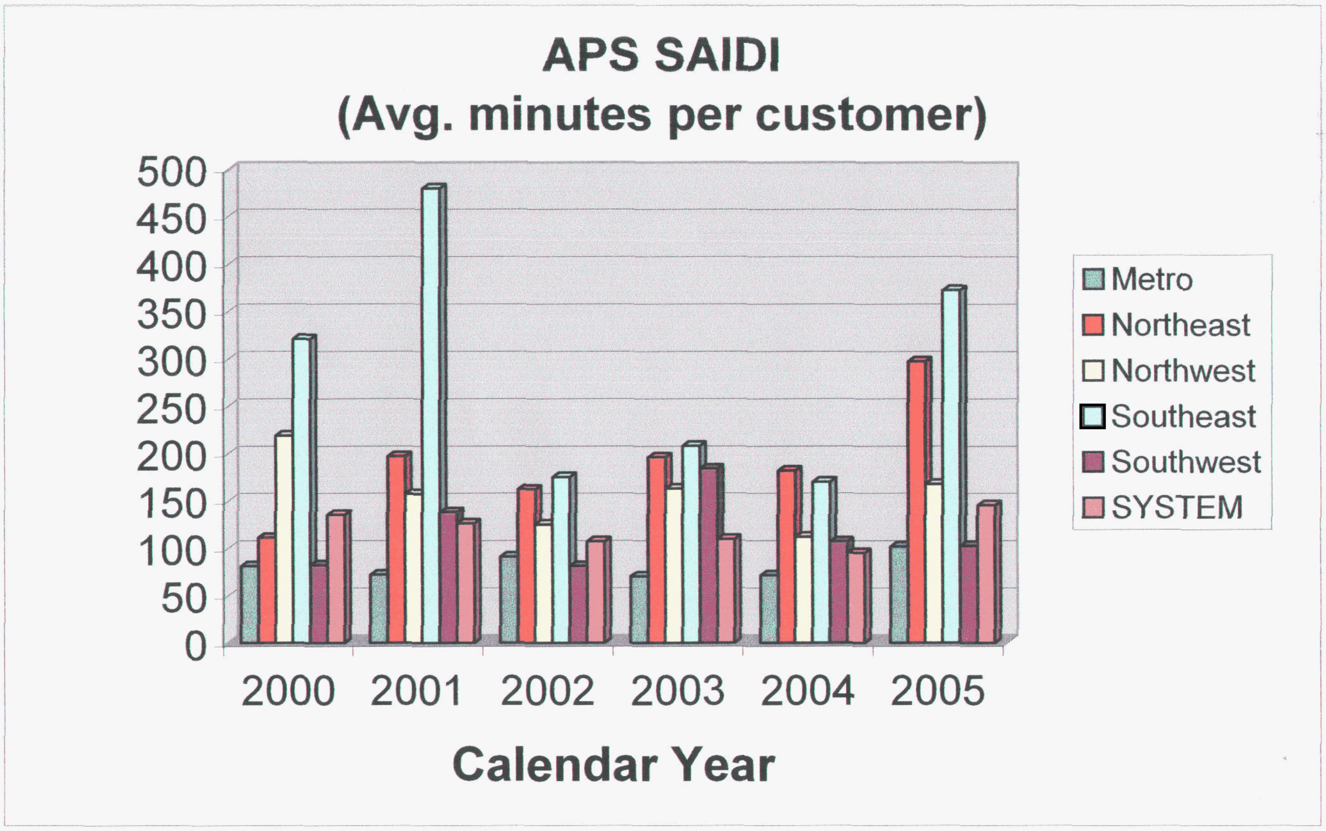
* 2000 - 2002 per APS response to Staff Data Request STF 8-54, Docket No. E-01345A-03-0347
2003 - 2005 per APS response to Staff Data Request JDS 2-3, Docket No. E-01345A-05-0816



SAIDI by APS Division* (Avg minutes per customer)

	2000	2001	2002	2003	2004	2005
Metro	81	72	91	70	71	102
Northeast	111	197	162	196	182	297
Northwest	219	157	125	163	112	168
Southeast	321	480	175	208	170	373
Southwest	82	138	81	184	107	102
SYSTEM	135	126	107	109	95	145

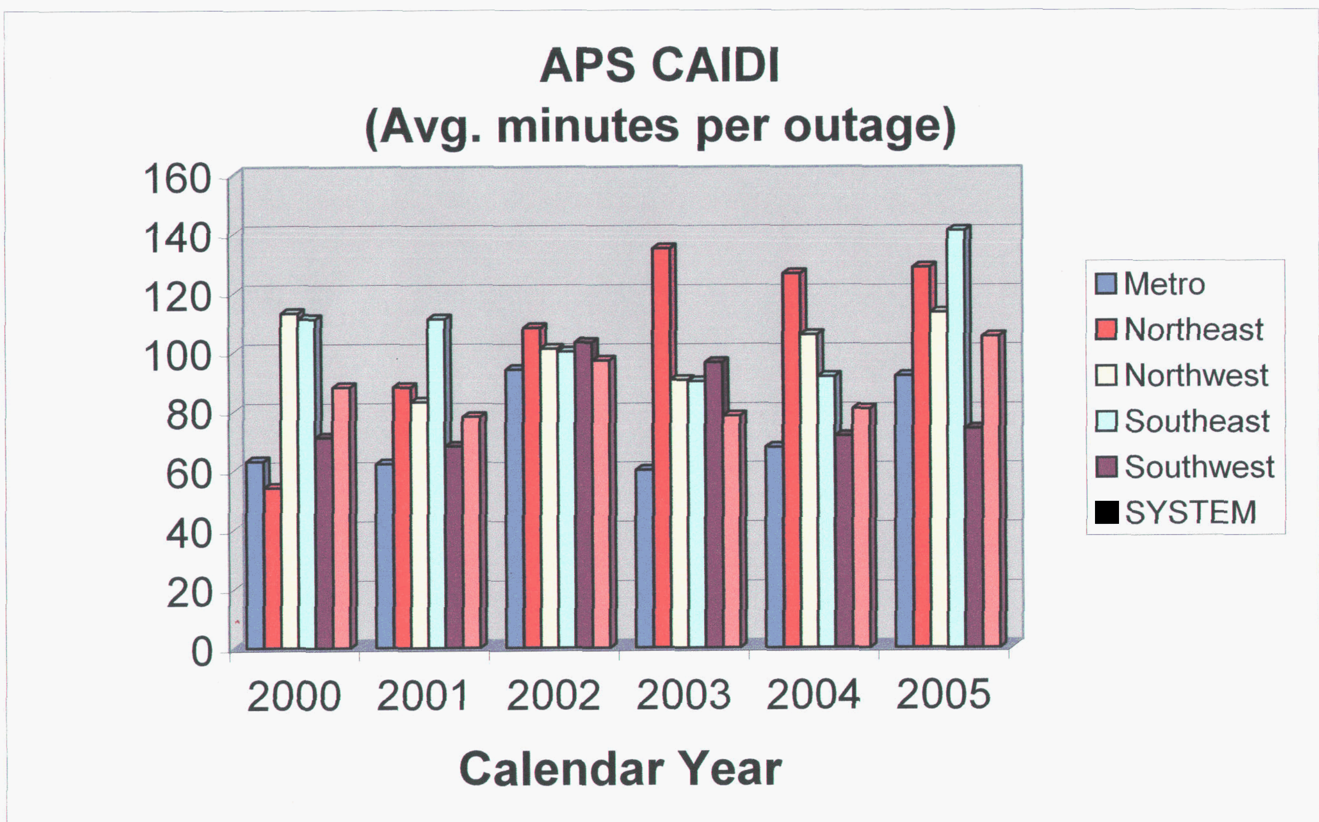
* 2000 - 2002 per APS response to Staff Data Request STF 8-54, Docket No. E-01345A-03-0347
2003 - 2005 per APS response to Staff Data Request JDS 2-3, Docket No. E-01345A-05-0816



CAIDI by APS Division* (Avg. minutes per outage)

	2000	2001	2002	2003	2004	2005
Metro	63	62	94	60	68	92
Northeast	54	88	108	135	126	128
Northwest	113	83	101	90	106	113
Southeast	111	111	100	90	91	141
Southwest	71	68	103	96	71	74
SYSTEM	88	78	97	78	81	105

* 2000 - 2002 per APS response to Staff Data Request STF 8-54, Docket No. E-01345A-03-0347
2003 - 2005 per APS response to Staff Data Request JDS 2-3, Docket No. E-01345A-05-0816



DIRECT

TESTIMONY

OF

WILLIAM R. JACOBS, JR., Ph.D.

DOCKET NO. E-01345A-05-0816

IN THE MATTER OF APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, AND TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, AND TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND TO AMEND DECISION NO. 67744

August 18, 2006

BEFORE THE ARIZONA CORPORATION COMMISSION

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

IN THE MATTER OF APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, AND TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, AND TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND TO AMEND DECISION NO. 67744	DOCKET NO. E-01345A-05-0816

DIRECT TESTIMONY AND EXHIBIT OF

WILLIAM R. JACOBS, JR., Ph.D.

ON BEHALF OF

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

August 18, 2006

ARIZONA PUBLIC SERVICE COMPANY
2006 RATE CASE
DOCKET NO. E-01545A-05-0816

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EXHIBIT

WRJ-1 Resume of William R. Jacobs, Jr., Ph.D.

ARIZONA PUBLIC SERVICE CORPORATION'S 2006 RATE CASE

Before the Arizona Corporation Commission Docket No. E-01345A-05-0816

DIRECT TESTIMONY OF

WILIAM R. JACOBS, JR., Ph.D.

I. INTRODUCTION

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

A. My name is William R. Jacobs, Jr., Ph.D. I am a Vice President of GDS Associates, Inc. My business address is 1850 Parkway Place, Suite 800, Marietta, Georgia, 30067.

Q. DR. JACOBS, PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A. I received a Bachelor of Mechanical Engineering in 1968, a Master of Science in Nuclear Engineering in 1969 and a Ph.D. in Nuclear Engineering in 1971, all from the Georgia Institute of Technology. I am a registered professional engineer and a member of the American Nuclear Society. I have more than thirty years of experience in the electric power industry including more than twelve years of power plant construction and startup experience. I have participated in the construction and startup of seven power plants in this country and overseas in management positions including startup manager and site manager. As a loaned employee at the Institute of Nuclear Power Operations (INPO), I participated in the Construction Project Evaluation Program, performed operating plant evaluations and assisted in development of the Outage Management Evaluation Program. Since joining GDS Associates, Inc. in 1986, I have participated in rate case and litigation support activities related to power plant construction, operation and decommissioning. I have evaluated nuclear power plant outages at numerous nuclear plants throughout the United States. My resume is included as Exhibit WRJ-1.

Q. WHOM ARE YOU REPRESENTING IN THIS PROCEEDING?

A. I am representing the Arizona Corporation Commission ("Commission") in this proceeding.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of this testimony is to sponsor GDS' conclusions reached and recommendations made in the report concerning the operation of the Palo Verde Nuclear Generating Station in 2005 filed in Docket No. E-01345A-05-0826. I will also provide additional information concerning the Nuclear Performance Standard ("NPS") recommended in that report.

II. CONCLUSIONS AND RECOMMENDATIONS

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS CONTAINED IN GDS' REPORT FILED IN THE DOCKET NO. E-01345A-05-0826.

A. My conclusions and recommendations as presented in the GDS' report filed with this Commission on August 17, 2006, are as follows:

Conclusions

1. Performance of the Palo Verde Plant has declined significantly over the past three years.
2. The number of outages in 2005 was much higher than normal and the capacity factor and generation were lower than should be expected.
3. APS acknowledges the decline in performance and has implemented an aggressive Performance Improvement Plan ("PIP") to return the Plant to its former levels of performance.
4. Four of the 2005 outages were avoidable and the result of imprudence.
5. Some of the unplanned Palo Verde outages were caused by faulty or defective vendor supplied equipment. We have evaluated APS' actions related to these specific outages and have concluded that APS' actions were not imprudent.
6. It is too soon to determine the prudence of the Unit 1 shutdown associated with the shutdown cooling line vibration. This is a unique problem. It appears that APS has made a concentrated effort to resolve the vibration problem, which continued into 2006. Additional investigation will be needed to determine the cause of and responsibility for this outage.
7. Although APS received a yellow finding from NRC in 2004 regarding

safety related issues of substantial importance, it is GDS' conclusion that there is no evidence or indication that operation of the plant in 2005 has compromised safety.

Recommendations

1. The Commission should disallow the additional costs resulting from outages identified as avoidable and imprudent in this report. The amount of $17.373 million incurred after the PSA mechanism was in place, April 1, 2005, should be expressly disallowed from recovery under the PSA mechanism. The amount of $1.623 million incurred before April 1, 2005 should not be eligible for consideration in establishing base fuel costs in the pending rate case.
2. An issue related to the unplanned Palo Verde outages attributable to faulty or defective vendor-supplied equipment is the degree to which APS has sought appropriate legal or other remedies. This report does not address this issue, but instead recommends that the Commission address it in the pending rate case. APS should be given the opportunity to demonstrate the steps that it has taken in this regard, and the Commission should evaluate APS' action.
3. The Commission should establish a Nuclear Performance Standard that would establish minimum acceptable levels of performance for Palo Verde and penalties for periods during which the performance of Palo Verde falls below the minimum levels. The Nuclear Performance Standard should be considered in APS' pending rate case.
4. The Commission should order APS to submit a semi-annual report to the Commission's Docket Control, describing plant performance, explaining any negative regulatory reports by the NRC or INPO, and providing

details of corrective actions taken. APS should submit this report semi-annually until the Commission decides that it is no longer necessary.

5. The Commission should order APS to evaluate its programs to deal with aging equipment at Palo Verde. This evaluation should consider industry experience with aging equipment, programs established at other nuclear plants that have been successful in managing aging equipment issues, and recent experience at Palo Verde. APS should submit a report to the Commission within 120 days of the Commission's order in this matter describing the findings of the evaluation and the actions taken to improve APS' management of aging equipment issues.
6. The Commission should order APS to evaluate its programs for receipt inspection and verification of parts prior to installation. This evaluation should consider industry experience, programs established at other nuclear plants that have been successful in avoiding outages due to installation of incorrect parts, and experience at Palo Verde. APS should submit a report to the Commission within 120 days of the Commission's order in this matter describing the findings of the evaluation and the actions taken to improve receipt inspection and pre-installation verification of parts at Palo Verde.

III. NUCLEAR PERFORMANCE STANDARD

Q. IN YOUR REPORT YOU RECOMMEND THAT THIS COMMISSION ADOPT A NUCLEAR PERFORMANCE STANDARD FOR PALO VERDE. WHY IS A NUCLEAR PERFORMANCE STANDARD NEEDED?

A. Nuclear power plants have the highest capital costs of any central power station. This high capital cost is embedded in base rates and APS ratepayers pay for this high capital cost whether or not the plant is in operation. Nuclear power is an economic source of electrical generation because the high capital cost of a nuclear power plant is offset by low fuel and low variable costs. However, low operating costs are sufficient to offset the high capital costs only when the plant is operated at a high capacity factor. Such high capital cost plants must be operated at a high capacity factor for the ratepayers to receive proportionate economic benefits. In addition, when the Palo Verde plant is out of service, the lost generation must be replaced by higher cost generation. When the operating performance of Palo Verde is poor, as it was in 2005, the cost of the replacement generation can be many millions of dollars. Since, in the absence of imprudence, these costs are passed through to ratepayers, APS does not bear the economic burden of these costs and the risk of poor performance is borne entirely by the ratepayer. Implementation of a Nuclear Performance Standard will result in a more equitable sharing of the risk and economic consequences of poor performance between the ratepayer and APS.

Q. PLEASE DESCRIBE THE GENERAL FEATURES OF A NUCLEAR PERFORMANCE STANDARD THAT YOU RECOMMEND THIS COMMISSION ADOPT.

A. The following features should be considered in designing a Nuclear Performance Standard: 1) The method of setting targets and evaluating actual versus target performance should be clearly defined and consistently applied, 2) plant performance should be evaluated in terms of its impact on the "bottom line" system production cost in order to ensure that system cost savings remains the primary operating goal, 3) disallowances should be based on the change in system production costs which is related to the difference between actual and target plant performance, 4) disallowances should closely correlate with the actual change in system production costs which is related to the difference between actual and target plant performance, 5) The range for disallowances should be capped at a level which prevents severe financial penalty and above which detailed reviews of extended outages or other extraordinary events can be conducted, and 6) the Nuclear Performance Standard should be relatively easy to administer and not overly burdensome on the Company or Commission Staff.

Q. **PLEASE PROVIDE MORE SPECIFIC DETAILS ON YOUR RECOMMENDED NUCLEAR PERFORMANCE STANDARD FOR PALO VERDE.**

A. I recommend that the Nuclear Performance Standard for Palo Verde be designed with the following attributes and features:

1. Palo Verde's performance will be measured by the capacity factor achieved, calculated every 3 years.
2. The capacity factor target value is the average capacity factor achieved over the 3-year period by similar U.S. nuclear power plants. Similar nuclear power plants are defined to be all pressurized water reactors ("PWR") operating in the United States with generating capacity greater than 600 MW.

3. U.S. PWRs with a 3-year capacity factor of less than 60% should be excluded from calculation of the target value.
4. If the 3-year capacity factor achieved by Palo Verde is greater than the target value, there would be no action resulting from the NPS.
5. If the 3-year capacity factor achieved by Palo Verde is less than the target value, APS will determine the additional fuel or replacement power costs incurred by comparing actual system costs to system costs that would have resulted if Palo Verde had operated at the target value capacity factor. APS should submit the calculation of Palo Verde performance, the target value and the cost impact if Palo Verde performance is below the target value within 90 days of the end of each 3-year period.
6. Treatment of these additional costs, if any, will be determined by the Commission.
7. At the Commission's discretion, detailed reviews may be conducted of extended outages or other extraordinary events that would significantly impact Palo Verde's capacity factor during the 3-year period.

Q. DOES THE PROPOSED NUCLEAR PERFORMANCE STANDARD REPRESENT A TARGET THAT WILL BE DIFFICULT TO ACHIEVE?

A. No, it does not. The goal of APS management is for Palo Verde to be one of the top performing nuclear power plants in the United States. Establishing a Nuclear Performance Standard based on the average performance of U.S. PWRs is a reasonable measure of nuclear plant performance and does not establish a level of performance that is challenging or will be difficult to achieve.

Q. ARE THERE OTHER ADVANTAGES TO IMPLEMENTING A NUCLEAR PERFORMANCE STANDARD AS RECOMMENDED?

A. Yes. As demonstrated during our investigation of the 2005 Palo Verde outages, a detailed outage investigation is labor intensive and places significant demands on the Commission Staff and on APS and Palo Verde personnel. Establishment of the Nuclear Performance Standard will minimize the need to conduct a detailed evaluation of each Palo Verde outage. Additional fuel and replacement power costs incurred during the period will be allowed or disallowed as determined by the NPS without the need to investigate each outage. Only in the event of an extended outage or other extraordinary event would the Commission need to conduct a detailed investigation. This will reduce the burden on the Commission and on APS to support detailed outage investigation during periods of routine operation.

Q. DOES THAT CONCLUDE YOUR TESTIMONY?

A. Yes it does.

EXHIBIT 1

EDUCATION: Ph.D., Nuclear Engineering, Georgia Tech 1971
MS, Nuclear Engineering, Georgia Tech 1969
BS, Mechanical Engineering, Georgia Tech 1968

ENGINEERING REGISTRATION: Registered Professional Engineer

PROFESSIONAL MEMBERSHIP: American Nuclear Society
National Society of Professional Engineers

EXPERIENCE:

Dr. Jacobs has over thirty years of experience in a wide range of activities in the electric power generation industry. He has extensive experience in the construction, startup and operation of nuclear power plants. While at the Institute of Nuclear Power Operation (INPO), Dr. Jacobs assisted in development of INPO's outage management evaluation group. He has provided expert testimony related to nuclear plant operation and outages in Texas, Louisiana, South Carolina, Florida, Wisconsin and Indiana. He currently provides nuclear plant operational monitoring services for GDS clients. He has assisted the Georgia Public Service Commission staff in development of energy policy issues related to supply-side resources and in evaluation of applications for certification of three combustion turbine peaking projects and assists the staff in monitoring the construction of these projects. He has also assisted in providing regulatory oversight related to an electric utility's evaluation of responses to an RFP for a supply-side resource and subsequent negotiations with short-listed bidders. He has provided technical litigation support and expert testimony support in several complex law suits involving power generation facilities. He monitors power plant operations for GDS clients and has provided testimony on power plant operations and decommissioning in several jurisdictions Dr. Jacobs has provided testimony before the Georgia Public Service Commission, the Public Utility Commission of Texas, the North Carolina Utilities Commission, the South Carolina Public Service Commission, the Iowa State Utilities Board, the Louisiana Public Service Commission, the Florida Public Service Commission, the Indiana Regulatory Commission, the Wisconsin Public Service Commission and the FERC.

A list of Dr. Jacobs' testimony is attached.

1986-Present GDS Associates, Inc.

As Principal, Dr. Jacobs directs GDS' nuclear plant monitoring activities and has assisted clients in evaluation of management and technical issues related to power plant operation and design. He has evaluated and testified on combustion turbine projects in certification hearings and has assisted the Georgia PSC in monitoring the construction of the combustion turbine projects. He has assisted the Georgia PSC staff in overseeing the evaluation and negotiation related to an electric utility's request for proposals for supply side resources. Dr. Jacobs has evaluated nuclear plant operations and provided testimony in the areas of nuclear plant operation, construction prudence and decommissioning in nine states. He has provided litigation support in complex law suits concerning the construction of nuclear power facilities.

1985-1986 Institute of Nuclear Power Operations (INPO)

Dr. Jacobs performed evaluations of operating nuclear power plants and nuclear power plant construction projects. He developed INPO Performance Objectives and Criteria for the INPO Outage Management Department. Dr. Jacobs performed Outage Management Evaluations at the following nuclear power plants:

- Connecticut Yankee - Connecticut Yankee Atomic Power Co.
- Callaway Unit I - Union Electric Co.
- Surry Unit I - Virginia Power Co.
- Ft. Calhoun - Omaha Public Power District
- Beaver Valley Unit 1 - Duquesne Light Co.

During these outage evaluations, he provided recommendations to senior utility management on techniques to improve outage performance and outage management effectiveness.

1979-1985 Westinghouse Electric Corporation

As site manager at Philippine Nuclear Power Plant Unit No. 1, a 655 MWe PWR located in Bataan, Philippines, Dr. Jacobs was responsible for all site activities during completion phase of the project. He had overall management responsibility for startup, site engineering, and plant completion departments. He managed workforce of approximately 50 expatriates and 1700 subcontractor personnel. Dr. Jacobs provided day-to-day direction of all site activities to ensure establishment of correct work priorities, prompt resolution of technical problems and on schedule plant completion.

Prior to being site manager, Dr. Jacobs was startup manager responsible for all startup activities including test procedure preparation, test performance and review and acceptance of test results. He established the system turnover program, resulting in a timely turnover of systems for startup testing.

As startup manager at the KRSKO Nuclear Power Plant, a 632 MWE PWR near Krsko, Yugoslavia, Dr. Jacobs' duties included development and review of startup test procedures, planning and coordination of all startup test activities, evaluation of test results and customer assistance with regulatory questions. He had overall responsibility for all startup testing from Hot Functional Testing through full power operation.

1973 - 1979 NUS Corporation

As Startup and Operations and Maintenance Advisor to Korea Electric Company during startup and commercial operation of Ko-Ri Unit 1, a 595 MWE PWR near Pusan, South Korea, Dr. Jacobs advised KECO on all phases of startup testing and plant operations and maintenance through the first year of commercial operation. He assisted in establishment of administrative procedures for plant operation.
As Shift Test Director at Crystal River Unit 3, an 825 MWE PWR, Dr. Jacobs directed and performed many systems and integrated plant tests during startup of Crystal River Unit 3. He acted as data analysis engineer and shift test director during core loading, low power physics testing and power escalation program.

As Startup engineer at Kewaunee Nuclear Power Plant and Beaver Valley, Unit 1, Dr. Jacobs developed and performed preoperational tests and surveillance test procedures.

1971 - 1973 Southern Nuclear Engineering, Inc.

Dr. Jacobs performed engineering studies including analysis of the emergency core cooling system for an early PWR, analysis of pressure drop through a redesigned reactor core support structure and developed a computer model to determine tritium build up throughout the operating life of a large PWR.

SIGNIFICANT CONSULTING ASSIGNMENTS:
Citizens Utility Board of Wisconsin – Evaluated Spring 2005 outage at the Kewaunee Nuclear Power Plant and provided direct and surrebuttal testimony before the Wisconsin Public Service Commission.

Georgia Public Service Commission - Assisted the Georgia PSC staff in evaluation of Integrated Resource Plans presented by two investor owned utilities. Review included analysis of purchase power agreements, analysis of supply-side resource mix and review of a proposed green power program.

State of Hawaii, Department of Business, Economic Development and Tourism – Assisted the State of Hawaii in development and analysis of a Renewable Portfolio Standard to increase the amount of renewable energy resources developed to meet growing electricity demand. Presented the results of this work in testimony before the State of Hawaii, House of Representatives.

Georgia Public Service Commission - Assisted the Georgia PSC staff in providing oversight to the bid evaluation process concerning an electric utility's evaluation of responses to a Request for Proposals for supply-side resources. Projects evaluated include simple cycle combustion turbine projects, combined cycle combustion turbine projects and co-generation projects.

Millstone 3 Nuclear Plant Non-operating Owners – Evaluated the lengthy outage at Millstone 3 and provided analysis of outage schedule and cost on behalf of the non-operating owners of Millstone 3. Direct testimony provided an analysis of additional post-outage O&M costs that would result due to the outage. Rebuttal testimony dealt with analysis of the outage schedule.

H.C. Price Company – Evaluated project management of the Healy Clean Coal Project on behalf of the General Contractor, H.C. Price Company. The Healy Clean Coal Project is a 50 megawatt coal burning power plant funded in part by the DOE to demonstrate advanced clean coal technologies. This project involved analysis of the project schedule and evaluation of the impact of the owner's project management performance on costs incurred by our client.

Steel Dynamics, Inc. – Evaluated a lengthy outage at the D.C. Cook nuclear plant and presented testimony to the Indiana Utility Regulatory Commission in a fuel factor adjustment case Docket No. 38702-FAC40-S1.

Florida Office of Public Counsel - Evaluated lengthy outage at Crystal River Unit 3 Nuclear Plant. Submitted expert testimony to the Florida Public Service Commission in Docket No. 970261-EI.

United States Trade and Development Agency - Assisted the government of the Republic of Mauritius in development of a Request for Proposal for a 30 MW power plant to be built on a Build, Own, Operate (BOO) basis and assisted in evaluation of Bids.

Louisiana Public Service Commission Staff - Evaluated management and operation of the River Bend Nuclear Plant. Submitted expert testimony before the LPSC in Docket No. U-19904.

U.S. Department of Justice - Provided expert testimony concerning the in-service date of the Harris Nuclear Plant on behalf of the Department of Justice U.S. District Court.

City of Houston - Conducted evaluation of a lengthy NRC required shutdown of the South Texas Project Nuclear Generating Station.

Georgia Public Service Commission Staff - Evaluated and provided testimony on Georgia Power Company's application for certification of the Intercession City Combustion Turbine Project - Docket No. 4895-U.

Seminole Electric Cooperative, Inc. - Evaluated and provided testimony on nuclear decommissioning and fossil plant dismantlement costs - FERC Docket Nos. ER93-465-000, et al.

Georgia Public Service Commission Staff - Evaluated and prepared testimony on application for certification of the Robins Combustion Turbine Project by Georgia Power Company - Docket No. 4311-U.

North Carolina Electric Membership Corporation - Conducted a detailed evaluation of Duke Power Company's plans and cost estimate for replacement of the Catawba Unit 1 Steam Generators.

Georgia Public Service Commission Staff - Evaluated and prepared testimony on application for certification of the McIntosh Combustion Turbine Project by Georgia Power Company and Savannah Electric Power Company - Docket No. 4133-U and 4136-U.

New Jersey Rate Counsel - Review of Public Service Electric & Gas Company nuclear and fossil capital additions in PSE&G general rate case.

Corn Belt Electric Cooperative/Central Iowa Power Electric Cooperative - Directs an operational monitoring program of the Duane Arnold Energy Center (565 Mwe BWR) on behalf of the non-operating owners.

Cities of Calvert and Kosse - Evaluated and submitted testimony of outages of the River Bend Nuclear Station - PUCT Docket No. 10894.

Iowa Office of Consumer Advocate - Evaluated and submitted testimony on the estimated decommissioning costs for the Cooper Nuclear Station - IUB Docket No. RPU-92-2.

Georgia Public Service Commission/Hicks, Maloof & Campbell - Prepared testimony related to Vogtle and Hatch plant decommissioning costs in 1991 Georgia Power rate case - Docket No. 4007-U.

City of El Paso - Testified before the Public Utility Commission of Texas regarding Palo Verde Unit 3 construction prudence - Docket No. 9945.

City of Houston - Testified before Texas Public Utility Commission regarding South Texas Project nuclear plant outages - Docket No. 9850.

NUCOR Steel Company - Evaluated and submitted testimony on outages of Carolina Power and Light nuclear power facilities - SCPSC Docket No. 90-4-E.

Georgia Public Service Commission/Hicks, Maloof & Campbell - Assisted Georgia Public Service Commission staff and attorneys in many aspects of Georgia Power Company's 1989 rate case including nuclear operation and maintenance costs, nuclear performance incentive plan for Georgia and provided expert testimony on construction prudence of Vogtle Unit 2 and decommissioning costs of Vogtle and Hatch nuclear units - Docket No. 3840-U.

Swidler & Berlin/Niagara Mohawk - Provided technical litigation support to Swidler & Berlin in law suit concerning construction mismanagement of the Nine Mile 2 Nuclear Plant.

Long Island Lighting Company/Shea & Gould - Assisted in preparation of expert testimony on nuclear plant construction.

North Carolina Electric Membership Corporation - Prepared testimony concerning prudence of construction of Carolina Power & Light Company's Shearon Harris Station - NCUC Docket No. E-2, Sub537.

City of Austin, Texas - Prepared estimates of the final cost and schedule of the South Texas Project in support of litigation.

Tex-La Electric Cooperative/Brazos Electric Cooperative - Participated in performance of a construction and operational monitoring program for minority owners of Comanche Peak Nuclear Station.

Tex-La Electric Cooperative/Brazos Electric Cooperative/Texas Municipal Power Authority (Attorneys - Burchette & Associates, Spiegel & McDiarmid, and Fulbright & Jaworski) - Assisted GDS personnel as consulting experts and litigation managers in all aspects of the lawsuit brought by Texas Utilities against the minority owners of Comanche Peak Nuclear Station.

BEFORE THE
ARIZONA CORPORATION COMMISSION

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

DIRECT TESTIMONY and ATTACHMENTS of

JAMES R. DITTMER

and

MICHAEL L. BROSCH

As well as

JOINT ACCOUNTING SCHEDULES

ON BEHALF OF THE UTILITIES DIVISION STAFF

AUGUST 18, 2006

BEFORE THE
ARIZONA CORPORATION COMMISSION

IN THE MATER 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) DOCKET NO. E-01345A-05-0816
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RETURN, AND TO AMEND DECISION NO. 67744)

DIRECT TESTIMONY AND

ATTACHMENTS OF

JAMES R. DITTMER

ON BEHALF OF THE
UTILITIES DIVISION STAFF

PUBLIC VERSION

Data Deemed to be Confidential by APS has Been Redacted

AUGUST 18, 2006

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DIRECT TESTIMONY OF JAMES R. DITTMER

DIRECT TESTIMONY
OF
JAMES R. DITTMER

ARIZONA PUBLIC SERVICE COMPANY
DOCKET NO. E-01345A-05-0816

Q. Please state your name and address.

A. My name is James R. Dittmer. My business address is 740 Northwest Blue Parkway, Suite 204, Lee's Summit, Missouri 64086.

Q. By whom are you employed?

A. I am a Senior Regulatory Consultant with the firm of Utilitech, Inc., a consulting firm engaged primarily in utility rate work. The firm's engagements include review of utility rate applications on behalf of various federal, state and municipal governmental agencies as well as industrial groups. In addition to utility intervention work, the firm has been engaged to perform special studies for use in utility contract negotiations.

Q. On whose behalf are you appearing?

A. Utilitech, Inc. has been retained by the Utilities Division Staff ("Staff") of the Arizona Corporation Commission ("ACC" or "Commission") to undertake a review of Arizona Public Service Company's ("APS" or "Company") application for a change in base rates.

Q. Is Utilitech responsible for the review of all elements of APS' rate request?

A. No. Utilitech has subcontracted with two firms to assist in this review. Liberty Consulting Group, Inc. ("Liberty") has been retained to review APS' proposed roll-in amount of ongoing fuel and purchased power expense – net of margins from off-system sales. Additionally, Liberty is responsible for addressing conceptual and mechanical changes that APS is proposing to the existing Power Supply Adjustor ("PSA").

Technical Associates, Inc. has also been retained as a subcontractor to Utilitech to address capital structure and cost of capital issues. Additionally, the ACC Staff is internally addressing some issue areas, including rate design, Demand Side Management Programs, Environmental Portfolio Standards, and quality of service issues – just to name a few.

Under the direction of the Utilities Division Staff, Utilitech has been responsible for the review and development of the majority of remaining issue areas, including proforma rate base and operating income, as well as a revised class cost of service study. Additionally, Utilitech is responsible for aggregating, summarizing and presenting the cumulative results of the recommendations of all Staff personnel and all ACC Staff consultants.

QUALIFICATIONS

Q. Before discussing in greater detail the issues and various recommendations that you will be addressing, please state your educational background.

A. I graduated from the University of Missouri - Columbia, with a Bachelor of Science Degree in Business Administration, with an Accounting Major, in 1975. I hold a Certified Public Accountant Certificate in the State of Missouri. I am a member of the American Institute of Certified Public Accountants.

Q. Please summarize your professional experience.

A. Subsequent to graduation from the University of Missouri, I accepted a position as auditor for the Missouri Public Service Commission. In 1978, I was promoted to Accounting Manager of the Kansas City Office of the Commission Staff. In that position, I was responsible for all utility audits performed in the western third of the State of Missouri. During my service with the Missouri Public Service Commission, I was involved in the audits of numerous electric, gas, water and sewer utility companies. Additionally, I was involved in numerous fuel adjustment clause audits, and played an active part in the formulation and implementation of accounting staff policies with regard to rate case audits and accounting issue presentations in Missouri. In 1979, I left the Missouri Public Service Commission to start my own consulting business. From 1979 through 1985 I practiced as an independent regulatory utility consultant. In 1985, Dittmer, Brosch and Associates was organized. Dittmer, Brosch and Associates, Inc. changed its name to Utilitech, Inc in 1992.

My professional experience since leaving the Missouri Public Service Commission has consisted primarily with issues associated with utility rate, contract and acquisition matters. For the past twenty-seven years, I have appeared on behalf of clients in utility rate proceedings before various federal and state regulatory agencies. In representing those clients, I performed revenue requirement studies for electric, gas, water and sewer utilities and testified as an expert witness on a variety of rate matters. As a consultant, I have filed testimony on behalf of industrial consumers, consumer groups, the Missouri Office of the Public Counsel, the Missouri Public Service Commission Staff, the Indiana Utility Consumer Counselor, the Mississippi Public Service Commission Staff, the Arizona Corporation Commission Staff, the Arizona Residential Utility Consumer Office, the Nevada Office of the Consumer Advocate, the Washington Attorney General's Office, the Hawaii Consumer Advocate's Staff, the Oklahoma Attorney General's Office, the West Virginia Public Service Commission Consumer Advocate's Staff, municipalities and the Federal government before regulatory agencies in the states of Arizona, Alaska, Michigan, Missouri, Oklahoma, Ohio, Oregon, Florida, Colorado, Hawaii, Kansas, Mississippi, New Mexico, Nevada, New York, West Virginia, Washington and Indiana, as well as the Federal Energy Regulatory Commission.

SUMMARY OF UTILITIES DIVISION STAFF'S RECOMMENDATIONS

Q. Please summarize your understanding of APS' request for rate relief in this docket.

A. Within its January 31, 2006 updated filing in this docket, APS requests and purports to justify an annual increase in base rates in the amount of $449.6 million over that which was approved in Decision No. 67744 on April 1, 2005 (i.e., APS' 2003 rate case – Docket No. E-01345A-03-437). In addition to the noted *base rate* increase requested, APS also seeks to implement an Environmental Improvement Charge ("EIC") tracker that would be initially established at a level designed to annually collect $4.3 million in addition to the requested $449.6 million base rate increase. The Company's requested $449.6 million increase in base rates represents an average increase to Arizona retail customers of 21.14%. With the additional EIC request, if each of APS' requested rate changes were to be approved, the average Arizona retail customer would experience a total increase of 21.34% over existing base rates.

The Company's base rate relief request can be further broken down into a "fuel" or "Power Supply Adjustor" component versus a "non-fuel" or "other" component. Specifically, of the total requested $449.6 million base rate increase, $298.7 million relates to APS' request for a 1.1161 cents per kWh increase in the PSA factor, while $150.9 million of the Company's total base rate increase request relates to "non-fuel" or costs "other than" power supply. If the Company's PSA factor roll-in request were approved the amount of PSA costs collected in base rates would rise from the current amount of 2.0743 cents per kWh to 3.1904 cents per kWh.

Q. What is the overall recommendation of the Utilities Division Staff that incorporates the cumulative proposals of all the various Staff in-house personnel as well as outside consultants testifying within this proceeding?

A. Staff is recommending an overall increase in base rates above that approved within Decision No. 67744 (i.e., the 2003 APS rate order) in the amount of $204.0 million. Such overall increase will result in an average increase to Arizona retail customers of 9.6%.

Further, Staff's recommended increase can also be broken into a PSA/fuel component of $193.5 million and a "non-fuel" or "other" component of $10.5 million. Liberty Consulting Group is recommending on behalf of the Utilities Division Staff that the PSA amount included in base rates be raised from the currently collected amount of 2.0743 cents per kWh to 2.7975 cents per kWh based upon an updated 2006 fuel forecast run.

Mr. Matthew Rowell appearing on behalf of the Utilities Division Staff is also recommending rejection of APS' proposed Environmental Improvement Charge tracker – that again, was requested by APS to be initially implemented to collect $4.3 million annually. While not a component of Staff's "base rate" recommendation, Staff witness Ms. Barbara Keene is recommending that

Environmental Portfolio Standard ("EPS") surcharges be increased to provide for annual collection of an additional $4.3 million.

Staff retained GDS Associates, Inc. ("GDS") to investigate prolonged outages that occurred at the Palo Verde Nuclear Generating Station during 2005 that, in turn, caused APS to incur higher power supply replacement costs that were initially deferred during 2005. As a result of the GDS investigation, Staff will be recommending that a portion of deferred power supply costs currently recorded within the "Paragraph 19d Balancing Account" be written off. However, Ms. Keene will be recommending implementation of a "second step" Paragraph 19 d Balancing Account surcharge that will provide for recovery of additional 2005 deferred power supply costs that remain to be collected after removing the Palo-Verde-outage related costs determined to have been imprudently incurred. Ms. Keene's recommendations regarding a "second step" Paragraph 19 Balancing Account surcharge has not been quantified as of this point in time, but will be included with rate design testimony to be filed on September 1, 2006

For convenience I have prepared Table A below that summarizes the Company's request versus the Staff's recommendation, including a further breakdown between the "fuel/PSA" components and "all other" components:

Table A Summary of APS' Request Versus Staff's Recommendations		
	APS' Request	**Staff's Recommenda-tion**
Annual Dollar Increase in Base Rates (millions):		
Fuel/power supply increase recommended	$298.7	$193.5
Non-fuel Increase Recommended	$150.9	$10.5
Total Overall Base Rate Increase Recommended	**$449.6**	**$204.0**
Environmental Improvement Charge	$4.3	
Incremental EPS		**4.3**
Paragraph 19 d Bal. Account "second step" (to be filed with Staff rate design testimony)		[1]
Total Increase – Base & Trackers	**$453.9**	**$208.3**
% Impact to Average Retail Customer:		
Fuel/power supply increase recommended	14.0%	9.1%
Non-fuel Increase Recommended	7.10%	0.5%
Total Overall Base Rate Increase Recommended	**21.1%**	**9.6%**
Environmental Improvement Charge	0.02%	–
Incremental EPS		**.2%**
Paragraph 19 d Bal. Account "second step" (to be filed with Staff rate design testimony)		
Total Increase – Base & Trackers	**21.3%**	**9.8%**

Q. Are the increases proposed by APS and recommended by Staff in addition to, or above and beyond, those increases that this Commission has thus far approved during the first half of 2006?

A. No. It is important for the Commission as well as ratepayers to understand that the increases being proposed are, for the most part, *not* additive to increases already granted. The increases granted by this Commission during the first half of 2006 all dealt with recovery of fuel/other power supply costs. As noted from

[1] As noted, this Staff recommendation has not been quantified as of the time this direct testimony is being filed. It will, however, be included with Staff's rate design testimony expected to be filed on September 1, 2006.

Table A above, approximately two-thirds of the Company's requested increase, and the majority of Staff's recommended increase in this docket, relate directly to recovery of fuel/other power supply costs. Thus, for the fuel/power supply portion of the recommended base rate increase – which represent the majority of each parties' rate proposals – the increases being recommended are largely in place of, or in lieu of, increases granted earlier in 2006.

Q. Please provide a brief description of your understanding of increases granted by the ACC thus far in 2006.

A. Thus far in 2006 the ACC has granted APS three rate increases – again, all regarding recovery of "ongoing" as well as previously deferred or "banked" power supply costs. First, within Decision No. 68437 issued in Docket No. E-01345A-03-0437 et al, this Commission authorized APS to increase its PSA factor by four mills per kWh ($.004 cents/kWh) effective on February 1, 2006. This increase will allow APS to recover approximately $110 million annually, and resulted in an average increase in Arizona retail rates of approximately 5.2 percent (5.2%). In 2005 APS under recovered in total approximately $170 million of PSA-includable power supply costs. Because of the current four mill cap on the PSA adjustor, the most that APS is permitted to collect under the annual PSA adjustor is the noted approximate $110 million. The remaining approximate $60 million of 2005 under collected PSA-includable costs were transferred to a separate account – commonly referred to as the "Paragraph 19 d Balancing Account."

In Decision No. 67744 issued following APS' 2003 rate case the Commission envisioned that the PSA would be adjusted annually, or in other words, it would not be adjusted for the first time following the issuance of Decision No. 67744 until April 1, 2006. However, given the dramatic increase in fuel and purchased power expense being incurred by APS in late 2005, this Commission elected to authorize earlier-than-originally-anticipated implementation of a new "annual" PSA factor. Further, as noted, APS was authorized to implement the maximum four mill PSA adder provided for within Decision No. 67744. As explained in greater detail below, it is currently expected that the four mill adder approved to collect 2005 under recovered power supply costs will be automatically renewed to continue recovering anticipated 2006 under recovered power supply costs.

Q. Please discuss the next APS increase authorized by this Commission in 2006.

A. In Decision No. 68646 issued within Docket No. E-01345A-06-0063 the ACC authorized APS to implement a surcharge in the amount $.000554 per kWh (.554 mills/kWh). As previously described, approximately $60 million of under recovered 2005 power supply costs could not be collected under the four mill PSA annual adjustor cap, and was therefore transferred to the Paragraph 19 d Balancing Account. In February 2006 APS sought to implement two separate surcharges designed to collect the $60 million transferred to the Paragraph 19 d Balancing Account over a twelve month period. Anticipating concerns regarding under recovery of power supply costs resulting from abnormal Palo Verde Nuclear Generating Station outages, APS elected to request a "first step" or immediate recovery of some $15.3 million of power supply costs that it had calculated would have occurred even absent the prolonged Palo Verde outages. APS requested that the remaining $44.6 million of under recoveries calculated to have occurred as a result of the prolonged Palo Verde outages be collected with a "second step" surcharge that would be implemented upon completion of this Commission's inquiry regarding the unplanned 2005 outages at the Palo Verde Station. Thus, the surcharge approved in Decision 68646 is designed to allow APS to recover over a one year period approximately $15.3 million of deferred fuel cost that was not impacted, or caused, by the 2005 Palo Verde outages. This surcharge became effective on May 1, 2006 and will remain in effect until the earlier of 1) the end of a twelve month collection period (i.e., April 30, 2007) or 2) full recovery of the $15.3 million deferred fuel balances. Arizona retail customers experienced a 0.7 percent (0.7%) average increase in rates as a result of this Commission decision.

Q. Please discuss the third increase authorized for APS in 2006.

A. In Decision No. 68685 issued within Docket No. E-01345A-06-0009, the ACC authorized APS to implement an "interim PSA" factor of seven mill per kWh ($.007/kWh). The noted seven mill "interim PSA" increase was in addition to the four mill "annual PSA" factor increase authorized on February 1, 2006 within Decision No. 68437. The "interim PSA" resulted in approximately a $192 million annual increase in retail rates and APS retail customers are experiencing approximately a 9.0% overall increase as a result of this final ACC order authorizing APS to change rates in 2006. The "interim PSA" which also became effective on May 1, 2006 is designed to alleviate an otherwise expected significant under recovery of 2006 power supply costs. Unlike the "annual" PSA adjustor that is designed to collect any prior year under recovery of power supply costs, the "interim" PSA adjustor approved was forward looking in nature -- considering forecasted 2006 power supply costs that otherwise would have resulted in a very significant under recovery of "2006 Annual Tracking Account" costs. It will remain in affect until all 2006 Annual Tracking Account costs are recovered except for the amount that can be expected to be collected under the February 2007 4 mill bandwidth limitation (about $110 million as is currently being collected pursuant to the 2005 under recovery).

Q. What amount of power supply costs, subject to future PSA factor modification, was rolled into base rates in APS' prior base rate case?

A. 20.743 mills per kWh (2.0743 cents per kWh).

Q. What amount of comparable power supply costs are being collected as a result of ACC authorizations occurring during the first half of 2006?

A. As described, Decision No. 68437 authorized an "annual PSA" modification of four mills effective February 1, 2006 designed to collect approximately $110 million out of approximately $170 million of total 2005 under recovered PSA-includable costs. Decision No. 68685 authorized an "interim PSA" modification of an *additional* seven mills designed to recover increased power supply costs being experienced, and forecasted to occur, in 2006. Thus, through an "annual" and an "interim" PSA modification, APS is currently recovering 31.743 mills per kWh (3.1743 cents per kWh). Additionally, APS is surcharging an additional .0554 mills per kWh for the recovery of the 2005-related Paragraph 19 d Balancing Account.

Q. How does Staff's recommendation compare to, and fit with, PSA increases granted during 2006?

A. First, APS' February 2006 "annual" PSA adjustor is set at the current cap of four mills per kWh. As discussed earlier, the "interim" PSA adjustor has been designed in anticipation that the February 2007 "annual" PSA adjustor would remain at the four mill cap. Accordingly, it is now anticipated that rates will not be increased or decreased on February 1, 2007 as the four mill "annual" PSA adjustor is expected to remain in effect to recover 2006 under recovered fuel costs.

Second, APS is currently charging an "interim" PSA of seven mills per kWh. Staff's proposal is to reset the PSA factor at zero and increase the base rate fuel component by .7232 cents per kWh – from the current amount of 2.0743 cents per kWh being collect within existing base rates – to 2.7975 cents per kWh. Presumably new base rates that incorporate or roll in the higher ongoing power supply costs in base rates at 2.7975 cents per kWh will go into effect following the expiration of the 2006 "interim" PSA adjustor, or concurrent with the expiration of the 2006 "interim" PSA adjustor. If new base rates that incorporate the higher PSA base (2.7975 cents per kWh) are implemented concurrent with the expiration of the 7 mill per kWh "interim" PSA and "existing" base rates that are collecting PSA cost of 2.0743 cents per kWh, ratepayers will experience a small .232 mills per kWh increase in rates.

Under the Staff's recommendations ratepayers will also experience a modest ($10.5 million annually) increase in base rates related to costs other than PSA-includable costs.

If Staff's recommendation to increase the various EPS surcharges is approved, retail rates will additionally be increased by approximately $21.4 million annually.

The "first step" Paragraph 19 d Balancing Account surcharge will expire under the terms described earlier. It is unaffected by Staff's other recommendations in this case. Further, as previously noted, Staff will be proposing with its rate design testimony to be filed on September 1, 2006 a "second step" Paragraph 19 d Balancing Account surcharge. Any "second step" Paragraph 19 d Balancing Account surcharge will be initiated and terminated under the terms that this Commission ultimately approves.

Q. Please summarize Staff's current PSA recommendations in relationship to Commission increases granted to APS thus far in 2006.

A. On Table B below I summarize the previous PSA increases granted APS thus far in 2006. I also show Staff's position regarding the PSA roll-in amount being recommended within this current base rate proceeding, as well as show Staff's various other "base" and "tracker" changes being proposed:

				Table B
	Prior Decisions			
	No. 68437	No. 68646	No. 68685	Staff's Current Recommendations
Related Docket No.	E-01345A-03-0437 et al	E-01345A-0063	E-01345A-06-0009	E-01345A-05-0816
Nature of increase	PSA "annual" factor – collecting 2005 deferred PSA costs with 4 mill cap	Paragraph 19 d surcharge designed to recover deferred costs above 4 mill PSA annual adjustor limitation	PSA "interim" increase designed to recover increased 2006 power supply costs to avoid significant 2006 under recovery	Base rate increase – includes new PSA roll-in of 2.7975 cents per kWh versus the current base rate factor of 2.0743 cents per kWh
Implementation date	February 1, 2006	May 1, 2006	May 1, 2006	Early 2007
Termination date	When replaced by a February 1, 2007 "annual" adjustor. It is currently anticipated that the four mill cap will remain in effect on February 1, 2007	Earlier of April 30, 2007 or whenever the bank balance of $15.3 million is collected	Until all 2006 Annual Tracking Account costs are recovered except the amount to be collected under the Feb. 2007 4 mil adjustor cap (about $110 million)	Upon approval of new base rates following the filing and review of a new APS base rate case

Approximate Incr'l Annual Revenues to be Collected pursuant to each Decision	$110 million	$15 million	$192 million	- Base fuel $193.5 - Base Other$10.5 - Step 2 Sur. [2] EPS Incr. $4.3 Overall $208.3
Cumulative increase in rates over *Existing* Base Rates Established in Dec. No. 67744	$110 million	$125 million	$317 million	- Base fuel $193.5 - Base Other$10.5 - Step 2 Sur. [3] EPS Incr. $4.3 Overall $208.3
Incremental kWh charge	4.0 mills	.0554 mills	7.0 mills	7.232 mill increase to reflect an updated PSA roll-in amount; remaining non-fuel increase based upon Class COS Study
Cumulative kWh charge increase	4.0 mills	4.0554 mills	11.0554 mills	7.232 mill increase to reflect an updated PSA roll-in amount; remaining non-fuel increase based upon Class COS Study

I would note that Staff consultant Mr. John Antonuk is recommending that the 2007 PSA adjustor be established by considering forecasted 2007 fuel, purchased power and off-system sales margins. He is not recommending that the 2007 PSA factor be established based upon estimates available at this time. However, at his request APS prepared a 2007 fuel forecast that calculates – utilizing current 2007 price forecast inputs – that annual power supply costs would increase by approximately $157.4 million above the 2006 power supply

[2] To be provided with Staff's September 1, 2006 rate design testimony
[3] To be provided with Staff's September 1, 2006 rate design testimony

cost level which Staff is recommending be rolled into base rate at this point in time.

DEVELOPMENT OF JURISDICTIONAL REVENUE REQUIREMENT ACCOUNTING EXHIBITS

Q. Have you prepared exhibits which quantify, summarize and incorporate the results of the various recommendations being made by ACC Staff witnesses, other co-consultants, as well as yourself?

A. Yes. I have prepared Staff Exhibit __ which consists of a series of Joint Accounting Schedules. The noted Joint Accounting Schedules reflect the individual and cumulative results of all the various recommendations being made by or on behalf of the Utilities Division Staff.

Q. Please describe how Staff Exhibit __ has been prepared and organized.

A. Staff Exhibit __ largely follows the style and format of the accounting exhibits prepared by the Company as part of the Standard Filing Requirements. Specifically, Schedule A is the Revenue Requirement Summary, which reflects the cumulative impact of the various revenue, operating expense, rate base and cost of capital recommendations being sponsored by witnesses appearing on behalf of the ACC Staff. Also shown on Schedule A are the values of the various components underlying the Company's revenue requirement recommendation. Thus, one can observe on a summary level basis how the various components of Staff's revenue requirement recommendation contrast with the Company's proposal (i.e., rate base, adjusted operating income, overall cost of capital).

Q. Does Schedule A – Revenue Requirement Summary also show a required return on a "fair value" rate base?

A. Yes, consistent with Arizona's legal requirements, Staff has developed a return requirement on a "fair value" basis. For purposes of this calculation and consistent with the Company's presentation, I have calculated a "fair value" rate base which consists of an average of a Reconstruction Cost New – Depreciated ("RCND") and original cost rate base. I have developed a RCND net plant in service value by applying ratios developed from APS' original cost and RCND plant in service values. Other RCND rate base components were deemed to be equal to their original cost values.

In order to determine a "fair value" return I calculated the rate of return that would be necessary, when applied to my calculated "fair value" rate base in order to allow the same revenue requirement as is required by my original cost rate base and rate of return calculations. Since I do not conclude that there is any reason to adjust my original cost calculations as a result of any factors that might result from calculating a "fair value" return, I am recommending the "fair value" rate base and rate of return that results from this calculation. Based on my review, I believe that APS has proposed the same method of addressing the "fair value" requirement.

Q. Please continue your discussion of the development of the Joint Accounting Schedules.

A. Schedule B is the Rate Base Summary. In developing Staff's proposed retail rate base I have started by showing APS' proposed jurisdictional rate base by detailed component (i.e., Column A). On page 1,Column C of Schedule B I show the sum of all Staff rate base adjustments, and in Column D one can observe Staff's proposed "as adjusted" retail rate base by detailed category. Page 2 of Schedule B provides a summary of each Staff rate base adjustment being proposed. Immediately following Schedule B – Rate Base Summary are a number of supporting schedules which set forth each individual Staff rate base adjustment. Each individual rate base adjustment has a separate designation such as B-1, B-2, etc. Thus, each rate base adjustment identified and presented with a separate "B-__" designation becomes a reconciling item between APS' and Staff's rate base recommendation.

Schedule C is the Net Operating Income Summary. In a manner similar to the rate base schedules, I begin on Schedule C by showing the Company's "proposed" or "as adjusted" net operating income by major component. The sum of all of Staff's adjustments to net operating income can be found in Column C of Schedule C, with the support for each income statement adjustment developed on separate schedules designated as Schedule C-1, C-2, etc. Thus, like the rate base schedules, each "Schedule C-__" reflects a reconciling component or adjustment between APS' proposed net operating income and Staff's proposed net operating income. Through the remainder of my testimony I will use the terms "Adjustment B-__" and "Schedule B-__" as well as "Adjustment C-__" and "Schedule C-__" interchangeably.

Schedule D reflects the Company's as well as the Staff's proposed capital structure, including the weighted cost of debt, preferred stock and recommended return on equity. Staff's proposed capital structure and component cost recommendations are sponsored by Mr. David Parcell. Mr. Parcell is Vice President of TAI – one of the consulting firms that Utilitech subcontracted with for this engagement.

Q. Please describe Schedule E.

A. Schedule E provides a reconciliation between the Company's requested rate increase and Staff's recommended increase by adjustment or issue area. I would note that the revenue requirement value assigned to rate base issues versus return issues is dependent upon the order in which calculations are undertaken. For instance, the revenue requirement value of the "return" issue will be greater if calculated on APS' proposed rate base rather than Staff's (lower) rate base recommendation. Similarly, the revenue requirement value assigned to an individual rate base adjustment will be higher if calculated utilizing the Company's proposed rate of return rather than Staff's (lower) rate of return recommendation. Schedule E reflects the revenue requirement impact of the Company-versus-Staff return difference based upon APS' proposed retail jurisdictional rate base and reflects the revenue requirement value of each Staff rate base adjustment based upon Staff's proposed rate of return recommendation.

SFAS 112 – OTHER DEFERRED CREDITS RATE BASE OFFSET (Schedule B-1)

Q. Have you reviewed APS' rate base proposal for various deferred debits and deferred credits?

A. Yes.

Q. Are you in agreement with the components that APS has included within its rate base development, as well as the amounts included for the various components?

A. No. Through discovery APS has acknowledged the propriety of including one additional deferred credit item as a rate base offset that was not included within its original rate base proposal. Specifically, in response to Data Request No. UTI-10-302, APS has indicated that it would be appropriate to include the end-of-test-year balance for the Accumulated Provision for SFAS 112. These SFAS 112 costs relate to payments to employees on long-term disability – costs that are ultimately included in the above-the-line cost of service. Accordingly, it is equitable to include these cost free funds as a rate base offset.

Q. Have you prepared a schedule posting this necessary rate base adjustment?

A. Yes. On Schedule B-1 I reflect the rate base adjustment for the Accumulated Provision of SFAS 112 costs that APS acknowledges should be reflected as an offset to rate base.

BARK BEETLE REMEDIATION COSTS (Schedule B-2 and Schedule C-14)

Q. Please give your understanding of the Company's request to reflect recovery of deferred bark beetle remediation costs in this docket.

A. In Docket No. E-01345A-03-0437 a Proposed Settlement was reached between APS and a number of parties – including the ACC Utilities Division Staff – that was in large measure adopted by this Commission. One element of the Proposed Settlement that was accepted by the ACC authorized APS to defer bark beetle remediation costs. The Commission may recall that in that previous rate case docket APS requested in rebuttal testimony to be allowed to recover an estimated amount of costs anticipated to be incurred in removing trees in northern portions of its service territory that had died from bark beetle infestation. The retail rates ultimately approved did not include any allowance for incremental tree and brush removal expense related to bark beetle remediation efforts, but the noted rate order did authorize APS to defer for later recovery reasonable and prudent costs for bark beetle remediation that exceed the prior test year level of tree and brush control expense.

In this proceeding APS has requested rate base inclusion of bark beetle remediation costs deferred on its books as of the end of the test year plus an estimate of additional bark beetle remediation costs expected to be incurred throughout the remainder of 2005 and 2006. Additionally, APS seeks to incorporate within the development of new base rates amortization expense designed to recover over a three year period end-of-test-year-actual plus estimated-through-end-of-2006 deferred bark beetle remediation costs.

Q. Are you in agreement with APS' deferred bark beetle rate base request and amortization expense proposal incorporated within its recommended retail cost of service?

A. No. APS essentially began deferring bark beetle remediation expenditures following the April 1, 2005 rate order from Docket No. E-01345A-03-0437 *retroactively* back to January 1, 2005. APS had no specific authority, nor was there any implied authority pursuant to the settlement or the final ACC decision from Docket No. E-01345A-03-0437, to begin deferring bark beetle costs prior to the effective date of Decision No. 67744. Accordingly, the bark beetle remediation costs incurred and later deferred by APS related to work undertaken between January 1, 2005 and March 31, 2005 (i.e., the period preceding the April 1, 2005 ordered effective date) should be removed from APS' proposed retail rate base. Further, that portion of APS' bark beetle amortization expense proposal related to the first quarter of 2005 deferrals should, similarly, be adjusted.

Q. Are there any other adjustments that need to be made to APS' proposed bark beetle deferral balance beyond removing the first quarter 2005 costs?

A. Yes. First, through discovery APS acknowledged two other problems with its proposed bark beetle deferral balance. First, when calculating its proposed proforma rate base adjustment, APS started with its projected end-of-2006 deferral balance. From the projected end-of-2006 deferral balance APS inadvertently subtracted out the November 30, 2005 actual balance of recorded deferred bark beetle costs *rather than* correctly subtracting out the September 30, 2005 historic test year ending balance that had already been included in the "per books" or "unadjusted test year" rate base values that became the starting point for the test year cost of service. Second, APS also acknowledged that it had failed to reflect or recognize related accumulated deferred income taxes as a reduction to its proforma rate base adjustment. (See response to Data Request No. UTI-14-351)

Q. Have you prepared adjustments to reflect all the needed corrections to bark beetle remediation costs that you have just described?

A. Yes. First, on Schedule B-2 I reflect the calculations necessary to properly recognize rate base adjustments that 1) eliminate deferrals related to expenditures incurred prior to April 1, 2005, 2) reflect related accumulated deferred income taxes associated with APS' before-tax proforma rate base adjustment, and 3) to correct for the problem of subtracting out the incorrect "per book" deferral balances to arrive at the Company's original proforma adjustment.

Further, on the income statement, I have proposed Adjustment No. C-14 to reduce the amount of amortization expense related to the deferral of expenditures occurring prior to April 1, 2005.

CASH WORKING CAPITAL (Schedule B-4)

Q. Please describe Staff Adjustment B-4.

A. Staff Adjustment B-4 reduces rate base to reflect the proper quantification of Cash Working Capital ("CWC") as a source of ratepayer supplied "zero" cost capital, using methodologies consistent with prior ACC decisions.

Q. Has APS proposed a rate base allowance for CWC?

A. Yes. As discussed in the direct testimony of Company witnesses Laura L. Rockenberger and Fred H. Balluff,[4] APS has prepared a lead lag study for its Arizona retail operations for purposes of quantifying CWC in the instant proceeding. Referring to Ms. Rockenberger's Attachment LLR-4 and Mr. Balluff's Attachment FB-1, APS has proposed a net CWC allowance of approximately $(29.1) million,[5] net of special deposits and working funds -- a $29.1 million *reduction* to rate base.

[4] Direct testimony of Company witnesses Rockenberger, pages 26-27, and Balluff, pages 4-11.

[5] APS' proposed $(29.4) million net negative CWC allowance offset by $234,000 for special deposits and working funds, before jurisdictional allocation to Arizona retail operations.

Q. How does the Company's negative CWC allowance of $(29.1) million, before retail allocation, as proposed in the current proceeding compare to APS' recommendation in its last Arizona rate case?

A. In direct testimony in the last APS rate case, the Company proposed to include in rate base a net *positive* CWC allowance of $54.1 million.[6] As summarized in the following table, the CWC allowance APS proposes to include in rate base in the current rate case is about $83 million lower than the amount initially requested in the last rate case:

Description		Net Working Capital Allowance (000's)
Last APS Rate Case (Docket No. E-01345A-03-0437)	(a)	$ 54,098
Current APS Rate Case (Docket No. E-01345A-05-0816)	(b)	(29,139)
Net Change in Working Capital		$ (83,237)

Sources:
(a) Rockenberger Direct, page 11 & Attachment LLR-2 (last rate case).
(b) Rockenberger Direct, page 27 & Attachment LLR-4 (current rate case).

Q. Could you briefly identify the key changes in the Company's valuation of cash working capital that materially contributed to this $83 million reduction in this component of the APS rate base?

A. Yes. About $42 million of the $83 million reduction is attributable to the reduction in the revenue lag from 41.81 days in the last study to 36.95 days in the current study. Another $12 million of the reduction is associated with the recognition of Sales and Franchise taxes in the current study, which were not

6 Direct testimony of Company witness Rockenberger, page 11, Docket No. E-01345A-03-0437.

considered by APS in the last case. The majority of the remaining reduction in CWC is a result of interrelated changes in overall expense levels and expense lags between the two studies, as set forth below:

Change in Expense Amounts & Expense Lags	Change in APS CWC Allowance (000s)
Fuel Expense	$ (708)
Purchased Power	9,525
Other O&M	237
Depreciation & Amortization	(9,242)
Income Taxes – Current	(7,687)
Income Taxes – Deferred	(14,778)
Property Taxes	(8,809)
Total	$ (31,462)

Source:
UTI Workpaper "CWC_reconciliation.xls" based on constant revenue lag of 41.81 days.

Q. The above table shows reductions in APS' requested net CWC allowance from the last case associated with depreciation and amortization as well as income taxes-deferred. Are these reductions due to the fact that APS is not seeking to include non-cash items in the determination of CWC in the current case?

A. No. APS' proposed lead lag study treatment for non-cash items of depreciation and amortization expense as well as deferred income tax expense continues to reflect a full revenue lag and zero expense lag – the same position presented by APS in the last rate case. It is the change in the overall level of these non-cash expense items that causes the reductions noted in the above table.

Q. In quantifying the $(29.1) million negative CWC allowance in the current rate case, did APS employ a methodology that was consistent with the longstanding approach used by this Commission as applied in the Company's last litigated rate case?

A. No. Although the following excerpt from Ms. Rockenberger's direct testimony implies that the Company's lead lag study methodology is consistent with the quantification approach previously adopted by this Commission, certain of the detailed study components are definitely contrary to past ACC decisions:

> "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."
> [Rockenberger Direct, p. 27]

The Company's calculation of the $(29.1) million negative CWC allowance clearly includes non-cash items (e.g., depreciation, amortization and deferred income tax expense) and fails to consider interest expense – contrary to the Commission's findings in Decision No. 55931. These significant exceptions to the precedents established in Decision No. 55931 will be discussed in detail later in this testimony section.

Q. In his direct testimony, does Mr. Balluff discuss Decision No. 55931 or the treatment of these non-cash items and interest expense?

A. Mr. Balluff does not discuss Decision No. 55931 in his direct testimony. However, Mr. Balluff's direct testimony is clear that depreciation, amortization and deferred income tax expenses were included in the Company's lead lag study and that interest expense was not considered in the lead lag study.[7]

Contrary to implications in Ms. Rockenberger's testimony, APS' proposed lead lag study approach goes far beyond the Commission's longstanding lead lag study methodology, as addressed within Decision No. 55931, and thus materially overstates the rate base allowance for CWC, by including non-cash items and excluding interest expense.

Q. The above quote from Ms. Rockenberger's direct testimony appears to indicate that she is not sponsoring the Company's CWC recommendation, which is instead the subject of Mr. Balluff's testimony. To your knowledge, is Mr. Balluff or Ms. Rockenberger responsible for the detailed analyses underlying the quantification of the APS lead lag study results?

A. This question was the subject of several data requests submitted by Utilitech, as the detailed workpapers underlying APS' lead lag study recommendation were actually provided by Ms. Rockenberger. Based on my review of APS' response to the relevant data requests,[8] it is my belief that Mr. Balluff is responsible for the theory and approach used by APS in quantifying CWC, but Ms. Rockenberger is responsible for the detailed workpapers and calculations necessary to implement that theory.

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[7] Balluff Direct, pages 9-11, and Attachment FB-1.

[8] APS responses to Data Request Nos. UTI-5-214, UTI-9-275 and UTI-9-277.

Q. In quantifying Staff Adjustment B-4, did you prepare a stand-alone lead lag study in order to correctly present this component of rate base?

A. No. Since a regulated entity does not record CWC in its general accounting records, the valuation of the amount of CWC to be included in rate base must be quantified through complex, labor intensive specialized analyses (i.e., a lead lag study) conducted within the context of a general rate case proceeding. Significant resources are required to prepare, maintain and review detailed lead lag studies. In lieu of preparing an independent study, resources were committed to the analysis, testing and correction of the lead lag study presented by APS.

Differences in CWC Recommendations

Q. Could you summarize the specific changes and corrections you have proposed with respect to APS' valuation of the CWC allowance?

A. Yes. In quantifying Staff's proposed rate base allowance for CWC, the following modifications and revisions were made to the Company's lead lag study. It is my opinion that recognition of these changes will more accurately quantify the cash working capital needs of APS in conformance with the Commission's CWC policies, as expressed in prior rate orders:

- Remove non-cash expenses (e.g., depreciation and amortization expense, deferred income tax expense, etc.) to limit study results to "cash" expense requirements;

- Recognize pro forma ratemaking interest expense and the extended (i.e., weekly, monthly, semiannual, etc.) interest payment patterns in the lead lag study;

- Revise purchase power expense level to reflect the elimination of significant unregulated power marketing activity from the quantification of CWC; and

- Incorporate the following miscellaneous corrections identified during the analysis of the APS study workpapers and supporting documentation:

  - Revenue lag: recalculate the composite revenue lag using test year revenues, rather than 2004 revenues used by APS, thereby using a re-weighting methodology that is consistent with the purchased power expense adjustment noted previously.

  - Palo Verde Lease expense lag: restate APS' expense lag calculation to reflect a material shift in semi-annual payment requirements beginning in 2005.

  - State Income Tax Expense: revise the payment lag for Arizona state income taxes consistent with the statutory payment due dates.

After removing the non-cash items, recognizing the interest expense lag and posting the other corrections to the APS lead lag study, Staff Adjustment B-4 results in a larger *negative* CWC allowance than proposed by APS.

Q. Please summarize the primary differences in the CWC recommendations being proposed by you and the Company.

A. The following table provides a general summary of the primary CWC quantification issues:

		Approximate CWC Issue Value[9]
APS Recommendation	(a)	$(29.3) million
Remove Non-Cash Items		(43.7) million
Recognize Interest Expense		(15.9) million
Revise Palo Verde Lease Payment Lag		(7.1) million
Adjust Level of Purchased Power Expense		2.6 million
Re-weight Revenue Lag		(.5) million
Staff Proposed CWC Allowance	(b)	$(93.9) million

Note (a): APS witness Balluff, Attachment FB-1.
Note (b): Staff Adjustment B-4.

Q. Why is it appropriate for the lead lag study methodology to produce a negative allowance that reduces rate base?

A. A "negative" CWC valuation, which reduces rate base, is appropriate for several reasons. First, a negative amount indicates that, on average, the Company collects electric sales revenues from ratepayers prior to the need to disburse cash to pay expenses incurred in the provision of electric service. Consequently, the Company has the advance use of ratepayer-provided funds for which ratepayers should be compensated through a rate base offset in the form of negative cash working capital.

Second, the fact that a properly prepared lead lag study results in a "negative" value for CWC should not be surprising or problematic in determining rate base. Just as the Company has previously collected customer advances, accumulated deferred income taxes and accumulated depreciation from ratepayers, which are

9 Amounts shown are before jurisdictional allocation.

used to reduce rate base (i.e., recognized as zero-cost capital), it is relatively common for a utility to collect operational cash flows from ratepayers in advance of the disbursement of those funds to pay expenses. If a lead lag study shows that CWC is a "negative" amount, it is just as reasonable and appropriate to reduce rate base as it would be to increase rate base if the result were positive.

Third, by definition, a fully developed and properly prepared lead lag study is not limited to producing a "zero" or positive rate base allowance. Consistent with this Commission's longstanding practice and procedure, it is possible and appropriate for CWC to yield a significant reduction to rate base, when circumstances warrant.

<u>Overview of Cash Working Capital</u>

Q. What is cash working capital and why should it be included in rate base?

A. Cash working capital is commonly defined as the amount of cash needed by a utility to pay day-to-day <u>expenses</u> incurred in providing service in relation to the timing of the collection of revenues for those services. In applying this definition, if the timing of a company's cash expenditures, in the aggregate, precedes the cash recovery of those expenses, investors must provide cash working capital. On the other hand, ratepayers are considered the providers of cash working capital in instances where their remittances, on the average, precede the company's cash disbursements for expenses. Whether "positive" or "negative" in amount, cash working capital is typically included in utility rate base to recognize the timing of cash flows through the utility.

Q. In your opinion, how should cash working capital be quantified for inclusion in rate base?

A. Sample-based lead lag studies represent the best available method for quantifying the revenue and expense component lags that are used in determining cash working capital. Although it may not be feasible to completely update such studies when a utility routinely seeks a periodic rate increase, due to the complex and detailed nature of such an undertaking, major components of the lead lag study should be updated periodically to ensure that the revenue and expense lag calculations reasonably represent current operational conditions and reflect the effects of recent changes in corporate policies as well as organizational structure.

Evaluation of the Company's lead lag study results included a review of data inputs and computational formulae within multiple lag day spreadsheet study files prepared by Company personnel, as well as judgmental sampling techniques to assess the relative accuracy of transaction source documentation.

Q. You previously referred to use of a "lead lag study" to quantify CWC. Please explain that reference.

A. Many years ago, it was fairly common for regulators to estimate a "provision" for the amount of CWC includable in rate base using an arbitrary "formula" method. The most common method was referred to as the 45-day, or 1/8th of O&M, formula. Variations of this formula method were generally used by regulators until the mid-1970's, as modified from time to time to include or exclude certain items from the formula calculation. Since that time, regulators have often relied on actual measurements of cash flows using detailed lead lag studies to quantify the rate base allowance for CWC.

In contrast, a lead lag study represents a systematic measurement of the timing of cash flows through the utility. Detailed analyses are conducted to calculate the utility's revenue lag – that is, the number of days between the provision of service to customers and the collection of related cash revenues for those services. The timing of cash outflows for the major cash expense elements comprising cost of service are also measured to determine the average number of days between the Company's receipt of goods or services supplied by vendors/ contractors/ employees used in the provision of electric service and the ultimate cash payment for such items.

If more "lag days" on average are involved in the collection of revenues from ratepayers than are available to a utility in the delayed payment of expenses incurred in the provision of related services, investors are required to provide the necessary cash working capital to bridge this gap between payment and collection, resulting in an addition to rate base. On the other hand, if cash disbursements are sufficiently delayed, or revenue collections are accelerated, so that the average expense payment lag days exceed the revenue lag days, ratepayers become cost free providers of cash working capital, causing a reduction to rate base.

Q. Could you explain the significance of the definition of cash working capital?

A. Yes. The definition of cash working capital is significant for purposes of determining and identifying the particular transactions that should be considered in quantifying the CWC allowance includable in rate base. This definition leads to, or implies, the establishment of certain boundaries as to which cash flows are relevant for ratemaking purposes, thereby defining the scope of the lead lag study.

Q. Please identify the major cash flows of a typical public utility, indicating those relevant to the measurement of utility cash working capital requirements.

A. The major sources and uses of cash are observable in a utility's statement of cash flows, or its equivalent, as follows:

Sources of cash for a utility ordinarily include:

- Operating revenues.
- Non-operating and non-jurisdictional revenues.
- Proceeds from outside financings or debt/ equity infusions from parent.
- Asset sales.

Uses of utility cash include:

- Payment of utility expenses.
- Utility plant construction expenditures.
- Payment of non-operating or non-jurisdictional expenses.

- Net change in other assets (inventory, cash, prepayments).
- Retirement of debt or equity.

Given the definition of cash working capital discussed previously (i.e., "the amount of cash needed by a utility to pay its day-to-day expenses . . ."), cash flow timing and measurement focuses on the first cash "source" and the first cash "use" listed above. All other sources and uses are either separately considered in the ratemaking process or are non-operational, financing or non-jurisdictional functions – not transactions related to the day-to-day payment of expenses. It is also important to note that some operating revenues represent a utility's recovery of recorded non-cash expenses, such as depreciation and deferred tax expense. These accrued expenses are properly recognized in determining overall revenue requirement, but do not require the current expenditure of cash. Consequently, these "non-cash" expenses fall outside the scope of a properly prepared lead/lag study.

CWC & Non-Cash Items

Q. Would you briefly explain your proposal to eliminate non-cash items from the lead lag study?

A. Similar to APS' last Arizona rate case, the most significant lead lag methodology difference relates to APS improper inclusion of non-cash expenses (e.g., depreciation, amortization, deferred taxes, etc.) in its lead lag study, which I am proposing to remove consistent with past ACC rate orders. As previously discussed, such items are not reasonably allowed or considered within lead lag studies because they are "non-cash" transactions. These substantive non-cash expenses improperly and significantly overstate the cash working capital required to pay APS' ongoing, day to day expenses. As previously noted, removal of non-cash expenses also complies with previous ACC Decisions addressing this issue.

Q. What is the CWC rate base impact of APS' inclusion of non-cash items in its lead lag study?

A. For ease of reference, Attachment JRD-A reproduces the APS exhibit (i.e., Balluff Attachment FB-1) supporting the calculation of the Company's \$(29.4)[10] million decrease to rate base, which includes these non-cash, accrual-basis expense items. The following table summarizes the non-cash elements of APS' lead lag study results.

Description	APS Proposed CWC Allowance [11]
Nuclear Amortization	\$ 3.5 million
Palo Verde S/L Gain Amortization	(.5) million
Insurance	.5 million
Depreciation and Amortization	32.5 million
Amort. of Prop. Losses & Reg. Study Costs	(.3) million
Deferred Income Taxes	7.9 million
Total Non-Cash Items	\$43.6 million

Sources: Rockenberger LLR_WP11, page 1, & Balluff Attachment FB-1.
Note: Slight rounding difference from amount included in earlier table.

10 The \$(29.1) million working capital allowance cited previously represents the \$(29.4) million lead lag study result less about \$234,000 of working cash and special deposits.

11 Amounts shown are before jurisdictional allocation.

Q. Referring to Attachment JRD – A the Company has assigned a "zero" expense lag day to each of the items in the above table. If the assigned expense lag is "zero", why do you believe that the Company has improperly overstated its cash working capital needs?

A. The use of an assumed "zero" expense lag in and of itself is not a problem. However, the Company has employed a study methodology which applies a revenue lag (i.e., 36.95 days)[12] to each of these "non-cash" expense items. Consequently, the Company's method results in the assignment of a positive revenue lag (see Column 2 of Attachment JRD – A) and a "zero" expense lag (see Column 3 of Attachment JRD – A) to each non-cash item (i.e., lines 6, 29, 30, 34, 36 and 43), thereby improperly overstating CWC by about $43.6 million as a result. By including these non-cash items, the Company's approach has essentially expanded the scope of cash working capital to include cash flows related to the construction and depreciation of plant and the accrual and later payment of deferred income taxes.

Assuming that the purpose of a lead/lag study was expanded to track the timing of <u>all</u> cash flows into and out of the utility, the analysis and measurement would then encompass <u>all</u> cash transactions, whether related to current period expenses, dividend payouts or construction activity. However, other rate base elements would also require analysis, as construction costs are not typically paid immediately in "cash" – as implied by an assumed zero expense payment lag for depreciation.

[12] See Rockenberger LLR_WP11, page 1, and Balluff Attachment FB-1.

Further, except for the Palo Verde Steam Generator Replacement completed near the end of 2005, the balance of APS' gross plant investment included in rate base is as of September 30, 2005. Certain payments for recently completed construction projects closed to plant in service or otherwise included in rate base would not have been fully paid for in cash as of September 30, 2005. However, neither APS nor I are proposing to reduce the recorded balance of gross plant at September 30, 2005 or the installed cost of the Palo Verde Steam Generator Replacement to reflect any delay in disbursement of funds on then-outstanding construction invoices and billings.

Furthermore, the rate base valuation date for both the accumulated depreciation reserve and accumulated deferred income tax reserve, adopted by Company and Staff, is September 30, 2005. Because this valuation date materially precedes the expected rate-effective date of this proceeding,[13] APS will have fully collected accruals to these September 2005 reserve balances from ratepayers months, if not over a year, before any rate change is granted by the Commission. Consequently, APS' proposed expansion to include non-cash items in CWC fails to analyze or account for delayed cash outflows in payment of construction costs, the collection of the reserve balances from ratepayers, or the turn-around and ultimate cash payment of deferred income taxes.

Q. Why are deferred income tax expenses considered to be non-cash items?

[13] The Commission's current procedural schedule has hearings scheduled for October 2006. As a consequence, it is not envisioned that a final rate order in the pending rate case will be issued prior to the first quarter of 2007.

A. Deferred income tax expenses, as the name implies, represent non-cash, deferred accounting transactions. In other words, the Company does not disburse cash in the current year for payment of deferred income tax expenses to Federal or State taxing authorities. Such income tax expenses arise from the normalization method of accounting for tax/ book timing differences – that is, differences that originate in one year and reverse or "turn-around" in other years. Since non-cash deferred income tax expenses are included in revenue requirement and "collected" from ratepayers, but are not “currently” paid to the taxing authorities, the cumulative balance of prior deferred income tax expenses (i.e., the accumulated deferred income tax reserve) is recognized as a <u>source</u> of cost free capital separately considered in determining overall revenue requirement (i.e., ratepayer funded “zero” cost capital typically reduces rate base) that need not be financed or provided by investors. Consequently, deferred income taxes should be excluded from the determination of the Company’s cash working capital requirements, because there are no current period cash requirements or outflows.

Deferred income tax expenses are somewhat similar to depreciation expenses: both represent accrued expenses; both expenses are recovered through utility rates; the cumulative recoveries of both expenses are recognized as zero cost capital and used to reduce rate base; neither of these expenses involve current period payments to suppliers, vendors or taxing authorities; and both expenses provide a <u>source</u> of cash, or positive cash flow, that can be used for investment in plant construction or to support other corporate activity.

Q. Why should non-cash expense items be excluded from a lead lag study?

A. As indicated previously, non-cash expense items represent elements of cost of service that do <u>not</u> require a current period cash payment. Therefore, they do not increase a Company's need for cash working capital, under the commonly used approach to lead lag analysis, but serve as a <u>source</u> of cash flow. Such accrued expense items themselves do not involve the issuance of a cash voucher or wire transfer to pay, for example, for depreciation expense or deferred income tax expense.

Thus, non-cash expense items are properly excluded from a lead lag study. Their inclusion would be inconsistent with the widely accepted view of cash working capital as the amount of invested capital required to bridge the gap between the <u>payment</u> of cash expenses and the <u>collection</u> of related revenues. When there is no expense payment, no cash working capital is required. Depreciation and deferred income tax expenses do not require current period cash payments. Since investors are not required to provide cash advances for these expense items prior to the collection of revenues, it would be improper to include such items in a study of cash working capital requirements.

CWC & Interest Expense

Q. Why should the Commission adopt your recommendation that interest expense be included in the lead lag study?

A. Interest expense arises as a direct result of the Company's debt obligations. Each debt issue requires the periodic cash payment of interest expense in known amounts that are due and payable at predetermined points in time (e.g., quarterly or semi-annual interest payments).

In the traditional revenue requirement formula, interest costs are included in the weighted cost of capital that is applied to rate base. Through this ratemaking formula, interest expense becomes as much a part of jurisdictional revenue requirement (i.e., costs borne by ratepayers) as do operating expenses such as fuel and payroll costs. Since the ratemaking process allows recovery of capital costs that include these periodic payments to debt holders and ratepayers pay for utility service on a monthly basis, fairness requires that the lead lag study recognize the Company's use of these interest funds for the extended time period between collection from ratepayers and payout of interest to debt holders.

Q. Should the lead lag study also include quarterly common equity dividends, since you are proposing to recognize interest expense?

A. No. While I am aware of utility recommendations in other proceedings that have proposed such treatment, common equity cash flows (including common stock dividends) are less certain as to timing and do not represent "cash" expenses. "Net income," from which common dividends are paid, represents the residual equity return remaining for shareholders after all other expenses are deducted from revenues, rendering it comparatively unpredictable in amount. However, CWC recognition of quarterly dividend payments would yield an estimated payment lag in excess of 45 days (i.e., 90 days in calendar quarter divided by two plus additional lag from end of quarter to dividend disbursement date), ignoring the retention of "current" earnings. A presumed "expense" lag over 45 days would exceed the Company's proposed 36.95 day revenue lag, resulting in a negative CWC allowance for common "dividends". As a result, any recognition of common dividends for lead lag study purposes would further decrease Staff's proposed "negative" CWC recommendation.

Consistency with Prior ACC Decisions

Q. You previously indicated that non-cash items, including depreciation and deferred income tax expenses, are not reasonably included within lead lag studies. How has the ACC previously treated these non-cash items?

A. While exhaustive research has not been conducted in this area, I am familiar with the Commission's treatment of non-cash items in a number of rate proceedings dating back to the early 1980's. Attachment JRD – B contains excerpts from a series of prior ACC decisions concerning lead lag studies and CWC theory. Based on my prior experience with Arizona utility regulation and a review of the excerpts included in JRD – B, I am not aware of any ACC order adopting the inclusion of non-cash expenses in determining CWC, as proposed by APS witness Balluff in the pending case.

Perhaps of greatest immediate relevance, the Commission specifically excluded non-cash expense items and recognized interest expense in quantifying the CWC allowance adopted in the rate order (Decision No. 55931) of APS' last fully litigated rate case – an ACC decision specifically referenced by Company witness Rockenberger:[14]

> The fundamental reason for the difference between APS's calculation and those of the FEA and Staff is the treatment of "non-cash" items, such as deferred taxes and depreciation. Although the argument is somewhat more difficult to follow with respect to deferred taxes (they represent taxes which will be paid in the future), we agree with APS that depreciation accounting represents the return of a cash outlay it made at the time it acquired utility assets. Thus, use of the term "non-cash item" may be a misnomer if read literally. However, neither depreciation nor deferred taxes require the expenditure of cash at the time the expense is recorded and thereby charged to the customers. They are not "current" cash expenses. We have repeatedly rejected the inclusion of deferred taxes and depreciation in the calculation of current cash working capital requirements. We have also finally concluded that interest expense should be included in a lead/lag study, and we have expressly approved the concept of negative cash working capital. E.g., Mountain States Tel. & Tel. Co., Decision No. 54843 (January 10, 1986). Therefore, in this case we have used the Staff's negative cash working capital requirement of ($46,757,000) in our rate base determination.

The Commission has issued numerous orders applying and interpreting the appropriate lead lag study approach to cash working capital. Although not exhaustive in scope, Attachment JRD - B contains excerpts from ten (10)

[14] See Rockenberger Direct, page 27.

different ACC decisions that discuss various CWC topics, including non-cash items, interest expense and use of pro forma (i.e., adjusted) operating expenses.

Corrections / Modifications to APS Study

Q. Have you or other members of your firm reviewed the Company's lead lag study workpapers and identified any specific corrections which should be recognized therein?

A. Yes. The Company's lead lag study workpapers and supporting calculations have been reviewed and analyzed. However, this work did not verify the accuracy of the Company's transaction data (i.e., receipt dates, payment dates, payment amounts, etc.) underlying <u>each</u> of the thousands of transactions contained in the multiple worksheets and spreadsheet files supporting APS' study results. Instead, our review was focused on the analysis, testing and correction of material lead lag study elements sponsored by APS, including reliance on judgmental sampling techniques to obtain transaction source documentation. As a result of this effort, certain corrections specific to the Company's study have been identified. The following table briefly summarizes the corrections, which have been reflected in the CWC calculation set forth in Staff Adjustment B-4:

Item	Correction
Expense Levels:	• Include pro forma interest expense; and • Exclude significant costs associated with power marketing activity from test year purchased power expense
Revenue lag:	*[Staff 36.85 days vs. APS 36.95 days]* Modify revenue lag weighting to reflect test year revenue levels, net of power marketing activity.
PV Lease expense lag:	*[Staff 103.99 days vs. APS 47.32 days]* Restate expense lag to reflect material shift in semi-annual payment requirements beginning in 2005.
State Income Taxes:	*[Staff 62.05 days vs. APS 58.95 days]* Recognize Arizona statutory payment due dates.

Q. In quantifying its proposed CWC allowance, did APS incorporate pro forma levels of expense in determining lead lag study results?

A. No. In quantifying its proposed rate base allowance for CWC, APS considered only actual, per book unadjusted test year expenses.[15] Generally, the use of unadjusted test year expenses for CWC quantification purposes can be considered reasonable, absent material ratemaking adjustments to the various expense components reflected in the study. However, referring to APS Schedule C-1, the Company's direct filing contains proposed ratemaking adjustments that increase O&M expenses and taxes by $360.6 million on a total Company basis (or $355.4 million on an Arizona jurisdictional basis).

[15] Total Company unadjusted, per book expenses per APS Schedule C-1, column (a) ties to column (1) of Rockenberger LLR-WP11, and Balluff Attachment FB-1, with several limited exceptions: fuel & purchased power expense (exclude mark to market costs on trading contract), sales and franchise taxes (not recorded on income statement), and the classification of other taxes. Also, see APS response to Staff Data Request No. UTI-5-213.

The magnitude of these collective expense adjustments suggest potentially large shifts in the calculation of the net CWC allowance (i.e., dollars times net lag day factor) that could distort lead lag study results – thereby warranting use of pro forma, rather than unadjusted, test year expense amounts.

Q. Given the reality of significant ratemaking adjustments to test year actual expenses levels, what amounts should be included in the APS lead lag study?

A. When feasible and significant to the outcome, material ratemaking adjustments to test year expense levels should be recognized in the lead lag study results, in order to ensure that the CWC rate base allowance is not materially misstated due to inconsistencies between actual and pro forma test year expense levels.

Q. Does Staff Adjustment B-4 fully reflect the net effect of all pro forma adjustments proposed by Staff and the Company?

A. No. While the Company has proposed ratemaking adjustments increasing jurisdictional O&M expense by about $355.4 million, Staff Schedule C (page 1) summarizes the various adjustments proposed by Staff that reduce jurisdictional O&M expense and taxes in excess of $960 million. Because of the diverse ratemaking recommendations of the parties in this proceeding and the complexity of compiling all Company and Staff adjustments into the various expense categories comprising the lead lag study, I have generally adopted APS' proposed use of per book expense levels for CWC valuation purposes – except for those items where per book levels would materially misstate the overall study results (i.e., purchased power expense adjustment and pro forma interest expense). When readily identifiable, quantifiable and material in amount, I recommend that it is appropriate for a lead lag study to recognize pro forma expense levels in quantifying the rate base allowance for CWC.

Q. Are there any lead lag study components where you have not used test year per book expense for CWC purposes?

A. Yes. I have proposed to revise the expense levels for two lead lag study components where reliance on "per book" expense levels would yield distorted results. During the test year, APS recorded $1.8 billion of fuel and purchased power expense, which included $1.3 billion of purchased power expense alone.[16] Although APS has proposed to increase actual fuel and purchase power expense by an aggregate $351 million,[17] Staff has recommended a reduction to APS' pro forma fuel and purchased power expense of about $966 million, including an $842 million to purchased power expense.[18] This material change in pro forma purchased power expense should be recognized in quantifying CWC – a change that increases rate base by about $2.6 million before jurisdictional allocation.

In addition I am proposing inclusion of interest expense in the lead lag study, contrary to APS' proposed exclusion. For ratemaking purposes, Staff's CWC allowance recognizes the amount of pro forma interest expense resulting from

16 See APS Schedule C-1, page 1; Rockenberger LLR_WP11, page 1; and Balluff Attachment FB-1.
17 See APS Schedule C-1, page 1.
18 See Staff Schedule C and Staff Adjustment C-4.

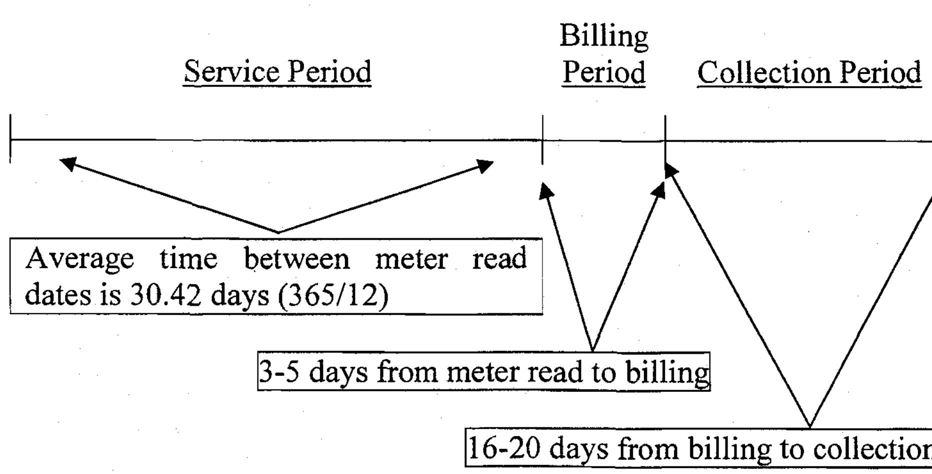
the interest synchronization adjustment set forth on Staff Adjustment C-19, in lieu of the actual amount of interest expense recorded by APS during the test year.

Q. You previously stated that material ratemaking adjustments to test year expense levels should be recognized in the lead lag study results when feasible and significant to the outcome. Is Staff largely accepting APS' proposed use of actual test year expense levels because it is not feasible to fully adjust each component of the lead lag study to reflect pro forma amounts or because the result of such an undertaking is not expected to be significant to the CWC outcome?

A. Both. Since APS did not assemble its rate filing in a manner that provided a clear breakdown of each pro forma adjustment between lead lag study components, the process required to dissect and reassemble each Company adjustment in the necessary format would be unduly time consuming and complex. However, an effort was undertaken to estimate the effect of APS' ratemaking adjustments on the Company's CWC approach, using certain simplifying assumptions. The results of that rather lengthy undertaking indicated that the magnitude of recognizing APS' ratemaking adjustments was relatively immaterial (i.e., slightly in excess of $1 million on rate base). Because significant resources would be required to conduct relatively complex data analyses, the decision to not pursue this course was considered to be rather conservative, as the expected result of a detailed break out and synchronization of into the lead lag study would appear to support an even larger negative CWC allowance further reducing rate base.

Q. Please explain how the revenue lag is employed in a lead lag study.

A. As mentioned earlier, a lead lag study is a means of measuring cash flows through the utility. In other words: Does the company, on average, collect revenues from its customers before or after it is required to disburse cash in payment of the goods and services consumed in support of its day to day operations? In answering this question, it is necessary to quantify the revenue lag, which is the average time lapse between the provision of utility service to customers and the collection of the related revenues. The following chart summarizes the components of the revenue lag, using hypothetical billing and collection lags:



Assuming utility service is provided to customers evenly throughout the service period, the follow table illustrates the components comprising the typical revenue lag, using values proposed by APS:[19]

Description	Days
Service Lag (1/2 the service period)	15.21
Billing Lag	5.03
Collection Lag	16.70
Revenue Lag	36.94

The revenue lag (i.e., 36.94 days in this example) would then compared to the expense lag quantified for each cash expense component (e.g., coal expense, payroll expense, etc.) of the lead lag study, in a manner similar to Staff Adjustment B-4.

Q. Please explain how the collection lag element of the revenue lag is estimated in the Company's lead lag study.

A. Rather than conducting a detailed, sample-based analysis of actual customer bill payment patterns, APS employed an accounting technique generally referred to as the "accounts receivable turnover ratio" to quantify the collection lag. In essence, this turnover ratio estimates how many days-worth of average daily revenues are in the accounts receivable balance, using the following algorithm:

Average Daily Accounts Receivable Balance $ /
(Annual Revenue $ / 365 Days)

This formula has been modified by APS since the last rate case, which had previously relied on average *month-end* rather than *daily* receivable balances.

[19] See APS LLR_WP11, page 5.

In the last rate case, Staff disagreed with the Company's reliance on average month-end receivable balances and instead proposed an average daily balance approach. Accurate application of the accounts receivable turnover ratio is highly dependent upon the reasonable quantification of average accounts receivable balances throughout each of the 365 days of the year. Thus, an average daily balance is preferred over employment of month-end balances inasmuch as it provides a more accurate calculation of the true revenue lag being experienced by the Company.

Q. Have you adopted APS' proposed use of average daily accounts receivable balances for purposes of quantifying the revenue collection lag in the current lead lag study?

A. Yes. I have adopted the Company's calculation of the CIS revenue lag for purposes of this case.

Q. Earlier in this testimony section, you identified the key changes in the Company's valuation of CWC that resulted in an $83 million reduction in the proposed rate base allowance from the last APS rate case. One of the key changes was a $42 million reduction in CWC due to a decrease in the revenue lag from 41.81 days in the last rate case to 36.95 days in the current study. Can you explain the primary factors contributing to this reduction in the revenue lag?

A. Although there are certain revenue lag weightings that cause a slight change in the composite revenue lag, the following table generally compares the Company's CIS revenue[20] lag in the current rate case with the lag from the last rate case:

	CIS Revenue Lag	
Description	**Current Rate Case**	**Last Rate Case**
Service Lag (1/2 service period)	15.21	15.21
Billing Lag	5.03	5.10
Collection Lag	16.70	22.21
Revenue Lag	36.94	42.52

Source:
Current Case – Rockenberger LLR_WP11, page 5.
Last Case – Rockenberger LLR_WP2, page 38.

Except for a slight shift in the billing lag from 5.10 to 5.03 days, the entire reduction in the composite CIS revenue[21] lag is attributable to the reduction in the collection lag. As mentioned previously, APS calculated its collection lag in the last rate case using an accounts receivable turnover ratio that relied on average monthly balances. On behalf of Staff, testimony sponsored by Mr. Steven Carver of Utilitech contested the Company's turnover ratio approach and proposed an average daily accounts receivable approach. In the current proceeding, APS has endorsed the daily accounts receivable method, which is the key driver for about $42 million of the $83 million reduction in the Company's proposed level of overall CWC since the last rate case.

[20] CIS revenues represent 80%-90% of annual APS revenues.

[21] CIS Revenue represents only one component of the weighted revenue lag. In APS' last Arizona rate case, the composite revenue lag proposed by the Company was 41.81 days (Rockenberger Attachment LLR-3, Docket No. E-01345A-03-0437) as compared to the composite revenue in the current case of 36.95 days (Balluff Attachment FB-1).

Q. For lead lag study purposes, have you and APS applied the full revenue lag in quantifying the sales tax and franchise tax impact on CWC?

A. No. In general terms, sales taxes are due on the 25th day of the month following customer "billing". At the time a customer is actually billed, it does not take the full revenue lag (either APS' 36.95 days or Staff's 36.85 days) for the Company to collect the revenues billed, including sales taxes, from its customers. Instead, I have adopted the Company's proposed collection lag of 16.69 days, representing the average time between customer billing and collection. Consequently, the collection lag, in this case 16.69 days, would be used as the revenue lag in computing the net lag associated with sales taxes.

Q. In the direct filing in APS' last Arizona rate case, did the Company recognize either sales taxes or franchise taxes in the calculation of CWC?

A. No. In the last APS rate case, Staff adjusted the Company's lead lag study to separately recognize sales taxes; however, prior to the last rate case, franchise taxes had been included in O&M expense and collected from customers as a component of base utility rates.[22] As indicated in response to Data Request UTI-15-369, APS began billing franchise tax as a separate line item on customer bills, like sales taxes, following the effective date (i.e., April 1, 2005) of the settlement in the Company's last Arizona rate case. Consequently, the treatment of franchise taxes in the lead lag study has changed since the last case. Although an argument could be presented that APS' proposed split of franchise

[22] See Staff Schedule B-7 included in the joint accounting exhibits, ACC Docket No. E-10345A-03-0437.

payments/ taxes between base rates and customer bill rider[23] for CWC purposes should be adjusted to represent the full annual effect of the bill rider treatment, I have adopted APS's proposed treatment of both sales taxes and franchise taxes for CWC purposes in order to conservatively limit the lead lag study issues in the current proceeding (see Balluff Attachment FB-1 and Staff Adjustment B-4).

Q. Do you have any further comments regarding APS' lead lag study calculations?

A. Yes. At the time this testimony was finalized, there were two areas in which our review and analysis had not yet been completed. During the review of the other taxes (i.e., taxes other than income taxes) detail set forth on pages 262-263 of APS' 2005 FERC Form 1, it was noted that the Company's lead lag study appears to have recognized the net lag associated with the employees' share of payroll tax withholdings, but may have overlooked the employer's share of such taxes (e.g., FICA and Medicare). Data Request No. UTI-17-382 was submitted to confirm this oversight and quantify a correction to APS' lead lag study, if necessary.

Further, Data Request No. UTI-19-387 was recently submitted in order to follow-up on what may be an inconsistency in the Company's calculation of the proposed 77.71 day pension and OPEB lag[24] and pension funding requirements, as discussed in the pension actuarial studies provided in the confidential

[23] See lines 25 and 49 of Balluff Attachment FB-1.
[24] See Rockenberger LLR_WP11, page 48.

response to Data Request RUCO 1.9. In quantifying the 77.71 day pension and OPEB lag, APS appears to have assumed that the pension contribution in the "current" year is related to the "current" pension plan year, rather than the "prior" plan year.[25] The referenced data request sought information to either confirm APS' assumption or support a recalculation of the composite payment lag.

At the time this testimony was prepared, the responses to these data requests remained outstanding. I intend to revise the lead lag study, as necessary and appropriate, upon receipt of the responses to the identified discovery requests.

<u>CWC Issue Summary</u>

Q. Please summarize the CWC issues in dispute.

A. The primary factors driving the significant difference (i.e., over $64 million before jurisdictional allocation) in the CWC recommendations of Company and Staff fall into four general areas – each of which are consistent with the Commission's longstanding, lead lag study policies:

- Exclude non-cash items (e.g., depreciation, amortization and deferred income tax expense);
- Recognize payment lags related to interest expense;
- Use pro forma/ adjusted revenue amounts to developed composite revenue lag; and

[25] For example, do the pension contributions made in 2004 relate to the 2004 or 2003 plan year?

- Use pro forma/ adjusted expenses, particularly interest expense and purchased power expense, to the extent feasible and material.

ADJUSTMENT FOR LOST MARGINS FROM DSM PROGRAMS (Schedule C-1)

Q. Please discuss the first adjustment to test year operating income.

A. The adjustment shown on Schedule C-1 reflects the reversal of a portion of the APS adjustment found on the Company's Accounting Schedule C-2, page 1, columns E and F. Specifically, this adjustment reverses the adjustment posted by APS to reflect "lost" retail margins it anticipates from implementation of various demand side management programs. This adjustment is sponsored by Staff witness Mr. Jerry D. Anderson.

MISCELLANEOUS OTHER REVENUES ADJUSTMENT (Schedule C-2)

Q. Please explain the purpose of Staff Adjustment C-2.

A. This adjustment is a correction of the Company's pro-forma adjustment for Schedule 1 Charges that APS has acknowledged is needed. The correction is needed to restate the transaction volumes used by the Company in calculating its adjustment, based upon actual test period data. In addition, APS has agreed in response to Staff discovery to remove the adjustment to expenses it had proposed for expected impacts associated with foregoing paper bills. Specifically, APS never instituted a $5.00 incentive to new paperless bill subscribers that it was once proposing because enrollment into this program has been strong even without the incentive. Thus, the estimated expense related to the $5.00 incentive designed to encourage customers to forego a paper bill has been eliminated. The revisions contained in Staff Schedule C-2 were provided in a "Revised DJR_WP8" attachment to Data Request UTI 13-344 while the paperless bill revision is more fully described in the APS response to Data Request No. UTI 13-345.

NORMALIZED FUEL, PURCHASED POWER EXPENSE AND OFF-SYSTEM SALES MARGINS (Schedule C-3)

Q. Please discuss your next adjustment to test year revenue and expense.

A. The adjustment found on Schedule C-3 reflects the proforma level of fuel, purchased power expense and off-systems sales revenues and related expense that Staff is proposing to be utilized in the development of base rates. Further, the proforma levels for these components become the basis for rebasing the PSA factor that will be employed in future PSA filings, reports and adjustor development. The inputs for this adjustment are being sponsored by Mr. John Antonuk of Liberty Consulting Group.

ELIMINATE EXPENSES ASSOCIATED WITH UNREGULATED MARKETING AND TRADING OPERATIONS (Schedule C-4 and Schedule C-5)

Q. Does APS continue to undertake unregulated marketing and trading ("M&T") operation?

A. Yes.

Q. Have the revenues and expenses associated with such activities been eliminated in the development of APS' retail jurisdictional cost of service?

A. No. According to answers received in response to discovery questions, the costs of such activities were inadvertently included within the development of the test year cost of service. Specifically, in response to Data Request No. UTI-10-315 the Company stated:

> In reviewing this information, the Company became aware that the revenue, purchased power costs, and operations and maintenance expenses associated with APS un-regulated Marketing and Trading were inadvertently included in the test year. All of these costs should have been excluded from the test year, as they relate to un-regulated operations.
>
> APS will propose a proforma adjustment addressing these costs, which will be included in the reply to Data Request UTI-14-350.

Q. What amount of revenues and expenses were inadvertently included within the development of the test year cost of service?

A. In response to UTI-14-350 APS has quantified the total revenues and expenses that should be eliminated from the test year cost of service. At this point I would emphasize that during the test year unregulated Marketing and Trading operations incurred a net loss of approximately $15 million. Thus, the removal of M&T revenues and expenses from test year operating results has the impact of reducing APS' adjusted test year cost of service – or reducing the otherwise justified requested revenue increase.

On Schedule C-5 I show the elimination of M&T operations and maintenance expense other than purchased power. However, Liberty Consulting Group is sponsoring a separate but related adjustment to eliminate M&T off-system sales revenues and related purchased power expense. This Liberty-sponsored adjustment is reflected on Schedule C-4. Thus, the net M&T loss of $8,273,000 sponsored by the Liberty Consulting Group shown on Schedule C-4 plus the removal of non-purchased power O&M expenses reflected on Schedule C-5 sum to the total $15 million of M&T before-tax loss included within APS' adjusted test year operations that I noted above.

PENSION EXPENSE ADJUSTMENT (Schedule C-6)

Q. Has APS proposed a proforma adjustment to test year operating expense for pension cost?

A. Yes. Ms. Laura Rockenberger proposes a significant upward adjustment to test year actual operating expense. Specifically, as discussed at pages 24 and 25 of her direct testimony, Ms. Rockenberger proposes to increase test year pension expense by approximately $44 million, purportedly to provide for a five-year amortization recovery of the Company's "underfunded pension liability."

Q. Please expand upon your understanding of the Company's request for recovery of the underfunded pension liability.

A. Ms. Rockenberger notes in direct testimony that, as of December 31, 2004, the Company's pension actuaries had calculated a projected benefit obligation of $1,371 million. Ms. Rockenberger further points out that the "fair value" or "market value" of the assets in the external pension trust was approximately $982 million, leaving approximately $389 million of the projected pension obligation "unfunded" or "underfunded" as of December 31, 2004. A significant portion (approximately 39%) of this underfunded amount will ultimately be the responsibility of other Pinnacle West Capital Corporation subsidiaries or other owners of production and transmission properties jointly owned with APS. Ms. Rockenberger and APS propose that the portion of the underfunded pension liability related to APS retail electric operations (i.e., 61% or approximately $218 million) be recovered from APS ratepayers over a five-year period – resulting in a test year proforma adjustment in the amount of approximately $44 million.[26]

Q. Please describe the calculations shown on Schedule C-6 wherein you develop your proposed adjustment to the Company's proposed adjusted test year level of pension expense.

A. First, the calculations shown on lines 1 through 3 of Schedule C-6 simply reverse the Company's proposed five-year amortization of the unfunded Projected Benefit Obligation – that is, the Company's $44 million amortization adjustment.

[26] APS' pro forma adjustment of about $44 million represents the $218 million underfunded pension liability divided by five years.

Line 5 on Schedule C-6 reflects the monthly amount of total APS pension expense currently being accrued within calendar year 2006. This monthly amount is multiplied times twelve to arrive at an *annualized* level of APS pension expense. From such annualized level of pension expense I subtract on line 7 the test year actual recorded pension expense, and on line 9 I also subtract out an additional proforma level of pension expense that APS has reflected in the development of its adjustment to annualize payroll and benefits costs.

Q. Are you stating that in addition to the Company's proposal to amortize the unfunded Pension Benefit Obligation that the Company has also proposed to increase test year pension expense in conjunction with its payroll annualization adjustment?

A. Yes. After annualizing payroll costs to reflect end-of-test year number of employees and wage increases granted through April of 2006, APS applied a benefits loading rate to the "payroll" adjustment amount to consider a purported corresponding increases in pension expense, post retirement medical benefits, health/medical costs, as well as payroll taxes. I have accepted the Company's implicit assumption that there is reasonable correlation between payroll cost and payroll taxes as well as health/medical costs for active employees. However, I disagree with the assumption implicit in the Company's adjustment that pension expense and post retirement medical expenses will go up correspondingly with payroll costs. As noted previously, I am proposing to include within Staff's recommended cost of service the 2006 estimated level of pension expense currently being accrued. It would be unnecessary, and duplicative, to also allow that portion of the Company's benefits loading on its payroll annualization adjustment that also considers incremental post-test year pension benefits cost changes. Thus, on lines 7 through 9 of Schedule C-6 I subtract out the increased pension expense that was captured with the Company's payroll/benefits adjustment, as well as test year actual recorded APS pension expense, from my proposed annualized level of APS pension expense.

To summarize my pension expense proposal, Schedule C-6 reverses the Company-proposed $44 million amortization expense adjustment, but adds back the increase in 2006 pension expense above the sum of the pension expense actually recorded during the test year and the pension expense component included within the Company's payroll/benefits loading adjustment. Schedule C-6 results in a net reduction in total APS-proposed pension expense of $33,483,000.

<u>Pension Amortization – Adjustment Overview</u>

Q. Why do you disagree with APS' proposed pension amortization adjustment?

A. I am opposed to this APS-proposed adjustment for several reasons. My arguments in opposition to this Company adjustment include:

- While it is not desirable that the Projected Benefit Obligation become significantly " under" *or* "over" funded relative to the current market value of plan assets, the "underfunded" position at December 31, 2004, is not highly unusual, nor a situation to become particularly alarmed about.

- The "underfunded" position of the Projected Benefit Obligation is, to a large extent, already considered within the determination of net periodic pension cost and test year pension expense included within the development of the retail cost of service. To add an *additional pension amortization* expense amount as proposed by the Company's proforma adjustment could, to some extent, lead to a *doubling up* of the collection of these so-called "underfunded" amounts from ratepayers.
- The Company's stated goal of fully funding the Projected Benefit Obligation is overly conservative and will likely lead to intergenerational inequity between existing and future ratepayers.
- The Company's proposed ratemaking departure from FAS 87 based pension expense is inconsistent with past ACC precedent, previous APS requests, as well the treatment being afforded pension expense in other regulatory jurisdictions that I am familiar with.
- If the Company's proposal were to be adopted, it is unclear whether the additional monies collected from ratepayers would actually be used to increase contributions to the pension trust or whether they could instead be used for other corporate purposes.
- The so-called underfunded position of the Projected Benefit Obligation is attributable to payroll dollars charged to expense as well as capital

activities. Additional intergenerational equity issues arise when current ratepayers are not only asked to fund a so-called funding deficiency on an accelerated basis, but also asked to fund the deficiency associated with payroll dollars that are typically capitalized rather than expensed.

- There is no evidence to suggest that the significant increase in costs that APS proposes to pass on to ratepayers at this time will eventually lead to long term savings for ratepayers.

While I reject, and strongly recommend that this Commission reject, APS' proposal for an accelerated amortization recovery of the alleged "underfunded pension liability," I am nonetheless proposing an upward adjustment to test year actual pension expense to reflect the latest available actuarial pension cost estimate for 2006. I believe the approach I am proposing to develop adjusted test year cost of service pension expense is identical in concept to what the Company proposed in its last rate case – an approach that was accepted by Staff and ultimately considered within the settlement agreement approved by the ACC.

<u>Pension Cost Accounting & Projected Obligations</u>

Q. Before expanding upon the various reasons why you oppose the Company's adjustment, could you please define certain terms that you will be utilizing and briefly discuss how pension expense and pension contributions are established?

A. Yes. First, it is important to understand that the pension costs and contributions that I will be discussing pertain to APS' *defined benefit* plan. In recent years, there has been much discussion in the media regarding corporate America's movement away from traditional *defined benefit* plans towards *defined contribution* plans – such as 401k or profit sharing plans.

In this case, APS offers a *defined benefit* plan wherein the Company has committed to providing prescribed pension benefits from the date of an employee's retirement until his or her death. The actual annual payments to, or on behalf of, a retiree are a function of each individual's wages paid during the later years of his or her employment as well as the number of years of service.

Estimating the retirement benefits a given individual employee will be entitled following retirement involves considering past *actual* historical wages and years of service, as well as estimating future years of service and future pay raises – all of which will also be considered in the calculations to determine actual annual pension benefits ultimately paid to each employee following retirement. Finally, in order to estimate the total amount that will *eventually* be paid to a given employee, one must also estimate the expected life of employees.

Thus, one step in the process of determining an appropriate level of pension cost is to estimate in *nominal dollars* the total pension payments that will be made to future retirees that considers actual employment history to date, as well as estimated future employment expectations – including years of service and future pay increases that are likely to be granted over the remaining employment period of all employees.

Q. When discussing the Company's proposed proforma adjustment you stated that as of December 31, 2004 the Company had a total company projected benefit obligation of $1,371 million. Does this projected benefit obligation represent the cumulative estimate of all PWCC employee pension obligations as of December 31, 2004?

A. The noted $1,371 million is the *net present value* of expected future pension pay outs that are initially calculated in *nominal* dollars. In other words, the nominal dollars represent the amounts expected to be paid out in future years, including increases in expected benefits resulting from assumed future years of service and future pay raises. Those nominal dollar payments are then discounted to "present day" dollars. Thus, the noted $1,371 million projected benefit obligation effectively represents an estimate of the *eventual* pension obligation of the Company stated in "today's" dollars – or the net present value of future nominal dollar pension obligations.

Q. Who calculates the projected benefit obligation?

A. The Company's actuaries, utilizing the Company's payroll and employee data (age, sex, years of service, historical pay, expected mortality, etc.), calculate the Company's projected benefit obligation.

Q. Obviously, the actuaries are dealing with estimates and assumption many years into the future. How do companies following generally accepted accounting principles ("GAAP") determine the amount of pension costs associated with a projected benefit obligation to attribute to and recognize within a given financial reporting period?

A. The guidelines for calculating *net periodic pension cost* are set forth within Statement of Financial Accounting Standards No. 87 (hereinafter referred to as "FAS 87"). Pursuant to those guidelines, one component of net periodic pension cost – service cost – consists of the actuarial present value of benefits attributed to, and assumed to be accrued/earned by, employees within the given reporting period. The precise calculation of the attribution/accrual of benefits earned within a given reporting period must consider remaining years of service as well as future pay increases. As I will discuss later, there are other elements that together sum to reported *net periodic pension cost.* However, the starting point in the measurement of total net periodic pension cost is the calculation of the "service cost" described above.

Q. In your prior answer, you used the term *net periodic pension cost.* Is *net periodic pension cost* the same as *pension expense*?

A. No. *Net periodic pension cost* calculates the total amount of the cost of pension benefits assumed to have been earned by all employees regardless of their activities during a given financial reporting period. Not all labor activities in a given reporting period are *expensed.* Some labor activities are properly capitalized to construction projects while other payroll costs are appropriately charged to other balance sheet accounts rather than to income statement *expense* accounts. Thus, *pension expense* refers to that portion of total *net periodic pension cost*, determined pursuant to FAS 87 guidelines, that is attributed to payroll costs incurred within a given reporting period associated with labor activities that are *expensed.* Later when I expand upon all the various reasons why I oppose the Company's proposed amortization adjustment, the importance of the distinction between *net periodic pension cost* and *pension expense* will become evident.

Q. Please expand upon the data that is considered in the development of the Projected Benefit Obligation.

A. As briefly noted, the Projected Benefit Obligation consists of the net present value of expected pay outs of retirement benefits that are initially calculated in nominal dollars, considering past and future years of service and pay increases. To be clear on this point, the Projected Benefit Obligation considers previous, actual pay and years of service *as well as* future pay increases and future years of service by existing employees. Thus, if the current market value of the external pension trust fund gets to a point where it equals or exceeds the Projected Benefit Obligation and actual future experience closely follows the assumptions included in the development of the Projected Benefit Obligation,[27] the Company should be required to recognize only a modest amount of future

[27] Actual returns on plan assets, pay raises, retirement/termination dates, mortality statistics, etc. equal the estimates used in developing the pension benefit obligation.

net periodic pension cost related to the existing workforce, even though the existing work force may not have earned or fully "vested" in a significant portion of the Projected Benefit Obligation.

Q. What "discount rate" do actuaries utilize to calculate the net present value of future pension obligations – obligations that are calculated by considering future pay raises and future years of employment service?

A. When estimating the Projected Benefit Obligation, FAS 87 requires that companies employ a discount rate based on a fairly conservative, low risk investment vehicle. Specifically, FAS 87 indicates that it is appropriate to consider an implicit interest rate underlying current annuity contracts or rates of return on high-quality fixed-income investments[28]. The FAS 87 *requirement* to employ a relatively low risk discount rate has had a significant impact on the calculation of the Projected Benefit Obligation in recent years, when interest rates have fallen to levels not experienced for several decades.

Q. Please further explain how low interest rates in recent years have impacted the calculation of the Projected Benefit Obligation.

A. Defined pension benefit plans, such as PWCC has in place, pay out retirement benefits based upon a formula that considers age, years of service and actual wages paid during the final years of employment. Thus, as previously noted, the calculation of the Projected Benefit Obligation includes estimates of future years of service and future pay raises, both of which directly and significantly

[28] Paragraph No. 44 of FAS 87 provides the noted guidance on the appropriate discount rate to employ.

impact the estimate of actual, *nominal dollar,* pay outs that will eventually be made. When future payouts are discounted to present day dollars utilizing a relatively high discount rate, the net present value of those future payouts become relatively low. Conversely, when future payouts are discounted to present day dollars utilizing a relatively low discount rate, as is currently the situation in today's relatively low interest rate environment, the net present value of those future payouts become relatively high. This occurrence is obvious when one views any present value table. For example, the present value of a dollar to be paid out 20 years in the future assuming a discount rate of 6% is approximately 31% -- or 31 cents. The present value of a dollar to be paid out 20 years in the future assuming a discount rate of 9% is approximately 18% -- or 18 cents. Thus, a three percent increase in an assumed discount rate for transactions occurring 20 years down the road reduces the present value of the transactions by over 40 percent.

As everyone is aware, interest rates in recent years have fallen to levels that have not been experienced for decades. The fall in interest rates has dramatically impacted the assumed interest rate the Company has been *required* to use for purposes of discounting the projected pension obligation. Specifically, in calendar year 2001 the Company utilized a discount rate of 7.75% based upon the then-prevailing interest rates being paid on high quality corporate bonds. For calendar year 2005, the discount rate used in the present value calculation had fallen to 5.84%. So significant is the impact of a change in discount rate assumptions that footnote disclosure of what a one percent (1.0%) change in interest rates would have on the present value of the Projected Benefit Obligation as well as pension expense is provided within the Company's public financials.

Specifically, as reported with PWCC's 2005 annual shareholders report, a one percent (1.0%) increase in the discount rate assumption would decrease the Projected Benefit Obligation and pension expense by $207 million and $8 million, respectively. Conversely, a one percent (1.0%) decrease in the discount rate assumption would increase the Projected Benefit Obligation and pension expense by $237 million and $8 million, respectively. Thus, one can easily observe, holding all other items and assumptions constant, if long term interest rates were simply to increase one percent (1.0%), over half of the $389 million (i.e., before allocation to APS) so-called "unfunded" pension obligation that the Company proposes to amortize and collect in rates over five years would automatically go away.

Q. Is the assumed discount rate the only element affecting the calculation of the relative "over" or "under" funding amount of the Projected Benefit Obligation?

A. No. Whether or not, and the extent to which, the Projected Benefit Obligation may be "over" or "under" funded is also significantly impacted by how well the external pension trust has earned on invested plan assets. Typically defined pension benefit plans will invest plan assets in a diversified portfolio of bonds and equity securities. While history has demonstrated that the returns on these investment vehicles *over the long term* can be expected to be in the high single digit range, for a given year or even for a few consecutive years, the actual returns can be significantly higher or lower (even negative) than the typical high-single-digit return rate that has been achieved historically *over the long term.* Thus, the under or over funded status of the Projected Benefit Obligation at a particular point in time can be significantly impacted in the short run by actual returns (or losses) experienced in recent years that are materially different than the rate of plan earnings assumed in actuarial studies.

Q. Do companies such as PWCC always make contributions to the external pension trust fund in amounts equal to the net periodic pension cost they report pursuant to FAS 87?

A. No. Whereas generally accepted accounting principles/financial accounting standards dictate the amount of *net periodic pension cost* and *pension expense* that must be recorded on the Company's financial statement, it is the Employee Retirement Income Security Act of 1974 ("ERISA") and the Internal Revenue Code ("IRC") provisions that dictate minimum and maximum *contributions*, respectively, that must be adhered to so that the retirement plan can meet required standards and remain "qualified." Specifically, it is very desirable that defined pension benefit plans be tax efficient by meeting certain requirements that allow them to be "qualified" plans. With a "qualified" plan, contributions are tax deductible for the employer while the earnings on the external trust are never taxable to the employer (the distributions to retirees, which actually consist of a combination of employer contributions and earnings on funds invested in the external trust will be taxable to the employee, but the earnings from the trust are never taxable to the employer so long as the plan remains "qualified"). Thus, it is very desirable to make sure a plan remains "qualified" and correspondingly tax efficient. Failure to make minimum funding contributions could lead to the termination of the plan, while making contributions in excess of the maximum allowed can result in the assessment of excise taxes on contributions made above the maximum tax deductible limitation.

Q. Do the ERISA and IRC regulations require use of the same assumptions and calculations for purposes establishing the minimum and maximum tax deductible contributions to the trust as are employed for purposes of calculating net periodic pension costs and the Projected Benefit Obligation under FAS 87?

A. No. While the assumptions might be the same or very close at times, my understanding is that the regulations require that funding calculations be based on assumptions that the actuary believes properly reflects the plan's long-term operations, and that the selection of these assumptions allow some subjective judgment.

Q. How have PWCC's actual contributions, as well as the ERISA minimum and IRC determined maximum contributions, compared to net periodic pension costs recorded over recent years?

A. Table C below shows actual net periodic pension costs, actual contributions, as well as the minimum/maximum contribution range for the years 2001 through 2005:

Table C

Table Contains Data Deemed Confidential by APS

Year	Net Periodic Pension Cost	Actual Contributions to the Trust	Maximum Allowable Contributions	Minimum Required Contribution
2001	[redacted]	[redacted]	[redacted]	[redacted]
2002	[redacted]	[redacted]	[redacted]	[redacted]
2003	[redacted]	[redacted]	[redacted]	[redacted]
2004	[redacted]	[redacted]	[redacted]	[redacted]
2005	[redacted]	[redacted]	[redacted]	[redacted]

Source: RUCO 1.9 and UTI-2-106

Thus, it is easily observed that actual contributions have deviated significantly from the amount of net periodic pension costs recorded for financial statement reporting purposes in recent years. Further, it is noted that the minimum required contribution [redacted]

Q. At page 24 of her direct testimony, Company witness Rockenberger indicates that the assets in its pension trust have caused the pension liability to be underfunded at this point in time. Are there other measurements of over or under funding of the external trust beyond comparing the market value of the trust to the Projected Benefit Obligation?

A. Yes. Companies also compare the market value of trust fund assets to the Accumulated Benefit Obligation. As the name implies, the Accumulated Benefit Obligation represents the net present value of benefits that have accrued to existing working employees as well as retired employees as of the reporting date. Since this measurement does not consider future years of service and future pay raises that are recognized in the development of the Projected Benefit Obligation, this value will typically be significantly less than the calculated Projected Benefit Obligation.

Q. How does the Accumulated Benefit Obligation compare to the Projected Benefit Obligation?

A. Table D below compares the historical estimates of the Projected Benefit Obligation and the Accumulated Benefit Obligation during the years 2001 through 2005. In order to enhance this comparison, the table also sets forth the market value of the pension trust balance during this same time frame, as well as the percentage of the Projected Benefit Obligation and the Accumulated Benefit Obligation funded by the market value of pension trust assets for each year.

Table D

Table Contains Data Deemed Confidential by APS

Year	Market Value of Trust	Projected Benefit Obligation	Accumulated Benefit Obligation	% PBO Funded	% ABO Funded
2001	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2002	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2003	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2004	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2005	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Source: RUCO 1.9 and UTI-2-106

Several noteworthy observations arise from a review of Table D. First, both the Accumulated Benefit Obligation and the Projected Benefit Obligation were "over funded" in 2001 and 2002, in the sense that the market value of the trust fund assets actually exceeded both the Accumulated Benefit Obligation as well as the Projected Benefit Obligation.

Second, between 2001 and 2003, the trust fund balance actually declined – which is not too surprising when one recalls that overall stock indexes also fell during this time frame. This "under performance" of the return on plan assets during the 2001 - 2003 time frame has undoubtedly contributed to the widening spread between trust fund assets and both the Projected and Accumulated Benefit Obligations.

Finally, in the context of my earlier discussion that the Projected Benefit Obligation is significantly influenced by the interest rate utilized to discount future benefit obligations, I noted that the discount rate fell from 7.75% to 5.84% between 2001 and 2005. While other relatively minor events have affected the calculation of the Projected and Accumulated Benefit Obligations, I believe the significant increase in each noted obligation has been most affected by the dramatic decline in the assumed discount rate used to calculate the net present values of Projected and Accumulated Benefit Obligations.

Q. Is the determination of net periodic pension cost impacted over time when the return on plan assets significantly falls short of, or significantly exceeds, the expected or forecasted return on plan assets?

A. When the *actual* return significantly exceeds or falls short of the *expected* or *assumed* return on plan assets, FAS 87 provides for a smoothing or levelizing adjustment designed to reduce the volatility in reported net periodic pension cost. Similarly, when the Projected Benefit Obligation significantly exceeds or falls short of the expected Projected Benefit Obligation made in the prior year, FAS 87 also provides for a smoothing or levelizing of such event – again, to reduce volatility in reported net periodic pension cost.

Q. Has net periodic pension cost been impacted by either the below-expected returns earned on plan assets in the years 2001 through 2003, or the significant rise in the Projected Benefit Obligation that has resulted from the requirement to discount future obligations utilizing ever lower interest rate assumptions between the years 2001 through 2005?

A. Yes.

Q. Table C above shows that net periodic pension costs have increased from approximately [redacted] in 2001 to amounts ranging between [redacted] million for years 2003 through 2005. Are you stating that the dramatic increase in net periodic pension costs in recent years is attributable, at least in part, to the FAS 87 adjustment made to capture or reflect the under performance of the return on trust assets as well as the significant increase in the Projected Benefit Obligation caused by the requirement to reflect ever-lower interest rates to discount such future obligations?

A. Yes. Paragraph Nos. 29 through 32 of FAS 87 require calculations to essentially require recognition of a "catch up" amortization provision as a component of net periodic pension cost whenever actual returns on plan assets or current estimates of the Projected Benefit Obligation deviate substantially from earlier assumptions and projections. For 2005, this "catch up" provision of net periodic pension cost that is amortizing the shortfall from previous projections totals to $19.8 million.

<u>Discussion – Bases for Opposition to APS' Proposed Amortization</u>

Q. If that concludes your background discussion on pension cost development and pension funding, let us return to your arguments in opposition to the Company's proposal. Please expand upon your first argument that it is not highly unusual, nor should it be particularly alarming, when one observes that the Projected Benefit Obligation appears to be significantly under funded.

A. As I have pointed out in my background discussion, the so-called "underfunded" position of the Projected Benefit Obligation is largely a function of: 1) under performance of return on plan assets for a short period of years, and 2) a significant increase in the calculated Projected Benefit Obligation directly linked to the FAS 87 requirement to utilize the interest rate of a conservative, low risk investment for purposes of discounting the future obligation. I am not necessarily predicting a rise in interest rates, but am merely emphasizing that a return to more "normal" interest rate levels, as would be defined by considering interest rates experienced during the three decades prior to 2000, would dramatically reduce the Projected Benefit Obligation and, in turn, the so-called "underfunded" position. Additionally, while I am certainly not predicting above-average returns on pension plan assets for the next few years, it is also important to realize that a short-term rally in the stock market could result in the realization of above-expected returns on plan assets that would, in turn, narrow the gap between the market value of plan assets and the Projected Benefit Obligation.

The important point of this discussion is to simply emphasize that the <u>difference</u> between the market value of plan assets and the Projected Benefit Obligation will vary – and vary significantly – over time (see Table D). While the current spread could be considered significant, I do not believe this Commission should necessarily be alarmed by the current spread. Further, even though there may be some concern about this spread, I certainly do not believe the current spread demands the drastic and unprecedented reaction being proposed by APS.

Q. Please further explain your second point that adoption of the Company's proforma pension amortization adjustment will lead to a "doubling up" of recovery of pension costs.

A. As also noted in the background discussion of this issue, when the return on plan assets falls significantly short of previous expectations and/or when the current calculation of the Projected Benefit Obligation significantly exceeds prior projections, FAS 87 provides for a component of net periodic pension cost to include an amortization of significant shortfalls from earlier projections. The 2005 total net periodic pension costs was $62,797,000, before allocation to APS' retail operations, which included $19,810,000 attributable to the amortization of the shortfalls from earlier projections of asset return/Projected Benefit Obligation. Thus, nearly a third of net periodic pension cost for 2005 consisted of the amortization of the net actuarial loss relating to plan return underperformance and/or growth in the Projected Benefit Obligation stemming from the reduction in the discount rate.

To my knowledge, the retail cost of service in all APS rate cases for at least the last two decades have been developed utilizing FAS 87-determined net periodic pension cost and related net pension expense. Thus, whenever retail rates include FAS 87-determined pension expense, such rates will automatically include the "catch up" or "correcting" amortization impact of the below-or-above-previously-estimated returns on plan assets or the growth/decline in the Projected Benefit Obligation above/below that assumed in prior projections. Consequently, the Company's proposal to amortize a point-in-time so-called underfunding of the Projected Benefit Obligation as an *incremental* above-the-line operating expense effectively duplicates, or *doubles up*, the recovery of such shortfall that is already occurring with the inclusion of the "amortization of the net actuarial loss" as a significant component of net periodic pension costs.

Q. Please elaborate upon your next argument that the Company's stated goal of fully funding the Projected Benefit Obligation is overly conservative and will likely lead to intergenerational inequity between existing and future ratepayers.

A. As noted previously, the Projected Benefit Obligation considers *future* years of employment as well as future pay raises. In my opinion, it would be an ultra conservative target for any company to seek to fully fund a Projected Benefit Obligation that has been estimated by considering future years of service to be provided by employees as well as expected future compensation levels.

Under the Company's proposal, ratepayers would be required to pay the FAS 87-determined pension expense (including the "catch up" amortization of net actuarial losses caused by under performance on returns earned on plan assets plus the increases in the Projected Benefit Obligation caused by discounting the future pension obligation utilizing ever-lower interest rate assumptions) as well as the Company-proposed five-year amortization of the so-called "underfunded" Pension Benefit Obligation. Specifically, under the Company's proposal, Arizona retail ratepayers are being asked to pay total annual pension expense in the approximate amount of $69 million[29]. Barring a long term "underperforming" trend of the plan assets or the Projected Benefit Obligation significantly growing, future ratepayers would likely pay little, if any, pension expense in rates after completion of the five year accelerated cost recovery period. In my opinion, it is both unnecessary and inequitable to design a cost recovery plan that front loads pension costs to existing ratepayers – while future ratepayers will significantly benefit from the services yet to be provided by active employees in future years. In other words, each generation of ratepayers should be responsible for their fair share of APS' cost of providing utility service, including pension and other benefit costs.

Q. You also argue that the Company's proposal is inconsistent with past ACC precedent, as well as the ratemaking treatment afforded pension expense by other regulatory jurisdictions. Please expand upon this observation.

A. At least for the last 20 years in which I have been involved in APS rate proceedings, APS has sought, and this Commission has authorized that rates be established by considering FAS 87-determined pension expense. Further, Data Request No. UTI-2-108 requested APS to provide any research that it may have

[29] Test year actual pension expense of $23,484,000 plus the pension benefits loading included with the APS payroll adjustment of $1,769,000 plus the amortization of the "underfunded" Projected Benefit Obligation of $43,695,000 equals a total pension expense request of $68,948,000.

undertaken in support of its proposal to accelerate recovery of the under funded Projected Benefit Obligation over a five-year period. APS' response to the noted request stated, in part:

> APS conducted no such research prior to proposing this adjustment. Subsequently, APS requested its outside counsel, Snell & Wilmer to conduct a brief review and analysis of instances involving pension expenses. APS has not compared the factual circumstances in any other proceeding to determine their similarity to the Company's situation. [Response to request number UTI-2-108 (a)]

In response to UTI-2-108, APS also provided copies of the orders resulting from the noted "brief review and analysis" undertaken by its outside counsel – an undertaking that occurred subsequent to the filing of APS' proposal regarding the issue of pension expense. I have reviewed the noted orders and observe *no* factual situations that appear identical to the Company's request in this docket or any instance where another regulatory commission has adopted such recovery mechanism. Based upon my personal observations in numerous rate cases over approximately 30 years as well as a review of the orders thus far provided by APS, I am not aware of a single instance where a regulatory commission has adopted the amortization proposal presented by APS for the first time in this case.

Q. You also make an argument that it is unclear whether funds that would be collected from ratepayers on an accelerated basis would be contributed to the pension fund so as to actually reduce the current gap between the market value of the pension trust fund assets and the Projected Benefit Obligation. Please explain this statement.

A. In response to Data Request No. UTI-2-137, APS was asked, among other things, to:

> Please confirm that, if the Commission adopts Company's accelerated amortization proposal, APS will make an additional annual contribution to the pension fund equal to the amount included in rates (e.g., $44 million) which will be above and beyond the contribution that would have otherwise been made. If this cannot be confirmed, please explain.

The Company's response to this part of the question went as follows:

> The funding decision will depend upon the minimum pension funding requirements and IRS maximum tax deduction limitations. This may or may not require the full $44 million to be contributed to bring the fund to an approximate 100% funded status. APS, of course, is proposing to credit customer with all amounts received as a result of accelerated funding through creation of a regulatory liability to be amortized beginning in 2012.

Based upon this response, it is not clear that APS is actually committing to take all monies being collected from ratepayers and make an additional, incremental contribution to the external trust fund. Based upon a follow up conversation with APS accountants and rate personnel as well as a review of the response to follow up Data Request No. UTI-7-266, my understanding is that APS is committed to funding $44 million *more than it would have otherwise contributed to the pension trust* so long as such calculated contribution amount does not exceed the IRS maximum.

Q. Does this verbal commitment, assuming you understand it correctly, quell your concerns as to whether monies collected from ratepayers would actually be used to fund the pension trust?

A. No. In the future, I believe it will be impossible to know how much APS might have contributed to the pension trust *absent the amortization of the so-called underfunded Projected Pension Obligation.* As demonstrated in Table C above, APS' pension fund contributions have differed significantly from the actuary's calculated net periodic pension costs in recent years. Further, such contributions were always significantly less than the IRS maximum allowed contribution. Thus, I believe it will be impossible to know what APS would have contributed to the pension fund absent the approval of its requested amortization.

Referring again to Table C, I would also emphasize that APS recorded net periodic pension cost of $[redacted] in 2005 but elected to contribute only [redacted] to the pension trust. In the 2003 rate case, the FAS 87-determined net periodic pension cost used to established rates was even higher than the net periodic pension cost recorded in 2005. In my opinion, it would be reasonable and appropriate to expect APS to at least fund the pension trust in the amount being collected within rates before requesting ratepayers to fund an additional liability deficiency on an accelerated basis.

Q. Please elaborate on your next argument that implementation of the Company's proposal would lead to other intergenerational equity issues inasmuch as some of the "underfunding" is attributable to payroll dollars being "capitalized" as well as "expensed."

A. Earlier I explained that the level of *net periodic pension cost* calculated by the Company's actuaries pertain to *total* payroll costs incurred within a given reporting period – regardless of whether such payroll dollars were "expensed" or "capitalized." The amount of *pension expense* recorded within a given reporting period relate to payroll dollars *expensed* during that same given reporting period. Similarly, for ratemaking purposes, only *pension expense* associated payroll dollars *expensed* are included within the test year cost of service.

The Company proposes to collect in rates a level of amortization expense that would recover a point-in-time calculation of the Projected Benefit Obligation in excess the market value of the pension trust assets. A portion of such difference is attributable to future payroll dollars that will be capitalized. Yet, under the Company's proposal, the unfunded amount would be charged in its entirety to existing ratepayers even though a portion of such costs should be capitalized. This disregard for the fact that a portion of such amount should be capitalized will lead to further intergenerational inequity among ratepayers as current ratepayers will be paying on an accelerated basis "costs" that should be properly capitalized into plant in service where *future* ratepayers would pay a return on and return of (i.e., depreciation) such capitalized costs.

Q. Turning to your final argument, is the Company claiming that the accelerated recovery of the unfunded Projected Benefit Obligation will ultimately result in savings to ratepayers?

A. No. Data Request No. UTI-2-140 asked APS to provide the amount of pension expense savings the Company estimates would be achieved over the next fifteen years if the Company's accelerated pension contribution proposal was adopted by the Commission. However, in response APS simply states that "[w]e have not quantified the amount of pension *expense* savings, if any, over the entire period in your question."

Q. You have stated numerous reasons for your opposition to the Company's proposed amortization of the unfunded Projected Benefit Obligation. Are you, nonetheless, proposing any adjustment to test year actual recorded pension expense?

A. Yes. Based upon preliminary actuary estimates, PWCC/APS began recording a level of pension expense in 2006 that exceeded the amount recorded during the historic test year ending September 30, 2005. While these estimates are not final – they will be trued up later in 2006 – I believe they may provide a better estimate of ongoing pension expense than what was recorded within the test year ending September 2005. Accordingly, Staff Schedule C-6 includes an allowance for the higher 2006 pension expense. While this "2006 estimate" has been included in Staff's calculation of overall revenue requirement at this point in time, I would recommend that APS be required to provide to the Commission and the Staff the final 2006 actuarial study as soon as such document becomes available so that the "final" calculation can be considered as a basis for establishing pension expense in this proceeding.

POST RETIREMENT MEDICAL BENEFITS ADJUSTMENT (Schedule C-7)

Q. Please discuss your next adjustment to test year operating expense.

A. On Schedule C-7 I post an adjustment to reflect ongoing post-retirement medical benefits ("PRMB") expense based upon the actuarial estimate that APS is relying upon for recording PRMB expense during 2006. The estimate used as a basis for recording PRMB expense in 2006 has been prepared prior to issuance of a final 2006 actuarial report. APS did not propose an adjustment to amortize "underfunded" PRMB expense comparable to that which it proposed regarding pension costs. Nonetheless, for consistency as well as to simply incorporate last known changes for this significant employee benefit, I am proposing a PRMB adjustment calculated identically to that which I am proposing for pension expense.

Q. Please explain the basis for the calculations shown on Schedule C-7.

A. As with pension expense, I first determined an "ongoing" or "normalized" level of PRMB expense by multiplying the monthly PRMB expense recorded during the first half of 2006 times twelve. From this annualized amount I subtracted 1) test year actual recorded PRMB expense and 2) the incremental PRMB expense amount that APS had calculated and included as part of it payroll annualization adjustment. Again, this adjustment is consistent with the approach I am recommending for pension expense. Further, I believe such approach is superior to the Company's "payroll annualization" methodology inasmuch as there is not always a strong correlation between increased payroll costs and increased PRMB expense which is implicit in the approach utilized by APS to annualize PRMB expense.

ADVERTISING EXPENSE (Schedule C-8)

Q. Has APS proposed a proforma adjustment to test year operating expense for advertising expenses?

A. Yes. Ms. Laura Rockenberger proposes a $6.1 million downward adjustment to test year actual operating expense to remove advertising costs related to Company branding, as set forth in her Attachment LLR-2-16. According to APS workpaper LLR_WP23, the Company's adjustment excludes costs for sports team sponsorships such as the Diamondbacks, Suns and Coyotes, as well as media advertising to promote the Company's brand identity. I concur with APS that such a disallowance of brand advertising is appropriate because these types of expenses are not required in order to provide utility services. On behalf of the ACC Staff, I proposed a comparable adjustment in the last APS rate case and Ms. Rockenberger's testimony at page 25 states, "This approach is consistent with Staff's recommendation in the Company's prior rate case."

Q. Is there a problem with the quantification of the APS-proposed advertising disallowance?

A. Yes. Through discovery, we learned that certain additional expenses should also be removed that were not captured in the APS-proposed adjustment. These additional expenses include APS Dodge Theatre sponsorship costs, sports suite costs and various other Pinnacle West advertising costs allocated to APS in the test year that are not necessary costs in the provision of utility services. In its responses to Staff Data Requests UTI 1-17 (Revised), UTI 5-239 and UTI 5-240, the Company has conceded that these additional expenses should also be removed from the revenue requirement and that such an additional adjustment will be made in the Company's rebuttal testimony.

Q. Does the Staff adjustment appearing at Schedule C-8 reflect the amounts of additional advertising expense disallowance that APS has conceded should be removed?

A. Yes.

NON-RECURRING OUT-OF-PERIOD SHARED SERVICES EXPENSES (Schedule C-9)

Q. Please continue by explaining your next adjustment to operating expense shown on Schedule C-9.

A. The adjustment reflected on Schedule C-9 is made to eliminate two out-of-period accruals recorded as PWEC administrative and general expense during the historic test year. Inasmuch as this adjustment has been conceded by APS in discovery as a needed adjustment it intends to make in rebuttal, I will not elaborate on the transactions recorded during the test year that now give rise to a need to eliminate such out-of-period expense accruals. I am affixing as Attachment JRD - C two data requests wherein APS 1) acknowledged the need for such adjustments, and 2) further explained the events giving rise to the transactions that were recorded during the historic test year.

LEGAL COSTS INCURRED IN SELLING THE PWEC SILVERHAWK POWER PLANT (Schedule C-10)

Q. Please discuss your next adjustment reducing test year operating expense?

A. Adjustment C-10 eliminates legal expenses incurred by PWEC during the historic test year related to the sale of the Silverhawk Power Plant that occurred in January, 2006. While the sale itself did not occur until after the end of the test year, many costs incurred to facilitate the sale were incurred during the historic test year and charged to PWEC operation and maintenance expense. In the prior APS rate case the parties agreed to, and ultimately this Commission approved, the rate basing of a number of PWEC units located in Arizona. However, the Commission may recall that the Silverhawk Power Plant, owned by PWEC, but located in Nevada, was not acquired to specifically serve APS' retail and firm wholesale load and was not one of the PWEC facilities rate based in the last

APS rate case. PWEC/PWCC elected to sell this "non-jurisdictional" plant in the fall of 2005.

When developing its PWEC O&M expense adjustment, the Company made an estimate of the percentage of costs incurred at the various shared services departments that would have been devoted to owning and operating the Silverhawk Plant during the historic test year. APS then eliminated the estimated percentage of shared services costs attributed to the Silverhawk Plant from PWEC test year operating and maintenance expense. However, it is apparent that at least with regard to the shared services Law Department such "estimation" process understated test year costs directly incurred for the benefit of the Silverhawk Plant. Accordingly, Adjustment C-10 appropriately eliminates the cost of an outside law firm's legal services incurred in the test year that exceeds the APS estimate of costs devoted to Silverhawk Plant Operations.

Q. Please further explain how your Adjustment C-10 was derived.

A. In the historic test year, prior to the transfer of PWEC assets and operations to APS, the shared services Law Department incurred $1,394,011 of costs. When developing its PWEC O&M expense adjustment, APS estimated that 10% of such department's costs – or $139,401 – was attributable to the non-jurisdictional Silverhawk Plant. Accordingly, when piecing together its PWEC O&M expense adjustment APS removed $139,401 of the Law Department's cost. However, in response to Data Request No. UTI-10-312 APS identified two charges totaling $$289,400 that were specifically attributable to the sale of the Silverhawk Plant. Accordingly, Adjustment C-10 eliminates the costs specifically attributable to the Silverhawk sale that exceeded the original APS estimate of total Silverhawk-related legal expenses in the amount of $139,401. This adjustment can be viewed as very conservative inasmuch as it implicitly assumes that *no* other legal costs incurred during the historic test year were associated with owning and operating the Silverhawk Plant.

SUNDANCE UNITS MAJOR OVERHAUL COSTS (Schedule C-11)

Q. APS has proposed to include within the development of its proposed retail jurisdictional cost of service operations and maintenance expense associated with its recently acquired Sundance Combustion Turbine Units. Are you in agreement with this APS proposed adjustment?

A. Inasmuch as Staff is not opposing retail rate recognition of return, depreciation and expenses associated with these newly acquired units, I have no conceptual disagreement with inclusion of O&M expenses associated with these units in the development the retail cost of service being established in this proceeding. That said, I do take issue with certain estimated Sundance maintenance costs included within APS' adjustment that will not actually be incurred for many years into the future. Accordingly, I am proposing an adjustment reflected on

Schedule C-11 wherein I eliminate the costs of major overhaul costs that will not be incurred during the period that I expect these rates to be in effect.

Q. Please elaborate upon the maintenance activities and costs that you are proposing to exclude because you understand they will not be undertaken and incurred for many years into the future.

A. As part of its O&M expense adjustment, APS has proposed to include $2.75 million for "non-routine" maintenance expense for the ten recently acquired Sundance units. The "non-routine" maintenance portion of APS' Sundance adjustment was calculated by considering the expected cost of certain major or non-routine maintenance activities, and dividing such projected costs into the expected number of hours of usage between such activities, to arrive at an average non-routine maintenance cost per hour of usage. The calculated average non-routine maintenance cost-per-hour-of-usage was then multiplied times the expected normalized annual usage to arrive at a normalized annual cost level for such non-routine maintenance activities.

Q. Please elaborate upon the types and timing of non-routine maintenance activities for which the Company's proforma Sundance O&M adjustment is intended to provide.

A. The non-routine maintenance adjustment is broken out between "Hot Gas Paths" and "Major" overhauls. The Hot Gas Paths overhauls are scheduled to occur at 18,000 usage hour intervals while the Major overhauls are scheduled to occur at 36,000 hour intervals. Each machine is predicted to be run *on average* approximately 1,500 hours a year. Accordingly, the average interval between Hot Gas Path overhauls and Major overhauls, assuming average annual hours of usage for each unit, is approximately 12 years and 24 years, respectively (i.e., 18,000/1,500 equals 12 years; 36,000/1,500 equals 24 years). It is the Company's intention to not run each unit equally during the early years of operations so that some units will reach the usage interval for the Hot Gas Path and Major overhaul earlier than other units. In other words, the Company intends to initially unevenly load certain of the ten units so as to begin a staggered overhaul cycle that will avoid a need to overhaul all or most of the ten units at the approximately the same time.

Q. Notwithstanding the predicted initial uneven loading of the ten units, when will the first Sundance Unit undergo the two noted non-routine maintenance activities?

A. It is predicted that the [redacted]. (Response to UTI-10-328) Thus, the Company's proforma adjustment to reflect non-routine maintenance expense begins to capture the cost of events that will not occur for many years into the future. Accordingly, the adjustment shown on Schedule C-11 eliminates that portion of the Company's Sundance Units expense component that will not be expended during the time that these rates will be in effect.

Q. Given that these non-routine maintenance activities are related to hours of usage, why is it not appropriate to begin to accrue for the cost of such activities as the units are being run prior to the actual cost incurrence?

A. There is some conceptual support for beginning to accrue for costs expected to be incurred in the future that are related to usage being experienced today. However, unless the cost for future expenses being recovered within retail rates today are accrued on the Company's balance sheet for consideration and "return" to ratepayer in future rate proceedings, there is a high probability that ratepayers will be "overcharged" or "double charged" for such non-routine maintenance. APS has indicated in discovery that it has no intentions of accruing on its balance sheet for consideration in future rate proceedings non-routine maintenance costs that – under its proposal – it would collect in rates today. (Response to UTI-11-336)

Q. Please explain why you believe there is a high probability for an overcharge for such costs unless expenses being recovered in rates today are accrued on the Company's balance sheet.

A. In this current rate case, and in the prior rate cases I have been involved in, APS has proposed to normalize maintenance costs for mature generating units by calculating a multi-year historical average of maintenance costs incurred, adjusted for inflation over time, to arrive at an "ongoing" or "normalized" level of maintenance expense. This methodology has the intended effect of smoothing the somewhat volatile and significant costs of major planned overhauls and other non-routine events. In the future, assuming this methodology continues to be employed, presumably when the Sundance Units eventually experience costs for the noted non-routine maintenance activities, such costs will be considered in the multi-year averaging process. *At that point in time in a future rate proceeding,* unless regulators remember and are aware that many of the Sundance Units non-routine maintenance expenses have already been recovered from ratepayers through rates that have been developed by considering such costs, I submit that it is very likely that ratepayers will be again be charged for these same costs. I would emphasize that we are discussing rate proceedings that will occur many years in the future.

Q. If the Commission were inclined to grant – over your recommendation in opposition – the Company's request to begin to recover non-routine maintenance expense for the Sundance Units, do you have any conditions that you would recommend the Commission impose?

A. Yes. Very simply, if the Commission were inclined to begin to allow for the recovery of these expenditures that will not be incurred until years in the future, I would recommend that the Commission order the Company to recognize as current period expense monies for non-routine maintenance being collected within rates and concurrently establish a regulatory liability on its balance sheet. When the non-routine maintenance costs are eventually incurred, such costs could then be charged against the deferred liability account rather than being charged to maintenance expense – where they would otherwise be considered in the development of future rates. Again, this is not my primary recommendation. I believe accruing for and deferring such relatively minor expenses is unnecessary and unduly complicated. Accordingly, I continue to recommend that the non-routine portion of the Company's Sundance Units O&M expense adjustment be rejected in its entirety. The accounting treatment I recommend should only be imposed if the Commission accepts the Company's adjustment and begins to allow for recovery of such costs in current rates.

NON-RECURRING TAX RESEARCH COSTS (Schedule C-12 and Schedule B-3)

Q. Please discuss the need for your next adjustment reflected on Schedule C-12.

A. There are two components to the adjustment reflected on Schedule C-12, both of which are related to non-recurring tax research charges which were recorded during the historic test year. By way of background, APS retained the independent certified public accounting firm of Deloitte and Touche, LLP ("Deloitte") to research whether prior federal income tax returns could be amended so as to be able to claim additional Investment Tax Credits ("ITC") related to properties being constructed in the mid-to-late 1980s. Federal Investment Tax Credits related to construction and acquisition of utility had, prior to 1987, been available to corporate utility taxpayers for a number of years. The Tax Reform Act of 1986 generally eliminated the ITC for tax years beginning 1987 concurrent with implementation of a significantly lower corporate federal income tax rate. While the elimination was generally eliminated post-1986, there existed the ability to claim some amount of ITC related to plant that was under construction, but not yet in service, at the end of 1986. In the case of APS, the Palo Verde Nuclear Units, with their very significant capital costs, were still under construction at that time.

Apparently in recent years APS, or perhaps its outside auditors – Deloitte – came to a conclusion that the ITCs claimed in the late 1980s associated with plant still under construction in the mid-1980s had been conservatively calculated. Or in other words, APS or its auditors came to a determination that it appeared possible that prior year tax returns could be amended so as to claim additional ITC related to plant under construction in the mid-1980s. Originally APS retained Deloitte on a contingency basis whereby Deloitte would only be paid for research undertaken out of "tax savings" realized if and when additional ITCs were claimed. In 2003, prior to the current test year, APS accrued $2,385,468 in anticipation of a payment to be made to Deloitte resulting from expected ITCs to be claimed resulting from Deloitte's tax research. The noted accrual occurred following the prior APS rate case test year (i.e., 2002) and clearly before the start of the current rate case test year that ends on September 30, 2005.

As the Commission is aware, APS jointly owns a number of generating facilities – including the Palo Verde Units and the Cholla units. Pursuant to operating agreements with joint owners of such production plant, APS is permitted to "load" direct production costs incurred at the jointly owned plants with administrative and general ("A&G") costs incurred by APS. In 2003, a portion of the A&G costs loaded onto the direct-assigned production costs considered, or included, the accrual for the contingency fee expected to be paid to Deloitte Touche for tax research.

Following an audit of 2003 joint production plant costs that occurred in 2004, the joint owners of production facilities contested the "loading" of A&G costs that consisted, in part, of the Deloitte contingency fee. Ultimately APS conceded that it would not be equitable to indirectly charge the joint owners of production facilities for tax research that would never result in benefits or savings to them. Accordingly, in December 2004, APS "credited" the joint owners for payments made in 2003 related to the Deloitte tax research. The "credit" given to the joint owners in December 2004 related to over billings occurring in 2003 ultimately resulted in the recording of incremental APS production expense during the test year in the amount of $1,224,795. Thus, one component of the adjustment reflected on Schedule C-12 eliminates or reverses the non-recurring credit to joint owners of certain production facilities that was recorded during the test year as additional APS production expense.

As noted, the initial tax research performed by Deloitte Touch was undertaken on a contingency basis. However, at some point that arrangement was renegotiated, and the work continued on a fee-for-service basis. As a result, during the test year APS recorded $1,533,333 of outside services expense for additional tax work undertaken by Deloitte Touch related to the ITC research. Thus, in addition to the reversal of the A&G credit given joint owners of production facilities in December 2004, I propose on Schedule C-12 to eliminate additional non-recurring tax research costs recorded during the historic test year. Thus, the total company adjustment on Schedule C-12 eliminates total non-recurring expense of $2,778,128 related to ITC research.

Q. What was the result of the ITC research issue?

A. According to the response to Data Request No. UTI-10-299, a tax refund in the amount of $6,483,389 is expected and "imminent." Thus, for a total outlay of cash resources of $3,918,801 (contingency fee of $2,385,468 recorded in 2003 and a fee-for-service charge of $1,533,333 recorded in December 2004), APS is expected to receive $6,483,389 of tax savings – or increased after-tax earnings. Stated in "revenue requirement" terms, APS is receiving approximately $10 million of before-tax savings in exchange for incurring $3,918,801 of tax research expense effectively resulting in a before-tax gain from the entire transaction of approximately $6.1 million.

Q. Are you proposing that APS be allowed to retain the approximate $6.1 million of before-tax savings net of the $3.9 million of costs incurred to achieve the savings?

A. I am proposing that APS be allowed to effectively retain half of "net" savings achieved. More specifically, I am proposing that the Company be allowed to retain for its shareholders 50% of the $6.1 million of revenue requirement savings achieved. The remaining 50% I am proposing to credit to ratepayers in the form of a rate base offset.

Q. Why are you proposing that the Company be allowed to retain for its shareholders one-half of the expected tax savings?

A. On the one hand, an argument could be made that 100% of the net savings should be credited to ratepayers. It is generally recognized that regulated monopoly utilities have an obligation to reduce costs whenever possible without jeopardizing safety concerns or quality of service. To that end, a good argument could be made that APS had an obligation to undertake such efforts and return net savings realized to its ratepayers. Further, it is possible that the ITCs being belatedly claimed today are as a result of less-than-diligent tax research efforts undertaken in the mid-to-late 1980s. If this were the case, arguably *all* savings should be passed on to ratepayers today – without consideration of costs incurred to achieve.

Conversely, if APS had not undertaken the extra efforts and costs to research this issue, it is a near certainty that these tax savings would have been permanently foregone. If 100% of tax savings achieved are passed on to ratepayers in this case, arguably in the future APS would have no incentive to pursue legitimate tax strategies that would only benefit ratepayers. Further, in this particular situation, it is difficult to speculate upon how such ITCs may have been considered in regulatory proceedings had they been claimed and known at a much earlier date.

Q. Please explain that last comment.

A. In APS rate cases occurring prior to 1994, any unamortized ITCs were reflected as a rate base offset. Thus, ratepayers received the benefit of this cost free source of capital within the development of retail rates. While ratepayers received savings in the form of ITCs as a rate base offset, the ITCs claimed were amortized as a "credit" or reduction to income tax expense "below the line." Or in other words, shareholders received the benefit of reduced federal income taxes resulting from the ITCs claim over the life of the facilities that generated the ITCs.

Pursuant to a 1994 Settlement Agreement, APS agreed to amortize over five years remaining unamortized Investment Tax Credits[30]. It is possible that if these recently claimed ITCs had been known and quantified at the time of the 1994 agreement that such ITCs would have simply been lumped in with other unamortized ITCs on APS' balance sheet existing at that time and amortized over the same five year period as other ITCs existing at that time.

In light of all the uncertainty surrounding how these ITCs might have been recognized in prior regulatory proceedings, the di minimus amount at issue, as well as all the other arguments for and against ratepayer participation in benefits

[30] Response to Data Request No. UTI-8-269

from the transaction, I am recommending that the costs incurred to achieve the ITC saving be deducted from the total revenue requirement benefits expected to be realized. I am proposing that one-half of the remaining benefits or savings resulting from the transaction be used as a rate base offset – as had been the precedent for ITCs prior to 1994. This outcome insures that APS is reimbursed for all out of pocket costs incurred to achieve the ITC savings, and further, that it is allowed to additionally retain some of the benefits realized from the transaction for its shareholders.

Q. Have you prepared an adjustment to capture the rate base offset adjustment you just described?

A. Yes. On Schedule B-3 I reflect the ITC rate base offset adjustment previously described.

INCENTIVE COMPENSATION (Schedule C-13)

Q. What is the purpose of Staff Adjustment C-13?

A. Staff Adjustment C-13 represents a partial disallowance of test period incentive compensation expense. I am proposing to eliminate the costs associated with APS' <u>stock-based</u> incentive compensation, while allowing ratemaking recovery of test period expense associated with the <u>cash-based</u> incentive compensation plans included within the Company's adjusted test year cost of service. After Staff's adjustment, the historic test period will still include approximately $17.8

million[31] of "cash" incentive compensation expense (before jurisdictional allocation) – providing APS with a conservatively generous recovery of various non-stock based incentive plan costs that are driven by both financial and operational performance measures.

Q. Please describe the stock-based incentive program Staff is proposing be disallowed from test period expenses.

A. Several types of incentives are provided to executives and directors under certain Long Term Incentive Plans in the form of Pinnacle West common stock, including: Performance Stock Option Awards, Performance Share Awards, Performance Accelerated Stock Option Awards, Stock Ownership Awards and Restricted Stock grants.[32] These awards were granted to APS executives and management team members during the test year, resulting in the incurrence of about $4.8 million of expenses that I am recommending be disallowed.

Q. What is the purpose of the noted stock based incentives?

A. The stated purpose of the Long Term Incentive Plan, as discussed in a March 22, 2006-dated PWCC prospectus, is as follows:[33]

> The Plan's goals are to promote the success and enhance the value of Pinnacle West Capital Corporation (the Company") ***by linking your personal interests to those of our shareholders*** by providing you with an incentive for outstanding performance. The Plan is

[31] Per Company's response to UTI-1-76 (g) total variable incentive compensation expense in the test year was $21,727,033. However, the Company voluntarily eliminated Officers' variable incentive compensation in the amount of $3,895,147, leaving $17,831,886 of remaining cash based test year variable incentive compensation within the Company's proposed test year cost of service that Staff is not objecting to.

[32] See APS responses to Staff Data Request No. UTI-1-83.

[33] See APS response to Staff Data Request No. UTI-1-83, attachment APS09850

> further intended to provide flexibility to the Company to choose among a broad range of awards to create appropriate incentive arrangements that allow the Company to attract, motivate, and retain the services of employees upon whose judgment, interest, and special effort the successful conduct of the Company's operation is largely dependent. (***emphasis added***)

Notably, these incentive compensation programs are driven by the financial performance of Pinnacle West, rather than performance criteria directly linked to customer service, employee safety, cost reductions or utility operational achievements.

Q. Please further describe the mechanics of the cash-based incentive compensation programs that resulted in expenses recorded during the test period that you are *not* proposing to eliminate.

A. In 2004 and 2005, an annual cash bonus Variable Incentive Plan ("VIP") was effective for Pinnacle West and subsidiary company employees that consisted of two primary components: (1) a Company plan and (2) various Business Unit plans. Cash bonuses payable under the VIP were established for different employee groups in a range of specified percentages relative to salary levels or a bonus pool established for particular groups. The following Table E generally summarizes plan parameters for various employee groups that were in effect for 2005, with more complex plan details for some groups simply noted as "complex" where plan terms were not conducive to this summarization:

Table E

	Company Earnings Plan		Business Unit Plan	
	$ Millions	Payout %	Indicators	Payout %
APS Var. Incentive Plan	$250-310	0% - 3%	various	0% - 3%
PVNGS Var. Incentive	$250-310	0% - 1.8%	various	0% -4.3%
Shared Services	$250-310	0% - 3%	various	0% - 3%
Management Incentive	$250-310	0% - 7.5%	various	0% -7.5%
Senior Management	$250-310	0% - 15%	various	0% - 15%
Officer Incentives	$250-310	0% - range	various	Various
Attorney Incentives	$250-310	0% - 7.5%	various	0% - 7.5%
Power Marketing/Trading		Complex	complex	complex
Nuclear Safety Plan		Complex	complex	complex
Nuclear Outage Plan		Complex	complex	complex
Fossil Incentive Plans		Complex	complex	complex

Note: For some groups, after the threshold earnings level of $250 million is met, if total customer satisfaction surveys achieve greater than 44% "very satisfied" an additional one percent is added. Further, if the total customer survey achieves greater than 90% "satisfied and very satisfied" an additional one percent is added, to a maximum payout of five percent.
Source: UTI-1-76

According to the terms of this plan, the funding of the "Company Plan" component of the 2005 VIP is conditioned upon Pinnacle West consolidated earnings reaching the $250 million threshold target level, with amounts payable under this portion of the incentive plan driven by the achievement of earnings above the threshold level. The Business Unit Plan component involved the establishment of Critical Success Indicators tailored to the responsibilities and goals of the individual business units, which are simply noted as "various"[34] on Table E above. Examples of Critical Success Indicators generally include: minimization of recordable injuries, achievement of targeted cost levels,

[34] See APS response to Staff Data Request No. UTI-1-76

equipment reliability and availability target achievements, outage minimizations, and various other operational and financial metrics. However, even the Business Unit incentives were not to be funded unless Pinnacle West achieved the threshold earnings levels in calendar year 2005. In effect, the Company's entire cash-based incentive program is primarily driven by Pinnacle West's attainment of the minimum earnings level.

Q. What amount of incentive compensation expense, for each of the plans and in total, has APS included in its test period revenue requirement?

A. APS' proposed test year expense includes approximately $4.8[35] million of stock-based incentive compensation and another $17.8[36] million in cash-based incentive compensation (discussed previously), resulting in total Company "as adjusted" incentive compensation costs of approximately $22.6 million.[37]

Q. Why are you proposing to allow full recovery of the Company-proposed "as adjusted" cost of the *cash-based* incentive plans, while excluding the cost associated with the *stock-based* incentives expensed in the historic test period?

A. Even though corporate earnings also serve as a threshold or precondition to the payout of cash-based incentive compensation, the Company-proposed level of test year cash incentives are tied primarily to performance measures that directly benefit APS consumers. In contrast, the stock-based incentives are entirely

35 See APS response to Staff Data Request No. UTI-1-87, attachment APS09852
36 See APS response to Staff Data Request No. UTI-12-298.
37 Amounts before allocation to regulated retail operations.

driven by Pinnacle West earnings objectives that, only very indirectly, might benefit consumers.

For example, the targets used to award stock-based incentives under the Performance Shares Plan are based upon Pinnacle West Earnings per Share ("EPS") growth from one year to the next in relation to a comparison group of electric utilities. Comparative EPS growth is not a criteria or element directly considered as a cost component in establishing electric utility rates. In and of itself, efforts to enhance EPS growth may not be consistent with the interests of utility customers or reasonable pricing for the regulated business, where changes in the level of rate base assets and the cost of capital are more directly relevant to earnings achievable by the utility.

Therefore, as a matter of regulatory policy, I believe it is unwise to encourage incentive compensation programs that are entirely or even primarily driven by earnings achievements or total return to shareholders vis-à-vis allowing recovery of such plan costs through regulated utility rates. "Superior," "above authorized," "exceeding peers," or "above targeted" earnings can sometimes be achieved or influenced by short term management decisions that, while temporarily boosting earnings, may not encourage the development of safe and reliable service at the lowest long term achievable costs.

For instance, some maintenance may be deferred temporarily – thereby boosting earnings. But deferral of maintenance can lead to safety concerns or higher subsequent "catch-up" costs. Additionally, incentive compensation based on achievement of earnings can lead to exaggerated or aggressive rate filings which, under a best case scenario leads to extra audit and litigation work, and under a worst case scenario leads simply to unnecessarily high utility rates. In short and in sum on this point, rate recovery of incentive compensation that is based entirely upon earnings or stock performance is simply bad regulatory policy. As noted within the quote from the PWCC prospectus, the stated purpose of the Company's stock based incentive compensation plan is to "to promote the success and enhance the value of Pinnacle West Capital Corporation (the Company") ***by linking your personal interests to those of our shareholders*** by providing you with an incentive for outstanding performance."

Accordingly, I am recommending the full disallowance of the Company's stock based incentive compensation plan that is entirely earnings driven and shareholder aligned while accepting the Company-proposed level of cash based incentive compensation that includes the achievement of goals that are customer oriented toward lowering costs, increasing reliability, or improving customer service and satisfaction.

Q. Will a "disallowance" of stock based compensation necessarily lead to a cost that must be absorbed by PWCC's shareholders?

A. No. The stock based compensation is dependent upon achievement of earnings that may or may not be realized. Thus, if earnings targets are not achieved, awards may not be granted – or perhaps only granted in part. Conversely, if above-targeted earnings are achieved, a good argument could be made that it is shareholders – and not ratepayers – that should pay for such costs inasmuch as it is the shareholders who have primarily benefited from the achievement of the targeted earnings.

I would also point out that if the threshold earnings established for the cash based incentive compensation are not met, and ultimately little or no cash based incentive compensation is awarded, ratepayers will nonetheless continue to pay within retail rates the test year adjusted level of cash based incentive compensation considered within the development of retail rates being established within this proceeding.

LOBBYING EXPENSES (Schedule C-15)

Q. Please discuss your next adjustment to test year operating expense.

A. The adjustment reflected on Schedule C-15 eliminates test year above-the-line charges for lobbying expense.

Q. Are lobbying costs generally included within the development of utility companies' cost of service?

A. No. I do not know of any regulatory jurisdiction that regularly or even occasionally allows recovery of lobbying costs in rates. Pursuant to the Federal Energy Regulatory Commission's ("FERC") Uniform System of Account ("USOA"), lobbying costs are supposed to be recorded within the "below-the-line" Account No. 426.4 where there is a presumption of non-recovery from ratepayers.

Q. Please explain your previous answer wherein you state that there is a "presumption of non-recovery from ratepayers" when lobbying costs are properly recorded within Account No. 426.4.

A. FERC Account No. 426 has several subcomponents to capture "miscellaneous expense items which are nonoperating in nature." Examples of nonoperating expenses recorded in Account 426 include payments and donations for charitable, social or community welfare purposes; penalties or fines for violation of regulatory statutes – as well as expenditures for the "purpose of influencing public opinion with respect to the election or appointment of public officials, referenda, legislation, or ordinances." While the FERC Uniform System of Accounts does not use the word "lobbying" when discussing charges to be recorded within Account No. 426.4, in my experience the quoted phrase "influencing public opinion" has been routinely interpreted by utility regulators to include all lobbying costs.

Further, the FERC Uniform System of Accounts instructions for Account No. 426 also state, in part:

> The classification of expenses as nonoperating and their inclusion in these accounts is for accounting purposes. It does not preclude the Commission consideration of proof to the contrary for ratemaking or other purposes.

On the income statement, Account No. 426 is located *below the* utility net *operating* income *line*. Typically, only utility *operating* revenues and expenses are considered within a cost of service determination. Non-operating revenues and expenses recorded "below-the-line" are typically *not* included within the development of retail or wholesale rate determinations. Thus, while the FERC USOA *accounting requirement* to record lobbying expenses in below-the-line account 426 are not binding for ratemaking purposes, it has been my observation in the various jurisdictions that I have worked in that there is a presumptive ratemaking disallowance for charges recorded to this below-the-line account.

Q. Please explain the rationale for disallowing recovery of lobbying costs.

A. The potential detriment to ratepayers and other constituents that could occur if utilities were effectively encouraged to lobby vis-à-vis the recovery of lobbying costs within utility rates could be significant. With the unique monopoly powers that utilities enjoy in providing "essential services" within exclusive certificated service territories, the potential for abuse through promotion of unfair or unnecessary legislation is obvious. This statement is not to suggest or imply that all lobbying efforts of utility companies – funded by their shareholders – are detrimental to ratepayers or other constituents. Indeed, viewed in isolation, enactment of certain specific utility-backed legislation has, no doubt, been beneficial to ratepayers in Arizona. However, it is virtually impossible to know at what "cost" the achievement of even the "pro-consumer" legislation was accomplished.

Q. Did APS record lobbying expenses to Account No. 426.4 during the historic test year?

A. APS recorded some lobbing costs to Account No. 426.4, and those charges were *not* included within its proposed test year cost of service. However, APS charged a number of its lobbying efforts to above-the-line administrative and general expense accounts that it did not adjust for cost of service ratemaking purposes. For reasons stated, I am proposing that all lobbying expenses recorded above-the-line be eliminated from the adjusted test year cost of service. As noted, test year lobbying expenses have been eliminated on Schedule C-15.

Q. Do you have any other recommendations regarding this issue?

A. Yes. APS should be directed to record all lobbying efforts to FERC USOA Account No. 426.4. My understanding is that APS is already required to follow the FERC USOA, and accordingly, arguably this specific directive should not be required. Inasmuch as APS does not appear to be fully following this accounting guideline, I would recommend that the ACC specifically require APS to record all lobbying costs to Account No. 426.4.

Q. Would a requirement to record lobbying costs below-the-line for accounting purposes be binding for ratemaking purposes?

A. No. APS would be free to request cost of service recognition for lobbying efforts. However, if costs are appropriately recorded below-the-line it would require a specific adjustment to utility operating income to achieve rate recovery of specifically identified lobbying costs. This accounting requirement would ensure that the issue was highlighted for review by rate auditors. Rate auditors are reliant upon proper accounting to assist in the rate review process. Notably, rate auditors rely upon the fact that utilities are properly recording a number of non-recoverable nonoperating expenses – including lobbying costs – within below-the-line Account No. 426.

ISFSI EXPENSE (Schedule C-16)

Q. Please provide your understanding of the Company's proposal regarding recovery of Independent Spent Fuel Storage Installation ("ISFSI") expense.

A. ISFSI is a dry storage facility for spent nuclear fuel constructed at the Company's Palo Verde Generating Station. The fuel pools where the spent nuclear fuel is currently stored will soon reach their maximum capacity. Because the U.S. Department of Energy has been delayed in siting and constructing permanent spent nuclear fuel storage facilities, the Palo Verde plant is required to construct an interim storage facility where spent nuclear fuel can be stored until DOE-funded permanent storage can be constructed.

The need for the interim storage facilities has been known for a number of years. Pursuant to a 1999 settlement, APS was permitted to defer ISFSI costs within a regulatory asset account for later recovery from ratepayers. In APS' 2003 rate case, the Company sought, and ultimately the ACC approved, recovery of previously deferred ISFSI costs. Additionally, the prior rate settlement provided for recovery of *ongoing* ISFSI cost related to current nuclear fuel burns. The basis for recovery of ISFSI costs previously deferred, as well as "ongoing" ISFSI expense to be included within base rates for current nuclear burns, was a study undertaken by TLG Services, Inc. in February 2002.

In the current case, APS is again posting an ISFSI adjustment. The order from the prior rate case (Decision No. 67744 from Docket No. E-01345A-03-0437) did not become effective until April 1, 2005. Thus, the test year ending September 30, 2005 only reflects one-half of the annual amortization level of deferred ISFSI costs that was approved in the prior docket. Therefore, the Company's ISFSI adjustment in this case, in part, reflects the "annualization" of amortization expense related to recovery of ISFSI deferrals approved in the prior case. However, additionally, the Company proposes to reflect incremental "ongoing" ISFSI expense as well as incremental ISFSI amortization expense resulting from the TLG Services, Inc. study that was updated in 2004. Also, the prior case settlement only calculated and considered deferrals then expected through June 30, 2004. The Company's proforma ISFSI amortization expense adjustment also considers additional deferrals following the June 30, 2004 cutoff employed in the last case through December 30, 2006 (i.e., the approximate effective date for rates being developed within this proceeding).

Q. Please provide additional detail regarding the recovery of deferred ISFSI costs approved in the prior APS case versus what is being requested by APS in the current case.

A. The Commission may recall that in the last case it issued an order approving APS' request to recover over a five-year period deferred ISFSI cost estimated to be attributable to pre-shutdown activities, while ISFSI cost deferred in prior periods estimated to be attributable to post-shutdown periods were to be recoverable over the license life of Palo Verde Units 1 and 3, and over the term of the sale/leaseback agreement for Unit 2. The estimates for costs attributable to pre- versus post-shutdown activities were derived from a TLG Services, Inc. study issued in 2002. In addition to providing for recovery of ISFSI costs related to previously burned nuclear fuel through reflection of amortization expense, the settlement also provided for recovery of "ongoing" ISFSI costs associated with "ongoing" or normalized nuclear fuel burns.

The 2004 TLG Services, Inc. study not only updated the projected *total* ISFSI costs expected to be incurred, but also provided a new estimated *split* between pre- and post-shutdown activities. There was a fairly significant increase in *total* overall projected ISFSI costs, but also, there was a significant shift in projected ISFSI costs between pre- and post-shutdown activities. Specifically, the 2004 TLG study estimated that the pre-shutdown activities would represent 88.3% of total ISFSI costs while the post-shutdown activities would represent 11.7% of total ISFSI costs. By comparison, in the 2002 TLG study it was estimated that pre-shutdown activities would be 73.9% of total ISFSI costs while post-shutdown activities would be 26.1% of total ISFSI costs.

In the current case the Company continues to recommend recovery of deferred ISFSI costs attributable to pre-shutdown activities over five years and recovery of deferred ISFSI costs attributable to post-shutdown activities over the longer life-of-plant/life-of-lease amortization schedule. The Company's adjustment for ISFSI amortization expense in this case is large, in part, because of a fairly significant increase in estimated overall ISFSI costs, but also because of the significant shift in percentages from post- to pre-shutdown activities between the two TLG studies. Stated more succinctly, a part of the increase in ISFSI amortization expense being requested results from the shift in estimated ISFSI from post-shutdown activities that were being amortized on a much longer life-of-plant/life-of-lease amortization schedule to pre-shutdown activities that are being recovered on a much shorter five-year amortization schedule.

Q. Are you in agreement with this Company adjustment?

A. No. While I have accepted the majority of the Company's proposed test year adjustment, certain relatively minor modifications to the Company's proposal are required. The ISFSI adjustment I am sponsoring is found on Schedule C-16.

Q. Please explain.

A. There are three components to my ISFSI adjustment. First, the Company calculated the amount of ISFSI costs that has been or is expected to be deferred between the cut off period considered in the prior case (June 30, 2004) and the end of the historic test year (September 30, 2005). Further, the Company split its deferral estimate into pre- and post-shutdown activities based upon the 2004 updated TLG study. The Company's ISFSI adjustment includes a calculation to provide for recovery of ISFSI costs deferred subsequent to the cutoff period utilized in the prior case related to pre-shutdown activities over a five-year period. However, the Company's ISFSI adjustment fails to consider and include any additional amortization expense associated with incremental ISFSI cost related to post-shutdown activities that were also deferred during this same June 30, 2004-through-September 30, 2005 time period. Thus, one element of my proposed adjustment picks up added amortization expense related to deferral of ISFSI costs occurring between June 30, 2004 and September 30, 2005 associated with post-shutdown activities.

Second, in a separate calculation, APS considers expected ISFSI deferrals to be recorded between the end of the historic test year (September 30, 2005) and the approximate effective date of rates resulting from this proceeding (January 1, 2007). Once again, APS' adjustment includes a five-year amortization for incremental ISFSI costs related to pre-shutdown activities, but it fails to include the amortization for changes in deferral of post-shutdown costs. Because of the updated 2004 TLG study's conclusion that a lower percentage of ISFSI costs will relate to post-shutdown activities, ISFSI post-shutdown costs are actually estimated to decline from previous projections. Or in other words, between the end of the historic test year (September 30, 2005) and the approximate rate effective period (January 1, 2007), APS now expects the post-shutdown deferral balance to decline. Accordingly, consistent with the prior rate settlement and rate order, APS should be required to amortize the *reduction* in the post-shutdown deferral balance expected to occur between September 30, 2005 and January 1, 2006 over a five-year period.

Finally, regarding the "ongoing" ISFSI costs to be collected in rates related to the current burn of nuclear fuel, APS has captured within its adjustment the *increase* in pre-shutdown costs based upon the updated 2004 TLG study, but has ignored the *net decrease* in post-shutdown costs derived from the same updated 2004 TLG study. For ongoing post-shutdown ISFSI costs APS continues to propose to reflect the *higher* estimate derived from the outdated 2002 TLG study. Thus, the third element of my ISFSI adjustment is calculated to reflect the *reduced* ongoing ISFSI costs as estimated within the updated 2004 TLG study.

Q. Do you understand why the Company's ISFSI adjustment relies, in part, upon the updated 2004 TLG study, but also ignores portions of the updated estimates included within the 2004 TLG study for other ISFSI components?

A. In addition to updating ISFSI costs, the noted 2004 TLG study estimated *overall* Palo Verde decommissioning costs. For reasons I do not fully understand, the Company elected *not* to update its overall decommissioning cost study, but only the ISFSI costs derived from the 2004 TLG study. According to the Company, monies collected for ISFSI post-shutdown activities are being contributed to a qualified external trust. Further, such contributions to the decommissioning trust for post-shutdown activities are tax deductible to APS so long as they remain "qualified" by being collected pursuant to regulatory authority (i.e., specific ACC authorization). Since APS is not proposing to change retail rates based upon the *overall* updated decommissioning cost estimates included within the 2004 TLG study, APS may believe it is required to continue collecting in rates – and contributing to the decommissioning fund – post-shutdown ISFSI activity costs based upon the 2003 rate case order. Or in other words, there may be a belief by the Company that it needs to continue to making contributions to the trust for post-shutdown ISFSI activities based upon the prior rate case funding levels in order to ensure that the trust remains "qualified" for IRC purposes – and that all contributions to the trust remain tax deductible.

Q. Does the possible loss of a deduction for contributions to the external decommissioning trust concern you?

A. No. I would suggest that APS continue to make contributions to the trust for post-shutdown ISFSI activities based upon the prior rate case findings. However, I would simply suggest that the difference between ongoing post-shutdown ISFSI cost determined to be reasonable in the last case and the ongoing post-shutdown ISFSI cost determined to be reasonable in the current case ($324,000) be recorded as a reduction to the otherwise-calculated ongoing pre-shutdown costs for which there are no IRC funding requirements or other restrictions. In so doing, overall ongoing ISFSI costs will be based upon the latest TLG study even though the *distribution* between pre- and post-shutdown activities will be somewhat different than suggested by the updated TLG study – at least until some future rate case wherein presumably updated TLG studies and rates will again be fully synchronized.

Q. The adjustments to the Company's ISFSI proposal that you have described are quite detailed and complex. Can you summarize the conceptual exception that you take to the Company's calculation?

A. As previously noted, the updated 2004 TLG study predicts an overall increase in ISFSI costs from that projected within the 2002 study. Further, the 2004 study predicts a fairly significant shift in ISFSI expenditures from post-shut down activities that have a relatively long amortization period to pre-shutdown activities that have only a five-year amortization period. In essence, APS' rate case adjustment incorporates the higher overall ISFSI estimate, and the shift to pre-shutdown activities that have the shorter five-year amortization period.

What APS' ISFSI adjustment fails to capture, however, is the reduction in costs attributed to lower post-shut down activities from that estimated in the 2002 TLG study. For the most part, my proposed adjustment simply captures the admittedly-small reduction in costs for post-shutdown activities that were ignored in APS' adjustment. In my opinion, it would be unfair to only reflect in new rates those elements of the updated 2004 TLG study that have risen from previous estimates while ignoring those elements that have actually declined from the earlier estimates.

PROPERTY TAX EXPENSE (Schedule C-17)

Q. Are you proposing any adjustment to APS' proposed level of property tax expense?

A. Yes. On Schedule C-17 I propose to eliminate that portion of APS' proforma property tax adjustment that is calculated to capture a property tax increase anticipated to occur in 2007. More specifically, one element of APS' proposed property tax adjustment is designed to capture the statutory phase-in of increases in property taxes associated with the former PWEC units. While it is probable at this point in time that some increased property tax related to these production facilities will occur pursuant to statute, selective reaching for post test year changes occurring so far beyond the end of the test year will cause a mismatch in cost-of-services revenues, expenses and rate base. Accordingly, I am proposing that that portion of the APS property tax adjustment attributable to anticipated 2007 phased-production-plant-related increases be eliminated from the test year cost of service.

GENERATION PRODUCTION INCOME TAX DEDUCTION (Schedule C-18)

Q. APS witness Mr. Chris Froggatt has proposed an income tax adjustment to reflect additional tax deductions, along with attendant income tax savings, resulting from the American Jobs Creation Act. Are you in agreement with Mr. Froggatt's calculation and ultimately the adjustment that he posts?

A. I am in agreement with Mr. Froggatt's approach to developing the additional tax deductions that should be generated as a result of passage of the American Jobs Creation Act. That said, Mr. Froggatt undertook his calculation based upon language contained within *proposed* Treasury Regulations that was providing guidance as to the intended application of the American Jobs Creation Act available at the time APS filed its case. Pursuant to those *proposed* Treasury Regulations, the additional production function deductions were not expected to be available for the operations of generating facilities that were less than 50% owned by a given utility taxpayer. APS owns less than 50% interest in a number of generating units. In fact, APS owns less than 50% interest in the majority of its generation investment. Thus, the noted ownership requirement significantly limited the incremental production deduction that would otherwise be available under the recently passed tax act. Accordingly, relying upon the *proposed* Treasury Regulations, APS calculated that it would only receive approximately

30% of the production deduction it otherwise would receive absent the 50% ownership requirement.

Subsequent to the time that the Company prepared its direct testimony, final Treasury Regulations regarding the American Jobs Creation Act have been issued. The original 50% ownership requirement included within the proposed Treasury Regulations was *not* included within the final Treasury Regulations. Accordingly, it is appropriate to recalculate the additional production deductions that should be available based upon *all* of APS' ownership of generation facilities. It is my understanding that APS fully agrees with the propriety of such a recalculation.

Q. Are there any other revisions required to the APS calculation of additional production function deductions?

A. The additional production deductions are a function of production income. When calculating the new production function deductions resulting from the American Jobs Creation Act, APS started with an assumption that it would receive the overall and common equity return that it is requesting in this case. Since Staff is recommending a lower equity and overall return than APS is requesting, it is necessary to revise the original APS calculation so that it is properly synchronized with the return that Staff is recommending.

Also, the additional production function deductions are being phased in over the period 2005 through 2010. For 2005 and 2006 the deduction starts at three percent of qualified production activities income. For 2007 through 2009 the deduction rises to six percent, and for 2010 and later years the deduction rises to nine percent. APS prepared its production tax credit adjustment by considering the 2007-2009 deduction percentage of six percent. Because Staff is generally recommending that cost of service component quantifications be limited to only a few significant components occurring through 2006, I am proposing to reflect the production tax credit with the 2006 three percent limitation.

Q. Does Schedule C-18 reflect the calculations and adjustment necessary to 1) remove the impact of the 50% ownership requirement, 2) synchronize the computations to reflect Staff's proposed overall and common equity return, and 3) reflect the three percent deduction limitation in effect for 2006?

A. Yes. I would again emphasize that I am in conceptual agreement with the Company's approach to calculating savings stemming from the recently enacted American Jobs Creation Act. The changes I have undertaken are only to consider the impact of the final Treasury Regulations that were not available to APS when it filed its case *and* to synchronize the calculation for Staff's proposed return recommendation.

INTEREST SYNCHRONIZATION (Schedule C-19)

Q. Please discuss your next adjustment to APS' proforma level of income tax expense.

A. The adjustment shown on Schedule C-19 is undertaken to synchronize the interest deduction for consideration in the development of Staff's cost of service income tax expense with the jurisdictional rate base and weighted cost of debt being proposed or recommended by various Staff witnesses. This adjustment, which is routinely calculated and adopted by regulatory commissions in utility rate cases, is derived by multiplying Staff's proposed retail jurisdictional rate base times the weighed cost of debt included within Staff's development of the overall cost of capital. To the extent this Commission may adopt a different rate base or cost of capital than that being proposed by the Utilities Division Staff, it would be appropriate to revise this calculation or adjustment for the return and rate base found reasonable by the ACC

FEDERAL AND STATE INCOME TAX EXPENSE (Schedule C-20)

Q. Please discuss your final adjustment to APS' proposed level of income tax expense.

A. I would describe the adjustment found on Schedule C-20 as a *correcting* calculation to the APS-proposed level of cost of service income tax expense. By way of background, most accountants can agree to the appropriate *conceptual* development of cost-of-service allowable income tax expense[38]. However, the mathematical or mechanical calculation of an appropriate test year income tax expense adjustment can become quite complicated – particularly when addressing an historic test year that spans two calendar years that may each include unique or non-recurring tax accrual entries.

I requested in discovery what is commonly referred to as a "top down" cost-of-service income tax expense calculation that is designed to determine whether, after considering all tax-related as well as non-tax adjustments, income tax expense included within the "as adjusted" cost of service is properly synchronized with the "as adjusted" utility operating income as well as an ongoing level of other permanent book and tax differences. As a result of a series of discussions and exchanges of data with the Company, I am of the opinion that a problem exists in the Company's development of its proposed "as adjusted" test year cost of service income tax expense – though no specific error in the Company's calculation or logic has thus far been identified.

Q. If you were unable to determine the specific problem in the Company's calculation, how then are you able to propose the "correcting" adjustment on Schedule C-20?

[38] There can be conceptual differences in cost of service determination of income tax expense regarding *normalization* versus *flow through* accounting, the appropriate composite federal or state income tax rate, or the appropriate turnaround amortization period for previously deferred items. Once those conceptual differences are agreed upon, the cost of service income tax expense calculation should become mathematical or mechanical in nature.

A. I am proposing an adjustment based upon a "top down" calculation that utilized estimated 2006 permanent book/tax differences and other income tax credits. Through discussions with APS rate, accounting and tax personnel, I am of the opinion that the Company agrees with this approach as well as the amounts I have used to calculate the adjustment on Schedule C-20. In other words, I believe it is a moot point that no specific "error" was found regarding the series of calculations that APS undertook to arrive at its initial cost-of-service income tax adjustment.

A. Yes.

Q. Does that conclude your direct testimony?

A. Yes, it does.

ATTACHMENTS OF

JAMES R. DITTMER

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	3,156,878,566					(29,372,869)

Mountain States Telephone and Telegraph Company
[Decision 53849; Page 18; Docket No. E-1051-83-035; December 22, 1983]

Needless to say, the primary discrepancy between Staff and Mountain States came in the area of cash working capital. **Both parties utilized a modified "formula" method.** The Commission has on several occasions indicated the numerous problems associated with the "formula" method of determining cash working capital. See Decision Nos. 53174 (August 11, 1982), 53612 (June 15, 1983), and 53665 (July 27, 1983). **Mountain States should consider itself forewarned that no allowance for cash working capital will henceforth be permitted to Mountain States unless supported by a valid "lead-lag" study.**

In the instant matter, the Commission is bound by the record at hand. Staff and Mountain States agreed that the usual "formula" had to be modified by an allowance for the fact that Mountain States receives local service revenues in advance of rendering local service, a situation contrary to that prevailing with other types of public service corporation. Staff further adjusted the "formula" to reflect the greatly deferred payment schedule for various state and federal taxes as well as the **lag in interest payments**. Mountain States opposed both adjustments, contending that Staff was "double-dipping" since an allowance had already been made for prepaid revenue. We disagree. There is no double counting since the pre-payment of revenue and the deferral of expense are two (2) separate items. Simply because both indicate a lower cash working capital requirement does not make out a case for "double-dipping."

In Decision No. 53761, the Commission, after considerable debate by the parties therein, concluded that interest was not a proper deduction in a "lead-lag" calculation of cash working capital. Upon further analysis, we are now convinced that Decision No. 53761 was in error in that determination. To the extent that the interest payment lag contributes to the common equity return, it is subsumed in our market derived cost of common equity. Although interest is a non-operating expense, we find that this is not dispositive. **Accrued but unpaid interest represents a consumer supplied source of cash working capital and should properly be treated as such.** Any remaining difference between the Commission's determination of a reasonable allowance for cash working capital and that of Mountain States is attributable to the different level of operating and interest expense utilized in the "formula" as modified herein.
[Emphasis Added]

Mountain States Telephone and Telegraph Company
[Decision 54843; Page 27; Docket No. E-1051-84-100 et al.; January 10, 1986]

We are in no such quandary when it comes to cash working capital. **The Commission has repeatedly rejected the inclusion of non-cash items such as deferred taxes and depreciation in cash working capital. Moreover, Staff erred in its exclusion of interest expense from the calculation of cash working capital. The Commission has admittedly taken conflicting positions on this issue in previous Decisions. However, in Decision No. 53849, the Commission finally concluded that the classification of interest expense as a non-operating expense did not preclude its inclusion in a cash working capital "lead/lag" study.** Intervenor Phoenix has utilized its calculation of pro forma interest expense (derived through "interest synchronization") to reduce recommended cash working capital to a negative figure. See Phoenix Exhibit No. 2. **The concept of negative cash working capital was expressly approved by the Commission in Decision No. 53761.**
[Emphasis Added]

Arizona Public Service
[Decision 55931; Page 66; Docket Nos. U-1345-86-062, U-1345-85-367; April 1, 1988]
6. Cash Working Capital

As previously mentioned, APS performed a lead/lag study of its cash working capital requirements. Although this study showed a requirement of $34,706,000, APS made no adjustment to include cash working capital in rate base. Thus, its proposed requirement is zero. APS witness Post testified that APS made this proposal to be consistent with Decision No. 55228 which held cash working capital at zero (in the absence of a lead/lag study), to minimize any Palo Verde rate increase, and to reduce the number of issues to be addressed in this case. (Ex. A-27 at 36.) Both FEA witness Miller and Staff witness Brosch recommended a negative cash working capital.

The fundamental reason for the difference between APS's calculation and those of the FEA and Staff is the treatment of "non-cash" items, such as deferred taxes and depreciation. Although the argument is somewhat more difficult to follow with respect to deferred taxes (they represent taxes which will be paid in the future), we agree with APS that depreciation accounting represents the return of a cash outlay it made at the time it acquired utility assets. Thus, use of the term "non-cash item" may be a misnomer if read literally. However, neither depreciation nor deferred taxes require the expenditure of cash at the time the expense is recorded and thereby charged to the customers. They are not "current" cash expenses. **We have repeatedly rejected the inclusion of deferred taxes and depreciation in the calculation of current cash working capital requirements. We have also finally concluded that interest expense should be included in a lead/lag study, and we have expressly approved the concept of negative cash working capital.** E.g., Mountain States Tel. & Tel. Co., Decision No. 54843 (January 10, 1986). Therefore, in this case we have used the Staff's negative cash working capital requirement of ($46,757,000) in our rate base determination.
[Emphasis Added]

Citizens Utilities Company
[Decision 56807; Page 41; Docket No. U-1954-88-102 et al.; February 1990]
8. Cash Working Capital

Citizens did not include any cash working capital allowance in its OCRB and opposed the use of a lead/lag study.

...

With respect to the cost and benefits of a lead/lag study, the annualized intrastate cost of Citizens' study which will be reflected in rates is $5,095. On the other hand, as a result of Citizens' study and the Staff and RUCO adjustments, our cash working capital determination is a negative $593,514, rather than zero (which was used in Citizens' last rate case, in the absence of a lead/lag study). This rate base adjustment represents approximately $97,500 in gross annual revenues. Thus, although for a company of Citizens' size, the benefit of a lead/lag study is not substantial, the benefit does outweigh the cost. Further, Citizens is a rapidly growing company and, with experience, the cost of preparing a lead/lag study should decline, if only because not all of the lead/lag days need to be recomputed for every study.

In Decision No. 55493, we discussed the benefits of a case-by-case approach to lead/lag studies. Citizens has not presented herein any new arguments or information which would warrant abandonment of that approach in favor of the use of a zero cash working capital requirement for Citizens (and presumably all of the larger utilities) pending completion of unnecessary and counter-productive rule making proceedings.

In summary, we agree with Staff and RUCO on the use of a lead/lag study in this proceeding and will not change our previous order requiring Citizens to prepare and include the results of a lead/lag study in its general rate applications. Further, our cash working capital adjustment to Citizens' OCRB reflects Staff's intrastate approach, **adjusted to reflect any differences in revenues and expenses** as determined hereinabove and inclusion of rate case

expense, the RUCO adjustments to the revenue and expense lags and the minimum bank and working funds balances, **and inclusion of interest expense based on our determination of Citizens' OCRB and embedded cost of debt.**
[Emphasis Added]

Southwest Gas Corporation
[Decision 57075; Page 45; Docket No. U-1551-89-102, et al.; August 31, 1990]
B. CASH WORKING CAPITAL
1. Non-Cash Items

Applicant, Staff, and RUCO relied upon lead/lag studies to calculate the cash component of the working capital allowance for the Central and Southern divisions. **The primary difference between the studies involves the treatment accorded non-cash expense items and interest expense. Staff excluded from its calculation those expenses which do not require current period cash payments, i.e., depreciation expense, deferred income tax expense, and return on equity capital, and included interest expense to capture its working capital effect although it is classified as a non-operating expense.** RUCO agrees that the non-cash items should be excluded.

Applicant contests the exclusion, but the opposition need not detain us. The Commission has repeatedly held that the determination of the cash working capital requirement does not properly encompass non-cash items. The Commission has also found that accrued but unpaid interest, as a customer-supplied source of cash working capital, is a proper deduction in the lead/lag calculation. See, e.g., Mountain States Telephone and Telegraph Company, Decision Nos. 53849 (December 22, 1983) and 54843 (January 10, 1986); APS, Decision No. 55931 (April 1, 1988); and TEP, Decision No. 55659 (October 24, 1989). Applicant has presented no arguments which persuade us to depart from this precedent.

2. Other Methodological Issues

Applicant maintains that the lead/lag methodology followed by Staff to determine cash working capital erroneously used adjusted income statement amounts rather than unadjusted test year values. As Staff witness Brosch explained, consistency requires that the income statement amounts used for purposes of the lead/lag study be synchronized with the adjusted amounts used elsewhere in the revenue requirement calculation. RUCO also used adjusted amounts in its lead/lag study.

...

For the reasons articulated by Mr. Brosch, the Commission will adopt the lead/lag methodology Staff followed.

3. Cash Working Capital Summary

For the Central division, the foregoing adjustments adopted by the Commission will reduce Applicant's proposed cash working capital by approximately $9.1 million and result in a negative component of approximately $3.9 million.

For the Southern division, the adjustments reduce Applicant's figure by approximately $3.9 million and produce a negative cash working capital component of approximately $2.2 million.
[Emphasis Added]

Southern Union Gas
[Decision 57396; Page 12; Docket No. U-1240-90-051; May 24, 1991]
A. Cash Working Capital

...

2. RUCO Adjustment

In its post-hearing briefs and in late-filed Ex. RUCO-9, RUCO refers to a $161,262 reduction to cash working capital as being an adjustment remaining in dispute. According to Ex. RUCO-2, pg. 15, this "working cash adjustment reflects [Commission] precedent because it results mainly from including the lag effect of long term-bond interest, as required by the Commission in [Southwest] and previous decisions." However, **Staff's working capital adjustment, as accepted by Southern Union, already recognizes the interest on long-term debt.** RUCO has provided no explanation of whether or how its adjustment differs from that sponsored by Staff. The Commission will, therefore, reject RUCO's adjustment because it lacks foundation.
[Emphasis Added]

Southwest Gas Corporation
[Decision 57745; Page 19; Docket No. U-1551-90-322; February 28, 1992]
I. Cash Working Capital

In its initial filing in this case, the Company asserted a zero working capital request. Both RUCO and Staff responded by filing lead/lag studies. The Commission in Decision No. 57075 had relied upon such studies to calculate the working allowance for the Company's Central and Southern divisions and determined both were in excess of a negative $4 million. In this case, Staff and RUCO calculated the cash working capital to be a negative $3,734,000 and a negative $2,408,652, respectively.

As in the previous case, Applicant was critical of Staff and RUCO's cash working capital because it did not take into consideration certain "non-cash" items such as depreciation. **As we stated in Decision No. 57075 as well as other Decisions cited therein, the calculation is for "cash working capital" and not "cash and non-cash working capital".** Similarly, as we stated in Decision No. 57075, "Applicant has presented no arguments which persuade us to depart from this precedent." Since Staff simply updated the cash working capital amount approach in Decision No. 57075, we will approve Staff's recommended cash working capital. As a result of criticism by the Company regarding Staff's adjustments to prepayments, Staff revised its calculations and reduced its negative cash working capital to $3,680,000.
[Emphasis Added]

Southwest Gas Corporation
[Decision 58377; Page 12; Docket No. U-1551-92-253; August 13, 1993]
Working Capital

Based on its lead/lag study, the Company determined its cash working capital requirement was ($2,513,921). This amount was then offset by $2,339,698 of prepayments and $1,761,907 for materials and supplies to arrive at the Company's proposed working capital of $1,587,684. Staff proposed a reduction to the Company's cash working capital in the amount of $1,521,237 and a reduction to prepayments in the amount of $433,183. RUCO proposed a reduction in cash working capital in the amount of $268,324 and a reduction to prepayments in the amount of $883,412.

Staff was critical of the Company for using unadjusted test year values in the Company's lead/lag study in calculating cash working capital. Accordingly, Staff modified the study to include adjusted TY amounts. Staff was also critical of the Company for assigning zero lag to items amortized into expenses. According to Staff, such treatment is inappropriate because it nets a cash item with a non-cash item. Included in the Company's proposed cash working capital were the average cash balances related to working funds, petty cash, and cash held by depository banks. Both RUCO and Staff eliminated these average cash balances from the cash working capital requirements. Staff indicated that the cash balances are funds provided by ratepayers while RUCO indicated inclusion of cash balances was not consistent with the use of lead/lag study. In response, the Company indicated the cash balances did represent stockholder funds in providing service to ratepayers. In addition, the Company indicated similar balances had been included in the Company's last five Arizona rate cases.

We generally concur with Staff's modification of the Company's lead/lag study. However, we concur with the Company that a reasonable amount of cash-on-hand is appropriate. There has been no evidence presented to demonstrate that the Company's average cash balances are unreasonable. Accordingly, we will reject Staff and RUCO's proposed $227,616 removal of the Company's average cash balances. Based on all the above, we find the Company's proposed cash working capital should be reduced by $1,293,621 with a result of ($3,807,542). ...
[Emphasis Added]

<u>**Tucson Electric Power Company**</u>
[Decision 58497; Page 26; Docket No. U-1933-93-006 et al.; January 13, 1994]
M. <u>Cash Working Capital</u>

TEP proposed a negative cash working capital ("CWC") in the amount of $16,389,000. Staff, RUCO, and JSA all proposed adjustments to the Company's requested CWC.

JSA recommended that if TEP is allowed to retain the net cash proceeds from its settlement agreement with Southern California Edison Company ("SCE") then TEP's CWC should be reduced by a like amount. According to JSA, this treatment should continue until ratepayers receive $27.6 million of refunds.

In response, the Company indicated this is a "non-current" cash transaction and as such should not be included as part of CWC.

We concur with the Company. As will be more fully discussed later, the Company's shareholders bore the risk and cost of pursuing the SCE litigation and should receive 100 percent of the cash benefits.

The MSR Option gain is being amortized as a credit to retail revenues. The unamortized balance of the revenues is not included as a rate base deduction since the gain was increased to allow for an implicit carrying charge to compensate for the time value of money. According to RUCO, the amortization is a non-cash transaction which is excluded from rate base. As a result, RUCO concluded that TEP's attributing $1.9 million of cash working capital to the MSR revenue was wrong and should be adjusted to zero.

In response, **the Company indicated it has excluded all "non-current" cash transactions. As a result, the Company excluded the MSR revenue credit as well as a number of "non-cash" expense debits.** According to the Company, the debits and credits should be treated consistently. We concur with the Company.

...

TEP deposits funds in a special account to match anticipated medical payments on claims in process. Once notified that payment is due on claims, the Company records the medical expense and reduces the balance in the special account. There were, on average, 19.3 days from the time funds are deposited in the special account until the Company is notified that payment is due on claims. The Company included the 19.3 days as part of its payment lag period of 66.62 days.

Staff deducted the 19.3 days from the payment lag period. According to Staff, the expense is incurred at the time medical services are provided and that is the date from which to measure the payment lag.

In response, the Company indicated that Staff was erroneously assuming that the ratepayers were providing cost free funding of medical expenses. TEP asserted it is Company funds that are being used to fund the medical expenses. As a result, TEP requested Staff's adjustment be denied.

We concur with Staff. The proper payment lag time should be measured from the date the expense is incurred.

Staff proposed to measure the expense lag used in the CWC study from the date an expense is incurred by the Company. The Company objected to Staff's approach and argued the expense lag should be based on the date the cost of service is recorded. Although TEP disputed Staff's concept, the Company indicated it could agree as long as Staff utilized the same concept for both revenue recovery and expense payment lags.

In response, Staff indicated that the revenue lag is not necessarily affected by the expense lag. According to Staff, the revenue lag is measured from the date service is provided to the customer. We concur with Staff.

[Emphasis Added]

Citizens Utilities Company

[Decision 60172; Page 19; Docket No. E-1032-95-417 et al.; May 7, 1997]

E. Cash Working Capital

Both Staff and RUCO proposed adjustments to the Company's cash working capital, a number of which were accepted by the Company, including adjustments to expense lead or lag days with salaries and wages, pumping power expense, administrative office expense, insurance, injuries and damages expense, and other taxes. **The Company also accepted inclusion of interest expense in the lead lag study at a 90-day lag** and also removed preliminary survey and investigation ("PS&I) charges from the working capital balance. Staff and RUCO agree that the revenue lag should be reduced by one day to reflect the Company's new lock box program which will allow customers to pay their bills through the bank rather than remitting them directly to the Company. Staff and the Company have agreed to certain increases to expense lags to reflect check clearing lags and have revised the pension lag expense to reflect an actual contribution made by Citizens to the pension trust. We will adopt those adjustments. RUCO recommends that, consistent with past Commission decisions, including Decisions Nos. 58360 and 58664, the Commission should exclude $83,354 in rate case and deferred TARGET: Excellence expenses from the cash working capital component. We agree with RUCO.

Staff and RUCO proposed that cash balances should be removed from the determination of cash working capital. RUCO notes that these two asset items have never been included in the calculation of cash working capital in any prior Commission decision. Staff notes that with the exception of only Sun City Sewer, there is a negative cash working capital requirement and to include a cash balance in the cash working capital requirement for these companies would grant them a return on cash when they have no cash requirement. We agree with Staff and RUCO's adjustment to remove cash balances.

We note that RUCO believes that the Company's sampling method for determining the lag for the O&M, administrative and general expense category analyzed too few invoices and does not capture the various types of expenses contained in the category. While we will not adopt RUCO's adjustment in this proceeding, we expect the Company to address the issues raised by RUCO in its next lead/lag study.

[Emphasis Added]

Utilitech, Inc.'s Second Set of Data Requests
To Arizona Public Service Company
Docket No. E-01345A-05-0816
April 24, 2006

UTI-2-100 Reference page 12 of Ms. Laura Rockenberger's direct testimony. Please provide actual PWEC A&G expenses by month for the period January 2002 through the transfer date of PWEC assets that would be comparable in composition to those considered in the development of the $20,415,000 proforma adjustment.

Response:

Note: Discussion regarding A& G components of Operating Income Pro forma is discussed at page 15 of Ms. Rockenbergers direct testimony.

Schedules of PWEC A&G expenses by month for the period January 2002 through the transfer date (July 29, 2005) of PWEC assets is attached as APS09887.

APS will be submitting a pro forma adjustment for $5,098,000 to remove out-of-period costs included in the test year with its Rebuttal testimony. See the attaché schedule of PWEC A&G expense for more information

Witness: Laura Rockenberger

Data Request
UTI 2-100
PWEC A & G Expenses by Month
January 2002 - July 2005

	2002	2003	2004	2005
January	210,678	672,542	6,910	2,457,139
February	156,533	359,476	701,426	(482,760)
March	(45,188)	215,082	750,715	2,015,992
April	170,348	382,009	662,193	869,667
May	49,358	773,148	802,273	1,559,300
June	225,285	505,151	460,094	1,313,578
July	337,586	797,506	1,292,785	1,135,373 *
August	207,157	268,534	679,627	N/A
September	1,108,456	685,559	1,445,231	N/A
October	321,307	680,198	563,024	N/A
November	(83,823)	685,496	4,496,622	N/A
December	660,491	1,242,151	4,633,754	N/A
Total	3,318,188	7,266,852	16,494,653	8,868,289

Shared Services Costs are allocated based on Pinnacle West's net equity and debt in it's Affliates in accordance with ACC Code of Conduct Policy 1. The annual increase in the allocation of costs to PWEC is associated with the construction of the PWEC units.

	2002	2003	2004	2005
PWEC Share - Corporate Allocation	19.80%	29.60%	35.00%	34.90%
PWEC Share - Corporate Governance Allocation	17.70%	27.00%	32.00%	32.30%

An adjustment for Pinnacle West's Shared Services Asset depreciation was recorded in November, 2004. The proforma adjustment should have excluded nine months of these charges as an out-of-period adjustment. We are proposing to reduce the pro forma by $2,001,367.

An adjustment for affiliate rent was recorded in December, 2004. The proforma adjustment should should have excluded nine months of these charges as an out-of-period adjustment. We are proposing to reduce the pro forma by $3,096,000.

* PWEC Assets transferred to APS effective July 29, 2005.

UTI-10-314. Reference the Company's response to UTI-2-100 addressing PWEC A&G expenses. Please provide:

a. A more detailed explanation of the proposed nine months of out-of-period costs related to Pinnacle West's Shared Services Asset depreciation recorded in November 2004. What caused or created the out-of-period entry? Did it just affect PWEC or were all the subsidiaries – including APS – affected by the entry?

b. A more detailed explanation of the proposed nine months of out-of-period costs related to Pinnacle West's Shared Services affiliate rent expense recorded in December 2004. What caused or created the out-of-period entry? Did it just affect PWEC or were all the subsidiaries – including APS – affected by the entry?

Response:

a. Shared Services costs are allocated based on Pinnacle West's net equity and debt invested in its Affiliates as defined in the policies provided in UTI-1-2(d). Shared Services costs include depreciation on Shared Services assets. From January through October, Shared Services depreciation was allocated to Depreciation Expense on Pinnacle West Energy's books and credited to Depreciation Expense on Pinnacle West Capital's books for the PWEC (as well as the affiliates) share of these costs. It was determined that Pinnacle West Energy and other affected PWCC affiliates should not record Depreciation Expense on their books for assets that were not recorded on their books. The out-of-period entry was to <u>move</u> the allocated Shared Service Depreciation from Depreciation Expense on the non-owning (of Shared Service assets) to A&G – Misc. General Expense. This entry affected all entities (APS, including, Power Marketing; APS Energy Services and PWCC) that receive these allocated costs.

b. Shared Services costs include rent offsets for CHQ (Corporate Headquarters) related to sub-tenant's and Pinnacle West Affiliates rent and credits for the use of certain Deer Valley facilities related to depreciation associated with Shared Services. It was discovered that these credits were incorrectly allocated throughout 2004. In order to properly state entity financial performance reports, an entry was recorded in December to ensure charges across entities were correct. This entry affected all entities (APS, including Power Marketing; APS Energy Services and PWEC) that receive these allocated costs, see LLR_WP27.

Witness: Laura Rockenberger

Pro Forma Adjustment Summary
UTI-10-314

Depreciation

	FERC Account	Despcription	PWEC	APS	Total
Total Shared Services Depreciation Adjustment (11/2004)	9302	O&M	(2,446,115)	(4,060,203)	(6,506,318)
	4030-4040	Depreciation	2,446,115	4,060,203	6,506,318
			-	-	-
Proforma Adjustment (Remove nine months from TY)	9302	O&M	(2,001,367)	(3,321,984)	(5,323,351) Reduction to expenses
			UTI 2-100	UTI 14-350 ~~(UTI 10-314)~~	

Rent

	APS	PWEC	PWCC Power Marketing	APSES	Total
Total Shared Service Affiliate Rent Adjustment (12/2004)	(4,320,000)	4,128,000	112,000	80,000	-
Proforma Adjustment (Remove nine months from TY)	(3,240,000)	3,096,000	84,000	60,000	-
	LLR_WP27	UTI 2-100 Reduction in expense			

BEFORE THE
ARIZONA CORPORATION COMMISSION

IN THE MATER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND TO AMEND DECISION NO. 67744	))))))))	DOCKET NO. E-01345A-05-0816

DIRECT TESTIMONY AND

ATTACHMENTS OF

MICHAEL L. BROSCH

ON BEHALF OF THE
UTILITIES DIVISION STAFF

AUGUST 18, 2006

DIRECT TESTIMONY
OF
MICHAEL L. BROSCH

ARIZONA PUBLIC SERVICE COMPANY
DOCKET NO. E-01345A-05-0816

Q. Please state your name and address.

A. My name is Michael L. Brosch. My business address is 740 Northwest Blue Parkway, Suite 204, Lee's Summit, Missouri 64086.

Q. Where are you employed and in what capacity?

A. I am a principal in the firm Utilitech, Inc., a consulting firm engaged primarily in utility rate and regulation work. The firm's business and my responsibilities are related to special services work for utility regulatory clients. These services include rate case reviews, cost of service analyses, jurisdictional and class cost allocations, financial studies, rate design analyses and focused investigations related to utility operations and ratemaking issues.

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

A. I am appearing on behalf of the Utilities Division Staff of the Arizona Corporation Commission ("Staff"). Utilitech entered into a contract with the Staff to review and respond to the rate case filing of Arizona Public Service Company ("APS" or "Company"). Utilitech's direct responsibilities generally relate to the development and presentation of the Staff's positions regarding APS's test period revenue requirement and cost of service allocations. Utilitech has employed sub-contractors in two areas. Liberty Consulting Group, Inc. is responsible for analyzing and presenting Staff's evidence regarding APS fuel and purchased power expenses and the related Fuel Adjustment Clause issues and this work is addressed in the Direct Testimony of Mr. John Antonuk. Technical Associates, Inc. also served as sub-contractor to Utilitech and Mr. David Parcell is sponsoring Staff's cost of capital evidence. Additionally, the ACC Staff is internally addressing some issue areas, including rate design, Demand Side Management Programs, Environmental Portfolio Standards, and quality of service issues.

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

A. My testimony is intended to describe and sponsor, on behalf of Staff, class cost of service evidence based upon Staff's calculated revenue requirement and appropriate cost allocation methodologies.

QUALIFICATIONS

Q. Will you summarize your educational background and professional experience in the field of utility regulation?

A. I graduated from the University of Missouri, Kansas City, in 1978 with a Bachelor of Business Administration Degree, majoring in accounting. I hold a CPA Certificate in the State of Missouri and in the State of Kansas. I am a member of the American Institute of Certified Public Accountants, the Missouri Society of Certified Public Accountants, and the Kansas Society of Certified

Public Accountants. Since completion of formal education, my entire professional career has been dedicated to utility operations and regulation consulting.

From 1978 to 1981, I served as a public utility accountant with the Staff of the Missouri Public Service Commission. While employed by the Missouri Commission, I participated in rate case examinations involving electric, gas, water, steam, transit, and telephone utilities operating in Missouri. In December 1981, I accepted employment with Troupe Kehoe Whiteaker & Kent, a Kansas City CPA firm, in its public utility department. While with Troupe Kehoe Whiteaker & Kent, I was involved in the review, analysis, and presentation of a wide range of utility rate case issues and various other utility management advisory functions for both utility company and regulatory agency clients. In May 1983, I commenced employment with Lubow, McKay, Stevens and Lewis, an accounting and public utility consulting firm. While employed by that firm, I was involved in numerous regulatory proceedings and directed work related to various special projects.

In June 1985, Dittmer, Brosch and Associates, Inc. (the predecessor firm to Utilitech, Inc.) was organized. The firm specializes in public utility regulatory and management consulting in the electric, gas, telecommunications, water, and waste water industries. As a principal of the firm, I am responsible for the supervision and conduct of the firm's various regulatory projects. A majority of the firm's business involves representation of utility commission staff and consumer advocate interveners in utility rate proceedings and special or focused investigations.

I have testified before utility regulatory agencies in Arizona, Arkansas, California, Florida, Hawaii, Illinois, Indiana, Iowa, Kansas, Michigan, Missouri, Nevada, New Mexico, Ohio, Oklahoma, Utah, Washington and Wisconsin in numerous regulatory proceedings involving electric, gas, telephone, water, sewer, transit, and steam utilities. Attachment MLB-1 to this testimony sets forth additional details regarding my qualifications.

Q. Have you previously participated in Arizona Public Service Company rate case proceedings before this Commission?

A. Yes. Mr. Dittmer and I worked together in preparing the Staff's revenue requirement position in the most recent APS Arizona rate case, Docket No. E-01345A-03-0437. Mr. Dittmer and I were also Staff's revenue requirement consultants in two prior APS rate cases, Docket Nos. U-1435-85-367 and U-1345-90-007. I have also been involved in many rate cases and other dockets before the Commission involving utilities other than APS. A table listing my formal testimony filings is contained within Attachment MLB-2.

COST OF SERVICE ALLOCATION

Q. Why are cost of service allocation studies ("Cost of Service Studies" or "COSS") required in APS electric rate cases?

A. Cost of Service Studies are required for several purposes. First, it is necessary to perform jurisdictional allocations to segregate the retail portion of APS rate base and operating income that is subject to the jurisdiction of the Arizona Corporation Commission from that which is under the jurisdiction of the Federal Energy Regulatory Commission ("FERC"). Then, these ACC-retail jurisdictional rate base and operating income elements are used to determine overall retail revenue requirements and are further allocated among retail customer classes using class cost of service allocations, so as to provide information reflective of the estimated cost to serve each customer class. The resulting class rates of return are often used as a guide for use in determining how the overall retail revenue change should be "spread" among customer classes. Class COSS results are also unbundled into functional and unit costs for each customer class as a guide in the design of tariff rate schedules.

Q. Has the Company prepared a test period COSS for these purposes?

A. Yes. APS actually conducted its COSS on a combined basis, performing jurisdictional and class allocations within a single spreadsheet-based model. The results of this work are sponsored by APS witness Mr. David Rumolo in a series of Schedules within the Company's filing identified as Schedules G-1 through G-7. At a summary level, APS Schedule G-1 indicates that the

Residential class Rate of Return at present rate levels (before any rate increase) of 1.52 percent on Rate Base is lower than the average return being earned by the entire ACC jurisdictional business of 2.59 percent. Other classes, such as General Service, Water Pumping and Dusk to Dawn (lighting), are shown to be earning above-average rates of return under present rates. All of these values are based upon the APS asserted revenue requirement before any rate increase.

Comparable results from the Company's COSS are shown on Schedule G-2 at "Proposed" rate levels, indicating how the class returns compare to the overall "Total ACC Jurisdiction" column of data if the entire rate increase proposed by APS is granted and implemented with the rate design proposed by the Company. Schedule G-1 shows the entire ACC Jurisdiction earning the Company's proposed 8.73 percent return on rate base, with comparable return levels from the other rate classes as shown in row 7.

Q. Is there only one single correct methodology that must be employed in the conduct of COSS studies?

A. No. There are generally accepted methods for the conduct of such studies that have been developed over many years of practice. For example, all COSS studies require that utility costs be separated by function, classified into three broad categories of cost causation (demand, energy and customer) and then allocated using reasonable data to estimate test year allocation factors. However, performing the COSS study requires judgment on the part of the analyst, particularly when determining specific cost classifications and in selecting and applying allocation factors. Because of this unavoidable judgment element in the COSS process, it is not unusual for there to be differences of opinion among analysts. The element of judgment also causes regulators to often view the results of COSS to be useful as a guide in formulating utility rate design, rather than an absolute and accurate indicator of reasonable rates.

Q. Have you reviewed the jurisdictional and class cost of service allocations performed by APS witness Mr. Rumolo, as summarized in Section G of the Company's filing and in Mr. Rumolo's workpapers DJR_WP-1 through DJR_WP-5?

A. Yes. After reviewing the numerous electronic spreadsheet models and detailed workpapers supporting the test period jurisdictional and class cost allocations, I interviewed Mr. Rumolo and conducted discovery to validate input data and to test allocation logic.

Q. Does the APS COSS model produce reasonable results that can be used to accurately determine jurisdictional revenue requirements as well as class cost of service guidance?

A. I found the allocations performed by Mr. Rumolo to generally be reasonable and comparable to the allocation methodologies previously employed in APS general rate case proceedings. In fact, my only objection to the Company's approach is the same objection raised by Staff and RUCO in the Company's last rate case. The Company's study uses a Four Coincident Peak ("4CP") allocation factor to allocate production demand costs, which are the costs associated with the Company's nuclear, coal and gas-fired generation facilities. Staff continues to believe that the Company's cost of service study should utilize an energy-weighted allocation approach, rather than allocating production demand costs based solely upon relative class demands registered during the four peak hours of the year. To correct this problem, I have modified the company's COSS to employ a 4 Coincident Peak (CP) and Average (4CP&Average) allocation approach for production plant investment and expenses for class cost of service allocations.

Q. What is the difference between using only coincident peak demand levels, such as the APS 4CP allocation approach, rather than using a combination of coincident peak and average demand levels?

A. Coincident peak demands are the measured maximum combined loads of all customers on the system, in the single hour (or 4 hours) when overall system demands are the highest during the year. The 4CP allocation factor would use these hourly demands registered by each customer class during the 4 highest peak system demand hours in test year to allocate cost responsibility for all power generation production resources among classes. Customer usage during the other 8,756 hours of the year would have no impact upon the allocation of APS power plants under the 4CP approach. The theoretical basis for the 4CP approach is that meeting hourly peak demand is the sole planning criteria used by APS that causes the Company to incur power generation facilities fixed costs.

In contrast, Staff does not accept the premise that the costs of APS power production facilities are incurred solely to meet peak hour demands, but are also incurred to efficiently produce electricity throughout the entire year. Staff therefore proposes that hourly peak demands should be heavily weighted in determining a production demand allocation factor, but that some weight should also be applied to customer demands throughout the rest of the year. Average demands are calculated by dividing total energy produced throughout the year by 8,760 annual hours to see how intensely power production resources are loaded throughout the year. To consider both peak demand levels and average demand levels, an energy-weighted allocation approach is often used by regulators, combining peak demands with average demands into a single allocation factor applicable to electric production facilities fixed costs.

Q. Have you prepared any Exhibits to quantify the changes to the Company's COSS that you sponsor?

A. Yes. Attachment MLB-3 to my testimony contains a series of Schedules that were prepared in the format of Mr. Rumolo's Workpaper DJR_WP1 and that incorporate Staff's revenue requirement accounting inputs along with COSS allocations performed using a 4CP & Average allocation of production demand costs. These calculations reflect all ratemaking adjustments that are being proposed by Staff witnesses, before any rate increases that may result from this Docket.

For comparison to Staff's recommended COSS allocations performed on a 4CP & Average basis, my Attachment MLB-4 was prepared indicating how Staff's revenue requirement case would roll through the COSS allocations under the APS proposed 4CP methodology. Generally, the effect of using an energy-weighted 4CP & Average approach is to attribute some generating capacity costs to the lighting classes, unlike under the 4CP approach, and to attribute somewhat more production cost responsibility to the higher load factor customers that use more energy relative to their peak demands. These results can be seen by comparing the "Rate of Return Present" results at row 39 of Attachment MLB-3 under the 4CP & Average approach to the comparable amounts appearing on the same row of Attachment MLB-4.

Q. Have you provided Staff witness Ms. Andreasen with the COSS model so that she can consider class allocated accounting costs in the design of rates for APS?

A. Yes.

Q. Turning back to the production demand allocation issue that exists between APS and Staff, how significant is the selection of an appropriate allocation factor for demand-related production costs?

A. The single most controversial COSS allocation within a base rate proceeding for electric utilities is typically the production demand allocation factor, because this factor is used to allocate a large percentage of non-fuel related expenses and all of the generating plant investment within rate base. For APS, production-demand classified costs are nearly half of total rate base and production-demand classified expenses total more than $570 million.[1]

Q. How does Mr. Rumolo explain his use of a 4CP allocation methodology for Production-Demand costs?

A. At page 7 of his testimony, Mr. Rumolo states, "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")."

Q. Do you dispute that APS designs and builds its production facilities to meet its system peak loads, as stated by Mr. Rumolo?

A. I dispute the notion that meeting peak demands in the summer months is the sole design criteria used by APS when it decides how to optimize its investment in electric production plant and how to operate and maintain generating resources. Even though APS is a summer peaking utility, it should be recognized that its generation facilities are required to serve customers during all of the non-peak hours of the year. Many of the costs incurred by APS to own, operate and maintain its power plants could be much lower if the

[1] APS Schedule G-3, column A, row 6 shows Production-Demand rate base of $2.1 billion, relative to total ACC rate base in column E, row 18 of $4.5 billion. Production-Demand classified expenses of $573 million are shown in APS Schedule G-4 at column A, row 6.

Company were concerned only with meeting demands during the four peak hours of the year.

For instance, rather than building expensive base load nuclear and coal-fired generating plants that run throughout the year at lower fuel expenses, APS theoretically could use much cheaper gas-fired peaking units throughout its generation fleet if its sole design criteria was meeting peak summer demands (without regard to energy costs). Additionally, APS could avoid significant operations expenses for its generating units if the units only needed to be available during the summer peak months and plant operations staff were not needed the other eight months. Production maintenance expenses could also be lower if generating unit available during the eight non-summer months was not a concern in the scheduling of unit overhauls. Thus, it is obvious that cost causation for APS production facilities goes beyond simply the need to meet peak demands in the summer.

Q. Under the APS-proposed 4CP approach, are there any customer classes that receive no allocation of demand-related costs for electric production facilities?

A. Yes. The Company-proposed 4CP allocation of production demand costs results in the Street Lighting and Dusk to Dawn lighting classes paying nothing toward the fixed costs of APS electric production facilities. This can be observed in at Schedule G-3 with respect to allocated Rate Base, in column A at Line Nos. 4 and 5, and at Schedule G-4, column A, Line Nos. 4 and 5 for Production Demand Operating Expenses. While it is obvious that APS must use its electric generating facilities to serve these lighting customers, the fact that lighting loads do not occur coincident with the four hours when 4CP demands are measured causes customers in these classes to be allocated no production demand-related cost responsibility under the Company's approach.

Q. How does an energy-weighted allocation factor consider the fact that electric production facilities are designed and operated to efficiently meet both peak demands as well as demands throughout the other 8,756 hours of the year?

A. The 4CP and Average approach involves a weighted combination of the peak demand allocation factor used by APS, together with an average demand (or energy-based) allocation factor. Average demand for this purpose is based upon test period energy volumes divided by the total 8,760 hours throughout the year. The combination occurs by weighting the 4CP and the average demand statistics, by the sum of the combined peak demand plus the average demand. For APS, the factor used by Staff combined Mr. Rumolo's 4CP demand data weighted 65 percent, with average demand levels weighted 35 percent.

Q. Do any published authorities recognize energy-weighted allocation methods to be appropriately reflective of cost causation for electric utility production plant and O&M costs?

A. Yes. According to the Electric Utility Cost Allocation Manual published by the National Association of Regulatory Utility Commissioners ("NARUC"), at page 49:

> There is evidence that energy loads are a major determinant of production plant costs. Thus, cost of service analysis may incorporate energy weighting into the treatment of production plant costs. One way to incorporate an energy weighting is to classify part of the utility's production plant costs as energy-related and to allocate those costs to classes on the basis of class energy consumption.

This publication illustrates and explains many different energy weighting methods that are widely used to allocate production plant costs with a conclusion at page 67:

> This review of production cost allocation methods may not contain every method, but it is hoped that the reader will agree that the broad outlines of all methods are here. The possibilities for varying the methods are numerous and should suit the analysts' assessment of allocation objectives. Keep in mind that no method is prescribed by regulators to be followed exactly; an agreed upon method can be revised to reflect new technology, new rate design objectives, new information or a new analyst with new ideas. These methods are laid out here to reveal their flexibility; they can be seen as maps and the road you take is the one that best suits you.

The point to be drawn from the NARUC Manual is that considerable judgment is involved in the selection and application of COSS allocations, particular with respect to costs that do not fall cleanly into a "demand" or "energy" classification. In my judgment, use of an energy weighted 4CP and Average production allocation approach is necessary for APS to reflect cost causation for production plant investment and is also reasonable for expenses because generating capacity non-fuel O&M costs are incurred both to meet peak demand and to minimize fuel and operating costs. A straight 4CP peak demand-based allocation approach completely ignores the notion of fuel and O&M cost avoidance as an important element of production capacity cost causation.

Q. Do differences in the installed costs of APS base-load generating units, compared to costs of peaking facilities, support the use of an energy-weighted allocation factor for such facilities?

A. Yes. If the sole planning criteria in the selection of power plant technologies was to meet system peak demands for only a few coincident peak hours of the year, the utility would install only relatively inexpensive peaking generation, so as to minimize fixed costs of the facilities without much regard for fuel and operating expenses during only these few hours of use. Clearly, the facts illustrate that this is not what APS has done – where a blend of more expensive base load generation is combined with peaking units to efficiently meet demands throughout the year.

Using information from the APS 2005 FERC Form 1 report at pages 403.2 and 403.3, a comparison of Palo Verde base-load nuclear unit installed costs per KW and operating expense per KWH to similar data for the West Phoenix gas-fired combustion turbine units produces the following information:

Unit Cost Information	Palo Verde Nuclear	West Phoenix CT
Kind of Plant	Nuclear Base Load	Combustion Turbine
Installed Capacity KW	1,225,000	106,000
Cost per Installed KW	$2,085	$162
Expense per KW - 2005	$0.0230	$0.2314

While an analyst might select different units for comparison or take issue with the fact that the West Phoenix units were constructed in the early 1970's while Palo Verde was completed in 1986, there is no escaping a conclusion that generating facility costs are caused in large part by a desire to efficiently provide energy throughout the year. Otherwise, APS would <u>not</u> have incurred the higher nuclear generation capacity costs and its generating fleet could be made up solely of combustion turbines to meet peak demand. To serve loads for only four peak hours in a year, APS could rationalize West Phoenix CT operating expenses that are orders of magnitude higher than the expense per KW associated with nuclear base load generation, but the lower operating costs of the nuclear facilities justify the large capital investment because they operate throughout the year.

Q. Do other Arizona utilities with summer peaking characteristics employ an energy-weighted production demand allocation methodology comparable to what you are recommending for APS?

A. Yes. I understand that Tucson Electric Power ("TEP") has employed a 4CP & Average approach. In its Decision No. 58497 in TEP Docket No. U-1933-93-006, the Commission stated:

> An electric utility's total cost of service results from three major interrelated causes: total output; the rate and time when customers use the output; and, the number of customers who receive service. In order to reflect these three major interrelated cost factors in rates, an electric utility's total costs are functionalized and then classified as energy-related, demand-related and customer-related. Once an electric utility's total costs

> have been classified, they are then allocated among the various classes of customers by the most appropriate allocation ratio.
>
> In recent cases, the Commission has indicated its dissatisfaction with the four-month coincident peak (4CP) method for allocating production and transmission costs. At the same time, the Commission recognized that other methodologies took into consideration annual energy usage and peak demand.
>
> TEP conducted a COS study using the average and four coincident peak ("A&4CP") production approach. DOD also conducted a COS study utilizing a demand based average of four coincident peak ("4CP") methodology. JSA recommended adoption of an average and excess four coincident peak allocation study ("A&E/4CP"). RUCO modified the Company's COS study to arrive at its recommended class revenue allocation. Staff generally accepted the Company's COS study with comments/criticisms. (Decision No. 58497, page 75)

After stating the positions of other parties in greater detail in this Decision, the Commission ultimately stated at page 77 of the Decision, "Based on all the above, we concur that TEP's COS study is a useful guide in establishing appropriate rates in this case."

In addition, I understand that Commission Staff has employed energy-weighted allocation methods to production costs in cases involving electric cooperatives in Arizona.[2]

Q. Earlier in your testimony, you mentioned that Staff and RUCO opposed the APS production demand allocation factor in the Company's last rate case, Docket No. E-01345A-03-0437. Were the reasons given by the Staff and RUCO witnesses in that docket consistent with your views in this docket?

[2] See for example, Decision No. 61721 in Duncan Valley Electric Cooperative Docket No. E-017003A-98-0431, Stipulation page 3 at "6. Cost-of-Service-Study, Load Research and Line Losses"

A. I believe so, yes. In the last APS rate case, Staff witness Ms. Lee Smith recommended an energy-weighted allocation approach, stating the following:

> For the most part I support the company's choice of allocators. However, I believe that the allocation of generation capacity costs is incorrect...The 4CP allocation method for generation capacity does not reflect cost causation because it does not reflect how the utility makes decisions regarding generation investment. Using the 4CP method implies that all generation capacity costs can be explained by the utility's need to meet its peak load. While it is true that the amount of capacity in MW's that a utility will build (or purchase) is determined by its need to meet its peak load, the types of generation capacity that the utility acquires, and thus the dollars that it spends on capacity, are affected by a number of other considerations, bur primarily by the tradeoff between capacity and energy costs.

RUCO witness Dr. Stutz also recommended using an energy weighting approach in the allocation of production capacity costs in the last APS rate case, as explained at page 20 of his testimony in Docket No. E-01345A-03-0437:

> Utility planners can choose different types of generating plants to meet customer loads. Peaking plants offer the advantage of lower costs but they are generally more expensive to run. Baseload plants, on the other hand, are more costly to build but have lower running costs. The choice of plant additions requires detailed analysis. However, underlying that analysis is the simple point that utility planners will only build more expensive baseload plants if they produce sufficient operating cost savings to outweigh their higher capital costs. Thus, the additional cost of baseload plants is justified by potential energy cost savings. The same is true for transmission lines. Both their role in meeting peak demand and their capacity to reduce costs by providing access to economic energy sources is considered.
>
> If APS only considered peak demands, then peaking plants would predominate in its generating mix because they are the cheapest plant sot build to meet a given demand. However, as Mr. Wheeler, APS's lead witness points out, the APS generation mix contains 44 percent coal as well as 31 percent nuclear units. The cost of coal and nuclear plants cannot be justified solely to meet peak demand.

These recommendations are consistent with the approach that I am recommending in this docket.

Q. How did APS respond to the recommendation of Staff and RUCO in the last case that production demand-related costs be allocated using an energy-weighted allocation approach?

A. In Rebuttal Testimony, APS witness Mr. Alan Propper listed several reasons "...for continuing to use a Coincident Peak methodology as opposed to the methodologies proposed by Staff and RUCO." Mr. Propper's listed reasons included his opinion that the 4CP method "best reflects generation capacity cost responsibility for a consistently strong summer peaking utility such as APS" and that "The Coincident Peak methodology uses a true demand (kW) allocation for what is a fixed cost, namely generation capacity, as opposed to an energy (kWh) allocation which is suitable for use with a variable cost such as fuel expense."

Q. Are these arguments a reasonable basis to <u>not</u> employ an energy-weighted allocation methodology as recommended by Staff then and now?

A. No. As explained in my earlier testimony, generation capacity cost causation for APS involves costs incurred by APS to install less expensive peaking units to meet peak demands, as well as substantial additional costs incurred to install more costly baseload generating units that produce energy at lower costs. It is important to note that an energy allocation factor is used by APS and Staff to allocate actual fuel and other variable energy-related costs among customer classes. Because APS energy costs are lower as a result of the Company's diversified mix of generation resources, including baseload nuclear and coal units, equity requires that the classes receiving allocated energy savings also bear some increased cost responsibility for the large investment in such generating facilities. It is important to use an energy-weighted production demand allocation factor to match the benefits and costs associated with the APS mix of generation resources. The fact that APS is a strong summer-peaking utility does not change the fact that generating resources have been planned to minimize electricity production costs in the summer and throughout the year.

Q. Mr. Propper also testified in the last rate case that, "The Commission has consistently accepted the 4CP methodology in APS proceedings." Did you find this to be correct?

A. I have not found any recent Commission decisions in which there was a determination that the 4CP method advocated by APS was reasonable over other methods. Many APS rate changes have been implemented based upon settlements before the Commission, but in Docket No. U-1345-85-367 in 1988 the Commission resolved cost of service and rate design issues in a litigated APS rate case, with an extensive discussion of cost of service including the following language:

> Much of the testimony offered by the expert witnesses attempted to demonstrate why their particular cost allocation

> methodology was superior to all others. However, we are not prepared to endorse for general application any single method of cost allocation. Further, although we have previously indicated our dissatisfaction with the 4-CP method for allocating demand related production costs of nuclear generating units [footnote 38], we do not believe that the evidence warrants the selection of any single alternative method for rate design purposes in this case.
>
> Based on our review of the return indexes, our dissatisfaction with the 4-CP method for allocating demand-related nuclear production costs and the evidence that the dramatic test year reversal of the trend towards unity could have been an aberration, we agree with Mr. Violette's recommendations regarding the allocation of the required increase in gross annual revenues. Thus, the increase should be spread across the board to the Residential, General Service, Irrigation, and Street Lighting classes by the application of an equal percentage increase to the base revenues for each class, excluding basic service charge and fuel revenues. (Decision No. 55931, pages 83-84)

Footnote 38 in that Decision acknowledged the inability of the 4-CP method of allocation to reasonably treat the "trade-off" between demand-related capacity costs and the energy cost savings created by baseload units:

> 38. Our dissatisfaction with the 4-CP method for nuclear plant does not stem from the absolute size of the nuclear production costs, per se. Rather, it is the relationship between those relatively high costs (allocated by a demand ratio) which were incurred to take advantage of the relatively low nuclear fuel costs (allocated by the energy ratio), which has caused our dissatisfaction. Although there is always a "trade-off" between demand and energy costs, in the case of nuclear plants the relationship is exaggerated, particularly in the early years of the plant.

At the end of its discussion of cost of service allocations in Decision No. 55931, at page 85, the Commission concluded, "APS should continue to provide the cost-of-service data it provided in this case. In addition, in the next general rate case we would also like to consider more carefully the feasibility of an allocation methodology which reflects both energy and peak demand. Of course, APS and the other parties can continue to offer other alternatives in addition to those presented in this case."

Q. Another concern raised by Mr. Propper in his rebuttal to Staff in the last rate case was that Staff's proposed method would "...shift approximately $5.1 million in annual costs or revenue requirement away from APS' Commission jurisdictional customers and inappropriately places it on the non-jurisdictional FERC customers. Since FERC does not accept the Average & Peak methodology, APS would not be able to recover this $5.1 million in cost from either jurisdiction, effectively 'stranding' dollars between state and federal regulation." Does this occur in using the 4CP & Average method you propose?

A. No. I have elected to <u>not</u> disturb the jurisdictional allocation of production plant in this docket, so that no jurisdictional "stranding" of costs will occur. The 4CP & Average calculation I performed was limited to revision of only the retail class allocation factors, such that the percentage of production demand-related costs allocated to the non-jurisdictional FERC customers is unchanged and is still based upon 4CP allocations. This modification impacts revenue requirement far less than in the last rate case and the concern raised by APS is easily avoided by my change in approach.

Q. Have you concurred in the APS treatment of transmission costs in its COSS study?

A. Yes. Transmission costs are treated as entirely non-jurisdictional, while the retail jurisdiction is charged for transmission services needed for native load at the FERC Open Access Transmission Tariff rates that are now effective. This was the resolution of this issue in settlement of the last APS rate case.

Q. Does that conclude your direct testimony?

A. Yes, it does.

Michael L. Brosch
Utilitech, Inc. – President
Bachelor of Business Administration (Accounting)
University of Missouri-Kansas City (1978)
Certified Public Accountant Examination (1979)

GENERAL

Mr. Brosch serves as the director of regulatory projects for the firm and is responsible for the planning, supervision and conduct of firm engagements. His academic background is in business administration and accounting and he holds CPA certificates in Kansas and Missouri.

EXPERIENCE

Mr. Brosch has supervised and conducted the preparation of rate case exhibits and testimony in support of revenue requirements of electric, gas, telephone, water, and sewer utilities in response to tariff change proposals as a consultant and while employed by the Missouri Commission Staff. Responsible for virtually all facets of revenue requirement determination cost of service allocations and tariff implementation in addition to involvement in numerous special project investigations.

Industry restructuring analysis for gas utility rate unbundling, deregulation, competitive bidding and strategic planning, with testimony on regulatory processes, asset identification and classification, revenue requirement and unbundled rate designs and class cost of service studies.

Responsible for analysis and presentation of income tax related issues within ratemaking proceedings involving interpretation of relevant IRS code provisions and regulatory restrictions.

Conducted extensive review of the economic impact upon regulated utility companies of various transactions involving affiliated companies. Reviewed the parent-subsidiary relationships of integrated utility holding companies to determine appropriate treatment of consolidated tax benefits and capital costs. Sponsored testimony on affiliated interests in numerous Bell and major independent telephone company rate proceedings.

Has substantial experience in the application of lead-lag study concepts and methodologies in determination of working capital investment to be included in rate base.

Alternative regulation analyses and consultation to clients in Arizona, California and Oklahoma, focused upon challenges introduced by cost-based regulation, incentive effects available through alternative regulation and balancing of risks, opportunities and benefits among stakeholders.

Mr. Brosch managed the detailed regulatory review of utility mergers and acquisitions, diversification studies and holding company formation issues in energy and telecommunications transactions in multiple states. Sponsored testimony regarding merger synergies, merger accounting and tax implications, regulatory planning and price path strategies. Traditional horizontal utility mergers as well as leveraged buyouts of utility properties by private equity investors were addressed in several states.

Analyzed the regulation of telephone company publishing affiliates, including the propriety of continued imputation of directory publishing profits and the valuation of publishing affiliates, including the identification and quantification of intangible assets and benefits of affiliation with the regulated business in Arizona, Indiana, Washington and Utah.

WORK HISTORY

1985 - Present	**Principal** - Utilitech, Inc. (Previously Dittmer, Brosch and Associates, Inc.)
1983 - 1985:	**Project manager** - Lubow McKay Stevens and Lewis. Responsible for supervision and conduct of utility regulatory projects on behalf of industry and regulatory agency clients.
1982 - 1983:	**Regulatory consultant** - Troupe Kehoe Whiteaker and Kent. Responsible for management of rate case activities involving analysis of utility operations and results, preparation of expert testimony and exhibits, and issue development including research and legal briefs. Also involved in numerous special projects including financial analysis and utility systems planning. Taught firm's professional education course on "utility income taxation - ratemaking and accounting considerations" in 1982.
1978 - 1982:	**Senior Regulatory Accountant** - Missouri Public Service Commission. Supervised and conducted rate case investigations of utilities subject to PSC jurisdiction in response to applications for tariff changes. Responsibilities included development of staff policy on ratemaking issues, planning and evaluating work of outside consultants, and the production of comprehensive testimony and exhibits in support of rate case positions taken.

OTHER QUALIFICATIONS

Bachelor of Business Administration - Accounting, 1978
University of Missouri - Kansas City "with distinction"

Member	American Institute of Certified Public Accountants Missouri Society of Certified Public Accountants Beta Alpha Psi, professional accounting scholastic fraternity Kansas Society of Certified Public Accountants
Attended	Iowa State Regulatory Conference 1981, 1985 Regulated Industries Symposium 1979, 1980 Michigan State Regulatory Conference 1981 United States Telephone Association Round Table 1984 NARUC/NASUCA Annual Meeting 1988, Speaker NARUC/NASUCA Annual Meeting 2000, Speaker
Instructor	INFOCAST Ratemaking Courses Arizona Staff Training Hawaii Staff Training

Michael L. Brosch
Summary of Previously Filed Testimony
1981 through 2006

Utility	Jurisdiction	Agency	Docket/Case Number	Represented	Year	Addressed
Kansas City Power and Light Co.	Missouri	PSC	ER-81-42	Staff	1981	Rate Base, Operating Income
Southwestern Bell Telephone	Missouri	PSC	TR-81-208	Staff	1981	Rate Base, Operating Income, Affiliated Interest
Northern Indiana Public Service	Indiana	PSC	36689	Consumers Counsel	1982	Rate Base, Operating Income
Northern Indiana Public Service	Indiana	URC	37023	Consumers Counsel	1983	Rate Base, Operating Income, Cost Allocations
Mountain Bell Telephone	Arizona	ACC	9981-E1051-81-406	Staff	1982	Affiliated Interest
Sun City Water	Arizona	ACC	U-1656-81-332	Staff	1982	Rate Base, Operating Income
Sun City Sewer	Arizona	ACC	U-1656-81-331	Staff	1982	Rate Base, Operating Income
El Paso Water	Kansas	City Counsel	Unknown	Company	1982	Rate Base, Operating Income, Rate of Return
Ohio Power Company	Ohio	PUCO	83-98-EL-AIR	Consumer Counsel	1983	Operating Income, Rate Design, Cost Allocations
Dayton Power & Light Company	Ohio	PUCO	83-777-GA-AIR	Consumer Counsel	1983	Rate Base
Walnut Hill Telephone	Arkansas	PSC	83-010-U	Company	1983	Operating Income, Rate Base
Cleveland Electric Illum.	Ohio	PUCO	84-188-EL-AIR	Consumer Counsel	1984	Rate Base, Operating Income, Cost Allocations
Cincinnati Gas & Electric	Ohio	PUCO	84-13-EL-EFC	Consumer Counsel	1984	Fuel Clause
Cincinnati Gas & Electric	Ohio	PUCO	84-13-EL-EFC (Subfile A)	Consumer Counsel	1984	Fuel Clause
General Telephone - Ohio	Ohio	PUCO	84-1026-TP-AIR	Consumer Counsel	1984	Rate Base
Cincinnati Bell Telephone	Ohio	PUCO	84-1272-TP-AIR	Consumer Counsel	1985	Rate Base
Ohio Bell Telephone	Ohio	PUCO	84-1535-TP-AIR	Consumer Counsel	1985	Rate Base
United Telephone - Missouri	Missouri	PSC	TR-85-179	Staff	1985	Rate Base, Operating Income
Wisconsin Gas	Wisconsin	PSC	05-UI-18	Staff	1985	Diversification-Restructuring
United Telephone - Indiana	Indiana	URC	37927	Consumer Counsel	1986	Rate Base, Affiliated Interest
Indianapolis Power & Light	Indiana	URC	37837	Consumer Counsel	1986	Rate Base
Northern Indiana Public Service	Indiana	URC	37972	Consumer Counsel	1986	Plant Cancellation Costs
Northern Indiana Public Service	Indiana	URC	38045	Consumer Counsel	1986	Rate Base, Operating Income, Cost Allocations, Capital Costs
Arizona Public Service	Arizona	ACC	U-1435-85-367	Staff	1987	Rate Base, Operating Income, Cost Allocations
Kansas City, KS Board of Public Utilities	Kansas	BPU	87-1	Municipal Utility	1987	Operating Income, Capital Costs
Detroit Edison	Michigan	PSC	U-8683	Industrial Customers	1987	Income Taxes

Michael L. Brosch
Summary of Previously Filed Testimony
1981 through 2006

Consumers Power	Michigan	PSC	U-8681	Industrial Customers	1987	Income Taxes
Consumers Power	Michigan	PSC	U-8680	Industrial Customers	1987	Income Taxes
Northern Indiana Public Service	Indiana	URC	38365	Consumer Counsel	1987	Rate Design
Indiana Gas	Indiana	URC	38080	Consumer Counsel	1987	Rate Base
Northern Indiana Public Service	Indiana	URC	38380	Consumers Counsel	1988	Rate Base, Operating Income, Rate Design, Capital Costs
Terre Haute Gas	Indiana	URC	38515	Consumers Counsel	1988	Rate Base, Operating Income, Capital Costs
United Telephone -Kansas	Kansas	KCC	162,044-U	Consumers Counsel	1989	Rate Base, Capital Costs, Affiliated Interest
US West Communications	Arizona	ACC	E-1051-88-146	Staff	1989	Rate Base, Operating Income, Affiliate Interest
All Kansas Electrics	Kansas	KCC	140,718-U	Consumers Counsel	1989	Generic Fuel Adjustment Hearing
Southwest Gas	Arizona	ACC	E-1551-89-102 E-1551-89-103	Staff	1989	Rate Base, Operating Income, Affiliated Interest
American Telephone and Telegraph	Kansas	KCC	167,493-U	Consumers Counsel	1990	Price/Flexible Regulation, Competition, Revenue Requirements
Indiana Michigan Power	Indiana	URC	38728	Consumer Counsel	1989	Rate Base, Operating Income, Rate Design
People Gas, Light and Coke Company	Illinois	ICC	90-0007	Public Counsel	1990	Rate Base, Operating Income
United Telephone Company	Florida	PSC	891239-TL	Public Counsel	1990	Affiliated Interest
Southwestern Bell Telephone Company	Oklahoma	OCC	PUD-000662	Attorney General	1990	Rate Base, Operating Income (Testimony not admitted)
Arizona Public Service Company	Arizona	ACC	U-1345-90-007	Staff	1991	Rate Base, Operating Income
Indiana Bell Telephone Company	Indiana	URC	39017	Consumer Counsel	1991	Test Year, Discovery, Schedule
Southwestern Bell Telephone Company	Oklahoma	OCC	39321	Attorney General	1991	Remand Issues
UtiliCorp United/ Centel	Kansas	KCC	175,476-U	Consumer Counsel	1991	Merger/Acquisition
Southwestern Bell Telephone Company	Oklahoma	OCC	PUD-000662	Attorney General	1991	Rate Base, Operating Income
United Telephone - Florida	Florida	PSC	910980-TL	Public Counsel	1992	Affiliated Interest
Hawaii Electric Light Company	Hawaii	PUC	6999	Consumer Advocate	1992	Rate Base, Operating Income, Budgets/Forecasts
Maui Electric Company	Hawaii	PUC	7000	Consumer Advocate	1992	Rate Base, Operating Income, Budgets/Forecasts
Southern Bell Telephone Company	Florida	PSC	920260-TL	Public Counsel	1992	Affiliated Interest
US West Communications	Washington	WUTC	U-89-3245-P	Attorney General	1992	Alternative Regulation
UtiliCorp United/ MPS	Missouri	PSC	ER-93-37	Staff	1993	Affiliated Interest

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Oklahoma Natural Gas Company	Oklahoma	OCC	PUD-1151, 1144, 1190	Attorney General	1993	Rate Base, Operating Income, Take or Pay, Rate Design
Public Service Company of Oklahoma	Oklahoma	OCC	PUD-1342	Staff	1993	Rate Base, Operating Income, Affiliated Interest
Illinois Bell Telephone	Illinois	ICC	92-0448 92-0239	Citizens Board	1993	Rate Base, Operating Income, Alt. Regulation, Forecasts, Affiliated Interest
Hawaii Electric Company	Hawaii	PUC	7700	Consumer Advocate	1993	Rate Base, Operating Income
US West Communications	Arizona	ACC	E-1051-93-183	Staff	1994	Rate Base, Operating Income
PSI Energy, Inc.	Indiana	URC	39584	Consumer Counselor	1994	Rate Base, Operating Income, Alt. Regulation, Forecasts, Affiliated Interest
Arkla, a Division of NORAM Energy	Oklahoma	OCC	PUD-940000354	Attorney General	1994	Cost Allocations, Rate Design
PSI Energy, Inc.	Indiana	URC	39584-S2	Consumer Counselor	1994	Merger Costs and Cost Savings, Non-Traditional Ratemaking
Transok, Inc.	Oklahoma	OCC	PUD-1342	Staff	1994	Rate Base, Operating Income, Affiliated Interest, Allocations
Oklahoma Natural Gas Company	Oklahoma	OCC	PUD-940000477	Attorney General	1995	Rate Base, Operating Income, Cost of Service, Rate Design
US West Communications	Washington	WUTC	UT-950200	Attorney General/ TRACER	1995	Operating Income, Affiliate Interest, Service Quality
PSI Energy, Inc.	Indiana	URC	40003	Consumer Counselor	1995	Rate Base, Operating Income
Oklahoma Natural Gas Company	Oklahoma	OCC	PUD-880000598	Attorney General	1995	Stand-by Tariff
GTE Hawaiian Telephone Co., Inc.	Hawaii	PUC	PUC 94-0298	Consumer Advocate	1996	Rate Base, Operating Income, Affiliate Interest, Cost Allocations
Mid-American Energy Company	Iowa	ICC	APP-96-1	Consumer Advocate	1996	Non-Traditional Ratemaking
Oklahoma Gas and Electric Company	Oklahoma	OCC	PUD-960000116	Attorney General	1996	Rate Base, Operating Income, Rate Design, Non-Traditional Ratemaking
Southwest Gas Corporation	Arizona	ACC	U-1551-96-596	Staff	1997	Operating Income, Affiliated Interest, Gas Supply
Utilicorp United - Missouri Public Service Division	Missouri	PSC	EO-97-144	Staff	1997	Operating Income
US West Communications	Utah	PSC	97-049-08	Consumer Advocate	1997	Rate Base, Operating Income, Affiliate Interest, Cost Allocations
US West Communications	Washington	WUTC	UT-970766	Attorney General	1997	Rate Base, Operating Income
Missouri Gas Energy	Missouri	PSC	GR 98-140	Public Counsel	1998	Affiliated Interest
ONEOK	Oklahoma	OCC	PUD980000177	Attorney General	1998	Gas Restructuring, rate Design, Unbundling
Nevada Power/Sierra Pacific Power Merger	Nevada	PSC	98-7023	Consumer Advocate	1998	Merger Savings, Rate Plan and Accounting

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PacifiCorp / Utah Power	Utah	PSC	97-035-1	Consumer Advocate	1998	Affiliated Interest
MidAmerican Energy / CalEnergy Merger	Iowa	PUB	SPU-98-8	Consumer Advocate	1998	Merger Savings, Rate Plan and Accounting
American Electric Power / Central and South West Merger	Oklahoma	OCC	980000444	Attorney General	1998	Merger Savings, Rate Plan and Accounting
ONEOK Gas Transportation	Oklahoma	OCC	970000088	Attorney General	1998	Cost of Service, Rate Design, Special Contract
U S West Communications	Washington	WUTC	UT-98048	Attorney General	1999	Directory Imputation and Business Valuation
U S West / Qwest Merger	Iowa	PUB	SPU 99-27	Consumer Advocate	1999	Merger Impacts, Service Quality and Accounting
U S West / Qwest Merger	Washington	WUTC	UT-991358	Attorney General	2000	Merger Impacts, Service Quality and Accounting
U S West / Qwest Merger	Utah	PSC	99-049-41	Consumer Advocate	2000	Merger Impacts, Service Quality and Accounting
PacifiCorp / Utah Power	Utah	PSC	99-035-10	Consumer Advocate	2000	Affiliated Interest
Oklahoma Natural Gas, ONEOK Gas Transportation	Oklahoma	OCC	980000683, 980000570, 990000166	Attorney General	2000	Operating Income, Rate Base, Cost of Service, Rate Design, Special Contract
U S West Communications	New Mexico	PRC	3008	Staff	2000	Operating Income, Directory Imputation
U S West Communications	Arizona	ACC	T-0105B-99-0105	Staff	2000	Operating Income, Rate Base, Directory Imputation
Northern Indiana Public Service Company	Indiana	IURC	41746	Consumer Counsel	2001	Operating Income, Rate Base, Affiliate Transactions
Nevada Power Company	Nevada	PUCN	01-10001	Attorney General-BCP	2001	Operating Income, Rate Base, Merger Costs, Affiliates
Sierra Pacific Power Company	Nevada	PUCN	01-11030	Attorney General-BCP	2002	Operating Income, Rate Base, Merger Costs, Affiliates
The Gas Company, Division of Citizens Communications	Hawaii	PUC	00-0309	Consumer Advocate	2001	Operating Income, Rate Base, Cost of Service, Rate Design
SBC Pacific Bell	California	PUC	I.01-09-002 R.01-09-001	Office of Ratepayer Advocate	2002	Depreciation, Income Taxes and Affiliates
Midwest Energy, Inc.	Kansas	KCC	02-MDWG-922-RTS	Agriculture Customers	2002	Rate Design, Cost of Capital
Qwest Communications – Dex Sale	Utah	PSC	02-049-76	Consumer Advocate	2003	Directory Publishing
Qwest Communications – Dex Sale	Washington	WUTC	UT-021120	Attorney General	2003	Directory Publishing
Qwest Communications – Dex Sale	Arizona	ACC	T-0105B-02-0666	Staff	2003	Directory Publishing
PSI Energy, Inc.	Indiana	IURC	42359	Consumer Counsel	2003	Operating Income, Rate Trackers, Cost of Service, Rate Design
Qwest Communications – Price Cap Review	Arizona	ACC	T-0105B-03-0454	Staff	2004	Operating Income, Rate Base, Fair Value, Alternative Regulation

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Verizon Northwest Corp	Washington	WUTC	UT-040788	Public Counsel	2004	Directory Publishing, Rate Base, Operating Income
Citizens Gas & Coke Utility	Indiana	IURC	42767	Consumer Counsel	2005	Operating Income, Debt Service, Working Capital, Affiliate Transactions, Alternative Regulation
Hawaiian Electric Company	Hawaii	HPUC	04-0113	Consumer Advocate	2005	Operating Income, Rate Base, Cost of Service, Rate Design
Sprint/Nextel Corporation	Washington	WUTC	UT-051291	Public Counsel	2006	Directory Publishing, Corporate Reorganization
Puget Sound Energy, Inc.	Washington	WUTC	UE-060266 and UG-060267	Public Counsel	2006	Alternative Regulation
Cascade Natural Gas Corporation	Washington	WUTC	UG-060256	Public Counsel	2006	Alternative Regulation
Hawaiian Electric Company	Hawaii	HPUC	05-0146	Consumer Advocate	2006	Community Benefits Program

ARIZONA PUBLIC SERVICE COMPANY
ADJUSTED ELECTRIC COST OF SERVICE STUDY
FOR THE 12 MONTHS ENDING 9/30/2005
($)

Line No.	Description	<---- GJ ---- ELECTRIC TOTAL (1)	ACC JURISDICTION (2)	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	($1,314,161)	$5,559,077	($6,873,238)
16	TOTAL RATE BASE	$5,254,532,031	$4,401,129,682	$853,402,349
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	$65,860,308	$66,084,186	($223,878)
21	OTHER ELECTRIC REVENUE	$476,428,509	$458,779,789	$17,648,720
22	TOTAL OPERATING REVENUES	$2,646,146,546	$2,591,008,701	$55,137,845
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	($540,817,385)	($531,955,639)	($8,861,746)
31	TAXES OTHER THAN INCOME	$139,970,767	$116,332,654	$23,638,113
32	INCOME TAX	$75,695,673	$64,509,260	$11,186,413
33	TOTAL OPERATING EXPENSES	$2,375,338,788	$2,361,049,596	$14,289,191
34				
35	OPERATING INCOME	$270,807,758	$229,959,105	$40,848,654
36				
37	RETURN	$270,807,758	$229,959,105	$40,848,654
38				
39	RATE OF RETURN (PRESENT)	5.15%	5.23%	4.79%
40				
41	INDEX RATE OF RETURN (PRESENT)	1.00	1.01	0.93

STAFF REVENUE REQUIREMENT - 4CP AVERAGE ALLOCATION
STAFF POSITION

ARIZONA PUBLIC SERVICE COMPANY
ADJUSTED ELECTRIC COST OF SERVICE STUDY
FOR THE 12 MONTHS ENDING 9/30/2005
($)

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	$4,602,622,773	$3,764,548,986	$61,903,231	$88,281,830	$38,822,797
3	GENERAL & INTANGIBLE PLANT	$666,173,004	$409,819,210	$243,171,737	$4,251,264	$6,282,265	$2,648,529
4	LESS: RESERVE FOR DEPRECIATION	($3,548,546,146)	($1,896,798,579)	($1,579,361,207)	($27,268,845)	($31,701,586)	($13,415,930)
5	OTHER DEFERRED CREDITS	($438,604,344)	($225,458,670)	($207,896,857)	($3,462,122)	($1,361,185)	($425,510)
6	WORKING CASH	($25,220,726)	($12,591,199)	($12,141,693)	($154,998)	($232,543)	($100,295)
7	MATERIALS, SUPPLIES & PREPAYMENTS	$177,653,628	$91,140,849	$83,008,225	$1,511,753	$1,434,729	$558,072
8	ACCUM. DEFERRED TAXES	($1,062,992,832)	($565,575,102)	($478,247,836)	($6,013,443)	($9,163,195)	($3,993,256)
9	REGULATORY ASSETS	($93,364,564)	($47,382,588)	($45,472,456)	($487,357)	($27,374)	$5,209
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)	($23,341,404)	($22,595,028)	($334,372)	($72,454)	($17,050)
12	MISCELLANEOUS DEFERRED DEBITS	$39,464,108	$24,261,926	$14,422,780	$251,962	$371,050	$156,389
13	CUSTOMER ADVANCES	($59,807,000)	($43,338,952)	($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	$5,559,077	$897,529	$5,246,267	$86,961	($457,853)	($213,828)
16	TOTAL RATE BASE	$4,401,129,682	$2,420,712,334	$1,871,346,960	$30,793,498	$54,102,574	$24,174,315
17							
18	DEVELOPMENT OF RETURN						
19	REVENUES FROM RATES	$2,066,144,726	$1,058,729,739	$967,398,538	$20,966,540	$12,913,053	$6,136,856
20	PROFORMA TO REVENUES FROM RATES	$66,084,186	$33,316,369	$32,153,204	($102,439)	$431,212	$285,840
21	OTHER ELECTRIC REVENUE	$458,779,789	$219,693,023	$228,817,968	$5,343,456	$4,254,055	$671,287
22	TOTAL OPERATING REVENUES	$2,591,008,701	$1,311,739,131	$1,228,369,710	$26,207,557	$17,598,320	$7,093,983
23							
24	OPERATING EXPENSES						
25	OPERATION & MAINTENANCE	$2,302,448,767	$1,138,939,802	$1,120,781,069	$25,864,564	$13,522,261	$3,341,071
26	ADMINISTRATIVE & GENERAL	$132,687,128	$80,699,072	$49,016,359	$1,006,399	$1,376,867	$588,431
27	DEPRECIATION & AMORT EXPENSE	$285,758,990	$157,680,051	$121,235,690	$2,187,881	$3,237,745	$1,417,623
28	AMORTIZATION ON GAIN	($6,528,055)	($3,227,883)	($3,223,300)	($57,045)	($16,050)	($3,777)
29	REGULATORY ASSETS	($2,203,510)	($1,144,245)	($1,049,237)	($10,028)	$0	$0
30	PROFORMA ADJUSTMENTS	($531,955,639)	($251,433,939)	($269,355,402)	($7,199,427)	($3,117,805)	($849,067)
31	TAXES OTHER THAN INCOME	$116,332,654	$64,881,575	$48,396,437	$871,630	$1,510,049	$672,963
32	INCOME TAX	$64,509,260	$22,373,128	$40,763,004	$986,541	($93,858)	$480,445
33	TOTAL OPERATING EXPENSES	$2,361,049,596	$1,208,767,563	$1,106,564,620	$23,650,515	$16,419,209	$5,647,690
34							
35	OPERATING INCOME	$229,959,105	$102,971,568	$121,805,090	$2,557,042	$1,179,112	$1,446,293
36							
37	RETURN	$229,959,105	$102,971,568	$121,805,090	$2,557,042	$1,179,112	$1,446,293
38							
39	RATE OF RETURN (PRESENT)	5.23%	4.25%	6.51%	8.30%	2.18%	5.98%
40							
41	INDEX RATE OF RETURN (PRESENT)	1.01	0.83	1.26	1.61	0.42	1.16

ARIZONA PUBLIC SERVICE COMPANY
ADJUSTED ELECTRIC COST OF SERVICE STUDY
FOR THE 12 MONTHS ENDING 9/30/2005
($)

		<------ GE-2								------>
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)
	SUMMARY OF RESULTS									
1	DEVELOPMENT OF RATE BASE									
2	ELECTRIC PLANT IN SERVICE	$3,764,548,986	$13,679,245	$656,098,930	$892,167,281	$848,257,037	$498,862,670	$377,642,500	$253,463,175	$224,378,148
3	GENERAL & INTANGIBLE PLANT	$243,171,737	$826,389	$49,786,704	$55,926,714	$50,386,041	$30,576,836	$23,394,716	$16,086,933	$16,187,402
4	LESS: RESERVE FOR DEPRECIATION	($1,579,361,207)	($5,208,752)	($256,260,916)	($363,391,966)	($360,466,930)	($216,764,101)	($161,684,879)	($110,545,733)	($105,037,929)
5	OTHER DEFERRED CREDITS	($207,896,857)	($539,468)	($30,115,445)	($44,818,356)	($47,013,066)	($29,215,741)	($23,177,050)	($16,118,629)	($16,899,102)
6	WORKING CASH	($12,141,693)	($43,109)	($1,880,898)	($2,802,224)	($2,789,068)	($1,677,517)	($1,285,564)	($869,182)	($794,132)
7	MATERIALS, SUPPLIES & PREPAYMENTS	$83,008,225	$272,101	$11,590,935	$17,785,164	$18,942,716	$12,179,392	$9,141,823	$6,408,033	$6,688,060
8	ACCUM. DEFERRED TAXES	($478,247,836)	($1,643,489)	($82,006,194)	($112,067,146)	($107,168,956)	($63,173,349)	($49,180,307)	($33,053,301)	($29,955,094)
9	REGULATORY ASSETS	($45,472,456)	($98,865)	($7,021,994)	($10,153,502)	($10,199,677)	($6,012,251)	($5,065,899)	($3,445,706)	($3,474,561)
10	DECOMMISSIONING FUND	$145,260,236	$396,517	$14,406,781	$27,667,366	$34,001,927	$23,592,112	$17,516,133	$12,742,045	$14,937,355
11	GAIN FROM DISP. OF PLANT	($22,595,028)	($55,271)	($3,321,005)	($4,958,184)	($5,129,225)	($3,106,666)	($2,520,407)	($1,734,649)	($1,769,621)
12	MISCELLANEOUS DEFERRED DEBITS	$14,422,780	$48,948	$2,948,928	$3,316,348	$2,989,814	$1,814,354	$1,388,622	$954,864	$960,901
13	CUSTOMER ADVANCES	($13,858,832)	($47,917)	($2,038,227)	($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	$5,246,267	($15,721)	$270,191	$891,732	$1,268,177	$760,272	$791,595	$564,839	$715,183
16	TOTAL RATE BASE	$1,871,346,960	$7,485,079	$348,819,652	$450,860,184	$413,916,850	$242,006,137	$183,204,842	$121,791,741	$103,262,475
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	$66,695,622	$67,026,166
20	PROFORMA TO REVENUES FROM RATES	$32,153,204	$250,921	$9,919,877	$3,997,949	$15,079,785	$1,059,540	$1,018,113	$135,964	$691,055
21	OTHER ELECTRIC REVENUE	$228,817,968	$651,979	$23,956,956	$44,297,681	$53,381,703	$36,759,026	$27,225,054	$19,742,836	$22,802,733
22	TOTAL OPERATING REVENUES	$1,228,369,710	$4,247,699	$176,152,722	$266,434,010	$298,101,933	$183,942,104	$122,396,866	$86,574,422	$90,519,954
23										
24	OPERATING EXPENSES									
25	OPERATION & MAINTENANCE	$1,120,781,069	$3,128,440	$126,621,013	$219,609,967	$259,237,105	$176,429,598	$131,575,208	$95,038,418	$109,141,321
26	ADMINISTRATIVE & GENERAL	$49,016,359	$173,476	$9,916,047	$11,419,329	$10,337,611	$6,219,546	$4,655,748	$3,187,324	$3,107,279
27	DEPRECIATION & AMORT EXPENSE	$121,235,690	$455,396	$21,606,492	$28,660,970	$27,100,974	$16,097,638	$11,986,345	$8,080,975	$7,246,900
28	AMORTIZATION ON GAIN	($3,223,300)	($8,174)	($425,055)	($677,794)	($738,914)	($468,573)	($368,758)	($258,611)	($277,422)
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	($269,355,402)	($736,963)	($23,522,830)	($52,154,313)	($58,247,680)	($46,249,800)	($33,786,836)	($25,418,410)	($29,238,569)
31	TAXES OTHER THAN INCOME	$48,396,437	$195,818	$9,056,807	$11,750,044	$10,805,909	$6,301,644	$4,626,033	$3,079,916	$2,580,266
32	INCOME TAX	$40,763,004	$306,854	$8,660,419	$13,072,703	$14,028,192	$6,964,924	($402,222)	($126,964)	($1,740,902)
33	TOTAL OPERATING EXPENSES	$1,106,564,620	$3,512,450	$151,729,942	$231,433,213	$262,289,181	$165,165,625	$118,174,186	$83,508,641	$90,751,383
34										
35	OPERATING INCOME	$121,805,090	$735,249	$24,422,780	$35,000,797	$35,812,752	$18,776,479	$4,222,680	$3,065,781	($231,429)
36										
37	RETURN	$121,805,090	$735,249	$24,422,780	$35,000,797	$35,812,752	$18,776,479	$4,222,680	$3,065,781	($231,429)
38										
39	RATE OF RETURN (PRESENT)	6.51%	9.82%	7.00%	7.76%	8.65%	7.76%	2.30%	2.52%	-0.22%
40										
41	INDEX RATE OF RETURN (PRESENT)	1.26	1.91	1.36	1.51	1.68	1.51	0.45	0.49	-0.04

ARIZONA PUBLIC SERVICE COMPANY
ADJUSTED ELECTRIC COST OF SERVICE STUDY
FOR THE 12 MONTHS ENDING 9/30/2005
($)

		<---- GE-3					---->
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)
	SUMMARY OF RESULTS						
1	DEVELOPMENT OF RATE BASE						
2	ELECTRIC PLANT IN SERVICE	$4,602,622,773	$283,119,906	$1,442,861,713	$156,429,020	$2,263,015,111	$457,197,023
3	GENERAL & INTANGIBLE PLANT	$409,819,210	$27,677,481	$147,822,129	$12,410,858	$187,476,540	$34,432,202
4	LESS: RESERVE FOR DEPRECIATION	($1,896,798,579)	($122,552,784)	($597,568,632)	($66,788,322)	($922,274,761)	($187,614,079)
5	OTHER DEFERRED CREDITS	($225,458,670)	($13,917,486)	($70,077,504)	($7,890,391)	($110,007,051)	($23,566,238)
6	WORKING CASH	($12,591,199)	($727,331)	($3,656,635)	($449,496)	($6,382,377)	($1,375,358)
7	MATERIALS, SUPPLIES & PREPAYMENTS	$91,140,849	$5,699,478	$28,406,169	$3,216,206	$44,336,909	$9,482,088
8	ACCUM. DEFERRED TAXES	($565,575,102)	($34,021,969)	($175,851,099)	($19,128,016)	($279,219,903)	($57,354,116)
9	REGULATORY ASSETS	($47,382,588)	($2,766,310)	($14,244,476)	($1,645,942)	($23,613,421)	($5,112,439)
10	DECOMMISSIONING FUND	$135,532,339	$8,749,151	$41,051,666	$5,176,484	$65,386,973	$15,168,064
11	GAIN FROM DISP. OF PLANT	($23,341,404)	($1,394,609)	($7,018,565)	($826,997)	($11,584,864)	($2,516,369)
12	MISCELLANEOUS DEFERRED DEBITS	$24,261,926	$1,637,996	$8,747,030	$735,108	$11,101,662	$2,040,131
13	CUSTOMER ADVANCES	($43,338,952)	($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	$897,529	($3,711)	($233,274)	$83,972	$706,428	$344,115
16	TOTAL RATE BASE	$2,420,712,334	$146,688,878	$775,575,299	$78,813,242	$1,185,394,078	$234,240,838
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	$33,316,369	($2,061,923)	$12,766,411	($1,178,134)	$21,464,438	$2,325,577
21	OTHER ELECTRIC REVENUE	$219,693,023	$14,128,249	$66,958,622	$8,281,943	$106,067,571	$24,256,638
22	TOTAL OPERATING REVENUES	$1,311,739,131	$82,403,913	$440,310,231	$43,789,838	$618,003,673	$127,231,476
23							
24	OPERATING EXPENSES						
25	OPERATION & MAINTENANCE	$1,138,939,802	$74,029,391	$356,088,331	$41,939,808	$545,124,324	$121,757,949
26	ADMINISTRATIVE & GENERAL	$80,699,072	$5,448,647	$28,728,968	$2,490,346	$37,185,619	$6,845,492
27	DEPRECIATION & AMORT EXPENSE	$157,680,051	$9,947,593	$50,905,484	$5,267,895	$76,428,253	$15,130,825
28	AMORTIZATION ON GAIN	($3,227,883)	($197,429)	($972,689)	($116,992)	($1,588,879)	($351,894)
29	REGULATORY ASSETS	($1,144,245)	($65,676)	($342,833)	($38,994)	($575,685)	($121,058)
30	PROFORMA ADJUSTMENTS	($251,433,939)	($17,957,337)	($75,734,616)	($10,492,034)	($118,944,305)	($28,305,647)
31	TAXES OTHER THAN INCOME	$64,881,575	$4,085,518	$20,964,750	$2,153,015	$31,525,406	$6,152,887
32	INCOME TAX	$22,373,128	$1,182,253	$14,613,737	$183,916	$6,415,929	($22,708)
33	TOTAL OPERATING EXPENSES	$1,208,767,563	$76,472,960	$394,251,132	$41,386,961	$575,570,662	$121,085,848
34							
35	OPERATING INCOME	$102,971,568	$5,930,953	$46,059,099	$2,402,877	$42,433,011	$6,145,628
36							
37	RETURN	$102,971,568	$5,930,953	$46,059,099	$2,402,877	$42,433,011	$6,145,628
38							
39	RATE OF RETURN (PRESENT)	4.25%	4.04%	5.94%	3.05%	3.58%	2.62%
40							
41	INDEX RATE OF RETURN (PRESENT)	0.83	0.78	1.15	0.59	0.69	0.51

STAFF REVENUE REQUIREMENT - 4CP ALLOCATION
FOR COMPARISON ONLY

ARIZONA PUBLIC SERVICE COMPANY
ADJUSTED ELECTRIC COST OF SERVICE STUDY
FOR THE 12 MONTHS ENDING 9/30/2005
($)

		<---------- GJ ---------->		
Line No.	Description	ELECTRIC TOTAL (1)	ACC JURISDICTION (2)	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	($1,314,161)	$5,559,077	($6,873,238)
16	TOTAL RATE BASE	$5,254,532,031	$4,401,129,682	$853,402,349
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	$65,860,308	$66,084,186	($223,878)
21	OTHER ELECTRIC REVENUE	$476,428,509	$458,779,789	$17,648,720
22	TOTAL OPERATING REVENUES	$2,646,146,546	$2,591,008,701	$55,137,845
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	($540,817,385)	($531,955,639)	($8,861,746)
31	TAXES OTHER THAN INCOME	$139,970,767	$116,332,654	$23,638,113
32	INCOME TAX	$75,695,673	$64,509,260	$11,186,413
33	TOTAL OPERATING EXPENSES	$2,375,338,788	$2,361,049,596	$14,289,191
34				
35	OPERATING INCOME	$270,807,758	$229,959,105	$40,848,654
36				
37	RETURN	$270,807,758	$229,959,105	$40,848,654
38				
39	RATE OF RETURN (PRESENT)	5.15%	5.23%	4.79%
40				
41	INDEX RATE OF RETURN (PRESENT)	1.00	1.01	0.93

ARIZONA PUBLIC SERVICE COMPANY
ADJUSTED ELECTRIC COST OF SERVICE STUDY
FOR THE 12 MONTHS ENDING 9/30/2005
($)

		<---------- GE-1 ----------					
Line No.	Description	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	$666,173,004	$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	$91,914,881	$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)	($43,338,952)	($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	$5,559,077	$1,390,835	$4,896,294	$3,888	($506,633)	($225,307)
16	TOTAL RATE BASE	$4,401,129,682	$2,453,935,289	$1,847,777,081	$25,198,732	$50,817,350	$23,401,231
17							
18	DEVELOPMENT OF RETURN						
19	REVENUES FROM RATES	$2,066,144,726	$1,058,729,739	$967,398,538	$20,966,540	$12,913,053	$6,136,856
20	PROFORMA TO REVENUES FROM RATES	$66,084,186	$33,316,369	$32,153,204	($102,439)	$431,212	$285,840
21	OTHER ELECTRIC REVENUE	$458,779,789	$219,766,673	$228,765,717	$5,331,054	$4,246,772	$669,573
22	TOTAL OPERATING REVENUES	$2,591,008,701	$1,311,812,781	$1,228,317,459	$26,195,155	$17,591,037	$7,092,269
23							
24	OPERATING EXPENSES						
25	OPERATION & MAINTENANCE	$2,302,448,767	$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)	($8,981)	($2,113)
29	REGULATORY ASSETS	($2,203,510)	($1,144,245)	($1,049,237)	($10,028)	$0	$0
30	PROFORMA ADJUSTMENTS	($531,955,639)	($250,025,162)	($270,354,853)	($7,436,666)	($3,257,110)	($881,848)
31	TAXES OTHER THAN INCOME	$116,332,654	$65,666,581	$47,839,518	$739,434	$1,432,424	$654,697
32	INCOME TAX	$64,509,260	$18,934,446	$43,202,562	$1,565,617	$246,173	$560,462
33	TOTAL OPERATING EXPENSES	$2,361,049,596	$1,213,976,724	$1,102,869,003	$22,773,289	$15,904,105	$5,526,475
34							
35	OPERATING INCOME	$229,959,105	$97,836,057	$125,448,456	$3,421,866	$1,686,932	$1,565,794
36							
37	RETURN	$229,959,105	$97,836,057	$125,448,456	$3,421,866	$1,686,932	$1,565,794
38							
39	RATE OF RETURN (PRESENT)	5.23%	3.99%	6.79%	13.58%	3.32%	6.69%
40							
41	INDEX RATE OF RETURN (PRESENT)	1.01	0.77	1.32	2.63	0.64	1.30

ARIZONA PUBLIC SERVICE COMPANY
ADJUSTED ELECTRIC COST OF SERVICE STUDY
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($)

		GE-2								
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)
	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	$800,809	$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)	($33,881,944)	($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)	($116,045,894)	($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	$17,516,133	$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)	($2,038,227)	($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	$4,896,294	($18,976)	$625,766	$1,062,131	$1,129,685	$500,955	$671,708	$445,264	$479,760
16	TOTAL RATE BASE	$1,847,777,081	$7,265,846	$372,766,746	$462,336,170	$404,589,762	$224,541,777	$175,130,767	$113,738,683	$87,407,331
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	$66,695,622	$67,026,166
20	PROFORMA TO REVENUES FROM RATES	$32,153,204	$250,921	$9,919,877	$3,997,949	$15,079,785	$1,059,540	$1,018,113	$135,964	$691,055
21	OTHER ELECTRIC REVENUE	$228,765,717	$651,493	$24,010,043	$44,323,121	$53,361,026	$36,720,311	$27,207,155	$19,724,984	$22,767,584
22	TOTAL OPERATING REVENUES	$1,228,317,459	$4,247,213	$176,205,809	$266,459,450	$298,081,256	$183,903,389	$122,378,967	$86,556,570	$90,484,805
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)	($476,581)	($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	($270,354,853)	($746,260)	($22,507,384)	($51,667,688)	($58,643,184)	($46,990,354)	($34,129,207)	($25,759,890)	($29,910,887)
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	$43,202,562	$329,545	$6,181,818	$11,884,902	$14,993,575	$8,772,541	$433,470	$706,553	($99,844)
33	TOTAL OPERATING EXPENSES	$1,102,869,003	$3,478,075	$155,484,704	$233,232,580	$260,826,749	$162,427,317	$116,908,219	$82,245,969	$88,265,390
34										
35	OPERATING INCOME	$125,448,456	$769,138	$20,721,105	$33,226,871	$37,254,507	$21,476,071	$5,470,748	$4,310,600	$2,219,415
36										
37	RETURN	$125,448,456	$769,138	$20,721,105	$33,226,871	$37,254,507	$21,476,071	$5,470,748	$4,310,600	$2,219,415
38										
39	RATE OF RETURN (PRESENT)	6.79%	10.59%	5.56%	7.19%	9.21%	9.56%	3.12%	3.79%	2.54%
40										
41	INDEX RATE OF RETURN (PRESENT)	1.32	2.05	1.08	1.39	1.79	1.86	0.61	0.74	0.49

ARIZONA PUBLIC SERVICE COMPANY
ADJUSTED ELECTRIC COST OF SERVICE STUDY
FOR THE 12 MONTHS ENDING 9/30/2005
($)

		<------ GE-3					------>
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)
	SUMMARY OF RESULTS						
1	DEVELOPMENT OF RATE BASE						
2	ELECTRIC PLANT IN SERVICE	$4,681,780,206	$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)	($606,018,515)	($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)	($287,506,652)	($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	$5,176,484	$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	($43,338,952)	($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	$1,390,835	($12,352)	($102,392)	$79,534	$1,061,327	$364,718
16	TOTAL RATE BASE	$2,453,935,289	$146,106,897	$784,389,906	$78,514,340	$1,209,295,724	$235,628,421
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	$33,316,369	($2,061,923)	$12,766,411	($1,178,134)	$21,464,438	$2,325,577
21	OTHER ELECTRIC REVENUE	$219,766,673	$14,126,959	$66,978,163	$8,281,280	$106,120,557	$24,259,714
22	TOTAL OPERATING REVENUES	$1,311,812,781	$82,402,623	$440,329,772	$43,789,175	$618,056,659	$127,234,552
23							
24	OPERATING EXPENSES						
25	OPERATION & MAINTENANCE	$1,142,667,874	$73,964,084	$357,077,451	$41,906,267	$547,806,416	$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	($250,025,162)	($17,982,015)	($75,360,844)	($10,504,709)	($117,930,786)	($28,246,808)
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	$18,934,446	$1,242,490	$13,701,397	$214,854	$3,942,033	($166,327)
33	TOTAL OPERATING EXPENSES	$1,213,976,724	$76,381,709	$395,633,210	$41,340,094	$579,318,298	$121,303,412
34							
35	OPERATING INCOME	$97,836,057	$6,020,914	$44,696,561	$2,449,080	$38,738,361	$5,931,139
36							
37	RETURN	$97,836,057	$6,020,914	$44,696,561	$2,449,080	$38,738,361	$5,931,139
38							
39	RATE OF RETURN (PRESENT)	3.99%	4.12%	5.70%	3.12%	3.20%	2.52%
40							
41	INDEX RATE OF RETURN (PRESENT)	0.77	0.80	1.11	0.61	0.62	0.49

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

JOINT ACCOUNTING SCHEDULES

OF THE

ARIZONA CORPORATION COMMISSION

UTILITIES DIVISION STAFF

PUBLIC VERSION

PREPARED
BY
UTILITECH, INC.

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
INDEX TO JOINT ACCOUNTING SCHEDULES

SCHEDULE NO.	DESCRIPTION	WITNESS
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A-1	REVENUE CONVERSION FACTOR	Dittmer
B	**SUMMARY OF ORIGINAL COST AND RCND RATE BASE ELEMENTS**	
B-1	SFAS 112 DEFERRED CREDIT RATE BASE ADJUSTMENT	Dittmer
B-2	CORRECT BARK BEETLE DEFERRAL RATE BASE BALANCE	Dittmer
B-3	INVESTMENT TAX CREDIT ADJUSTMENT TO RATE BASE	Dittmer
B-4	CASH WORKING CAPITAL	Dittmer
C	**SUMMARY OF OPERATING INCOME**	
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C-15	ELIMINATE LOBBYING COSTS CHARGED ABOVE-THE-LINE	Dittmer
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		Dittmer
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ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
COMPUTATION OF INCREASE IN GROSS REVENUE REQUIREMENT
FOR THE TEST YEAR ENDED SEPTEMBER 2005
(000's)

LINE NO.	DESCRIPTION	REFERENCE	APS PROPOSED ORIGINAL COST	APS PROPOSED FAIR VALUE	STAFF PROPOSED ORIGINAL COST	STAFF PROPOSED FAIR VALUE
	(A)	(B)	(C)	(D)	(E)	(F)
1	PROPOSED RATE BASE	Sch B	$ 4,466,697	$ 6,120,755	$ 4,401,130	$ 6,055,188
2	RATE OF RETURN	Sch D	8.73%	6.37%	8.05%	5.85%
3	OPERATING INCOME REQUIRED	Line 1 * 2	$ 389,943	$ 389,943	$ 354,291	$ 354,291
4	NET OPERATING INCOME AVAILABLE	Sch C	115,904	115,904	229,960	229,960
5	OPERATING INCOME EXCESS/DEFICIENCY	Line 3 - 4	$ 274,039	$ 274,039	$ 124,331	$ 124,331
6	REVENUE CONVERSION FACTOR	Sch A-1	1.6407	1.6407	1.6407	1.6407
7	OVERALL REVENUE REQUIREMENT	Line 5 * 6	$ 449,616	$ 449,616	$ 203,993	$ 203,993
8	ENVIRONMENTAL IMPROVEMENT CHARGE		4,315	4,315		
9	TOTAL INCREASE IN RATES	Line 7 + 8	$ 453,931	$ 453,931	$ 203,993	$ 203,993

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
REVENUE CONVERSION FACTOR
FOR THE TEST YEAR ENDED SEPTEMBER 2005

LINE NO.	DESCRIPTION	REFERENCE	COMPANY PROPOSED
	(A)	(B)	(C)
1	Gross Jurisdictional Revenue		100.0000%
2	Less: Effective State Income Tax	APS Sch. 3	6.23%
3	Less: Effective Federal Income Tax	APS Sch. 3	32.82%
4	Operating Income % = 100% - Tax Percentage	Ln1-Ln2-Ln3	60.9500%
5	Income to Revenue Multiplier	Line 1/Line 4	1.640689 (a) (b)

Footnote:
(a) Source: APS Schedules A-1 & C-3.

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
SUMMARY OF ORIGINAL COST AND RCND RATE BASE ELEMENTS
FOR THE TEST YEAR ENDED SEPTEMBER 2005
(000's)

		ORIGINAL COST			RCND		
LINE NO.	DESCRIPTION	AS ADJUSTED BY APS	STAFF ADJUSTMENTS	AS ADJUSTED BY STAFF	AS ADJUSTED BY APS	STAFF ADJUSTMENTS	AS ADJUSTED BY STAFF
	(A)	(B)	(C)	(D)	(E)	(F)	(G)
1	Gross Utility Plant in Service	$ 9,296,308	$ -	$ 9,296,308	$ 15,219,192		$ 15,219,192
2	Less: Accumulated Depreciation & Amort.	(3,546,560)	-	(3,546,560)	(6,161,346)		(6,161,346)
3	Net Utility Plant in Service	5,749,748	-	5,749,748	9,057,846	-	9,057,846
	Deductions:						
4	Deferred Taxes	(1,064,449)	(2,018)	(1,066,467)	(1,064,432)	(2,018)	(1,066,450)
5	Investment Tax Credits	-	-	-	-	-	-
6	Customer Advances for Construction	(59,807)	-	(59,807)	(59,807)	-	(59,807)
7	Customer Deposits	(54,860)	-	(54,860)	(54,860)	-	(54,860)
8	Pension Liability	(68,699)	-	(68,699)	(68,699)	-	(68,699)
9	Liability for Asset Retirement	(260,419)	-	(260,419)	(260,419)	-	(260,419)
10	Other Deferred Credits	(109,485)	-	(109,485)	(109,485)	-	(109,485)
11	Unamortized Gain-sale of Utility Plant	(46,360)	-	(46,360)	(46,360)	-	(46,360)
12	Regulatory Liabilities	(160,744)	(3,661)	(164,405)	(160,744)	(3,661)	(164,405)
13	Total Deductions	(1,824,823)	(5,679)	(1,830,502)	(1,824,806)	(5,679)	(1,830,485)
	Additions:						
14	Regulatory Assets	64,020	(2,873)	61,147	64,020	(2,873)	61,147
15	Miscellaneous Deferred Debits	39,464	-	39,464	39,464	-	39,464
16	Depreciation Fund - Decommissioning	285,855	-	285,855	285,855	-	285,855
17	Allowance for Working Capital	152,433	(57,014)	95,419	152,433	(57,014)	95,419
18	Total Additions	541,772	(59,888)	481,884	541,772	(59,888)	481,884
19	Total Rate Base	$ 4,466,697	$ (65,567)	$ 4,401,130	$ 7,774,812	$ (65,567)	$ 7,709,245

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
RATE BASE SUMMARY
FOR THE TEST YEAR ENDED SEPTEMBER 2005
(000's)

LINE NO.	DESCRIPTION	B-1	B-2	B-3	B-4	B-5	B-6	B-7	B-8	Page Total
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
1	Gross Utility Plant in Service									$ -
2	Less: Accumulated Depreciation & Amort.									-
3	Net Utility Plant in Service	-	-	-	-	-	-	-	-	-
	Deductions:									
4	Deferred Taxes			(2,018)						(2,018)
5	Investment Tax Credits									-
6	Customer Advances for Construction									-
7	Customer Deposits									-
8	Pension Liability									-
9	Liability for Asset Retirement									-
10	Other Deferred Credits									-
11	Unamortized Gain-sale of Utility Plant									-
12	Regulatory Liabilities	(3,661)								(3,661)
13	Total Deductions	(3,661)	-	(2,018)	-	-	-	-	-	(5,679)
	Additions:									
14	Regulatory Assets		(2,873)							(2,873)
15	Miscellaneous Deferred Debits									-
16	Depreciation Fund -- Decommissioning									-
17	Allowance for Working Capital				(57,014)					(57,014)
18	Total Additions	-	(2,873)	-	(57,014)	-	-	-	-	(59,888)
19	Total Rate Base	$ (3,661)	$ (2,873)	$ (2,018)	$ (57,014)	$ -	$ -	$ -	$ -	$ (65,567)

ADJUSTMENTS:

B-1 SFAS 112 DEFERRED CREDIT RATE BASE ADJUSTMENT
B-2 CORRECT BARK BEETLE DEFERRAL RATE BASE BALANCE
B-3 INVESTMENT TAX CREDIT ADJUSTMENT TO RATE BASE
B-4 CASH WORKING CAPITAL
B-5 **reserved**
B-6 **reserved**
B-7 **reserved**
B-8 **reserved**

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
SFAS 112 DEFERRED CREDIT RATE BASE ADJUSTMENT
FOR THE TEST YEAR ENDED SEPTEMBER 2005

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1	Accumulated Provision for SFAS 112 Deferred Credits		
2	Acquiesced by APS in Discovery to be Properly Included		
3	as a Rate Base Offset	UTI-10-302	$ (3,886,000)
4	Composite Retail Jurisdictional Wages & Salaries Allocator		94.212%
5	ACC Jurisdictional Adjustment to Reflect SFAS 112 Deferred		
6	Credits as a Rate Base Offset	Line 3 * Line 4	$ (3,661,453)

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
CORRECT BARK BEETLE DEFERRAL RATE BASE BALANCE
FOR THE TEST YEAR ENDED SEPTEMBER 2005

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1	Proforma Rate Base Adjustment Proposed by APS to Reflect		
2	Estimated Growth in Deferred Bark Beetle Costs Between		
3	the End of the Historic Test Year and December 31, 2006	LLR_WP7, p. 2	$ 6,114,585
4	Correction Required as Noted in Response to Discovery	UTI-14-351	704,820
5	Eliminate Bark Beetle Cost Deferred Prior to April 1, 2005 (the		
6	Rate Effective Period Resulting from 2003 Rate Case Order)	LLR_WP17, p. 3	(1,501,069)
7	Corrected Before-Tax Bark Beetle Rate Base Deferral Adjustment		
8	to End of Test Year Actual Recorded Balance	Sum Lines 3 thru 6	5,318,336
9	Composite Federal and State Income Tax Rate		39.05%
10	Related Accumulated Deferred Income Tax Expense Properly		
11	Reflected as a Rate Base Deduction	Line 8 * Line 9	2,076,810
12	Correct Total Before and After Tax Adjustment to Test Year		
13	End Recorded Deferred Bark Beetle Costs	Line 8 - Line 11	3,241,526
14	Total Company Rate Base Adjustment for Deferred Bark		
15	Beetle Remediation Costs	Line 13 - Line 3	$ (2,873,059)

Footnote: This adjustment is 100% ACC Retail Jurisdictional

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
INVESTMENT TAX CREDIT ADJUSTMENT TO RATE BASE
FOR THE TEST YEAR ENDED SEPTEMBER 2005

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1	Total Amount of Investment Tax Credits Expected to be Realized		
2	As a Result of Amending Prior Year Federal Income Tax Returns	UTI-10-299	$ 6,483,389
3	Revenue Conversion Factor	Sch. A-1	1.64069
4	Total Revenue Requirement Savings Resulting From Amending		
5	Prior Years Tax Returns to Claim Additional ITCs	Line 2 * 3	10,637,226
6	Total Costs Incurred to Research and Claim Additional ITCs		
7	Total Contingency Charge Recorded in 2003	UTI-10-301	(2,385,468)
8	Fee for Service Charge Recorded in February 2005	UTI-10-301	(1,553,333)
9	Net Total Company Revenue Requirement Savings Realized	Lines 5+ 7 + 8	6,698,425
10	Allocate to Ratepayers		50.00%
11	Revenue Requirement Savings Allocated to Ratepayers	Line 9 * Line 10	3,349,212
12	Equivalent Total Company Rate Base Offset	Line11/Line 3	(2,041,345)
13	ACC Jurisdictional Demand Factor		98.847%
14	ACC Jurisdictional Adjustment to Rate Base for ITCs Allocated		
15	to Rate Payers	Line 12 * Line 13	$ (2,017,811)

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
CASH WORKING CAPITAL
FOR THE TEST YEAR ENDED SEPTEMBER 2005

LINE NO.	DESCRIPTION		AMOUNT	REVENUE LAG (a)	EXPENSE LAG	NET LAG (DAYS)	CWC FACTOR	CWC REQUIREMENT
	(A)		(B)	(C)	(D)	(E)	(F)	(G)
1	FUEL FOR ELECTRIC GENERATION							
2	COAL		$ 200,856,342	36.85231	32.36664	4.48567	0.01229	$ 2,468,428
3	NATURAL GAS		237,557,927	36.85231	44.25857	-7.40625	-0.02029	(4,820,311)
4	FUEL OIL		1,077,082	36.85231	32.34060	4.51172	0.01236	13,314
5	NUCLEAR:							
6	AMORTIZATION		34,445,413	0.00000	0.00000	0.00000	0.00000	0
7	SPENT FUEL		7,336,099	36.85231	76.35359	-39.50128	-0.10822	(793,932)
8	SUBTOTAL		481,272,863					(3,132,502)
9	PURCHASED POWER	(b)	471,931,131	36.85231	38.15020	-1.29789	-0.00356	(1,678,121)
10	TRANSMISSION BY OTHERS		14,391,245	36.85231	33.69389	3.15842	0.00865	124,531
11	SUBTOTAL		486,322,376					(1,553,591)
12	OTHER OPERATIONS & MAINTENANCE							
13	PAYROLL		240,714,447	36.85231	15.00192	21.85039	0.05986	14,410,153
14	INCENTIVE		8,653,091	36.85231	214.50000	-177.64769	-0.48671	(4,211,511)
15	PENSION AND OPEB		38,986,000	36.85231	77.71371	-40.86140	-0.11195	(4,364,445)
16	EMPLOYEE BENEFITS		26,995,515	36.85231	20.35895	16.49337	0.04519	1,219,855
17	PAYROLL TAXES		18,118,131	36.85231	21.78589	15.06643	0.04128	747,878
18	MATERIALS & SUPPLIES		53,466,114	36.85231	24.22000	12.63231	0.03461	1,850,413
19	FRANCHISE PAYMENTS		11,986,402	36.85231	52.83966	-15.98735	-0.04380	(525,016)
20	VEHICLE LEASE PAYMENTS		3,169,771	36.85231	7.43789	29.41442	0.08059	255,444
21	RENTS		6,776,038	36.85231	-33.48601	70.33832	0.19271	1,305,795
22	PALO VERDE LEASE	(c)	45,900,681	36.85231	103.99426	-67.14195	-0.18395	(8,443,456)
23	PALO VERDE S/L GAIN AMORT		(4,575,722)	0.00000	0.00000	0.00000	0.00000	0
24	INSURANCE		4,639,562	0.00000	0.00000	0.00000	0.00000	0
25	OTHER		119,131,971	36.85231	35.39000	1.46231	0.00401	477,283
26	SUBTOTAL		573,962,001					2,722,393
27	DEPRECIATION & AMORTIZATION		321,525,565	0.00000	0.00000	0.00000	0.00000	0
28	AMORT OF ELECTRIC PLT ACQ ADJ		0	0.00000	0.00000	0.00000	0.00000	0
29	AMORT OF PROP LOSSES & REG STUDY COSTS		(2,564,492)	0.00000	0.00000	0.00000	0.00000	0
30	SUBTOTAL		318,961,073					0
31	INCOME TAXES							
32	CURRENT-FEDERAL		59,824,326	36.85231	58.95000	-22.09769	-0.06054	(3,621,861)
33	CURRENT- STATE	(d)	16,379,288	36.85231	62.05000	-25.19769	-0.06903	(1,130,740)
34	DEFERRED		77,758,889	0.00000	0.00000	0.00000	0.00000	0
35	SUBTOTAL		153,962,503					(4,752,601)
36	OTHER TAXES							
37	PROPERTY TAXES		123,403,653	36.85231	211.94223	-175.08992	-0.47970	(59,196,535)
38	SALES TAXES		158,240,555	16.69615	40.21000	-23.51385	-0.06442	(10,194,095)
39	FRANCHISE TAXES		18,920,381	16.69615	52.83966	-36.14351	-0.09902	(1,873,559)
40	SUBTOTAL		300,564,589					(71,264,189)
41	INTEREST EXPENSE	(e)	108,267,803	36.85231	90.43103	-53.57872	-0.14679	(15,892,741)
42	SUBTOTAL		108,267,803					(15,892,741)
43	TOTALS		$ 2,423,313,208					(93,873,230)
44	APS CWC ALLOWANCE							(29,372,869)
45	STAFF CWC ADJUSTMENT -- TOTAL COMPANY							(64,500,361)
46	% ARIZONA RETAIL -- Jurisdictional Factor							0.88394
47	STAFF CWC ADJUSTMENT -- RETAIL							$ (57,014,492)

Footnotes :

(a) See Workpaper B-4, p. 1, for calculation of re-weighted revenue lag.
(b) Test year purchased power reduced by expenses incurred to facilitate unregulaged marketing and trading (see Staff Adjustment C-4).
(c) See Workpaper B-4, p. 2, for calculation of PV lease expense lag.
(d) See Workpaper B-4, p. 3, for calculation of State income tax expense lag.
(e) See Workpaper B-4, p. 4, for calculation of interest expense lag & Staff Adjustment C-19 for pro forma interest expense.

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
SUMMARY OF OPERATING INCOME
FOR THE TEST YEAR ENDED SEPTEMBER 2005
(000's)

LINE NO.	DESCRIPTION	AS ADJUSTED BY APS	STAFF ADJUSTMENTS	AS ADJUSTED BY STAFF
	(A)	(B)	(C)	(D)
1	Electric Operating Revenues	$ 3,440,590	$ (849,582)	$ 2,591,008
	Operating Expenses:			
2	Purchased Power and Fuel	2,129,741	(966,175)	1,163,566
3	Operations and Maintenance	766,212	(59,870)	706,342
4	Depreciation and Amortization	306,988	(500)	306,488
5	Income Taxes	395	64,596	64,991
6	Other Taxes	121,350	(1,689)	119,661
7	Total	3,324,686	(963,637)	2,361,049
8	Operating Income	$ 115,904	$ 114,056	$ 229,960

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
SUMMARY OF RATEMAKING ADJUSTMENTS
FOR THE TEST YEAR ENDED SEPTEMBER 2005
(000's)

		ADJUSTMENT NUMBER / SCHEDULE REFERENCE									
LINE NO.	DESCRIPTION	C-1	C-2	C-3	C-4	C-5	C-6	C-7	C-8	C-9	SUBTOTAL
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
1	Electric Operating Revenues	$ 4,907	$ 1	$ (18,924)	$ (835,566)						$ (849,582)
	Operating Expenses:										
2	Purchased Power and Fuel			(124,082)	(841,833)						(965,915)
3	Operations and Maintenance		19			(8,273)	(33,483)	1,920	(437)	(7,933)	(48,187)
4	Depreciation and Amortization										-
5	Income Taxes	1,916	(7)	41,064	2,447	3,231	13,075	(750)	171	3,098	64,245
6	Other Taxes										-
7	Total	1,916	12	(83,018)	(839,386)	(5,042)	(20,408)	1,170	(267)	(4,835)	(949,857)
8	Operating Income	$ 2,991	$ (11)	$ 64,094	$ 3,820	$ 5,042	$ 20,408	$ (1,170)	$ 267	$ 4,835	$ 100,275

Composite Federal and State Income Tax Rate 39.05%

ADJUSTMENTS:
- **C-1** REVERSE ESTIMATED CONSERVATION IMPACT FROM DSM
- **C-2** CORRECTION OF MISCELLANEOUS OTHER REVENUES
- **C-3** NORMALIZE FUEL, PURCH POWER EXPENSE & OFF-SYSTEM SALES
- **C-4** ELIMINATE M&T REVENUES & PURCHASE POWER EXPENSE
- **C-5** ELIMINATE MARKETING AND TRADING O&M EXPENSES
- **C-6** PENSION EXPENSE ADJUSTMENT
- **C-7** POST RETIREMENT MEDICAL BENEFITS ADJUSTMENT
- **C-8** ELIMINATE ADDITIONAL MARKETING EXPENSES
- **C-9** ELIMINATE NON-RECURRING SHARED SERVICES COSTS

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
SUMMARY OF RATEMAKING ADJUSTMENTS
FOR THE TEST YEAR ENDED SEPTEMBER 2005
(000's)

			ADJUSTMENT NUMBER / SCHEDULE REFERENCE								
LINE NO.	DESCRIPTION	PRIOR PAGE SUBTOTAL	C-10	C-11	C-12	C-13	C-14	C-15	C-16	C-17	SUBTOTAL
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
1	Electric Operating Revenues	$ (849,582)									$ (849,582)
	Other Operating Expenses:										
2	Purchased Power and Fuel	(965,915)							(260)		(966,175)
3	Operations and Maintenance	(48,187)	(95)	(2,718)	(2,618)	(4,488)		(1,764)			(59,870)
4	Depreciation and Amortization	-					(500)				(500)
5	Income Taxes	64,245	37	1,062	1,022	1,752	195	689	101	659	69,764
6	Other Taxes	-								(1,689)	(1,689)
7	Total	(949,857)	(58)	(1,657)	(1,595)	(2,735)	(305)	(1,075)	(158)	(1,029)	(958,470)
8	Operating Income	$ 100,275	$ 58	$ 1,657	$ 1,595	$ 2,735	$ 305	$ 1,075	$ 158	$ 1,029	$ 108,888

Composite Federal and State Income Tax Rate 39.05%

ADJUSTMENTS:
C-10 ELIMINATE SILVERHAWK RELATED LEGAL EXPENSES
C-11 ELIMINATE SUNDANCE NON-ROUTINE MAINTENANCE EXPENSE
C-12 ELIMINATE NON-RECURRING TAX RESEARCH COSTS
C-13 ELIMINATE STOCK BASED INCENTIVE COMPENSATION
C-14 ELIMINATE BARK BEETLE AMORT - DEFERRED PRE-RATE ORDER
C-15 ELIMINATE LOBBYING COSTS CHARGED ABOVE-THE-LINE
C-16 NUCLEAR FUEL/ISFSI AMORTIZATION EXPENSE ADJUSTMENT
C-17 ELIMINATE ESTIMATED INCREASE IN 2007 PWEC PROPERTY TAXES

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
SUMMARY OF RATEMAKING ADJUSTMENTS
FOR THE TEST YEAR ENDED SEPTEMBER 2005
(000's)

LINE NO.	DESCRIPTION	PRIOR PAGE SUBTOTAL	ADJUSTMENT NUMBER / SCHEDULE REFERENCE								TOTAL
			C-18	C-19	C-20	C-21	C-22	C-23	C-24	C-25	
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(F)
1	Electric Operating Revenues	$ (849,582)									$ (849,582)
	Operating Expenses:										
2	Purchased Power and Fuel	(966,175)									(966,175)
3	Operations and Maintenance	(59,870)									(59,870)
4	Depreciation and Amortization	(500)									(500)
5	Income Taxes	69,764	(959)	630	(4,838)						64,596
6	Other Taxes	(1,689)									(1,689)
7	Total	(958,470)	(959)	630	(4,838)	-	-	-	-	-	(963,637)
8	Operating Income	$ 108,888	$ 959	$ (630)	$ 4,838	$ -	$ -	$ -	$ -	$ -	$ 114,056

Composite Federal and State Income Tax Rate 39.05%

C-18	PRODUCTION TAX CREDIT ADJUSTMENT	**C-22**	
C-19	INTEREST SYNCHRONIZATION DEDUCTION ADJUSTMENT	**C-23**	
C-20	CORRECT COS INCOME TAX EXPENSE ADJUSTMENT	**C-24**	
C-21		**C-25**	

Witness: J. Anderson

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
REVERSE ESTIMATED CONSERVATION IMPACT FROM DSM
FOR THE TEST YEAR ENDED SEPTEMBER 2005

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1	Adjustment to Reverse APS' Proposal to Reduce Test Year		
2	Margins Predicted to Occur as a Result of Implementing	APS Sch. C-2,	
3	Various Demand Side Management Programs	Page 1, Col F	$ 4,907,000

Footnote: Adjustment is 100% Retail Jurisdictional

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
CORRECTION OF MISCELLANEOUS OTHER REVENUES
FOR THE TEST YEAR ENDED SEPTEMBER 2005

LINE NO.	DESCRIPTION	REFERENCE	REVENUE AMOUNT	EXPENSE AMOUNT
	(A)	(B)	(C)	(D)
1	APS Adjustment for Schedule 1 Rate Changes	Workpaper DJR_WP8	$ 127,000	$ (19,000)
2	APS Revised Adj. for Schedule 1 Rate Changes	UTI 13-344, 13-345	128,339	-
3	Adjustment Correcting APS Schedule 1 Rate Adjustment	Line 2 - Line 1	$ 1,339	$ 19,000
4	Jurisdictional Allocation Factor		100%	99.12%
5	Staff Retail Adjustment for Schedule 1 Rate Changes	Line 3 * Line 4	$ 1,339	$ 18,833

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1	Normalized Fuel and Purchased Power Expense Proposed by:		
2	Staff/Liberty Consulting Group (cents/kWh)		2.8942
3	APS (cents/kWh)	PME_WP6, P. 2	3.2859
4	Net Cents/kWh Reduction Proposed by Staff to be		
5	Rolled Into Base Rates	Line 2 - Line 3	(0.3917)
6	Adjusted Test Year Retail Sales	PME_WP6, P. 3	$ 26,759,478
7	Subtotal: Reduction in Fuel and Purchased Power Expense		
8	Attributable to Serving Retail Load	Line 5 * Line 6	(104,816,875)
9	**Note: This portion of fuel adjustment is 100% retail**		
10	**Proforma Off-Systems Sales Margin Adjustment:**		
11	Proforma Off-System Sales Revenues Per:		
12	Staff/Liberty Consulting Group		133,863,799
13	APS	PME_WP6, P. 5	153,098,000
14	Total Co. Adjustment Decreasing Off-System Sales Revenues	Line 12 - Line 13	(19,234,201)
15	Proforma Fuel and Purchased Power Expense Incurred to		
16	Facilitate Off-system Sales Per:		
17	Staff/Liberty Consulting Group		107,553,298
18	APS	PME_WP6, P. 5	127,134,000
19	Subtotal: Total Co. Additional Fuel and Purchased Power		
20	Expense to Facilitate Off-system Sales	Line 17 - Line 18	(19,580,702)
21	Net Total Company Decrease in Off-System Sales Margins	Line 14 - Line 20	346,501
22	Retail Jurisdictional Energy Allocator		98.389%
23	ACC Jurisdictional Adjustment Reducing Off-system		
24	Sales Revenues	Line 14 * Line 22	(18,924,319)
25	ACC Jurisdictional Adjustment Reducing Fuel/Purchased		
26	Power Expense Related to Reduced Off-system Sales	Line 20 * Line 22	(19,265,238)
27	ACC Jurisdictional Adjustment Increasing Net Margins		
28	Resulting from Reduced Off-system Sales Forecasted	Line 24 - Line 26	$ 340,919

Witness: J. Dittmer
& Liberty

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
ELIMINATE M&T REVENUES & PURCHASE POWER EXPENSE
FOR THE TEST YEAR ENDED SEPTEMBER 2005

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT (000s)
	(A)	(B)	(C)
1	Unregulated Marketing and Trading Revenue Included Within the	GAAPversus FERC_	
2	Total Company Cost of Service Study	Reporting(2).xls	$ 849,248
3	Purchased Power Expense Incurred in Facilitating Unregulated	GAAPversus FERC_	
4	Marketing and Trading Revenues	Reporting(2).xls	(855,618)
5	Total Company Net Margin (Loss) on M&T Operations		
6	Exclusive of Payroll and Other Non-fuel O&M Expenses	Line 2 + Line 3	(6,370)
7	Energy Allocator		98.389%
8	ACC Retail Jurisdictional		
9	Revenues	Line 2 * Line 7	835,566
10	Purchased Power Expense	Line 4 * Line 7	(841,833)
11	Net Margin (Loss)	Line 9 + Line 10	$ (6,267)

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
ELIMINATE MARKETING AND TRADING O&M EXPENSES
FOR THE TEST YEAR ENDED SEPTEMBER 2005

LINE NO.	DESCRIPTION	REFERENCE		AMOUNT (000S)
	(A)	(B)		(C)
1	Eliminate Unregulated Marketing and Trading			
2	Non-Purchased Power Operations and			
3	Maintenance Expenses Included Within APS'			
4	Total Company Cost of Service:			
5	Payroll	Response to	$	6,618
6	Outside Services	UTI-10-315		1,078
7	Corporate Allocations			33
8	Miscellaneous			811
9	Corporate Allocable and Governance			241
10	Total Company Unregulated Marketing and Trading Non-			
11	Purchased Power Operations and Maintenance			
12	Expenses to be Eliminated From APS' Proposed			
13	Total Company Cost of Service	Sum Lines 5 - 9		(8,781)
14	Composite ACC Jurisdictional Allocator			94.212%
15	ACC Jurisdictional Unregulated Marketing and Trading Non-			
16	Purchased Power Operations and Maintenance			
17	Expenses to be Eliminated From APS' Proposed			
18	ACC Jurisdictional Cost of Service	Line 13 * Line 14	$	(8,273)

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
PENSION EXPENSE ADJUSTMENT
FOR THE TEST YEAR ENDED SEPTEMBER 2005

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT (000s)
	(A)	(B)	(C)
1	Reversal of APS' Proposed Total Company	APS Exhibits	
2	Adjustment to Amortize the Unfunded Projected	Sch. C-2, page 7	
3	Benefit Obligation Over a Five Year Period	Adj't No. 21	$ (43,695)
4	Total Company Monthly Accrual for Pension		
5	Expense in 2006	UTI-7-258	2,784
6	Annualized 2006 Total Company Pension Expense	Line 5 * 12	33,408
7	Test Year Actual Recorded Pension Expense	UTI-7-258	(23,484)
8	Pension Expense Adjustment Included Within APS'	LLR_WP21,	
9	Payroll Annualization Adjustment	page 34	(1,769)
10	Subtotal:	Sum Lines 6 - 9	8,155
11	Net Total Company Adjustment to APS' Proposed		
12	Level of Pension Expense	Line 3 + Line 10	(35,540)
13	Composite ACC Jurisdictional Wages		
14	and Salaries Allocator		94.212%
15	ACC Jurisdictional Adjustment to APS' Proposed		
16	ACC Jurisdictional Pension Expense	Line 12 * Line 14	$ (33,483)

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
POST RETIREMENT MEDICAL BENEFITS ADJUSTMENT
FOR THE TEST YEAR ENDED SEPTEMBER 2005

LINE NO.	DESCRIPTION		REFERENCE	AMOUNT (000s)
	(A)		(B)	(C)
1	Monthly Post Retirement Medical Benefits			
2	Expense Being Accrued in 2006		UTI-7-259	$ 1,423
3	Annualized 2006 PRMB Expense		Line 2 * 12	17,076
4	Less:	Test Year Actual PRMB Expense	UTI-7-259	(14,020)
5		APS PRMB Expense Annualization		
6		Adjustment Included as Part of the	LLR_WP21,	
7		Payroll Expense Annualization	page 34	(1,018)
8	Net Total Company PRMB Adjustment to Annualize			
9	Expenses for 2006 Actuarial Estimates		Sum Lines 3 - 7	2,038
10	Composite ACC Jurisdictional Wages			
11	and Salaries Allocator			94.212%
12	ACC Jurisdictional Adjustment to APS' Proposed			
13	ACC Jurisdictional Pension Expense		Line 9 * Line 11	$ 1,920

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
ELIMINATE ADDITIONAL MARKETING EXPENSES
FOR THE TEST YEAR ENDED SEPTEMBER 2005

LINE NO.	DESCRIPTION	REFERENCE	AMOUNTS
	(A)	(B)	(C)
1	Additional Marketing and Sponsorship Costs Identified and		
2	Conceded by APS to be Excluded From Retail Cost of		
3	Service Development		
4	Eliminate Dodge Theater Sponsorship	UTI-5-240	$ (100,000)
5	Eliminate Allocated PWCC Radio and	UTI-1-17	
6	Television Advertising	(Revised)	(337,351)
7	Total Additional Marketing and Sponsorship Costs to be		
8	Eliminated from Retail Cost of Service Development	Line 4 + Line 6	$ (437,351)

Footnote: This adjustment is assigned 100% to ACC Jurisdictional Cost of Service

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
ELIMINATE NON-RECURRING SHARED SERVICES COSTS
FOR THE TEST YEAR ENDED SEPTEMBER 2005

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1	Reverse Correcting Journal Entries Recorded During the		
2	Historic Test Year that Had the Impact of Overstating "On Going"		
3	Shared Services Expenses:		
4	Reverse Correcting Journal Entry Recorded in		
5	November 2004 Posted to Transfer Shared Services		
6	Costs Originally Recorded as Depreciation Expense		
7	as "A&G" Expense	UTI-10-314	$ (5,323,351)
8	Reverse a Correcting Journal Entry Recorded in		
9	December 2004 to Reallocate Rents Improperly		
10	Allocated Throughout 2004	UTI-10-314	(3,096,000)
11	Total Company Adjustment to Reverse Correcting Journal Entries		
12	Recorded During the Historic Test Year that Had the Impact of		
13	Overstating "On Going" Shared Services Expenses	Line 7 + 8	(8,419,351)
14	Composite ACC Jurisdictional Wages		
15	and Salaries Allocator		94.212%
16	ACC Jurisdictional Adjustment to Reverse Correcting Journal		
17	Entries Recorded During the Historic Test Year that Had the		
18	Impact of Overstating "On Going" Shared Services Expenses	Line 13 * 15	$ (7,932,850)

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
ELIMINATE SILVERHAWK RELATED LEGAL EXPENSES
FOR THE TEST YEAR ENDED SEPTEMBER 2005

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1 2	Legal Expenses Incurred in the Sale of the Unregulated Silverhawk Power Plant	UTI-14-349	$ 240,238
3 4	Silverhawk Legal Costs Already Eliminated by APS from the Test Year Cost of Service		
5 6	Total Shared Services Legal Costs Allocated to PWEC During the Historic Test Years	LLR_WP13, pages 6 & 7	1,394,011
7 8	Percentage of PWEC Legal Costs Assigned by APS to PWEC Activities	LLR_WP13, pages 6 & 7	10%
9 10	Total Company Silverhawk-related Legal Expenses Already Eliminated from the COS by APS	Line 6 * Line 8	139,401
11 12	Net Total Company Adjustment to Eliminate Additional Silverhawk-Related Legal Costs from the Test Year Cost of Service	Line 10 - Line 2	(100,837)
13 14	Composite ACC Jurisdictional Wages and Salaries Allocator		94.212%
15 16	ACC Jurisdictional Adjustment to Eliminate Additional Silverhawk-Related Legal Costs from the Test Year Cost of Service	Line 12 * Line 14	$ (95,010)

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
ELIMINATE SUNDANCE NON-ROUTINE MAINTENANCE EXPENSE
FOR THE TEST YEAR ENDED SEPTEMBER 2005

LINE NO.	DESCRIPTION	REFERENCE	AMOUNTS
	(A)	(B)	(C)
1	Eliminate APS' Proposed Accrual for "Non-Routine"		
2	Maintenance or "Major" Overhaul Costs at the Sundance		
3	Power Station Not Expected to Occur For Many Years	LLR_WP14	$ (2,750,100)
4	ACC Jurisdictional Production Demand Allocator		98.847%
5	Eliminate ACC Jurisdictional Accrual for "Non-Routine"		
6	Maintenance or "Major" Overhaul Costs at the Sundance		
7	Power Station Not Expected to Occur For Many Years	Line 3 * Line 4	$ (2,718,396)

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
ELIMINATE NON-RECURRING TAX RESEARCH COSTS
FOR THE TEST YEAR ENDED SEPTEMBER 2005

LINE NO.	DESCRIPTION	REFERENCE	AMOUNTS
	(A)	(B)	(C)
1	Total Company Adjustment to Eliminate a Credit Given to		
2	Joint Owners of Palo Verde During the Historic Test Year		
3	Related to a Tax Contingency Fee Recorded in 2003 That		
4	in Turn Resulted in Incremental TY Charges to Account 9302	UTI-10-296	$ (1,224,795)
5	Total Company Adjustment to Eliminate Non-recurring		
6	Tax Research Costs Incurred on a Fee for Service Basis		
7	During the Historic Test Year	UTI-10-301	(1,553,333)
8	Total Company Adjustment to Eliminate Non-Recurring		
9	Tax Research Costs/Credits Recorded During the		
10	Historic Test Year	Line 4 + Line 7	(2,778,128)
11	Composite ACC Jurisdictional Wages		
12	and Salaries Allocator		94.212%
13	ACC Jurisdictional Adjustment to Eliminate Non-Recurring		
14	Tax Research Costs/Credits Recorded During the		
15	Historic Test Year	Line 10 * Line 12	$ (2,617,594)

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
ELIMINATE STOCK BASED INCENTIVE COMPENSATION
FOR THE TEST YEAR ENDED SEPTEMBER 2005

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1	Total Company Adjustment to Eliminate Above-		
2	the-Line Expense Charges for Stock Based		
3	Incentive Compensation	UTI-1-83	$ (4,762,874)
4	Composite ACC Jurisdictional Wages		
5	and Salaries Allocator		94.212%
6	ACC Jurisdictional Adjustment to Eliminate Above-		
7	the-Line Expense Charges for Stock Based		
8	Incentive Compensation	Line 3 * Line 5	$ (4,487,657)

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
ELIMINATE BARK BEETLE AMORT - DEFERRED PRE-RATE ORDER
FOR THE TEST YEAR ENDED SEPTEMBER 2005

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1	Eliminate Bark Beetle Remediation Costs Deferred in		
2	January through March 2005 Prior to the Effective Date		
3	of Decision No. 67744 (April 1, 2005)	LLR_WP7	$ (1,501,069)
4	Amortization Period -- Years		3
5	Adjustment to Eliminate Bark Beetle Amortization Expense		
6	Related to Costs Inappropriately Deferred Prior to		
7	Effective Date of ACC's Prior Case Rate Order	Line 3 / Line 4	$ (500,356)

Footnote: This adjustment is 100% ACC Retail Jurisdictional

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
ELIMINATE LOBBYING COSTS CHARGED ABOVE-THE-LINE
FOR THE TEST YEAR ENDED SEPTEMBER 2005

Schedule C-15
Page 1 of 1

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1	Federal Affairs Charged to "Governance" Activities		
2	During the Historic Test Year - Ultimately Allocated		
3	to Various PWCC Subsidiaries	UTI-6-244	$ 1,352,479
4	Percent of Governance Activities Allocated		
5	During the Historic Test Year to PWEC	UTI-6-244	28.930%
6	Federal Affairs Lobbying Costs Allocated as		
7	Corporate Governance Activities to PWEC	Line 3 * Line 17	391,272
8	Total Federal Affairs Shared Services Costs		
9	Charged to APS Above-the-Line Operating		
10	Expense in the Historic Test Year	UTI-10-305	834,125
11	Subtotal: Federal Affairs Lobbying Costs Charged		
12	Above-the-Line to APS and PWEC During the		
13	Historic Test Year	Line 7 + Line 10	1,225,397
14	Public Affairs Costs Charged Above-the-Line to		
15	APS During the Historic Test Year	UTI-10-306	595,455
15			
16	Total Public Affairs Costs Charged to		
17	APS During the Historic Test Year	UTI-10-306	1,617,107
18			
	Percent of Public Affairs Costs Charged		
19	Above the Line During the Historic Test Year	Line 15/Line 17	36.82%
20			
20	Public Affairs Costs Direct Assigned to PWEC		
21	During the Historic Test Year	UTI-6-244	139,377
22	Estimate of Public Affairs Costs Charged to PWEC		
23	Above-the-Line During the Historic Test Year	Line 19 * Line 21	51,322
23			
24	Total Company Above-the-Line Lobbying Costs to		
25	Be Eliminated from Cost of Service Development	Line 13 +15 + 23	(1,872,174)
25			
26	Composite ACC Jurisdictional Wages		
27	and Salaries Allocator		94.212%
27			
28	ACC Jurisdictional Above-the-Line Lobbying Costs to		
29	Be Eliminated from Cost of Service Development	Line 25 * Line 27	$ (1,763,994)

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
NUCLEAR FUEL/ISFSI AMORTIZATION EXPENSE ADJUSTMENT
FOR THE TEST YEAR ENDED SEPTEMBER 2005

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1	Yearly Amortization of Post Shutdown ISFSI Costs Based on	LLR_WP16	
2	Funding Expiration Date	Page 7	$ 108,000
3	Negative Amortization of Reduction in Post Shutdown		
4	ISFSI Costs Accrued Between September 30, 2005 and	LLR_WP16	
5	January 1, 2006	Page 8	(48,000)
6	Reduction in Ongoing ISFSI Costs to be Collected in Base	LLR_WP16	
7	Rates Based Upon Updated TLG Study	Page 7	(324,000)
8	Net Total Company Adjustment Reducing Nuclear Fuel		
9	Expense and Amortization of ISFSI Expense	Sum Lines 2 - 7	(264,000)
10	Retail Jurisdictional Energy Allocation Factor		98.389%
11	ACC Jurisdictional Adjustment Reducing Nuclear Fuel		
12	Expense and Amortization of ISFSI Expense	Line 9 * Line 10	$ (259,747)

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
ELIMINATE ESTIMATED INCREASE IN 2007 PWEC PROPERTY TAXES
FOR THE TEST YEAR ENDED SEPTEMBER 2005

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1	Eliminate APS Proposed Inclusion of Increased PWEC	LLR_WP20	
2	Property Tax Expense Attributable to Legislative Phase-in	Pages 2 & 10	$ (1,708,338)
3	ACC Jurisdictional Production Demand Allocator		98.847%
4	Eliminate ACC Jurisdictional Portion of APS' Proposed		
5	Inclusion of Increased PWEC Property Tax Expense		
6	Attributable to Legislative Phase-in	Line 2 * Line 3	$ (1,688,644)

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
PRODUCTION TAX CREDIT ADJUSTMENT
FOR THE TEST YEAR ENDED SEPTEMBER 2005

LINE NO.	DESCRIPTION	REFERENCE	DEMAND RELATED AMOUNT (000s)	ENERGY RELATED AMOUNT (000s)	TOTAL COMPANY AMOUNT (000s)
	(A)	(B)	(C)	(D)	(E)
1	Total Company Production Rate Base	CNF_WP13, p.2	$ 2,172,190	$ 95,432	$ 2,267,622
2	Staff Proposed Weighted Cost of Common Equity	Sch. D	5.59%	5.59%	5.59%
3	After-Tax Net Income	Line 1 * Line 2	121,425	5,335	126,760
4	Revenue Conversion Factor	Sch. A-1	1.64069	1.64069	1.64069
5	Pre-Tax Net Income	Line 3 * Line 4	199,221	8,753	207,974
6	Book/Tax Differences	CNF_WP13, p.2	32,377	1,422	33,799
7	Taxable Income	Line 5 + Line 6	231,598	10,175	241,773
8	Deduction Percentage - Effective in 2006		3.00%	3.00%	3.00%
9	Additional Production Deduction	Line 7 * Line 8	6,948	305	7,253
10	Composite Income Tax Rate	Sch. A-1	39.05%	39.05%	39.05%
11	Total Company Annualized Income Tax Savings	Line 9 * Line 10	2,713	119	2,832
12	Total Company Annualized Savings per APS	CNF_WP13, p.2	1,784	78	1,862
13 14	Total Company Adjustment to APS' Original Production Tax Credit Calculation	Line 12 - Line 11	(929)	(41)	(970)
15	Jurisdictional Allocator		98.847%	98.389%	98.828%
16 17	ACC Jurisdictional Annualized Income Tax Savings Adjustment	Line 14 * Line 15	$ (918)	$ (40)	$ (959)

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
INTEREST SYNCHRONIZATION DEDUCTION ADJUSTMENT
FOR THE TEST YEAR ENDED SEPTEMBER 2005

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT (000s)
	(A)	(B)	(C)
1	ACC Jurisdictional Rate Base Proposed by Staff	Sch. B	$ 4,401,130
2	Weighted Cost of Debt Proposed by Staff	Sch. D	2.460%
3	Annualized Interest Deduction Based Upon ACC Staff		
4	Proposed Retail Jurisdictional Rate Base and the		
5	ACC Staff' Proposed Weighted Cost of Debt	Line 1 * Line 2	108,268
6	Annualized Interest Deduction per APS		
7	APS Proposed As Adjusted ACC Jurisdictional	APS Sch. B-1	
8	Rate Based	Page 1, Col. F	4,466,697
9	APS Proposed Weighted Cost of Debt	APS Sch. D-1	2.460%
10	APS Proposed ACC Retail Jurisdictional Interest		
11	Expense Deduction	Line 8 * Line 9	109,881
12	Retail Jurisdictional Reduction in Annual		
13	Interest Deduction	Line 11 - Line 5	1,613
14	Composite Federal and State Income Tax Rate	Sch. A-1	39.05%
15	Adjustment Increasing Retail Jurisdictional Income		
16	Tax Expense to Reflect the Synchronization of the		
17	Interest Deduction with Staff's Proposed Rate Base		
18	and Cost of Capital Recommendations	Line 13 * Line 14	$ 630

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
CORRECT COS INCOME TAX EXPENSE ADJUSTMENT
FOR THE TEST YEAR ENDED SEPTEMBER 2005

LINE NO.	DESCRIPTION	TOTAL COMPANY AS ADJUSTED AS FILED BY APS (PER ORIGINAL UTI-3-169 & UTI-10-297) TAX EXP. $s	2006 AS ADJUSTED PERMANENT DIFFERENCES PER UPDATED UTI-10-297 TAX EXP. $s	ADDITIONAL ON GOING 2006 PER UPDATED UTI-10-297 TAX EXP. $s	ADJUSTMENT EXCLUDING PRODUCTION TAX CREDIT TAX EXP. $s
	(A)	(B)	(C)	(D)	(E)
1	Other Permanent Differences:				
2	OPEB Subsidy	$ 1,349,000			$ (1,349,000)
3	DCP & SERBP CSV	1,250,000			(1,250,000)
4	2005 vs. 2006 statutory rate	1,181,000			(1,181,000)
5	Tax exempt Interest Income	449,000			(449,000)
6	Depreciation on AFUDC	276,000		394,614	118,614
7	Officer's Compensation	83,000	70,924	27,696	(55,304)
8	Misc. tax credit true-up	28,000			(28,000)
9	Interest on tax reserve - net of tax	-			-
10	Meals & Entertainment	(102,000)	1,644,804	642,296	744,296
11	Penalties	(36,000)			36,000
12	Other	1,536,000			(1,536,000)
13	Subtotal: Other Permanent Differences	6,014,000			(4,949,394)
14	Medicare Subsidy	(3,872,000)		(3,338,429)	533,571
15	AZ State Credits	(570,000)		(482,950)	87,050
16	Amortization of FAS 109 Reg Liability			(460,435)	(460,435)
17	Depreciation on Medicare Subsidy			(49,195)	(49,195)
18	Net Add (Deduction) to Otherwise Calculated				
19	COS Income Tax Expense Based Upon "As				
20	Adjusted Book Income" Including a Deduction				
21	for Synchronized Interest Expense	$ 1,572,000		$ (3,266,403)	$ (4,838,403)

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
CAPITAL STRUCTURE & COSTS
FOR THE TEST YEAR ENDED SEPTEMBER 2005

LINE NO.	DESCRIPTION (A)	AMOUNT (000'S) (B)	CAPITAL RATIO (C)	COST RATES (D)	WEIGHTED COST (E)
	APS - PROPOSED (a)				
1	Long-Term Debt	$ 2,574,825	45.50%	5.41%	2.46000%
2	Preferred Stock	-	0.00%	0.00%	0.00000%
3	Common Equity	3,083,591	54.50%	11.50%	6.27000%
4	Short-Term Debt	-	0.00%	0.00%	0.00000%
5	Total	$ 5,658,416	100%		8.73%
	ACC STAFF- PROPOSED (b)				
6	Long-Term Debt	$ 2,574,825	45.50%	5.41%	2.46000%
7	Preferred Stock	-	0.00%	0.00%	0.00000%
8	Common Equity	3,083,591	54.50%	10.25%	5.59000%
9	Short-Term Debt	-	0.00%	0.00%	0.00000%
10	Total	$ 5,658,416	100%		8.05%

Footnotes:
(a) Source: APS Schedule D-1, p. 1. Test year ended 9/30/05.
(b) Source: Staff witness Parcell, Exhibt__(DCP-1)

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-05-0816
RECONCILIATION OF POSITIONS
FOR THE TEST YEAR ENDED SEPTEMBER 2005
(000's)

Description (A)		Amount (B)	Difference In Pretax Return (C)		Revenue Requirement Value (D)
APS PROPOSED REVENUE REQUIREMENT				$	453,931
RETURN DIFFERENCE (on APS Proposed Rate Base)	$	4,466,697	-1.120%		(50,027)
SUBTOTAL - REVENUE REQUIREMENT				$	403,904
			Pre-Tax Return		
RATE BASE ADJUSTMENTS					
SFAS 112 DEFERRED CREDIT RATE BASE ADJUSTMENT	$	(3,661)	11.63%	$	(426)
CORRECT BARK BEETLE DEFERRAL RATE BASE BALANCE		(2,873)	11.63%		(334)
INVESTMENT TAX CREDIT ADJUSTMENT TO RATE BASE		(2,018)	11.63%		(235)
CASH WORKING CAPITAL		(57,014)	11.63%		(6,632)
reserved		-	11.63%		-
reserved		-	11.63%		-
reserved		-	11.63%		-
reserved		-	11.63%		-
TOTAL VALUE OF STAFF RATE BASE ADJUSTMENTS		(65,567)		$	(7,626)
STAFF RATE BASE RECOMMENDATION	$	4,401,130			
Company Proposed Net Operating Income	$	115,904	**Revenue Conversion Multiplier**		
NET OPERATING INCOME ADJUSTMENTS					
REVERSE ESTIMATED CONSERVATION IMPACT FROM DSM	$	2,991	1.6407	$	(4,907)
CORRECTION OF MISCELLANEOUS OTHER REVENUES		(11)	1.6407		17
NORMALIZE FUEL, PURCH POWER EXPENSE & OFF-SYSTEM SALES		64,094	1.6407		(105,158)
ELIMINATE M&T REVENUES & PURCHASE POWER EXPENSE		3,820	1.6407		(6,267)
ELIMINATE MARKETING AND TRADING O&M EXPENSES		5,042	1.6407		(8,273)
PENSION EXPENSE ADJUSTMENT		20,408	1.6407		(33,483)
POST RETIREMENT MEDICAL BENEFITS ADJUSTMENT		(1,170)	1.6407		1,920
ELIMINATE ADDITIONAL MARKETING EXPENSES		267	1.6407		(437)
ELIMINATE NON-RECURRING SHARED SERVICES COSTS		4,835	1.6407		(7,933)
ELIMINATE SILVERHAWK RELATED LEGAL EXPENSES		58	1.6407		(95)
ELIMINATE SUNDANCE NON-ROUTINE MAINTENANCE EXPENSE		1,657	1.6407		(2,718)
ELIMINATE NON-RECURRING TAX RESEARCH COSTS		1,595	1.6407		(2,618)
ELIMINATE STOCK BASED INCENTIVE COMPENSATION		2,735	1.6407		(4,488)
ELIMINATE BARK BEETLE AMORT - DEFERRED PRE-RATE ORDER		305	1.6407		(500)
ELIMINATE LOBBYING COSTS CHARGED ABOVE-THE-LINE		1,075	1.6407		(1,764)
NUCLEAR FUEL/ISFSI AMORTIZATION EXPENSE ADJUSTMENT		158	1.6407		(260)
ELIMINATE ESTIMATED INCREASE IN 2007 PWEC PROPERTY TAXES		1,029	1.6407		(1,689)
PRODUCTION TAX CREDIT ADJUSTMENT		959	1.6407		(1,573)
INTEREST SYNCHRONIZATION DEDUCTION ADJUSTMENT		(630)			-
CORRECT COS INCOME TAX EXPENSE ADJUSTMENT		4,838	1.6407		(7,938)
TOTAL VALUE OF STAFF NET OPERATING INCOME ADJUSTMENTS		114,056		$	(188,163)
STAFF NET OPERATING INCOME RECOMMENDATION	$	229,960			
RECONCILED REVENUE REQUIREMENT				$	208,115
OTHER RECONCILING ITEMS					
APS PROPOSED ENVIRONMENTAL CHARGE					(4,315)
UNRECONCILED DIFFERENCE					193
REVENUE REQUIREMENT RECOMMENDATION				$	203,993

DIRECT TESTIMONY OF JOHN ANTONUK
President, The Liberty Consulting Group

Docket No. E-01345A-05-0816

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

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

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND TO AMEND DECISION NO. 57744.	DOCKET NO. E-01345A-05-0816

DIRECT TESTIMONY OF JOHN ANTONUK
President, The Liberty Consulting Group

1. Introduction

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

A. My name is John Antonuk. I am the president of The Liberty Consulting Group. My business address is 65 Main Street, P. O. Box 1237, Quentin, PA 17083.

Q. Please describe your educational background and professional experience.

A. I graduated in 1973 from Dickinson College, earning a bachelors degree, with honors. I graduated in 1976 from the Dickinson School of Law, earning a juris doctor degree, with honors. I began my career in 1975 as an investigator for the litigation section of the Pennsylvania Attorney General's office. I then spent several years as assistant counsel to the Pennsylvania Public Utility Commission, for which I conducted administrative and civil litigation involving a wide variety of case types in the electricity, natural gas, telecommunications, water, and transportation industries. I also served in a number of capacities on a variety of matters involving commission administration and operations.

I then served as head of the service and facilities section of Pennsylvania Power & Light ("PP&L") Company's regulatory-affairs department. I left PP&L to begin consulting in the utility industry in 1982. I managed the litigation-services practice of Management Analysis Company, a consulting firm that specialized in the electric-utility industry.

I am one of the founders of Liberty, which I helped to establish 19 years ago. I have led or managed over 150 projects since I began consulting in the utility industries.

Q. Have you participated previously in state commission proceedings?

A. Yes. I have been engaged in many state utility regulatory proceedings in the electric, natural gas, and telecommunications industries in 25 years as a utility consultant. Much but not all of it has been on behalf of commissions or their staffs. I have served as a staff witness, an independent witness appearing on the commission's behalf, a contracted administrative law judge, a facilitator, an arbitrator, and a commission advisor.

Q. Please describe the business of The Liberty Consulting Group.

A. Liberty is a management-consulting firm that has been serving utility industry regulators and managers for 19 years. Liberty has performed over 250 utility engagements. Liberty's experience includes energy and telecommunications utilities across the country. Liberty has performed or is performing substantial engagements for utility regulatory authorities in two thirds of the states. Along with Arizona, these states are:

Arizona	Hawaii	Minnesota	New York	Tennessee
Arkansas	Idaho	Mississippi	North Dakota	Utah
Colorado	Illinois	Montana	Ohio	Vermont
Connecticut	Iowa	Nebraska	Oklahoma	Virginia
Delaware	Kentucky	New Hampshire	Oregon	Washington
District of Columbia	Maine	New Jersey	Pennsylvania	Wyoming
Georgia	Maryland	New Mexico	South Dakota	

Liberty's work in Arizona includes an examination of the recently proposed UniSource acquisition, a review of telecommunications matters involving Qwest, and the work at issue here, which relates to fuel and energy procurement and management by APS.

Q. What familiarity do you have with utility fuel and energy procurement matters?

A. For the Pennsylvania Public Utility Commission Staff, I managed proceedings arising from Commission Audit Bureau's first fuel audits. Later, as a consultant with Management Analysis Company I examined coal procurement for Central Illinois Public Service Company. Most recently, leading Liberty's practice for public service commissions, I have directed, managed, and participated in many examinations of fuel and energy procurement for regulators in Connecticut, Kentucky, New Hampshire, New Jersey, New York, Nova Scotia, Ohio, Pennsylvania, Tennessee, Virginia, and Wyoming.

Q. What is the purpose of your testimony?

A. My testimony addresses the results of Liberty's examination and evaluation of three inter-related subjects: (a) an audit of the procurement and management of fuel and energy by Arizona Public Service Company ("APS"), focusing on the 2005 months during which its Power Supply Adjustment mechanism ("PSA") applied, (b) the information and analysis that APS has offered to support recovery of fuel and energy expenses in this proceeding, and (c) potential adjustments to the PSA that will take advantage of lessons learned during its first year of operation and that will reflect likely conditions in the fuel and energy markets across the next several years.

2. Testimony Summary

Q. Provide an overall summary of the principal conclusions that you reach in this testimony.

A. Liberty's fuel and energy audit verified that APS handled fuel and energy procurement and management in a manner that produced appropriate costs during the April through December 2005 period. We did conclude, however, that APS should make a number of changes to improve management and operations on a going-forward basis.

Liberty's review of evidence from the rate case disclosed no reason to conclude that there have been any material changes in fuel and energy procurement and management performance through mid-2006, but that conclusion is more qualitative than quantitative, because Liberty has not performed the same audit activities for that period.

Liberty believes that it is appropriate to continue some form of a PSA-type mechanism, because fuel and energy volatility have returned to the marketplace in dramatic fashion. That volatility will likely continue for some time. Such volatility substantially diminishes the chance that rate-case decisions about fuel and energy expenses will bear a reasonably close relationship to costs experienced while rates apply, particularly given the dependence of APS on natural gas. Given a continuing justification for a PSA, it is appropriate to use costs for a 12-month period closely preceding the effectiveness of new rates to set the base rate portion of fuel and energy expense recovery. Calendar year 2006 costs, which APS witness Ewen has normalized in his testimony in these proceedings, serve this purpose. Normalization of 2006 costs for operational factors (such as unit outages) is also proper. APS witness Ewen took that approach. APS proposes his normalization as the basis for establishing the fuel and energy costs component of base rates.

We believe that the APS normalization requires a number of adjustments. First and most important, it relied upon late-2005 energy market prices, which have proven far to exceed what APS has had to pay in 2006. APS should adjust its calculations to use actual fuel and energy prices for the first half of 2006 and its current estimate of fuel and energy prices for the remainder of 2006. Second, the Ewen normalization of 2006 fuel and energy costs makes adjustments for exogenous (*i.e.*, not related to internal, operational factors such as unit outages or heat rates) events that happened mid-stream in 2006, or that will not happen until 2007. These factors include: (a) a later-than-expected 2006 rate increase for natural gas transportation, (b) a 2007 reduction in expensive capacity from SRP, and (c) the exclusion of a 75 MW sale to Tucson Electric Power. APS also erroneously included in utility revenue and expenses affiliate non-utility energy marketing and trading activity, which produced a net loss. Those non-utility revenues and expenses and the resulting loss should be excluded. This exclusion will reduce the increase in fuel and energy costs that APS has predicted. Actual net costs for the first half of 2007 also include about $3.7 million in margins from the optimization of an APS transmission capability. The Ewen normalized 2006 costs exclude those margins.

Liberty asked APS to recalculate its normalized 2006 fuel and energy expenses by correcting for the preceding factors, except for the $3.7 million in margins, which we discovered only recently. That recalculation supports a reduction of $111.6 million in fuel and energy expenses from those shown in the Ewen testimony workpapers. The "Net Retail Fuel Cost" shown in Workpaper PME_WP1 as $935,939,000 declines to $824,357,000 under the recalculation. This number includes the hedging-sharing method proposed by APS. Eliminating that sharing method would drop the reduction slightly, to \$111.4 million. Eliminating the sharing increases Net Retail Fuel Cost to \$824,566,000. We also believe that fuel and energy costs should be reduced by a further \$3,702,501 to reflect 2006 margins for PWCC non-utility transactions that involved an APS utility transmission asset.

Going forward, we believe that ways other than caps and collars can also provide the limits that the Commission seeks to place on fuel and energy cost adjustments. Caps and collars may prove difficult when current recovery of costs is most critical; *i.e.*, when market prices diverge most greatly from those that form the basis of base rates and the PSA. We believe that using forecasted fuel and energy prices (*e.g.*; those for calendar 2007) to set the PSA component for 2007 can serve the combined purposes of: (a) limiting the variation between recovery and cost to a level that maintains key financial ratios, (b) preserving Commission flexibility to set the duration of the amortization period for over- or under-collection balances, and (c) monitoring earnings to verify that variations in revenues and expenses in other areas do not offset variations between fuel and energy costs and recovery.

We also believe that the APS proposal to share an additional 10 percent of savings or losses from hedging activities is not appropriate. The APS hedging program does not operate on the basis of discretionary amounts or timing. It in fact discourages, as we believe it should, traders from timing hedges on the basis of expected future movements in market prices. Therefore, the current APS strategy and methods give no particular reason to reward or to penalize. Sharing thus will provide no useful incentive under current operations. Most importantly, there should be no incentive to change strategy or methods so as to invite the introduction of speculation into the utility hedging program. Liberty believes it is not sound to promote utility efforts to out-guess the energy market. As this testimony will discuss later, however, we believe that a much more limited hedging sharing opportunity is appropriate because it will induce APS to seek economies without taking undue risk.

3. Fuel and Energy Audit

Q. Describe the scope of the fuel and energy audit.

A. Liberty responded to a Commission Staff request for proposals seeking an examination and analysis of the management and operations of fuel and purchased-power functions at APS, and the formulation of any appropriate recommendations. Liberty was awarded the engagement and proceeded to conduct an examination of: (a) organization structure, responsibilities, and staffing, (b) policies, procedures, systems, and tools, and (c) procurement approach, methods, and decisions. Liberty's examination addressed the following 12 work elements described in the RFP:

1. Identification of authorized decision makers up to the Board level for fuel and purchased-power procurement policy and transactions
2. The fuel and purchased-power costs in the PSA
3. Overall fuel and purchased-power procurement policy, goals, and strategies
4. Significant outages at plants other than Palo Verde for 2004 and 2005

5. Identification of any declines in non-nuclear plant performance
6. On-site inspections of fuel handling, quality control, inventory surveying methods and results, performance monitoring, and maintenance at generating stations
7. Review of the simulation models used to develop fuel and purchased-power volume requirements forecasts
8. Analysis of the models used by day-ahead traders to determine the correct dispatch of resources and other short-term decisions
9. Review of fuel and purchased-power contracts for reasonableness and for compliance with the terms and conditions
10. Review of hedging
11. Review of off-system sales
12. Review of audit reports on fuel and purchased-power procurement.

Q. Describe the work you performed in conducting this audit.

A. Liberty and the Commission's Staff began the audit by issuing a first set of data requests on February 3, 2006. Data requests eventually totaled more than 225. Liberty and Staff also conducted an extensive set of in-person interviews during the week of March 27, 2006. The audit team conducted on-site work observations and inspections at the West Phoenix and Redhawk gas-fired plants, and at the Cholla and the Four Corners coal-handling areas, to address operations issues. The team also directly observed work processes and conducted interviews at the coal lab at Four Corners, and at the combined utility and non-utility trading floor where dispatch, power sales and purchases, gas transportation management, and hedging transactions take place. This inspection included the front office (where planning, simulation, and actual trading take place) and the middle and back offices (where accounting and controls related to energy transacting take place). Liberty and Staff followed these in-person sessions with many telephone interviews during the course of the audit, which produced a draft report early in May 2006.

Q. Please discuss APS's cooperation with the audit.

A. APS made timely and generally full responses to all requests, save one. The resources it assigned to the audit showed dedication to making people and data available, and to providing explanations and supplemental information when Liberty and Staff needed them. The exception was that APS declined to make members of the board of directors available for interviews. Liberty explained that such interviews were material in addressing the scope of the audit as defined by the RFP under which we conducted it. APS continued to object to making directors available. In Liberty's many examinations of director oversight of public utility management and operations, we have always gained such access previously.

Q. Please describe the consequences of failing to make that access available.

A. Liberty was ultimately able to gain sufficient information to conclude that there was no failure of information flow to the board. APS offered access to board minutes and the views of senior executives on what role the directors play in fuel and energy matters and on how they exercise that role. Liberty was able to conclude that the directors received sufficient regular reporting on fuel and energy matters. It would have been much better to discuss with the directors in person what information they consider important and how they use it to oversee this important area of operations. In Liberty's prior engagements, speaking directly with directors formed an important process in concluding how well they serve in meeting public service responsibilities.

We have no reason to believe that there is a gap in senior oversight of fuel and energy matters. We did lose, however, an opportunity to firm up that conclusion with a typical and usual audit step. Given the lack of any observed problems of major consequence in APS fuel and energy procurement and management, there is not a substantial reason for concern about costs. However, board performance can sometimes form an important element of a public service commission's examination of utility management and operations. Liberty believes that, independently from its bearing on APS base or PSA rates, there should be a clear recognition by APS that the Commission's interests may warrant direct communication with directors. We understand the environment that now exists with respect to director statutory responsibilities and the exposures to suit that they face. Risks like these do call for discretion, but should not lead to a situation where directors become unwilling, when appropriate, to respond directly to questions directly posed by a utility regulatory body.

Q. Briefly summarize the APS generation portfolio that you considered in your audit.

A. APS is responsible for managing 10,400 MW of capacity at a number of generating stations, including Palo Verde. APS owns much generation jointly with others; APS therefore has responsibility for operating more capacity than it owns. Its ownership during the audit totaled 6,415MW, which consists of the components listed in the following table.

Source	Megawatts	Percent
Natural Gas	3,411	53.2
Coal	1,835	28.6
Nuclear	1,164	18.1
Solar	5	0.1
Totals	6,415	100

The natural-gas fired units include:

- Ocotillo: two steam and two combustion-turbine units, totaling 340MW; owned and operated by APS, located in Tempe, Arizona;
- Redhawk: 1,060 MW; combined cycle units; owned and operated by APS since operation began in 2002; located west of Phoenix;
- Saguaro: two steam units and three combustion-turbine units totaling 395MW; owned and operated by APS; located north of Tucson, Arizona;
- Sundance: one simple-cycle gas-fired unit and 10 quick-start combustion turbines totaling 450MW; owned and operated by APS, which purchased the station in the spring of 2005; located in Coolidge, Arizona;
- West Phoenix: two combustion-turbine units and five combined-cycle units totaling 1,000MW; owned and operated by APS, located in southwest Phoenix;
- Yucca: four combustion-turbine units totaling 150MW; owned and operated by APS; located near Yuma, Arizona.

The coal-fired units include:

- Four Corners: 2,040MW total capability; 782MW share owned by APS, operated by APS; located in New Mexico; uses low-sulfur coal from the nearby Navajo mine;
- Cholla: 995MW total capability, 615MW owned by APS, operated by APS; located in Arizona; uses coal from the McKinley Mine in New Mexico;
- Navajo: 2,250MW, 14 percent share owned by APS; operated by Salt River Project; located in Arizona; uses coal from a Navajo and Hopi Indian Reservations mine at Black Mesa, Arizona.

The APS share of Palo Verde capacity comprises the nuclear element of its generation portfolio.

Q. What conclusions and recommendations do you reach as a result of audit work?

A. I summarize them below.

Organization and Staffing

Fuel and power procurement work groups have the necessary skills and experience, operate under adequate job descriptions, communicate effectively, have access to appropriate training, use generally adequate procedures and decision processes, document decisions sufficiently, operate under established procurement approval limits, and undergo regular internal auditing. There is a need, however, for improvements in procedures for fuel contract management and administration, and in procedures for accepting gas-supply offers.

Coal Management

With respect to coal, APS has effectively managed inventory levels and variance analysis, administered coal contracts, measured supplier performance, carried out sampling processes, automated its coal-sampling data systems, and made economical use of combustion by-products. However, APS still uses some inefficient manual processes for handling coal-weight information. In addition, it has reduced the Cholla inventory target, but has since been carrying amounts in excess of that lower mark. The APS practice is actually more appropriate than its target; therefore, the Company should change the target to reflect that practice.

Natural Gas Management

The historical APS approach to gas-supply management has been typical and effective. It now, however, faces substantially increased prices for pipeline transportation. Gas transportation for electricity generation is a matter of significant current debate, as providers seek to make large increases for customers whose volumes can swing substantially. APS does not currently have substantial options to address changes in its full-requirements arrangement for service from the El Paso Natural Gas pipeline.

APS should examine through a comprehensive, structured analysis its alternatives for reducing future pipeline-transportation costs. Examples of the alternatives include altering generating station facilities to reduce flow variations, participation in high-deliverability storage projects, and identification of other users who may have complementary (and therefore mutually cost-reducing) usage patterns. APS should report the results of this analysis to the Commission within one year.

Fuel Contracts

APS's long-term coal supply agreements providing the primary supply to the Cholla and Four Corners Stations are effective. APS applied an appropriate process in its recent solicitation of new long-term coal supplies for the Cholla Station. APS's two short-term coal supply agreements for the Cholla Station are also appropriate. APS uses a sound process to contract for gas commodity. APS's contracting process for fuel oils is appropriate.

Purchased Power

APS bases its marketing and trading activities on sound hedging policies and procedures, and conducts electricity sales and purchases consistently with least-cost dispatch guidelines. APS has produced economic transactions, and it trades with a diverse population of counterparties. The trading patterns observed during audit work showed no indication of favoritism to any counterparty, whether affiliated or not, with the exception of the since corrected and discontinued transmission optimization transactions of PWCC. This testimony addresses that exception later. APS is using appropriate tools and documentation to conduct electric power trading to achieve least-cost total dispatch.

APS's economic dispatch procedures and operations appear to have operated smoothly since the April 2005 integration of the former merchant generating assets. APS has been meeting its requirements with appropriate short-term purchases, and the May 2005 RFP adds a long-term contract component.

APS Internal Auditing has been effective in monitoring the activities of electric power procurement and sale. The APS internal documentation separating the activities of regulated versus unregulated electric power trading is sufficient, but the external data presented in FERC forms does not make the appropriate distinctions between these two business segments. Electric power purchase and sale data related to both regulated and unregulated APS activities is not delineated in some publicly available documents, specifically the FERC Form 1.

The principal negative finding in this area of fuel and energy management is that APS does not separate its utility and non-utility activities sufficiently. They operate in the same markets and with common counterparties, but they do so without physical separation. These factors create too great a risk of opportunity sharing between utility and non-utility traders, who are separate individuals. Locating the APS and non-utility trader next to each other on the trading floor fails to assure clear separation of their trading activities.

Verification that no such sharing has harmed utility customers is extremely difficult. APS should physically separate its utility and non-utility traders, unless it can demonstrate that non-utility trading, which has been at very large levels, will very soon diminish substantially. APS also needs to complete promptly its efforts to assure that there is no non-utility co-opting of utility resources or opportunities.

Another concern was that PWCC, which conducts non-utility operations, made a number of transactions during 2005 to optimize a transmission corridor between delivery points at Borah Brady in Idaho and Four Corners. That corridor, however, represents a utility asset associated with an exchange agreement between APS and PacifiCorp. The two systems peak in different seasons; the difference allows PacifiCorp to make power available to APS in warmer months and APS to make power available to PacifiCorp in colder months. PWCC's non-utility use of this transmission capability generated positive margins of about $4.3 million from November 2005 through March 2006, and smaller margins in earlier months. APS discovered the non-utility use of the asset after non-utility operations made arrangements to use it and to retain the margins it produced. After this discovery in late 2005, APS was credited with the margins produced before November 2005. For transactions committed to earlier, but transpiring between November 2005 and March 2006, APS received credit before the fact for the $4.2 million in margins noted above.

This non-utility use of a utility asset was not appropriate and should not have occurred. APS did, however, discover the matter itself and make corrections. Moreover, the Company is now in the process of implementing internal procedures that will prevent a recurrence of this or similar use of utility resources or opportunities by affiliates. The occurrence of this situation shows the difficulties inherent in juxtaposing utility and non-utility trading activities. It also underscores the need for robust internal monitoring and periodic commission review. We cannot address the sufficiency of the corrective measures now because they remain under implementation or in discussion with the Commission.

Off-System Sales

The audit found that the comparatively small margins that APS has recently produced for off-system sales result from the relatively "short" position it has in low-cost generation (*e.g.*, coal, nuclear, and hydro). The market price for bulk power in the Desert Southwest region is generally set by combined-cycle, gas-fired generation. Surplus operating capacity having low operating costs is the key to generating large positive margins on off-system sales. Some of APS' neighboring utilities, such as SRP, TEP and PNM, have this advantage. APS does not have excess coal and nuclear generation available for substantial portions of the year because its system load has grown past the company's coal and nuclear resources. APS therefore sells from (*i.e.*, at the cost of) plants with economic characteristics similar to those whose output sets the market-clearing price. Therefore, its sales opportunities and its margins from those opportunities are constrained.

Hedging

APS has designed and it operates a sound hedging program. The amounts of natural gas and purchased power that it hedges fall at the high end of the range of experience. The program has been successful in meeting its primary objective, which is to promote price stability. It protects substantially against price increases, but will not operate to allow costs to fall when the market does. This lack of downward flexibility is not necessarily a problem; there exists a range of perspectives on the question. For example, the available market options that would allow APS to reduce costs if market prices fall either involve speculation or transaction costs that make their benefits dubious. There should, however, be a dialogue with stakeholders and with the Commission to make clear what goals the program should have and the extent to which it should produce hedged prices. This dialogue may not lead to a change in goals or hedge levels, but it will promote a common understanding of program operation and verify that it is meeting the needs and expectations of all customers.

Forecasting and Modeling

APS uses sufficiently accurate modeling to predict fuel and purchased-power volume and cost. APS has taken appropriate actions to ensure that it achieves least-cost total dispatch. APS uses outside reviews appropriately to improve management and operations. APS maintains adequate documentation to support regulatory oversight and review.

Plant Operations

The performance metrics of the base-loaded coal units demonstrate effective operation. The same is true for the gas units, but they have been adversely affected by the introduction of those units into the APS dispatch order in April 2005. APS has appropriately recognized the shift in the market paradigm brought about by inserting the former merchant units into the Company's dispatch order, and is appropriately dealing with Redhawk #1 and #2 and West Phoenix #5 issues and the need for re-engineering them for intermediate dispatch operation. Capital and O&M expenditure patterns for the APS generating fleet have been consistent with operational requirements. APS times and layers its unit outage schedules effectively, and conducts scheduled outages within reasonable durations.

The large gas units have experienced representative outage frequency and duration, considering their recent in-service dates, generic problems, and the changes in mode of operation. APS, however, should focus on optimizing the performance of the units as they complete the transition from early and merchant operation. APS is not sufficiently reflecting the high net replacement power costs in its economic evaluations related to minimization of outage costs or spare parts procurement. The Company should improve its economic evaluations related to minimization of outage time.

Boiler leaks account for a conspicuously high percentage of net replacement power costs associated with some units. APS needs to evaluate the replacement of boiler sections at Four Corners #5, Navajo #2, and Navajo #3. In addition, there is a high level of operator and maintenance error at Four Corners Unit #3 and Navajo Unit #3. The Company should conduct a centralized review of operator and maintenance errors at APS base-loaded coal plants and at Navajo, in order to assure that root causes are being correctly identified and addressed. Also, the Company should determine the reasons why such errors appear to be concentrated at Four Corners Unit #3 and Navajo Unit #3. Moreover, because improving West Phoenix Unit #5 availability is important to the dispatch and keeping net replacement power costs at minimum levels, APS should implement at this facility its policy requiring root-cause analysis when generation is lost.

The use of a 50/50 load forecast, coupled with fast growth and system constraints in the Phoenix Load Pocket, makes achievement of targeted reserves less certain. APS should analyze system reserve calculations using both a 50/50 and 90/10 load forecast, incorporating the constraints of the Phoenix Load Pocket.

Financial Audit of PSA Costs

The APS accounting systems are adequate and reasonably maintained to provide the necessary collection, reporting, and auditing of the PSA filings, and provide for reasonable testing. The monthly PSA filings were in general compliance with filing requirements and the sum total of costs were reasonably accurate. Detail testing of August 2005 PSA data found the supporting information to be well documented and reasonably consistent with the values reported.

There are a number of moderate improvements warranted, however. First, APS has yet to audit the PSA filing preparation. The PSA's newness and importance indicate that it become part of the next audit plan and APS's auditors should continue to address it thereafter periodically. Our audit found that APS documents its filing information well, but should adopt a formal written procedure addressing preparation of the monthly PSA filings. The audit did disclose one minor error. APS should correct an error that results in a misclassification of costs among its three major types of generation. Total costs, however, are correct; the error involves apportioning those costs among generation types.

The audit's detailed review of the non-confidential PSA Over/Under values found them to be accurate, but APS should more transparently support them. The audit also disclosed that APS has not used consistent accounting methods for purposes of recording refunds associated with supplemental fuel charges. The audit did not find this inconsistency to have had a material impact on the PSA. APS should nevertheless more closely review and monitor adjustments to fuel costs to assure that supplemental charges and refunds appropriately consider the impact on inventory values and fuel expenses for financial reporting purposes.

Q. How would you assess the significance of these findings and conclusions?

A. We did not reach any conclusions that would indicate imprudently incurred fuel and purchased power costs for 2005. There was in 2005 an inappropriate use by non-utility operations of a utility transmission asset. APS has already corrected for that situation, however. Most of the changes recommended as a result of the audit seek to move APS in the direction of using best practices in terms of procedures and analytical methods. I would describe these changes as incremental improvements to overall management that is already effective in the areas we examined.

Some of the recommendations, however, may have significant future cost impact. One example is dealing effectively with the consideration of boiler replacements, operator issues, and the remaining transitional issues associated with bringing a number of relatively new units into a utility (versus merchant-generator) environment. Another is the need to look closely at dealing with the large rate increases that the El Paso pipeline has been seeking at the FERC. Third is eliminating the common location of utility and non-utility trading personnel and activities, unless the remaining life of APS non-utility trading at high levels is definitively to be of very short duration. Finally, although we did not base the recommendations regarding the administration of the PSA on any finding that there is more than a very nominal mis-classification of costs, it is important that APS place strong emphasis on getting its accounting, auditing, and documentary support needs met as soon as possible.

Q. Did your audit find any basis for an adjustment in 2005 fuel and energy costs?

A. No. The standards we applied to such adjustments are imprudence, good utility practice, and reporting accuracy. The audit found no imprudence and no material variance from good utility practice (given the correction of the PWCC transmission optimization transactions). The inaccuracies found did not have a measurable impact on the fuel and energy revenues or costs material to PSA operation.

Q. Is there any other basis for an adjustment to 2005 fuel and energy costs?

A. A recommendation of the recent GDS report examining 2005 Palo Verde outages was that the Commission disallow amounts GDS found to have resulted from what it determined to be avoidable and imprudent outages. The audit did not address that subject.

Q. That report also recommended that the impact of those outages be considered in these base rate proceedings; have you done so?

A. We have not studied or formed an independent opinion on the reasonableness or prudence of the 2005 outages. We did however examine the Palo Verde performance that witness Ewen assumed in normalizing 2006 fuel and energy expenditures. His normalization did not rely upon actual 2005 performance of any generating unit, including Palo Verde. Instead it made adjustments intended to reflect normal operations with respect to characteristics such as outages. Therefore, it is not necessary to make any further adjustment to the Ewen normalization in order to remove the effects of below standard performance of Palo Verde or any other generating units during 2005.

Q. Did you examine 2006 fuel and energy costs?

A. We did not conduct detailed, transaction-based analysis of fuel and energy agreements and transactions. We also did not perform a detailed review of PSA filings, calculations, and support. Those types of analyses and reviews did serve, however, as material contributors to audit conclusions and recommendations focused primarily on 2005 activities and operations. The audit work, however, did support a conclusion that the organizations, systems, approaches, major contracts, strategies, activities, and priorities related to fuel and energy procurement and management continued into 2006.

In addition, we did determine that APS has accounted properly for the 2006 revenues and costs associated with the inappropriate non-utility use of an APS transmission asset discussed above.

Q. Can you reach any conclusions about APS performance in managing fuel and energy costs for 2006?

A. We believe that qualitatively it has continued to be effective through roughly the end of the first quarter, which is when audit field work ended. Moreover, most of the contracts, agreements, and hedging activities that we examined have continued in place for 2006. We have seen nothing that would suggest that 2006 conditions have deteriorated, or that performance has weakened. We consider 2006 conditions (with the specific exceptions discussed below regarding base rate adjustments) to be representative. We caution only that we do not represent our information and beliefs about 2006 conditions as constituting the kind of accounting or prudence review that we consider important for effective PSA administration, again as outlined below in this testimony. In any case, such a review in the middle of any target year (in this case, 2006) would be premature.

Q. Are you familiar with the questions raised by Mundell Amendment #1 in the recent proceedings addressing emergency relief for APS?

A. Yes; we conducted a review of them in the context of our audit and rate-case work.

Q. Please describe your efforts in connection with those questions?

A. We examined the transactions and parties with whom APS and non-utility operations made purchases and sales. We looked at transactions with common counterparties for any patterns that might suggest a failure of the utility traders to pursue utility opportunities. We looked at publicly available information dealing with off-system sales by other energy providers in the region.

These efforts supplemented the audit efforts that had already begun, which included assessing the organization, personnel, separation, modeling, dispatching, and trading floor operations involved in utility and non-utility off-system sales.

Q. What conclusions did you reach with respect to those questions?

A. We concluded that APS has acted to maximize off-system sales opportunities from the utility perspective. Our examination of transactions with common counterparties did not give any reason, with one exception (the PWCC transmission optimization transactions), to suspect that non-utility operations "co-opted" any utility opportunities, recognizing that such problems are difficult to detect in the absence of a very detailed, focused examination. We also found that the off-system sales and margins of APS were consistent with market prices and with the resources that APS had available for such use, after considering the relationship between its assets and its native usage.

We also found that other regional providers, in particular, appear to have a material advantage that APS does not. That advantage is the ability to provide, on more frequent occasions, low-cost base-load capacity for off-system sales at times when more expensive natural gas is setting the market price for such sales. The gap between provider costs and market-clearing prices provides for large margins on sales made at those times. APS by contrast frequently has only gas-fired generation available to make off-system sales. Thus, even if its units are competitive in costs to operate, its use of gas to sell in competition with others using gas reduces its margins substantially.

We caution that competitive sensitivities in the industry today place strong constraints on the data that is publicly available. Those constraints make only general analyses practicable to perform. At that level, it is clear that APS has, compared to others whose data we examined, much less ability to make its low-cost generation available at times when market prices are the most attractive from a seller's perspective.

4. Fuel and Energy Component of Base Rates

Q. Have you examined the base rate filing of APS in this proceeding?

A. Yes; on behalf of Staff we examined the fuel and energy aspects of the filing. In particular we focused on the testimony of APS witness Ewen, who used normalized, projected 2006 data to form the basis of the fuel and energy components of the APS request for an increase in base rates. We also examined the testimony of APS witness Richardson, who proposed a continuation of the PSA, but with changes.

Q. What did you conclude with respect to the normalized 2006 fuel and energy expenses discussed in the Ewen testimony?

A. We concluded that calendar-year 2006 serves appropriately as the period from which to establish the fuel and energy portion of base rates that APS would charge on a going-forward basis. We believe that normalizing 2006 data for plant operating characteristics (*e.g.*, outages, heat rates, capacity) is appropriate. We also believe that normalizing that data for factors such as customer growth, weather, and demand-side management is appropriate, particularly given the predominance of natural gas and purchased power as the incremental energy sources that will serve as the primary sources for accommodating increased usage by APS retail customers.

We also believe that the Commission should rely on actual, recent data for market prices for fuel and energy, because they are so volatile. The November 2005 prices relied upon in the Ewen testimony to forecast 2006 fuel and energy costs have turned out not to bear a sufficiently close relationship to what APS has actually paid for them so far this year. Those late-2005 prices also do not comprise a good proxy for what APS is likely to pay for the remainder of 2006, based on end-of-June prices in the forward markets. We believe it appropriate in setting base rates to use: (a) actual costs for fuel and purchased power (and hedge prices and values) for the first half of 2006 and (b) current forward prices for these items for the remainder of 2006 rates.

We also believe that there should not be adjustments to base rate fuel and energy components for changes that will take place in contracts for fuel, transportation, capacity, or energy after 2006 ends. Moreover, changes that took place during 2006 should not be treated as though they began at other times. The actual costs under those contracts or agreements for the first half of 2006 and their currently estimated costs for the remainder of 2006 should form the basis of normalized 2006 costs. Like fluctuating market prices, they reflect the kinds of factors that we believe adjustment mechanisms appropriately address.

We also observed that APS erroneously included non-utility wholesale sales activity in its filing. The revenues and expenses associated with those activities (which lost money and therefore added to the net costs that APS assigned to retail customers) require exclusion from APS calculations of the rates at issue in this proceeding.

Finally, we do not agree with the APS proposal in this case to retain 10 percent of the margins (positive or negative) produced by its hedging program. As this testimony will address later, that program operates on a largely (and appropriately so) non-discretionary basis.

Q. Summarize the changes that you have asked APS to make to its normalization of 2006 fuel and energy expenses to bring the results closer to actual 2006 fuel and energy market prices.

A. They consist of the following:

1. Use the loads as APS has normalized them for customer growth, weather, auxiliary power, and demand-side management.
2. Continue to use the APS-normalized plant operating assumptions for forced outages, plant capacities, and maintenance.
3. Use actual natural gas and power prices through June.
4. Use forward natural gas prices as of June 30 to estimate costs for the second half of 2006.
5. Use actual realized hedge values through June.
6. Use forward prices as of June 30 to estimate values for the second half of 2006.

7. Use actual nuclear and coal fuel costs through June, 2006.
8. Use the APS 2006 long-range forecast projections of nuclear and coal fuel costs for the second half of 2006.
9. Do not change for purposes of the recalculation the APS-proposed 10 percent value sharing, which has been included in their original calculation.

Q. Earlier you testified that there were 2006 transactions involving non-utility use of an APS transmission asset; how were they treated in the Ewen testimony's normalization of 2006 costs?

A. They had no effect. After APS discovered the non-utility use of the asset, it secured corrections to pre-November 2005 accounting for margins and it made from the outset a correct assignment of margins for 2006. The 2006 margins for use of the asset were $3,702,501. APS believes that it is not appropriate to include these margins in its normalization because the utility no longer enters those transactions, and does not permit non-utility entry of such transactions because they involve a utility asset. APS does not permit utility entry of such transactions because they impose market risk, which subjects the utility to earning negative margins.

Q. Do you agree with that treatment?

A. We agree that the transactions do involve market risk and we agree that utilities should not take material market risk in making off-system sales. Therefore, we do not disagree with the forward-looking assumption that APS will not directly make such transactions and earn margins from them. However, we would continue to include the actual 2006 margins of some $3.7 million in normalized 2006 fuel and energy costs, while excluding them from 2007 projections of fuel and energy costs. We did not include a request to include these margins in the revised 2006 normalization that we asked APS to perform. We did not learn about the transmission optimization transactions until after we had made our request of APS. Therefore, we treat those margins distinctly, as this testimony will discuss later.

That said, however, a more difficult question is whether APS can in the future capture some portion of the margin without taking market risk. APS should aggressively explore arrangements allowing for use of the asset by PWCC or by a third party under a margin sharing approach. A fixed payment per year or a percentage of gross revenues might be options. APS has not yet examined whether such an arrangement would be economically attractive to a marketer or whether the Company can structure it consistently with FERC requirements and limitations. Should APS have success, it is not likely, however, to produce more than a marginal reduction in the costs recoverable through the PSA.

Q. You did not ask that APS recalculate normalized 2006 fuel and energy costs without the Company's proposed 10 percent sharing involving hedging activities; explain why.

A. We do not agree with the APS proposal. Our goal, however, with respect to the recalculation was to measure the net change in revenue requirements on as common a basis as possible with the Ewen testimony, which included the effects of the Company's proposed sharing. Maintaining the effects of the sharing facilitated a direct comparison between the Company's approach and ours with respect to the normalization of key operations and market factors. With that direct comparison in hand, it is a fairly straightforward process to size the effects of the proposed sharing and to provide for their elimination, should the Commission determine it appropriate to do so.

Q. What changes did you ask APS to make to amend the Ewen testimony's 2006 normalization by eliminating contract changes?

A. We asked that the recalculation include, in addition to the market price factors listed above, the following changes:

1. Use actual Cholla coal transport rates for the first half of 2006.
2. Use the current projection of rates per ton on to calculate Cholla transport costs for the second half of the year.
3. Use an SRP T&C contract maximum capacity of 364MW through May and 372MW for June through December, use actual costs thereunder for the first half of 2006, and APS's best estimate for the remainder of the year.
4. Use Sundance capacity at 8 units (352MW) to reflect the 75MW agreement for sales to TEP through December 2006.
5. Include revenue from this TEP agreement in off-system revenue.
6. Use actual natural gas transport costs through June.
7. Use the best estimate of natural gas transport costs for the remainder of the year at current tariff rates, in order to account for the FERC rate case involving APS's pipeline transporter.

8. Recalculate capacity options needed to cover peak loads based on revised resources available (preceding SRP T&C and Sundance changes), and price them at June 30 market prices.

Q. What position did APS take with respect to your requested recalculation?

A. APS agreed to make the recalculation (without any concession as to its merits) and to provide the results by the end of July 2006.

Q. What did that recalculation show?

A. That recalculation showed net retail fuel cost of $824.4 million, for an average fuel cost of 2.8104¢/kwh. This amount represents a reduction of $111.6 million from the same measure as presented in Ewen testimony Workpaper PME_WP1. Adding the $3,702,501 in 2006 margins for transactions involving the transmission asset would further reduce the average fuel cost by 0.0138¢/kwh, to 2.7966¢/kwh.

Q. By how much would those numbers change with the elimination of the APS-proposed sharing mechanism?

A. The net retail fuel cost would increase nominally to $824.6 million and the average fuel cost would increase nominally to 2.8111¢/kwh. That cost would change to 2.7975¢/kwh after adjusting further for the 2006 margins on transactions involving PWCC's use of the APS transmission capability.

Q. What do you conclude about the fuel and energy portion of the APS claim for increased base rates in this proceeding?

A. It should be adjusted downward by $111.6 million (including the APS sharing proposal) or $111.4 million (excluding the APS sharing proposal) to reflect what we believe is a better approach to normalizing fuel and energy expenses in the context of an accompanying PSA. We also believe that it should be reduced by a further $3,702,501 to reflect 2006 margins for transactions involving the transmission asset. We believe that it should also be reduced further, as Mr. Dittmer's testimony discusses, to account for the removal of non fuel and energy costs associated with non-utility energy marketing and trading activity.

5. PSA Changes

Q. Did you ask that APS conduct any other calculations of fuel and energy expenses?

A. Yes. We asked that APS provide an estimate of 2007 expenses under similar assumptions.

Q. What was your purpose for this request?

A. We had two reasons. First, we do not consider 2007 circumstances irrelevant; we simply did not want them included in the 2006 normalization. We asked for the 2007 estimate to assess the impact of the 2007 changes that APS had included in its 2006 normalization. Second, we recommend the use of a forecasted year for setting the PSA rate in the future. We view calendar 2007 as an appropriate forecast period, given the timing of these proceedings and the view that an annual PSA resetting is generally a sound approach. The 2007 estimate we requested shows the expected difference from 2006 costs (normalized as we would propose). That difference allows for a current estimate of the amount that the PSA would have to capture in current costs, should it change to operate on a prospective basis.

Q. Summarize the estimate that you have asked APS to prepare for its expected 2007 fuel and energy expenses.

A. It proceeds generally from the 2006 normalization that APS prepared, and includes the following specific items:

1. Normalize 2007 loads, for customer growth, weather, and DSM; reduce them for distributed generation resulting from new RES.
2. Base 2007 natural gas and power prices on forward prices as of June 30, 2006.
3. Calculate 2007 hedge values on the basis of June 30, 2006 forward prices, with 10 percent of the value excluded.
4. Price nuclear and coal fuel cost at APS 2006 long-range forecast projections for 2007.
5. Use the Cholla coal transport rate per ton expected to be in effect under the tariff for 2007.
6. Use an SRP T&C contract maximum capacity of 372MW through May; reduce it to 230MW in June.
7. Use a Sundance capacity of 440 MW to reflect all 10 units.
8. Use natural gas transport cost based on tariff rates currently in place for 2007.

9. Include renewable energy resource contracts currently in place (10MW geothermal, 6MW biomass, 77MW wind) at the market price.
10. Reflect that purchased-power contracts from the reliability RFP start in the summer of 2007.
11. Include capacity contracted for under the Reliability RFP of 400MW Gila River Combined Cycle gas plant toll (May through December) and 650MW call options (June through September) as of their effective dates.
12. Use the plant forced outage rates, plant capacities, and maintenance as normalized by APS for 2006.
13. Calculate capacity options needed to cover peak loads on the basis of resources available; price them at June 30, 2006 forward-market prices.

Q. What position did APS take with respect to your requested 2007 estimate?

A. APS agreed to make it (again without any concession as to its merits) and to provide the results by the end of July 2006.

Q. What did that estimate show?

A. That estimate produced a net retail fuel cost of $981.7 million, an increase of $45.8 million over the Ewen testimony workpapers' normalized 2006 fuel and energy costs. The 2007 estimate was also $157.4 million more than the 2006 estimate prepared to our specifications. The 2007 estimate produced an estimated average fuel cost of 3.2296 ¢/kwh.

Q. By how much would those numbers change with the elimination of the APS-proposed sharing mechanism?

A. The net retail fuel cost would drop to $975.0 million and the average cost would drop to 3.2074 ¢/kwh.

Q. What are the principal challenges in adopting an effective adjustment mechanism?

A. The specific challenges faced when implementing an adjustment mechanism with a sliding scale of rates whose intent is to minimize volatility include the following:

- Preserving opportunity for examining forward costs
- Maintaining incentives for good performance
- Reconciling actual costs to estimates
- Recognizing the time value of money
- Promoting rate continuity
- Balancing risks and rewards
- Maintaining APS financial benchmarks that promote the ability to secure financing at costs favorable for customers.

The PSA's brief history at APS also shows that the Commission considers it important to assure that the other factors that affect earnings, particularly customer growth, do not offset changes in fuel and energy costs. Ordinarily, those other factors are not as volatile as fuel and energy costs have been recently. However, with the extraordinarily strong growth that APS is experiencing, care needs to be taken to assure that full, current fuel and energy-cost recovery does not produce returns in excess of those allowed because profitability is growing through other revenue and cost changes that affect base rates.

Q. What is the first principal feature of the design of a sound adjustment mechanism?

A. We believe that there should be Commission review of proposed charges before they become applicable. In one sense, the current PSA already does that, by basing PSA recovery on historical costs and by closely limiting changes in the PSA charge. That method can be effective, but in particularly volatile fuel markets can cause large deferrals of uncollected costs or recoveries far in excess of actual costs. The more volatile the market, the more difficult it becomes to match revenues and expenses on a fairly current basis when an historical period forms the basis of the charge.

Another approach would call for the filing, review, and approval of forecasts (*e.g.*, quarterly filings with annual approval) of costs and units of sale. Such forecasts would undergo inquiry by the Commission and other stakeholders. These forecasts, after review and approval, would determine whether a prospective adjustment to the PSA rate should be permitted.

Q. As compared with an historical-cost approach, what effect would the forecast approach have on the offsetting-costs criterion you just cited?

A. The historical approach, the 90 percent factor, and the collars on the current PSA make the current approach suitable for addressing the concern that APS will experience offsetting net revenue growth through increased usage. The forecasted approach would not do so as it is generally used, but two specific changes would make it more effective in doing so.

First, the Commission can retain the flexibility to use the results of the fuel and energy revenue and expense forecasts to set whatever PSA rate it deems to be appropriate. It would not be bound to set the rate at a level that would produce an expected current balance for the year of zero. The Commission could combine the PSA-related forecast filings with some form of abbreviated financial review. This approach would provide assurances that changes in the PSA component are sufficient to maintain utility financial strength on the one hand, while not so large as to create a material over-earnings situation, on the other hand.

Second, the Commission could do as many other commissions have done. Specifically it need not set only the ensuing 12-months for the recovery of any deferred balances or of any expected, very-large changes in projected costs. It can change the recovery-period start times or lengths. This approach can be applied alone, or in combination with the financial review approach. This "amortization" approach is common in providing a rate path that provides for adequate recovery but along a more stable rate path.

The amortization technique, while effective in promoting rate stability, can become troublesome where third parties compete for utility customers. The reason is that changes in recovery periods can cause utility rates to be far under market rates, which will make it hard for marketers to compete. Alternatively, where a rate stabilization approach places rates far above market, marketers get a price cushion that makes them look attractive even if they do not, by efficiency or other internal competence, have any edge that a fully and equally competitive marketplace would reward.

Q. What is the next principal feature of an effective PSA mechanism?

A. There should be clear provision for reconciliation of revenues and costs. These reconciliations should be provided for not less frequently than the period across which the adjustment applies (*e.g.*, quarterly or annually). They can be made more frequent, to the extent that variances exceed some predetermined level. APS should be subjected to clear filing requirements, addressing content and schedule, and identifying the information necessary to allow this reconciliation. There should also be a clearly scheduled opportunity to inquire into those filings, and for the Commission to consider and, if necessary, order any adjustments to any proposed APS reconciliation.

Q. What is the next principal feature of an effective PSA mechanism?

A. There should be an opportunity for an independent Commission review of prudence and reasonableness in all areas that drive the costs collected under the mechanism. These reviews should occur every two years or so, and they should be used to make justified, retroactive adjustments, even to reconciled costs/revenues, back to the end date of the last such independent review. The content of these reviews and the issues that they address should also be subject to examination and comment by the affected stakeholders, following which the Commission should make a determination of what, if any, costs resulted from ineffective or imprudent utility performance, and of what, if any, adjustments should be made to future recoveries and over what period of time.

Q. Won't the forecast review, reconciliation, and performance evaluation aspects you have just discussed impose additional requirements on the Commission's staff?

A. Yes. The three activities will take expertise and they will take significant review time. We think that those time commitments are worth the results they will produce, in assuring that APS secures timely recovery of volatile fuel and energy costs, and in assuring customers that performance has been effective and that price changes are fair and accurate. That said, however, it will likely take time for the Commission to marshal the resources it will take to conduct these reviews. A number of utility regulatory commissions perform these functions almost entirely in-house, but they have generally had several decades to develop the resources it takes to do so. Others make limited use of outside consultants; *e.g.*, in conducting the performance evaluations at one or two-year intervals. Those reviews are generally at the direction of the regulators (in terms of contractor selection and work supervision), but at the expense of the utility.

Q. Should the Commission set advance restrictions on changes in the size of the adjustment factor?

A. A collar and recovery limits such as those imposed currently have particular merit when there are not regular methods for assuring that prospective changes are appropriate and that there is prompt reconciliation and regular review of prudence. The three techniques that we have proposed, however, can provide those methods, and assure that the

Commission has regular insight into and oversight of the mechanism. Given the protections provided by these three mechanisms, it is appropriate to consider removal of the collar and recovery limits. Recent experience has shown energy prices to be volatile. There is not a sound basis for projecting a reduction in that volatility. As upward market movement has put APS into a significant under-recovery position, so may future downward movements cause customers at least temporarily to overpay.

The financial circumstances in which APS and its parent found themselves prior to the emergency rate relief granted by the Commission underscore the potential seriousness of imbalances due to market price movements. We should expect that the existence of a reliable mechanism assuring reasonably prompt recovery of prudent and reasonable fuel and energy costs will remain a primary consideration for those who examine and rely upon creditworthiness of utilities. We further believe that measures should be taken to preclude delayed recovery from having material financial consequences (*e.g.*, through increased financing costs or restraints on access to financial resources). We also believe that the potential for downward market movements should be recognized. In a volatile market, delay in rate adjustment may also keep customer money in the utility's hands.

We value the concern about creating over-earnings situation. We believe that this concern can be addressed by consideration of financial condition at the annual forecast filings and proceedings, and by adjusting PSA recovery if necessary to prevent a problem. In order not to bog those proceedings down too much, the Commission could entertain them every other year.

Q. Do you propose to set a 2007 PSA rate on the basis of the APS estimate of 2007 fuel and energy costs under the assumptions you gave the Company?

A. No; we offer it as a current overall measure of the likely amount by which 2007 recovery by APS will under-run actual estimated costs under the assumptions that: (a) the Commission decides to set base rates on the basis of 2006 costs "re-normalized" as we propose, and (b) establishes a PSA rate of zero for 2007. It is also important to emphasize that this measure does not address how the Commission may choose to deal with current deferred fuel and energy costs (*i.e.*, how balances have changed since the end of 2005) and any changes through the remainder of 2006.

We do not consider a June 30, 2006 measure to be close enough in time to serve as a firm basis for setting a 2007 PSA rate. There will also have to be other adjustments to reflect changes that will occur in cost-driving factors that occur mid-year in 2007. Its value now is primarily to show that it is reasonable, based on current assumptions, to expect that 2007 increases will substantially offset 2006 decreases that result from our re-normalization for 2006.

Q. What then do you propose?

A. Should the Commission decide to alter the current 90/10 sharing approach based on historical costs, we would propose the use of a late-2006 estimate that applies then-current market price assumptions and accounts for mid-2007 changes that are reasonably certain to occur.

Q. What is your position on the APS proposal to exclude 10 percent of gains or losses from hedging from the calculation of both base fuel cost and the PSA?

A. We consider it too broad to serve as an incentive, but recommend a narrower incentive.

Q. How does the APS hedging strategy work?

A. The Company's hedging strategy focuses on stability in fuel costs. It accomplishes that objective by "locking in" the prices that it will pay for fuels and purchased power well in advance of when those fuels will be used. Prices are locked in through a variety of devices: long-term contracts with stable pricing provisions in the case of coal and nuclear fuel, and forward-purchase contracts, futures contracts and certain derivative contracts in the case of natural gas and purchased power.

In the case of natural gas and purchased power, the strategy is implemented by setting target proportions of the Company's requirements for which the price would be set at defined points in the future. Under the current strategy, those proportions are as follows:

- First 12 months of energy (natural gas and purchased power): 85 percent
- First 12 months of natural gas basis differential (difference in value between the pricing point in Louisiana where the NYMEX futures contract for natural gas settles, and pricing points in New Mexico and West Texas where the Company buys most of its gas): 50 percent
- Second 12 months of energy: 50-60 percent
- Third 12 months of energy: 30-40 percent.

The Company's traders are required to fix prices for these proportions of the Company's requirements for these fuels, using the devices listed above. The 36-month period covered by the strategy rolls forward quarterly; *i.e.*, each quarter, the traders increase the proportion of requirements hedged, from 30-40 percent to 50-60 percent for the months that move from the third 12 months into the second, and from 50-60 percent to 85 percent for the months that move from the second 12 months into the first.

Q. Why should the Company not share in profits and losses produced by that strategy?

A. The APS hedging strategy and its resulting program begin from the premise that the Company cannot realistically expect to "beat the market" over long periods of time. Thus, the program effectively limits the Company's ability to influence program results by limiting trader discretion. When the program generates large apparent profits, those profits result from post-commitment movements in market prices, not by superior Company performance. In fact, because the Company believes that its traders cannot consistently beat the market, it designs its hedging program to limit trader ability to try to do so. We share the view that inducing market-beating performance should be avoided in the case of trading activities of this type.

Q. In what area do you favor a balanced risk/reward provision?

A. We favor such a provision in the hedging area that the Company refers to as "optimization". When the Company transacts in the marketplace to generate hedges, it buys some "instruments" covering natural gas and some covering electric power. Typically, these instruments are NYMEX futures contracts for natural gas, and forward-purchase contracts at Palo Verde for electric power. Natural gas and purchased power substitute for each other in the Company's incremental purchases of fuel because the generating equipment that the Company would operate to supply a marginal customer is gas-fired. To supply an incremental kWh of electricity to a customer, the Company could buy some gas and operate a gas-fired generating facility, or instead buy some power. Good practice is to make this decision after considering the relative prices of gas versus power delivered to APS's system. APS determines how much gas and how much power to buy after examining the relative prices of those commodities in forward markets.

Those price relationships change. When they do, the Company's traders can sell gas and buy power (or vice versa), to "optimize" the Company's hedge position, as long as the overall position stays at (or above) the target hedge level.

APS updates its estimates of its requirements for gas and purchased power weekly. These updated estimates consider factors such as revised load forecasts (updated semi-annually) and revisions to future prices for gas and power, scheduled outages for APS generating units, and operating characteristics of APS's generating units. APS traders can use the updated estimates to re-optimize the mix between gas and power purchases.

Available evidence suggests that the re-optimization process can make a notable difference. When the Ewen testimony normalization (which used November 2005 market prices) was prepared, the optimal balance between gas and purchased power in the Company's hedges was 88 percent gas and 12 percent purchased power. See Workpaper

PME_WP4. Since that time, power prices appear to have declined relative to gas prices, given that the balance of energy purchases has moved from gas to purchased power. The Company's responses to data requests submitted by Liberty (LCG-2-4) report that purchased-power volumes and costs in the first three months of 2006 were much higher than forecast under November 2005 market prices. Similarly, even though more than 90 percent of the Company's fuel and purchased-power expense for 2006 was hedged at the beginning of 2006, the Company's current estimate of that expense is $95.2 million. That sum is about 10 percent lower than what appears in the Ewen workpapers. This difference is the result of comparing system total fuel and purchased-power expense (after adjustment of hedge values to 100 percent) of $942,040,000 in PME_WP1 to $846,810,000 at p. 1 of APS10630.

This optimization (or re-optimization) process is an area where truly discretionary energy trading activities can add value. Updating the forecasts might be required for other aspects of the Company's operations, but re-balancing the hedge position between gas and purchased power might not. As suggested by recent experience, the benefits to customers of re-balancing can be significant. We consider it appropriate to provide a moderate level of sharing as an inducement to make sure that it happens. Good utility practice would suggest that it happen even without sharing, but we consider it very difficult to assess after the fact and through audit techniques how well such re-optimization took place.

Q. Does this complete your testimony?

A. Yes it does.

BEFORE THE

ARIZONA CORPORATION COMMISSION

APPLICATION OF ARIZONA PUBLIC SERVICE CO. FOR AN INCREASE IN ELECTRIC RATES	))))	**DOCKET NO. E-01345A-05-0816**

DIRECT TESTIMONY AND EXHIBIT

OF

DAVID C. PARCELL

ON BEHALF OF THE

COMMISSION STAFF

AUGUST 18, 2006

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BEFORE THE ARIZONA CORPORATION COMMISSION

DOCKET NO. E-01345A-05-0816

DIRECT TESTIMONY AND EXHIBIT

OF

DAVID C. PARCELL

I. INTRODUCTION

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

A. My name is David C. Parcell. I am Executive Vice President and Senior Economist of Technical Associates, Inc. My business address is Suite 601, 1051 East Cary Street, Richmond, Virginia 23219.

Q. PLEASE DESCRIBE YOUR BACKGROUND AND EXPERIENCE.

A. I hold B.A. (1969) and M.A. (1970) degrees in economics from Virginia Polytechnic Institute and State University (Virginia Tech) and a M.B.A. (1985) from Virginia Commonwealth University. I have been a consulting economist with Technical Associates since 1970. The large majority of my consulting experience has involved the provision of cost of capital testimony in public utility ratemaking proceedings. I have previously testified in about 375 utility proceedings before some 35 regulatory agencies in the United States and Canada. Schedule 1 contains a more complete description of my education and professional experience.

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

A. I have been retained by the Commission Staff to evaluate the cost of capital aspects of the current filing of Arizona Public Service Co. ("APS" or "Company"). Based on my analyses, I am making a recommendation of the current cost of capital for APS. In addition, since APS is a subsidiary of Pinnacle West Capital Corp. ("PWC"), I am also evaluating this entity in my analyses.

Q. HAVE YOU PREPARED EXHIBITS IN SUPPORT OF YOUR TESTIMONY?

A. Yes, I have prepared one exhibit, identified as Schedule 1 through Schedule 15. This exhibit was prepared either by me or under my direction. The information contained in this exhibit is correct to the best of my knowledge and belief.

II. RECOMMENDATIONS AND SUMMARY

Q. WHAT ARE YOUR RECOMMENDATIONS IN THIS PROCEEDING?

A. My overall cost of capital recommendation for APS is follows:

	Percent	Cost	Return
Long-Term Debt	45.5%	5.41%	2.46%
Common Equity	54.5%	10.25%	2.59%
Total	100.00%		8.05%

APS's application requests a return on equity of 11.5 percent and a total cost of capital of 8.73%.

Q. PLEASE SUMMARIZE YOUR ANALYSES AND CONCLUSIONS.

A. This proceeding is concerned with APS's regulated electric utility operations in Arizona. My analyses are concerned with APS's total cost of capital. The first step in performing these analyses is the development of the appropriate capital structure. APS's proposed capital structure is its adjusted September 30, 2005 capital structure ratios of 45.5 percent long-term debt and 54.5 percent common equity. I have adopted these capital structure ratios in my cost of capital analyses.

The second step in a cost of capital calculation is a determination of the embedded cost rate of long-term debt. I have used the 5.41 percent cost of long-term debt proposed by APS.

The third step in the cost of capital calculation is the estimation of the cost of common equity. I have employed three recognized methodologies to estimate the cost of equity for APS. I applied each of these methodologies to two proxy groups: 1) a group of comparison electric utilities with similar operating and risk characteristics to APS and

PWC; and, 2) and the group of proxy electric companies analyzed by Company witness Avera. These three methodologies and my findings are:

Methodology	Range
Discounted Cash Flow	9½-10%
Capital Asset Pricing Model	10½-10¾%
Comparable Earnings	10%

Based upon these findings, I conclude that the cost of common equity for APS is a range of 9½ percent to 10¾ percent, with an approximate mid-point of 10.25 percent. I recommend a cost of equity for APS of 10.25 percent.

Combining these three steps into weighted costs of capital results in an overall rate of return of 8.05 percent.

III. ECONOMIC/LEGAL PRINCIPLES AND METHODOLOGIES

Q. WHAT IS YOUR UNDERSTANDING OF THE ECONOMIC AND LEGAL PRINCIPLES WHICH UNDERLIE THE CONCEPT OF A FAIR RATE OF RETURN FOR A REGULATED UTILITY?

A. Cost of service rates for regulated public utilities have traditionally been primarily established using the "rate base - rate of return" concept. Under this method, utilities are allowed to recover a level of operating expenses, taxes, and depreciation deemed reasonable for rate-setting purposes, and are granted an opportunity to earn a fair rate of return on the assets utilized (i.e., rate base) in providing service to their customers. The rate base is derived from the asset side of the utility's balance sheet as a dollar amount and the rate of return is developed from the liabilities/owners' equity side of the balance sheet as a percentage. The rate of return is developed from the cost of capital, which is estimated by weighting the capital structure components (i.e., debt, preferred stock, and common equity) by their percentages in the capital structure and multiplying these by their cost rates. This is also known as the weighted cost of capital.

Technically, the fair rate of return is a legal and accounting concept that refers to an ex post (after the fact) earned return on an asset base, while the cost of capital is an economic and financial concept which refers to an ex ante (before the fact) expected or required return on a liability base. In regulatory proceedings, however, the two terms are often used interchangeably, as I have done in my testimony.

From an economic standpoint, a fair rate of return is normally interpreted to incorporate the financial concepts of financial integrity, capital attraction, and comparable returns for similar risk investments. These concepts are derived from economic and financial theory and are generally implemented using financial models and economic concepts.

Although I am not a lawyer and I do not offer a legal opinion, my testimony is based on my understanding that two U.S. Supreme Court decisions are universally cited as providing the standards for a fair rate of return. The first is Bluefield Water Works and Improvement Co. v. Public Serv. Comm'n of West Virginia, 262 U.S. 679 (1923). In this decision, the Court stated:

> What annual rate will constitute **just compensation** depends upon many circumstances and must be **determined by** the **exercise of a fair and enlightened judgment**, having regard to all relevant facts. A **public utility** is entitled to such rates as will permit it to **earn a return** on the value of the property which it employs for the convenience of the public equal to that **generally being made** at the same time and in the same general part of the country on **investments in other business undertakings** which are **attended by corresponding risks and uncertainties**; but it has no **constitutional right to profits** such as are realized or anticipated in **highly profitable enterprises or speculative ventures**. The **return** should be reasonably sufficient to assure confidence in the **financial soundness** of the utility, and should be adequate, **under efficient and economical management**, to maintain and **support its credit** and **enable it to raise the money** necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time, and become too high or too low by changes affecting opportunities for investment, the money market, and business conditions generally. **[Emphasis added.]**

Based on my understanding, this decision established the following standards for a fair rate of return: comparable earnings, financial integrity, and capital attraction. It also noted the changing level of required returns over time as well as an underlying assumption that the utility be operated in an efficient manner.

The second decision is Federal Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591 (1942). In that decision, the Court stated:

> The rate-making process under the [Natural Gas] Act, i.e., the fixing of 'just and reasonable' rates, involves a **balancing** of the **investor** and **consumer interests**. . . . From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. By that standard the **return** to the equity **owner** should be **commensurate** with **returns** on **investments** in **other enterprises having corresponding risks**. That return, moreover, should be sufficient to assure confidence in the **financial integrity** of the

> enterprise, so as to **maintain its credit** and to **attract capital**. **[Emphasis added.]**

The Hope case is also frequently credited with establishing the "end result" doctrine, which maintains that the methods utilized to develop a fair return are not important as long as the end result is reasonable.

Three economic and financial parameters identified in the Bluefield and Hope decisions – comparable earnings, financial integrity, and capital attraction – reflect the economic criteria encompassed in the "opportunity cost" principle of economics, which holds that a utility and its investors should be afforded an opportunity (not a guarantee) to earn a return commensurate with returns they could expect to achieve on investments of similar risk. The opportunity cost principle is consistent with the fundamental premise on which regulation rests, namely that it is intended to act as a surrogate for competition.

I understand that because Arizona is a "Fair Value" state, Hope and Bluefield do not set forth the legal requirements applicable to determining fair rate of return in Arizona. Nevertheless, the economic principles that I utilize in developing my recommendations are appropriate for determining APS's cost of capital in this proceeding.

Q. HOW CAN THESE PARAMETERS BE EMPLOYED TO ESTIMATE THE COST OF CAPITAL FOR A UTILITY?

A. Neither the courts nor economic/financial theory have developed exact and mechanical procedures for precisely determining the cost of capital. This is the case because the cost of capital is an opportunity cost and is prospective-looking, which dictates that it must be estimated.

There are several useful models that can be employed to assist in estimating the cost of equity capital, which is the capital structure item that is the most difficult to determine. These include the discounted cash flow ("DCF"), capital asset pricing model ("CAPM"), comparable earnings ("CE") and risk premium ("RP") methods. Each of these methods (or models) differs from the others and each, if properly employed, can be a useful tool in estimating the cost of common equity for a regulated utility.

Q. WHICH METHODS HAVE YOU EMPLOYED IN YOUR ANALYSES OF THE COST OF COMMON EQUITY?

A. I have utilized three methodologies to determine APS's cost of common equity: the DCF, CAPM, and CE methods. The results of each of these methodologies will be described in my testimony.

IV. GENERAL ECONOMIC CONDITIONS

Q. WHAT IS THE IMPORTANCE OF ECONOMIC AND FINANCIAL CONDITIONS IN DETERMINING THE COST OF CAPITAL?

A. The costs of capital, for both fixed-cost (debt and preferred stock) components and common equity, are determined in part by economic and financial conditions. At any given time, each of the following factors has a direct and significant influence on the costs of capital: the level of economic activity, the stage of the business cycle, the level of inflation, and expected economic conditions. My understanding is that this position is consistent with the Supreme Court Bluefield decision that noted that "[a] rate of return may be reasonable at one time, and become too high or too low by changes affecting opportunities for investment, the money market, and business conditions generally."

Q. WHAT INDICATORS OF ECONOMIC AND FINANCIAL ACTIVITY HAVE YOU EVALUATED IN YOUR ANALYSES?

A. I have examined several sets of economic statistics for the period 1975 to the present. I chose this period because it permits the evaluation of economic conditions over three full business cycles plus the current cycle to date, and thus makes it possible to assess changes in long-term trends. A business cycle is commonly defined as a complete period of expansion (recovery and growth) and contraction (recession). A full business cycle is a useful and convenient period over which to measure levels and trends in long-term capital costs because it incorporates the cyclical (i.e., stage of business cycle) influences and thus permits a comparison of structural (or long-term) trends.

Q. PLEASE DESCRIBE THE THREE PRIOR BUSINESS CYCLES AND THE MOST CURRENT CYCLE.

A. The most recent complete cycle began with an expansion in April of 1991 and ended in the fourth quarter of 2001, constituting a length of more than ten and one-half years. Following that, the economy slowed considerably in late 2000 and 2001 and was in a recession during three quarters of 2001, notwithstanding the Federal Reserve lowering interest rates (i.e, Fed Funds rate) eleven times in 2001 (as well as twice in 2003) in an aggressive effort to create a soft landing and avoid a recession. The events of September 11, 2001 further damaged the U.S. economy.

This cycle and the two prior complete cycles cover the following periods:

Business Cycle	Expansion Period	Contraction Period
1975-1982	Mar. 1975-July 1981	Aug. 1981-Oct. 1982
1982-1991	Nov. 1982-July 1990	Aug. 1990-Mar. 1991
1991-2001	Apr. 1991-Mar. 2001	Apr. 2001-Nov. 2001

The expansion phase of the recent cycle well surpassed the average length of expansions in the post-World War II era (i.e., about five years). The 1982-1990 expansion (seven years, eight months) was the previous longest peacetime expansion of this era.

Q. PLEASE DESCRIBE RECENT AND CURRENT ECONOMIC AND FINANCIAL CONDITIONS AND THEIR IMPACT ON THE COSTS OF CAPITAL.

A. Schedule 2 shows several sets of economic data. Page 1 contains general macroeconomic statistics while pages 2 and 3 contain financial market statistics. Page 1 of Schedule 2 shows that growth in the initial stage of the current cycle was somewhat slower than the typical initial recovery period. This is indicated by the growth in real (i.e., adjusted for inflation) Gross Domestic Product, industrial production, and the unemployment rate.

The rate of inflation is also shown on page 1 of Schedule 2, reflected in the Consumer Price Index (CPI). The CPI rose significantly during the 1975-1982 business cycle and reached double-digit levels in 1979-1980. The rate of inflation declined substantially in 1981 and remained at or below 6.1 percent during the 1983-1991 business cycle. Since 1991, the CPI has been 3.4 percent or lower. The 3.3 percent rate of inflation in 2005, along with a similar level for 2004, were slightly higher than the most recent years, but were both well below the levels of the past thirty years.

Q. WHAT HAVE BEEN THE TRENDS IN INTEREST RATES?

A. Page 2 of Schedule 2 shows several series of interest rates. Rates rose sharply in 1975-1981 when the inflation rate was high and rising. Rates then fell substantially throughout the remainder of the 1980s and into the 1990s. During the recent business cycle, long-term rates remained relatively stable, in comparison to the prior cycles. Rates have increased somewhat over the past year, but nevertheless currently are generally lower than at any time during the prior three cycles.

This low level of interest rates, in conjunction with the apparent strengthening of the U.S. economy, may create an expectation that any near-term movement of interest rates will be upward. In fact, the Federal Reserve has, since the middle portion of 2004, increased short-term interest rates on seventeen occasions, although each by only a small 0.25 percent level, in an attempt to insure that any perceived inflationary expectations will not stifle continued economic growth. Nevertheless, the economic recovery to date has not resulted in a pronounced increase in long-term rates (in fact, the current level of Fed Funds is about the same as the level in existence when the series of reductions began in 2000) and, even if rates were to increase moderately, they would still remain well below historical levels.

Q. WHAT HAVE BEEN THE TRENDS IN COMMON SHARE PRICES?

A. Page 3 of Schedule 2 shows several series of common stock prices and ratios. These indicate that share prices were basically stagnant during the high inflation/interest rate environment of the late 1970s and early 1980s, as evidenced by the fact that the Dow Jones Industrial average (DJI) remained in the 800-900 range for eight years. On the other hand, the 1983-1991 business cycle and the most recent cycle have witnessed a significant upward trend in stock prices as the DJI rose to over 11,000. Over the past five years, however, stock prices have been volatile.

Q. WHAT CONCLUSIONS DO YOU DRAW FROM THIS DISCUSSION OF ECONOMIC AND FINANCIAL CONDITIONS?

A. It is apparent that capital costs are currently low in comparison to the levels that have prevailed over the past three decades. In addition, even a moderate increase in interest rates, as well as other capital costs, would still result in capital costs that are low by historic standards. Therefore, it can reasonably be expected that cost of equity models, such as the DCF, currently produce returns that are lower than was the case in prior years.

V. APS'S OPERATIONS AND RISKS

Q. PLEASE SUMMARIZE APS AND ITS OPERATIONS.

A. APS is a public utility that delivers electricity through its generation, transmission and distribution systems in Arizona. APS is the primary electric utility in Arizona and provides service to about one million customers in the state. APS is a subsidiary of PWC.

Q. PLEASE DESCRIBE PWC.

A. PWC is a holding company whose major subsidiary is APS. Other subsidiaries of PWC are: SunCor (engaged in real estate development and investment activities) and APS Energy Services (provides competitive energy services and products in the western U.S).

Q. WHAT ARE PWC'S BUSINESS SEGMENT RATIOS?

A. This is shown on Schedule 3 for the years 2002-2005. As indicated, the "Regulated Electricity" segment has accounted for the following percentages:

	2002	2003	2004	2005
Operating Revenue	77.5%	71.7%	71.9%	74.9%
Operating Income	82.5%	75.6%	61.5%	74.9%
Net Income	114.1%	70.5%	62.6%	94.9%
Total Assets	89.6%	91.9%	87.6%	85.9%

This indicates that the electric regulated operations (i.e., APS) of PWC account for the vast majority of income for the consolidated enterprise. It is also apparent that the regulated operations are the most profitable.

Q. WHAT ARE THE CURRENT BOND RATINGS OF APS?

A. The present bond ratings of APS are as follows:

Moody's	Baa2
Standard & Poor's	BBB-
Fitch	BBB-

Q. WHAT HAVE BEEN THE TRENDS IN APS'S AND PWC'S BOND RATINGS?

A. This is shown on Schedule 4, which indicates that APS has had triple B ratings since 2000. It is also apparent that the ratings of APS have declined in 2006. Finally, it is evident that APS has maintained higher ratings than PWC.

Q. WHAT ARE THE STATED REASONS FOR THE CURRENT RATINGS OF APS AND THE REASONS FOR THE DECLINES IN 2006?

A. It is apparent that APS is viewed as a utility characterized by a strong and growing service area and strong rating metrics. On the other hand, a primary rating issue for the Company, and a significant stated reason for the recent downgrades, is the difficulties the Company has had in recovering power costs.

Standard &Poor's (S&P) recently stated, in a February 15, 2006 report on APS:

> Arizona Public Service's (APS) 'BBB-' corporate credit rating is based on the consolidated credit quality of Pinnacle West Capital Corp. (PWCC), of which APS is the principal subsidiary. APS is a vertically integrated investor-owned utility that provides retail electric service to about one million customers throughout Arizona, including about half of the Phoenix MSA.
>
> . . .
>
> A strong and diversified Phoenix economy has fueled significant utility growth, and a large residential base that accounted for 50% of APS' retail electric sales in 2004 provides stability. On the other hand, regulatory risk has increased, reflected in uncertainty related to the recovery of rising fuel and purchased power costs and in APS' significant pending general rate case, in which the company is requesting a 21.3%, or $453.9 million, rate increase.
>
> Regulatory uncertainty is exacerbated by the establishment in 2004 of a weak power supply adjuster (PSA) that exposes the utility to potential cash flow volatility.

These points were also cited by Moody's Investors Service (Moody's) in an April 27, 2006 report announcing the downgrades of APS:

> Moody's Investors Service downgraded the long-term ratings of Pinnacle West Capital Corporation (Pinnacle: Issuer Rating to Baa3 from Baa2) and its subsidiaries Arizona Public Service Company (APS: senior unsecured to Baa2 from Baa1).
>
> . . .
>
> The rating downgrades reflect deterioration in key financial metrics as a result of increased fuel and purchased power costs that APS is unable to recover on a timely basis.

Finally, Fitch Ratings (Fitch) made the following comments in a May 5, 2006 report:

> PNW and APS's ratings and Outlook consider the utility's rapidly growing electric service territory and solid credit metrics.
>
> . . .
>
> The ACC's supportive response to the company's request for emergency rate relief authorizes a $140 million interim rate increase to recover deferred power supply costs, subject to a final ruling in APS's general rate case.
>
> Prior rate decisions have been less constructive to the credit profile of APS. The January 2006 downgrade of APS by Fitch Ratings was triggered by rejection of the company's surcharge request for recovery of deferred power supply costs, and adoption of PSA provisions by the commission that are less favorable than had been anticipated by Fitch in its previous ratings.

Q. HOW DO THE BOND RATINGS OF APS COMPARE TO ELECTRIC UTILITIES?

A. As I indicated in a previous answer, APS has triple B bond ratings, which are investment grade (i.e., triple B or above). Of the 65 electric utilities and combination gas and electric utilities covered by AUS Utilities Reports, the following bond ratings currently exist:

	Moody's	S&P
Aa/AA	3	5
A/A	24	20
Baa/BBB	29	35
Ba/BB or Below	3	3
Not Rated	6	6

This comparison indicates that APS' ratings are in the largest rating category of electric utilities.

Q. YOU HAVE CITED A PERCEIVED HIGHER LEVEL OF RISK ATTRIBUTED TO APS RESULTING FROM ITS RECENT DIFFICULTIES ASSOCIATED WITH THE RECOVERY OF ITS POWER COSTS. ARE THERE ANY FACTORS IN THE PRESENT CASE THAT MAY IMPACT THIS?

A. Yes, there are. It is my understanding that other Commission Staff witnesses are making recommendations in this proceeding that, if adopted by the Commission, will have the effect of reducing APS's exposure to the collection and timing of its power costs. In particular, Staff witness Antonuk addresses the alternative of using a forward-year forecast as the basis of setting the amount of the PSA. If the Commission adopts that alternative, the required cost of equity for APS could be less than it would in the absence of its adoption.

VI. CAPITAL STRUCTURE AND COSTS OF DEBT AND PREFERRED STOCK

Q. WHAT IS THE IMPORTANCE OF DETERMINING A PROPER CAPITAL STRUCTURE IN A REGULATORY FRAMEWORK?

A. A utility's capital structure is important since the concept of rate base - rate of return regulation requires that a utility's capital structure be determined and utilized in estimating the total cost of capital. Within this framework, it is proper to ascertain whether the utility's capital structure is appropriate relative to its level of business risk and relative to other utilities.

As discussed in Section III of my testimony, the purpose of determining the proper capital structure for a utility is to help ascertain the capital costs of the company. The rate base - rate of return concept recognizes the assets which are employed in providing utility services and provides for a return on these assets by identifying the liabilities and common equity (and their cost rates) which are used to finance the assets. In this process, the rate base is derived from the asset side of the balance sheet and the cost of capital is derived from the liabilities/owners' equity side of the balance sheet. The inherent assumption in this procedure is that the dollar values of the capital structure and the rate base are approximately equal and the former is utilized to finance the latter.

The common equity ratio (i.e., the percentage of common equity in the capital structure) is the capital structure item which normally receives the most attention. This is the case since common equity: (1) usually commands the highest cost rate; (2) generates associated income tax liabilities; and (3) causes the most controversy since its cost cannot be precisely determined.

Q. HOW IS APS FINANCED?

A. APS's common stock is owned by PWC. As a result, APS obtains all of its equity funding from PWC. APS obtains its own debt stock financing.

Q. HOW HAVE YOU EVALUATED THE CAPITAL STRUCTURE OF APS?

A. I have examined the five year historic (2001-2005) capital structure ratios of APS and PWC. These are shown on Schedule 5.

I have summarized below the common equity ratios for APS and PWC for the last five years:

	APS		PWC	
	Inc'l S-T Debt	Exc'l S-T Debt	Inc'l S-T Debt	Exc'l S-T Debt
2001	48.9%	50.9%	43.8%	47.2%
2002	49.3%	49.3%	45.2%	47.0%
2003	45.7%	45.7%	45.4%	46.0%
2004	45.1%	45.1%	47.4%	48.0%
2005	53.8%	53.8%	53.2%	53.4%

This indicates that APS and PWC have generally had rising common equity ratios since 2001.

Q. HOW DO THESE CAPITAL STRUCTURE RATIOS COMPARE TO ELECTRIC UTILITIES IN GENERAL?

A. This is shown on Schedule 6. This indicates that the average common equity ratios for the two groups of electric utilities are below those of APS over the past five years. This is indicative of a lower degree of financial risk for APS.

Q. WHAT CAPITAL STRUCTURE RATIO HAS APS REQUESTED IN THIS PROCEEDING?

A. The Company requests use of the following capital structure:

Capital Item	Percentage
Long-term Debt	45.5%
Common Equity	54.5%

According to the Company's application these are the "adjusted" September 30, 2005 capital structure ratios of APS.

Q. WHAT CAPITAL STRUCTURE DO YOU PROPOSE TO USE IN THIS PROCEEDING?

A. I have adopted the adjusted test period capital structure of APS, as proposed by the Company. I do this since the proposed capital structure appears to be the actual capital structure. I note, on the other hand, that this capital structure contains a higher equity ratio than both electric utilities in general and the proxy groups in particular. As such, the APS capital structure, as proposed and as accepted by me, reflects a lower degree of financial risk than both the proxy groups and electric utilities.

Q. WHAT IS THE COST OF LONG-TERM DEBT?

A. The Company's filing cites a long-term debt cost of 5.41 percent. I use this cost rate in my cost of capital analyses.

Q. CAN THE COST OF COMMON EQUITY BE DETERMINED WITH THE SAME DEGREE OF PRECISION AS THE COSTS OF DEBT AND PREFERRED STOCK?

A. No. The cost rates of debt are largely determined by interest payments, issue prices, and related expenses. Even though alternative methodologies exist for determining the embedded cost rate, the cost rate for debt is generally agreed to, at least within a relatively small range.

The cost of common equity, on the other hand, is not susceptible of specific measurement, primarily because this cost is an opportunity cost. There are, however, several models that can be employed to estimate the cost of common equity. Three of the primary methods - DCF, CAPM, and CE - are developed in the following sections of my testimony.

VII. SELECTION OF COMPARISON GROUPS

Q. HOW HAVE YOU ESTIMATED THE COST OF COMMON EQUITY FOR APS?

A. APS is not a publicly traded company; rather, it is a subsidiary of PWC. As a result, it is not possible to conduct direct analyses of the cost of common equity for APS. It is possible to conduct studies of PWC's cost of equity; however, the diversified nature of this company's operations indicate that it is not an adequate proxy, standing alone, for the cost of equity for APS. As a result, it is useful to also analyze groups of comparison or "proxy" companies as a substitute for APS to determine its cost of common equity.

The most frequently used alternative is to select a group of comparison utilities. I have examined two such groups for comparison to APS. I have first selected one group of electric utilities similar to APS and PWC using the criteria listed on Schedule 7 These criteria are as follows:

(1) Market capitalization of $1 billion to $8 billion;
(2) Electric revenues 50% or greater;
(3) Common equity ratio 40% or greater;
(4) Value Line Safety of 1, 2 or 3;
(5) S&P and Moody's bond ratings of Triple B; and,
(6) S&P stock ranking of B, B+, or A-.

Second, I have further conducted studies of the cost of equity for the proxy group of electric utilities selected by APS's witness William Avera.

VIII. DISCOUNTED CASH FLOW ANALYSIS

Q. WHAT IS THE THEORY AND METHODOLOGICAL BASIS OF THE DISCOUNTED CASH FLOW MODEL?

A. The discounted cash flow (DCF) model is one of the oldest, as well as the most commonly-used, models for estimating the cost of common equity for public utilities. The DCF model is based on the "dividend discount model" of financial theory, which maintains that the value (price) of any security or commodity is the discounted present value of all future cash flows. When applied to common stocks, the dividend discount model describes the value of a stock as follows:

$$P = \frac{D_1}{(1+K_1)} + \frac{D_2}{(1+K_2)^2} + \ldots + \frac{D_n}{(1+K_n)^n} = \sum_{t=1}^{n} \frac{D_t}{(1+K)^t}$$

where: P = current price

D_1 = dividends paid in period 1, etc.

K_1 = discount rate in period 1, etc.

n = infinity

This relationship can be simplified if dividends are assumed to grow at a constant rate of g. This variant of the dividend discount model is known as the constant growth or Gordon DCF model. In this framework, the price of a stock is determined as follows:

$$P = \frac{D}{(K-g)}$$

where: P = current price

D = current dividend rate

K = discount rate (cost of capital)

g = constant rate of expected growth

This equation can be solved for K (i.e., the cost of capital) to yield the following formula:

$$K = \frac{D}{P} + g$$

This formula essentially states that the return expected or required by investors is comprised of two factors: the yield (current income) and expected growth (future income).

Q. PLEASE EXPLAIN HOW YOU HAVE EMPLOYED THE DCF MODEL.

A. I have utilized the constant growth DCF model. In doing so, I have combined the current dividend yield for each group of proxy companies described in the previous section with several indicators of expected growth.

Q. HOW DID YOU DERIVE THE DIVIDEND YIELD COMPONENT OF THE DCF EQUATION?

A. There are several methods which can be used for calculating the yield component. These methods generally differ in the manner in which the dividend rate is employed, i.e., current versus future dividends or annual versus quarterly compounding of dividends. I believe the most appropriate yield component is a quarterly compounding variant which is expressed as follows:

$$Yield = \frac{D_0(1 + 0.5g)}{P_0}$$

This yield component recognizes the timing of dividend payments and dividend increases.

The P_0 in my yield calculation is the average (of high and low) stock price for each company for the most recent three month period (May-July, 2006). The D_0 is the current annualized dividend rate for each company.

Q. HOW HAVE YOU ESTIMATED THE GROWTH COMPONENT OF THE DCF EQUATION?

A. The growth rate component of the DCF model is usually the most crucial and controversial element involved in using this methodology. The objective of estimating the growth component is to reflect the growth expected by investors which is embodied in the price (and yield) of a company's stock. As such, it is important to recognize that individual investors have different expectations and consider alternative indicators in deriving their expectations. A wide array of techniques exist for estimating the growth expectations of investors. As a result, it is evident that no single indicator of growth is always used by all investors. It therefore is necessary to consider alternative indicators of growth in deriving the growth component of the DCF model.

I have considered five indicators of growth in my DCF analyses. These are:

1. 2001-2005 (5-year average) earnings retention, or fundamental growth;
2. 5-year average of historic growth in earnings per share (EPS), dividends per share (DPS), and book value per share (BVPS);
3. 2006-2010 projections of earnings retention growth;
4. 2004-2010 projections of EPS, DPS, and BVPS; and
5. 5-year projections of EPS growth as reported in First Call (formerly I/B/E/S).

I believe this combination of growth indicators is a representative and appropriate set with which to estimate investor expectations of growth for the groups of natural gas companies.

Q. PLEASE DESCRIBE YOUR DCF CALCULATIONS.

A. Schedule 8 presents my DCF analysis. Page 1 shows the calculation of the "raw" (i.e., prior to adjustment for growth) dividend yield. Pages 2-3 show the growth rate for the groups of comparison companies. Page 4 shows the DCF calculations, which are presented on several bases: average, median, and high values. These results can be summarized as follows:

	Average	Median	High Value
Proxy Group	8.1%	8.4%	10.0%
Avera Group	8.8%	8.8%	9.6%

Q. WHAT DO YOU CONCLUDE FROM YOUR DCF ANALYSES?

A. Based upon my analyses, I believe a range of 9 percent to 10 percent represents the current DCF cost of equity for APS. The lower end (9 percent) approximates the upper values for the average/median results, while the upper end (10 percent) reflects the high value of the constant growth DCF calculations for the groups examined.

IX. CAPITAL ASSET PRICING MODEL ANALYSIS

Q. PLEASE DESCRIBE THE THEORY AND METHODOLOGICAL BASIS OF THE CAPITAL ASSET PRICING MODEL.

A. The Capital Asset Pricing Model (CAPM) is a version of the risk premium method. The CAPM describes and measures the relationship between a security's investment risk and its market rate of return. The CAPM was developed in the 1960s and 1970s as an extension of modern portfolio theory (MPT), which studies the relationships among risk, diversification, and expected returns.

Q. HOW IS THE CAPM DERIVED?

A. The general form of the CAPM is:

$$K = R_f + \beta(R_m - R_f)$$

where: K = cost of equity

R_f = risk free rate

R_m = return on market

$\exists$ = beta

R_m-R_f = market risk premium

As noted previously, the CAPM is a variant of the risk premium method. I believe the CAPM is generally superior to the simple risk premium method because the CAPM specifically recognizes the risk of a particular company or industry, whereas the simple risk premium method does not.

Q. WHAT GROUPS OF COMPANIES HAVE YOU UTILIZED TO PERFORM YOUR CAPM ANALYSES?

A. I have performed CAPM analyses for the same groups of electric utilities evaluated in my DCF analyses.

Q. WHAT RATE DID YOU USE FOR THE RISK-FREE RATE?

A. The first term of the CAPM is the risk free rate (R_f). The risk-free rate reflects the level of return that can be achieved without accepting any risk.

In reality, there is no such thing as a truly riskless asset. In CAPM applications, the risk-free rate is generally recognized by use of U.S. Treasury securities. This follows since Treasury securities are default-free owing to the government's ability to print money and/or raise taxes to pay its debts.

Two types of Treasury securities are often utilized as the R_f component - short-term U.S. Treasury bills and long-term U.S. Treasury bonds. I have performed CAPM calculations using the three-month average yield (May-July 2006) for 20-year U.S. Treasury bonds. Over this three-month period, these bonds had an average yield of 5.30 percent.

Q. WHAT BETAS DID YOU EMPLOY IN YOUR CAPM?

A. I utilized the most current Value Line betas for each company in the groups of comparison electric companies. These are shown on Schedule 10 and are seen to be within a range of 0.70 to 1.20 (the beta for the entire market is 1.00).

Q. HOW DID YOU ESTIMATE THE MARKET RISK PREMIUM COMPONENT?

A. The market risk premium component (R_m-R_f) represents the investor-expected premium of common stocks over the risk-free rate, or government bonds. For the purpose of estimating the market risk premium, I considered returns of the S&P 500 (a broad-based group of large U.S. companies) and 20-year U.S. Treasury bonds.

Schedule 9 shows the return on equity for the S&P 500 group for the period 1978-2004 (all available years reported by S&P). The average return on equity for the S&P 500 group over the 1978-2004 period is 14.02 percent. This Schedule also indicates the annual yields on 20-Year U.S. Treasury bonds, as well as the annual differentials (i.e., risk premiums) between the S&P 500 and U.S. Treasury 20-Year bonds. Based upon these returns, I conclude that the risk premium is about 6 percent.

I have also considered the total returns for the S&P 500 group as well as for long-term government bonds, as tabulated by Ibbotson Associates, using both arithmetic and geometric means. I have considered the total returns for the entire 1926-2005 period, which are as follows:

	S&P 500	L-T Gov't Bonds	Risk Premium
Arithmetic	12.3%	5.8%	6.5%
Geometric	10.4%	5.5%	4.9%

I conclude from this that the expected risk premium is about 5.8 percent (i.e., average of all three risk premiums). I believe that a combination of arithmetic and geometric means is appropriate since investors have access to both types of means and, presumably, both types are reflected in investment decisions and thus stock prices and cost of capital.

Schedule 10 shows my CAPM calculations using this risk premium. The results are:

	Mean	Median
Proxy Group	10.4%	10.5%
Avera Group	10.7%	10.8%

Q. **WHAT IS YOUR CONCLUSION CONCERNING THE CAPM COST OF EQUITY FOR THE GROUPS OF COMPARISON COMPANIES?**

A. The CAPM results collectively indicate a cost of about 10½-10¾ percent for the two groups of proxy companies.

X. COMPARABLE EARNINGS ANALYSIS

Q. PLEASE DESCRIBE THE BASIS OF THE CE METHODOLOGY.

A. The CE method is derived from the "corresponding risk" standard of the Bluefield and Hope cases. This method is based upon the economic concept of opportunity cost. As previously noted, the cost of capital is an opportunity cost: the prospective return available to investors from alternative investments of similar risk.

The CE method is designed to measure the returns expected to be earned on the original cost book value of similar risk enterprises. Thus, this method provides a direct measure of the fair return, since it translates into practice the competitive principle upon which regulation rests.

The CE method normally examines the experienced and/or projected returns on book common equity. The logic for returns on book equity follows from the use of original cost rate base regulation for public utilities, which uses a utility's book common equity to determine the cost of capital. This cost of capital is, in turn, used as the fair rate of return which is then applied (multiplied) to the book value of rate base to establish the dollar level of capital costs to be recovered by the utility. This technique is thus consistent with the rate base methodology used to set utility rates.

Q. HOW HAVE YOU EMPLOYED THE CE METHODOLOGY IN YOUR ANALYSIS OF APS's COMMON EQUITY COST?

A. I conducted the CE methodology by examining realized returns on equity for several groups of companies and evaluating the investor acceptance of these returns by reference to the resulting market-to-book ratios. In this manner it is possible to assess the degree to which a given level of return equates to the cost of capital. It is generally recognized for utilities that market-to-book ratios of greater than one (i.e., 100%) reflect a situation where a company is able to attract new equity capital without dilution (i.e., above book value). As a result, one objective of a fair cost of equity is the maintenance of stock prices above book value.

I would further note that the CE analysis, as I have employed it, is based upon market data (through the use of market-to-book ratios) and is thus essentially a market test. As a result, my comparable earnings analysis is not subject to the criticisms occasionally made by some who maintain that past earned returns do not represent the cost of capital. In addition, my comparable earnings analysis uses prospective returns and thus is not strictly backward looking.

Q. WHAT TIME PERIODS HAVE YOU EXAMINED IN YOUR CE ANALYSIS?

A. My CE analysis considers the experienced equity returns of the proxy groups of companies for the historic period 1992-2005 (i.e., last 14 years) as well as the future periods 2006-2010. The CE analysis requires that I examine a relatively long period of time in order to determine trends in earnings over at least a full business cycle. Further, in estimating a fair level of return for a future period, it is important to examine earnings over a diverse period of time in order to avoid any undue influence by unusual or abnormal conditions that may occur in a single year or shorter period. Therefore, in forming my judgment of the current cost of equity I have focused on two historic periods – 2001-2005 (the last five years), and 1992-2001 (the most recent complete business cycle) – as well as the 2006-2010 projected period.

Q. PLEASE DESCRIBE YOUR CE ANALYSIS.

A. Schedule 11 and Schedule 12 contain summaries of experienced returns on equity for several groups of companies, while Schedule 13 presents a risk comparison of utilities versus unregulated firms.

Schedule 11 shows the earned returns on average common equity and market-to-book ratios for the two groups of proxy utilities. These can be summarized as follows:

Group	Historic ROE	Historic M/B	Prospective ROE
Proxy Group	9.9-11.5%	139-141%	8.2-9.3%
Avera Group	11.3-11.7%	148-161%	9.9-10.4%

These results indicate that historic returns of 9.9-11.7 percent have been adequate to produce market-to-book ratios of 139-161 percent.

Furthermore, projected returns on equity for 2006, 2007 and 2009-2011 are within a range of 8.2 percent to 10.4 percent for the proxy groups. These relate to 2005 market-to-book ratios of 150 percent and higher.

Q. HAVE YOU ALSO REVIEWED EARNINGS OF UNREGULATED FIRMS?

A. Yes. As an alternative, I also examined a group of largely unregulated firms. I have examined the Standard & Poor's 500 Composite group, since this is a well recognized group of firms that is widely utilized in the investment community and is indicative of the competitive sector of the economy. Schedule 12 presents the earned returns on equity and market-to-book ratios for the S&P 500 group over the past thirteen years (i.e., 1992-2004). As this exhibit indicates, over the two periods this group's average earned returns ranged from 12.3-14.7 percent with market-to-book ratios ranging between 334-409 percent.

Q. HOW CAN THE ABOVE INFORMATION BE USED TO ESTIMATE THE COST OF EQUITY FOR APS?

A. The recent earnings of the utility and S&P 500 groups can be utilized as an indication of the level of return realized and expected in the regulated and competitive sectors of the economy. In order to apply these returns to the cost of equity for electric utilities, however, it is necessary to compare the risk levels of the electric utility industry with those of the competitive sector. I have done this in Schedule 13, which compares several risk indicators for the S&P 500 group and the proxy groups. The information in this schedule indicates that the S&P 500 group is more risky than the utility proxy groups.

Q. WHAT RETURN ON EQUITY IS INDICATED BY THE CE ANALYSIS?

A. Based on the recent earnings and market-to-book ratios, I believe the CE analysis indicates that the cost of equity for APS is no greater than 10 percent. Recent returns of 9.9-11.7 percent have resulted in market-to-book ratios of 139 and greater. Prospective returns of 8.9-10.4 percent have been accompanied by market-to-book ratios of over 150 percent. As a result, it is apparent that returns below this level would result in market-to-book ratios of well above 100 percent. An earned return of 10 percent or less should thus result in a market-to-book ratio of at least 100 percent.

XI. RETURN ON EQUITY RECOMMENDATION

Q. PLEASE SUMMARIZE THE RESULTS OF YOUR THREE COST OF EQUITY ANALYSES.

A. My three methodologies produce the following results for the proxy groups, as summarized below:

Discounted Cash Flow	9-10% (9.5% Mid-Point)
Capital Asset Pricing Model	10½-10¾%
Comparable Earnings	10%

My overall conclusion from these results is a range of 9½ percent to 10¾ percent, which focuses on the upper portions of the respective model results. My specific recommendation for APS is 10.25 percent, the approximate mid-point of this range.

XII. TOTAL COST OF CAPITAL

Q. WHAT IS THE TOTAL COST OF CAPITAL FOR APS?

A. Schedule 14 reflects the total cost of capital for the Company using the APS capital structure, the Company's proposed cost of long-term debt, and my common equity recommendation. The resulting total cost of capital is 8.05 percent.

Q. DOES YOUR COST OF CAPITAL RECOMMENDATION PROVIDE THE COMPANY WITH A SUFFICIENT LEVEL OF EARNINGS TO MAINTAIN ITS FINANCIAL INTEGRITY?

A. Yes, it does. Schedule 15 shows the pre-tax coverage that would result if APS earned the mid-point of my cost of capital recommendation. As the results indicate, the mid-point of my recommended range would produce a coverage level that is above the benchmark range for an A rated utility. In addition, the debt ratio is consistent with that of an A rated utility.

XIII. COMMENTS ON COMPANY TESTIMONY

Q. HAVE YOU RECEIVED THE TESTIMONY OF APS' COST OF EQUITY WITNESS?

A. Yes, I have. Dr. William E. Avera is the Company's cost of equity witness.

Q. PLEASE SUMMARIZE YOUR UNDERSTANDING OF DR. AVERA'S COST OF EQUITY ANALYSES AND RECOMMENDATION.

A. Dr. Avera's cost of equity findings can be summarized as follows:

DCF	9.0%
Risk Premium	
Authorized Returns	10.7-11.4%
Realized Rates of Return	9.8-11.0%
CAPM	
Forward-Looking	12.5-12.6%
Historical	10.9-11.9%
Comparable Earnings	11.0-12.0%
Cost of Equity-Proxy Group	10.8-11.8%
Flotation Cost Allowance	0.2%
Rate of Return-Proxy Group	11.0-12.0%
Recommendation	11.5%

Q. DO YOU HAVE ANY COMMENTS CONCERNING DR. AVERA'S DCF ANALYSES AND CONCLUSIONS?

A. Yes, I do. Dr. Avera's DCF analyses contain a 9.0 percent conclusion, which matches the bottom end of my DCF range of 9 percent to 10 percent. However, he apparently gives this methodology little or no weight in his 11 percent to 12 percent recommendation for APS. I believe this is a deficiency in his analyses, in that he has virtually ignored the results of the most commonly-used cost of capital methodology.

Q. DO YOU HAVE ANY COMMENTS ABOUT DR. AVERA'S "SURVEYS OF ALLOWED RATES OF RETURN" RISK PREMIUM ANALYSIS?

A. Yes, I do. This analysis simply compares authorized returns on common equity for electric utilities with the yield on public utility bonds for the period 1974-2004 (average differential of 3.17 percent). He then performs a regression analysis to reflect his belief "that the magnitude of equity risk premiums is not constant and that equity risk premiums tend to move inversely with interest rates." His conclusion is that a 4.93 percent equity risk premium is necessary for the "current" 5.51 percent yield (as of August, 2005) on BBB rated public utility bonds.

This 4.93 percent spread is clearly excessive. A review of Dr. Avera's Schedule WEA-4 indicates that the actual "risk premium" did not reach 4.93 percent in any of the thirty-one years covered in the 1974-2004 period. If we focus on more recent periods (e.g., last 10 years), the average "spread" is about 3.8 percent. If this were combined with the 6.7 percent (June, 2006) yield on BBB rated utility debt, the result is 10.4 percent.

This example exposes the fallacy of comparing authorized returns with bond yields. The period examined, regression results, and many other factors impact the results. It seems very doubtful that regulatory commissions, including this Commission, would want to set rates of return based upon the Commissions' decisions over vastly different circumstances.

Q. WHAT ARE YOUR COMMENTS CONCERNING DR. AVERA'S "REALIZED RATES OF RETURN" RISK PREMIUM ANALYSIS?

A. This approach compares realized returns" (capital gains/losses plus dividends) for the S&P Electric Utilities groups and A rated public utility bond yields over the 1946-2004 period. The resulting 4.04 percent average "equity risk premium" is added to his 7.0 percent yield on triple-B public utility bonds to yield an 11.0 percent return.

I disagree conceptually with this type of analysis for many of the same reasons described in my response to Dr. Avera's allowed rates of return risk premium analysis; changing trends in capital costs, sensitivity to period selected, etc.

Q. WHAT ARE YOUR COMMENTS REGARDING DR. AVERA'S CAPM RISK PREMIUM ANALYSIS?

A. Dr. Avera's CAPM uses the following inputs.

Market rate of return	13.1%
Risk free rate	4.5%
Beta	0.89

My primary disagreement is with his 13.5 percent market return and resulting 9.0 percent risk premium (i.e., 13.5% minus 4.5%). I have previously indicated that risk premium associated with the S&P 500 composite group (as used by Dr. Avera in his CAPM) has been about 5.8 percent. There is no legitimate reason, therefore, to expect this group to achieve a 9 percent risk premium over the longer term.

Use of a more reasonable expected market return, such as that contained in my CAPM analyses, and more recent yield on risk-free rate, produces a CAPM result similar to my 10½ - 10¾ percent conclusion.

Q. DO YOU HAVE ANY COMMENTS ABOUT DR. AVERA'S COMPARABLE EARNINGS ANALYSIS?

A. Yes, I do. Dr. Avera's comparable earnings analysis is based on his observations that Value Line projections of electric utility returns on equity (as of September, 2005) were 10.5 percent to 11.0 percent. I note that my Schedule 11 indicates that Value Line currently projects returns on equity for his proxy group of 9.9 percent (2009-2011) to 10.4 percent (2006). These projections are consistent with my 9½ percent to 11¾ percent recommendation.

Q. WHAT COMMENTS DO YOU HAVE CONCERNING DR. AVERA'S FLOTATION COST ADJUSTMENT?

A. Dr. Avera increases each of his cost of equity estimates by 20 basis points as a flotation cost adjustment. There is no need to make a flotation adjustment, as Dr. Avera recommends. A utility should only be allowed to recover from ratepayers its actual, quantifiable levels of issuance costs. Neither Dr. Avera nor APS has made any demonstration that the company has incurred any issuance costs. In addition, as my Schedule 11 reflects, his electricity distribution group has 2005 market-to-book ratios of 162 percent. To make a market-to-book adjustment for companies whose market-to-book ratio already exceeds 162 percent is unnecessary and inappropriate, since any common stock issuance would actually increase to book value of existing stockholders. I also note that the revenue requirement associated with Dr. Avera's flotation cost adjustment is nearly $8 million annually (Source: Response to TAI-1-13). This is clearly an excessive level of flotation costs for ratepayers to incur.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes, it does.

BACKGROUND AND EXPERIENCE PROFILE
DAVID C. PARCELL, MBA, CRRA
EXECUTIVE VICE PRESIDENT/SENIOR ECONOMIST

EDUCATION

1985	M.B.A., Virginia Commonwealth University
1970	M.A., Economics, Virginia Polytechnic Institute and State University, (Virginia Tech)
1969	B.A., Economics, Virginia Polytechnic Institute and State University, (Virginia Tech)

POSITIONS

1995-Present	Executive Vice President and Senior Economist, Technical Associates, Inc.
1993-1995	Vice President and Senior Economist, C. W. Amos of Virginia
1972-1993	Vice President and Senior Economist, Technical Associates, Inc.
1969-1972	Research Economist, Technical Associates, Inc.
1968-1969	Research Associate, Department of Economics, Virginia Polytechnic Institute and State University

ACADEMIC HONORS

Omicron Delta Epsilon - Honor Society in Economics
Beta Gamma Sigma - National Scholastic Honor Society of Business Administration
Alpha Iota Delta - National Decision Sciences Honorary Society
Phi Kappa Phi - Scholastic Honor Society

PROFESSIONAL DESIGNATIONS

Certified Rate of Return Analyst - Founding Member
Member of Association for Investment Management and Research (AIMR)

RELEVANT EXPERIENCE

Financial Economics -- Advised and assisted many Virginia banks and savings and loan associations on organizational and regulatory matters. Testified approximately 25 times before the Virginia State Corporation Commission and the Regional Administrator of National Banks on matters related to branching and organization for banks, savings and loan associations, and consumer finance companies.

Advised financial institutions on interest rate structure and loan maturity. Testified before Virginia State Corporation Commission on maximum rates for consumer finance companies.

Testified before several committees and subcommittees of Virginia General Assembly on numerous banking matters.

Clients have included First National Bank of Rocky Mount, Patrick Henry National Bank, Peoples Bank of Danville, Blue Ridge Bank, Bank of Essex, and Signet Bank.

Published articles in law reviews and other periodicals on structure and regulation of banking/financial services industry.

<u>Utility Economics</u> -- Performed numerous financial studies of regulated public utilities. Testified in over 300 cases before some thirty state and federal regulatory agencies.

Prepared numerous rate of return studies incorporating cost of equity determination based on DCF, CAPM, comparable earnings and other models. Developed procedures for identifying differential risk characteristics by nuclear construction and other factors.

Conducted studies with respect to cost of service and indexing for determining utility rates, the development of annual review procedures for regulatory control of utilities, fuel and power plant cost recovery adjustment clauses, power supply agreements among affiliates, utility franchise fees, and use of short-term debt in capital structure.

Presented expert testimony before federal regulatory agencies Federal Energy Regulatory Commission, Federal Power Commission, and National Energy Board (Canada), state regulatory agencies in Alabama, Alaska, Arizona, California, Connecticut, Delaware, District of Columbia, Florida, Georgia, Hawaii, Illinois, Indiana, Kansas, Kentucky, Maine, Maryland, Missouri, Nebraska, Nevada, New Mexico, Ohio, Oklahoma, Ontario (Canada), Pennsylvania, South Carolina, Texas, Utah, Vermont, Virginia, West Virginia, Washington, Wisconsin, and Yukon Territory (Canada).

Published articles in law reviews and other periodicals on the theory and purpose of regulation and other regulatory subjects.

Clients served include state regulatory agencies in Alaska, Arizona, Delaware, Missouri, North Carolina, Ontario (Canada), and Virginia; consumer advocates and attorneys general in Alabama, Arizona, District of Columbia, Florida, Georgia, Hawaii, Illinois, Indiana, Kansas, Kentucky, Maryland, Nevada, New Mexico, Ohio, Oklahoma, Pennsylvania, South Carolina, Texas, Utah, Vermont, Virginia, and West Virginia; federal agencies including Defense Communications Agency, the Department of Energy, Department of the Navy, and General Services Administration; and various organizations such as Bath Iron Works, Illinois Citizens' Utility Board, Illinois Governor's

Office of Consumer Services, Illinois Small Business Utility Advocate, Wisconsin's Environmental Decade, Wisconsin's Citizens Utility Board, and Old Dominion Electric Cooperative.

Insurance Economics -- Conducted analyses of the relationship between the investment income earned by insurance companies on their portfolios and the premiums charged for insurance. Analyzed impact of diversification on financial strength of Blue Cross/Blue Shield Plans in Virginia.

Conducted studies of profitability and cost of capital for property/casualty insurance industry. Evaluated risk of and required return on surplus for various lines of insurance business.

Presented expert testimony before Virginia State Corporation Commission concerning cost of capital and expected gains from investment portfolio. Testified before insurance bureaus of Maine, New Jersey, North Carolina, Rhode Island, South Carolina and Vermont concerning cost of equity for insurance companies.

Prepared cost of capital and investment income return analyses for numerous insurance companies concerning several lines of insurance business. Analyses used by Virginia Bureau of Insurance for purposes of setting rates.

Special Studies -- Conducted analyses which evaluated the financial and economic implications of legislative and administrative changes. Subject matter of analyses include returnable bottles, retail beer sales, wine sales regulations, taxi-cab taxation, and bank regulation. Testified before several Virginia General Assembly subcommittees.

Testified before Virginia ABC Commission concerning economic impact of mixed beverage license.

Clients include Virginia Beer Wholesalers, Wine Institute, Virginia Retail Merchants Association, and Virginia Taxicab Association.

Franchise, Merger & Anti-Trust Economics -- Conducted studies on competitive impact on market structures due to joint ventures, mergers, franchising and other business restructuring. Analyzed the costs and benefits to parties involved in mergers. Testified in federal courts and before banking and other regulatory bodies concerning the structure and performance of markets, as well as on the impact of restrictive practices.

Clients served include Dominion Bankshares, asphalt contractors, and law firms.

Transportation Economics -- Conducted cost of capital studies to assess profitability of oil pipelines, trucks, taxicabs and railroads. Analyses have been presented before the Federal Energy Regulatory Commission and Alaska Pipeline Commission in rate proceedings. Served as a consultant to the Rail Services Planning Office on the reorganization of rail services in the U.S.

Economic Loss Analyses -- Testified in federal courts, state courts, and other adjudicative forums regarding the economic loss sustained through personal and business injury whether due to bodily harm, discrimination, non-performance, or anticompetitive practices. Testified on economic loss to a commercial bank resulting from publication of adverse information concerning solvency. Testimony has been presented on behalf of private individuals and business firms.

MEMBERSHIPS

American Economic Association
Virginia Association of Economists
Richmond Society of Financial Analysts
Financial Analysts Federation
Society of Utility and Regulatory Financial Analysts

Board of Directors	1992-2000
Secretary/Treasurer	1994-1998
President	1998-2000

RESEARCH ACTIVITY

Books and Major Research Reports

"Stock Price As An Indicator of Performance," Master of Arts Thesis, Virginia Tech, 1970

"Revision of the Property and Casualty Insurance Ratemaking Process Under Prior Approval in the Commonwealth of Virginia," prepared for the Bureau of Insurance of the Virginia State Corporation Commission, with Charles Schotta and Michael J. Ileo, 1971

"An analysis of the Virginia Consumer Finance Industry to Determine the Need for Restructuring the Rate and Size Ceilings on Small Loans in Virginia and the Process by which They are Governed," prepared for the Virginia Consumer Finance Association, with Michael J. Ileo, 1973

State Banks and the State Corporation Commission: A Historical Review, Technical Associates, Inc., 1974

"A Study of the Implications of the Sale of Wine by the Virginia Department of Alcoholic Beverage Control", prepared for the Virginia Wine Wholesalers Association, Virginia Retail Merchants Association,
Virginia Food Dealers Association, Virginia Association of Chain Drugstores, Southland Corporation, and the Wine Institute, 1983.

"Performance and Diversification of the Blue Cross/Blue Shield Plans in Virginia: An Operational Review", prepared for the Bureau of Insurance of the Virginia State Corporation Commission, with Michael J. Ileo and Alexander F. Skirpan, 1988.

The Cost of Capital - A Practitioners' Guide, Society of Utility and Regulatory Financial Analysts, 1997 (previous editions in 1991, 1992, 1993, 1994, and 1995).

Papers Presented and Articles Published

"The Differential Effect of Bank Structure on the Transmission of Open Market Operations," Western Economic Association Meeting, with Charles Schotta, 1971

"The Economic Objectives of Regulation: The Trend in Virginia," (with Michael J. Ileo), William and Mary Law Review, Vol. 14, No. 2, 1973

"Evolution of the Virginia Banking Structure, 1962-1974: The Effects of the Buck-Holland Bill", (with Michael J. Ileo), William and Mary Law Review, Vol. 16, No. 3, 1975

"Banking Structure and Statewide Branching: The Potential for Virginia", William and Mary Law Review, Vol. 18, No. 1, 1976

"Bank Expansion and Electronic Banking: Virginia Banking Structure Changes Past, Present, and Future," William and Mary Business Review," Vol. 1, No. 2, 1976

"Electronic Banking - Wave of the Future?" (with James R. Marchand), Journal of Management and Business Consulting, Vol. 1, No. 1, 1976

"The Pricing of Electricity" (with James R. Marchand), Journal of Management and Business Consulting, Vol. 1, No. 2, 1976

"The Public Interest - Bank and Savings and Loan Expansion in Virginia" (with Richard D. Rogers), University of Richmond Law Review, Vol. 11, No. 3, 1977

"When Is It In the 'Public Interest' to Authorize a New Bank?", University of Richmond Law Review, Vol. 13, No. 3, 1979

"Banking Deregulation and Its Implications on the Virginia Banking Structure," William and Mary Business Review, Vol. 5, No. 1, 1983

"The Impact of Reciprocal Interstate Banking Statutes on The Performance of Virginia Bank Stocks", with William B. Harrison, Virginia Social Science Journal, Vol. 23, 1988

"The Financial Performance of New Banks in Virginia", Virginia Social Science Journal, Vol. 24, 1989

"Identifying and Managing Community Bank Performance After Deregulation", with William B. Harrison, Journal of Managerial Issues, Vol. II, No. 2, Summer 1990

"The Flotation Cost Adjustment To Utility Cost of Common Equity - Theory, Measurement and Implementation," presented at Twenty-Fifth Financial Forum, National Society of Rate of Return Analysts, Philadelphia, Pennsylvania, April 28, 1993.

Biography of Myon Edison Bristow, Dictionary of Virginia Biography, Volume 2, 2001.

ECONOMIC INDICATORS

YEAR	REAL GDP GROWTH	IND PROD GROWTH	UNEMP RATE	CPI	PPI
			1975 - 1982 Cycle		
1975	-1.1%	-8.9%	8.5%	7.0%	6.6%
1976	5.4%	10.8%	7.7%	4.8%	3.7%
1977	5.5%	5.9%	7.0%	6.8%	6.9%
1978	5.0%	5.7%	6.0%	9.0%	9.2%
1979	2.8%	4.4%	5.8%	13.3%	12.8%
1980	-0.2%	-1.9%	7.0%	12.4%	11.8%
1981	1.8%	1.9%	7.5%	8.9%	7.1%
1982	-2.1%	-4.4%	9.5%	3.8%	3.6%
			1983 - 1991 Cycle		
1983	4.0%	3.7%	9.5%	3.8%	0.6%
1984	6.8%	9.3%	7.5%	3.9%	1.7%
1985	3.7%	1.7%	7.2%	3.8%	1.8%
1986	3.1%	0.9%	7.0%	1.1%	-2.3%
1987	2.9%	4.9%	6.2%	4.4%	2.2%
1988	3.8%	4.5%	5.5%	4.4%	4.0%
1989	3.5%	1.8%	5.3%	4.6%	4.9%
1990	1.8%	-0.2%	5.6%	6.1%	5.7%
1991	-0.5%	-2.0%	6.8%	3.1%	-0.1%
			1992 - 2001 Cycle		
1992	3.0%	3.1%	7.5%	2.9%	1.6%
1993	2.7%	3.3%	6.9%	2.7%	0.2%
1994	4.0%	5.4%	6.1%	2.7%	1.7%
1995	2.5%	4.8%	5.6%	2.5%	2.3%
1996	3.7%	4.2%	5.4%	3.3%	2.8%
1997	4.5%	7.3%	4.9%	1.7%	-1.2%
1998	4.2%	5.9%	4.5%	1.6%	0.0%
1999	4.5%	4.5%	4.2%	2.7%	2.9%
2000	3.7%	4.3%	4.0%	3.4%	3.6%
2001	0.8%	-3.5%	4.7%	1.6%	-1.6%
			Current Cycle		
2002	1.6%	0.1%	5.8%	2.4%	1.2%
2003	2.7%	0.6%	6.0%	1.9%	4.0%
2004	4.2%	4.1%	5.5%	3.3%	4.2%
2005	3.5%	3.3%	5.1%	3.4%	5.4%
2004					
1st Qtr.	4.3%	2.8%	5.6%	5.2%	5.2%
2nd Qtr.	3.5%	4.9%	5.6%	4.4%	4.4%
3rd Qtr.	4.0%	4.6%	5.4%	0.8%	0.8%
4th Qtr.	3.3%	4.3%	5.4%	3.6%	7.2%
2005					
1st Qtr.	3.8%	3.8%	5.3%	4.4%	5.6%
2nd Qtr.	3.3%	3.0%	5.1%	1.2%	1.6%
3rd Qtr.	4.1%	2.7%	5.0%	9.6%	10.8%
4th Qtr.	1.7%	3.1%	4.9%	-2.0%	4.0%
2006					
1st Qtr.	5.6%	3.4%	4.7%	4.8%	-0.2%

Source: Council of Economic Advisors, Economic Indicators, various issues.

INTEREST RATES

YEAR	PRIME RATE	US TREAS T BILLS 3 MONTH	US TREAS T BONDS 10 YEAR	UTILITY BONDS Aaa	UTILITY BONDS Aa	UTILITY BONDS A	UTILITY BONDS Baa
			1975 - 1982 Cycle				
1975	7.86%	5.84%	7.99%	9.03%	9.44%	10.09%	10.96%
1976	6.84%	4.99%	7.61%	8.63%	8.92%	9.29%	9.82%
1977	6.83%	5.27%	7.42%	8.19%	8.43%	8.61%	9.06%
1978	9.06%	7.22%	8.41%	8.87%	9.10%	9.29%	9.62%
1979	12.67%	10.04%	9.44%	9.86%	10.22%	10.49%	10.96%
1980	15.27%	11.51%	11.46%	12.30%	13.00%	13.34%	13.95%
1981	18.89%	14.03%	13.93%	14.64%	15.30%	15.95%	16.60%
1982	14.86%	10.69%	13.00%	14.22%	14.79%	15.86%	16.45%
			1983 - 1991 Cycle				
1983	10.79%	8.63%	11.10%	12.52%	12.83%	13.66%	14.20%
1984	12.04%	9.58%	12.44%	12.72%	13.66%	14.03%	14.53%
1985	9.93%	7.48%	10.62%	11.68%	12.06%	12.47%	12.96%
1986	8.33%	5.98%	7.68%	8.92%	9.30%	9.58%	10.00%
1987	8.21%	5.82%	8.39%	9.52%	9.77%	10.10%	10.53%
1988	9.32%	6.69%	8.85%	10.05%	10.26%	10.49%	11.00%
1989	10.87%	8.12%	8.49%	9.32%	9.56%	9.77%	9.97%
1990	10.01%	7.51%	8.55%	9.45%	9.65%	9.86%	10.06%
1991	8.46%	5.42%	7.86%	8.85%	9.09%	9.36%	9.55%
			1992 - 2001 Cycle				
1992	6.25%	3.45%	7.01%	8.19%	8.55%	8.69%	8.86%
1993	6.00%	3.02%	5.87%	7.29%	7.44%	7.59%	7.91%
1994	7.15%	4.29%	7.09%	8.07%	8.21%	8.31%	8.63%
1995	8.83%	5.51%	6.57%	7.68%	7.77%	7.89%	8.29%
1996	8.27%	5.02%	6.44%	7.48%	7.57%	7.75%	8.16%
1997	8.44%	5.07%	6.35%	7.43%	7.54%	7.60%	7.95%
1998	8.35%	4.81%	5.26%	6.77%	6.91%	7.04%	7.26%
1999	8.00%	4.66%	5.65%	7.21%	7.51%	7.62%	7.88%
2000	9.23%	5.85%	6.03%	7.88%	8.06%	8.24%	8.36%
2001	6.91%	3.45%	5.02%	7.47%	7.59%	7.78%	8.02%
			Current Cycle				
2002	4.67%	1.62%	4.61%		7.19%	7.37%	8.02%
2003	4.12%	1.02%	4.01%		6.40%	6.58%	6.84%
2004	4.34%	1.38%	4.27%		6.04%	6.16%	6.40%
2005	6.19%	3.16%	4.29%		5.44%	5.65%	5.93%
2004							
Jan	4.00%	0.89%	4.15%		6.06%	6.15%	6.47%
Feb	4.00%	0.92%	4.08%		6.10%	6.15%	6.28%
Mar	4.00%	0.94%	3.83%		5.93%	5.97%	6.12%
Apr	4.00%	0.94%	4.35%		6.33%	6.35%	6.46%
May	4.00%	1.04%	4.72%		6.66%	6.62%	6.75%
June	4.00%	1.27%	4.73%		6.30%	6.46%	6.84%
July	4.25%	1.35%	4.50%		6.09%	6.27%	6.67%
Aug	4.50%	1.48%	4.28%		5.95%	6.14%	6.45%
Sept	4.75%	1.65%	4.13%		5.79%	5.98%	6.27%
Oct	4.75%	1.75%	4.10%		5.74%	5.94%	6.17%
Nov	5.00%	2.06%	4.19%		5.79%	5.97%	6.16%
Dec	5.25%	2.20%	4.23%		5.78%	5.92%	6.10%
2005							
Jan	5.25%	2.32%	4.22%		5.68%	5.78%	5.95%
Feb	5.50%	2.53%	4.17%		5.55%	5.61%	5.76%
Mar	5.75%	2.75%	4.50%		5.76%	5.83%	6.01%
Apr	5.75%	2.79%	4.34%		5.56%	5.64%	5.95%
May	6.00%	2.86%	4.14%		5.39%	5.53%	5.88%
June	6.25%	2.99%	4.00%		5.05%	5.40%	5.70%
July	6.25%	3.22%	4.18%		5.18%	5.51%	5.81%
Aug	6.50%	3.45%	4.26%		5.23%	5.50%	5.80%
Sept	6.75%	3.47%	4.20%		5.27%	5.52%	5.83%
Oct	6.75%	3.70%	4.46%		5.50%	5.79%	6.08%
Nov	7.00%	3.90%	4.54%		5.59%	5.88%	6.19%
Dec	7.25%	3.89%	4.47%		5.55%	5.80%	6.14%
2006							
Jan	7.50%	4.20%	4.42%		5.50%	5.75%	6.06%
Feb	7.50%	4.41%	4.57%		5.55%	5.82%	6.11%
Mar	7.75%	4.51%	4.72%		5.71%	5.98%	6.26%
Apr	7.75%	4.59%	4.99%		6.02%	6.29%	6.54%
May	8.00%	4.72%	5.11%		6.16%	6.42%	6.59%
June	8.25%	4.79%	5.11%		6.16%	6.40%	6.61%

Sources: Council of Economic Advisors, Economic Indicators; Moody's Bond Record; Federal Reserve Bulletin; various issues.

STOCK PRICE INDICATORS

YEAR	S&P Composite	Nasdaq Composite	DJIA	S&P D/P	S&P E/P
		1975 - 1982 Cycle			
1975			802.49	4.31%	9.15%
1976			974.92	3.77%	8.90%
1977			894.63	4.62%	10.79%
1978			820.23	5.28%	12.03%
1979			844.40	5.47%	13.46%
1980			891.41	5.26%	12.66%
1981			932.92	5.20%	11.96%
1982			884.36	5.81%	11.60%
		1983 - 1991 Cycle			
1983			1,190.34	4.40%	8.03%
1984			1,178.48	4.64%	10.02%
1985			1,328.23	4.25%	8.12%
1986			1,792.76	3.49%	6.09%
1987			2,275.99	3.08%	5.48%
1988			2,060.82	3.64%	8.01%
1989	322.84		2,508.91	3.45%	7.41%
1990	334.59		2,678.94	3.61%	6.47%
1991	376.18	491.69	2,929.33	3.24%	4.79%
		1992 - 2001 Cycle			
1992	415.74	599.26	3,284.29	2.99%	4.22%
1993	451.21	715.16	3,522.06	2.78%	4.46%
1994	460.42	751.65	3,793.77	2.82%	5.83%
1995	541.72	925.19	4,493.76	2.56%	6.09%
1996	670.50	1,164.96	5,742.89	2.19%	5.24%
1997	873.43	1,469.49	7,441.15	1.77%	4.57%
1998	1,085.50	1,794.91	8,625.52	1.49%	3.46%
1999	1,327.33	2,728.15	10,464.88	1.25%	3.17%
2000	1,427.22	3,783.67	10,734.90	1.15%	3.63%
2001	1,194.18	2,035.00	10,189.13	1.32%	2.95%
		Current Cycle			
2002	993.94	1,539.73	9,226.43	1.61%	2.92%
2003	965.23	1,647.17	8,993.59	1.77%	3.84%
2004	1,130.65	1,986.53	10,317.39	1.72%	4.89%
2005	1,207.23	2,099.32	10,547.67	1.83%	5.40%
2002					
1st Qtr.	1,131.56	1,879.85	10,105.27	1.39%	2.15%
2nd Qtr.	1,068.45	1,641.53	9,912.70	1.49%	2.70%
3rd Qtr.	894.65	1,308.17	8,487.59	1.76%	3.68%
4th Qtr.	887.91	1,346.07	8,400.17	1.79%	3.14%
2003					
1st Qtr.	860.03	1,350.44	8,122.83	1.89%	3.57%
2nd Qtr.	938.00	1,521.92	8,684.52	1.75%	3.55%
3rd Qtr.	1,000.50	1,765.96	9,310.57	1.74%	3.87%
4th Qtr.	1,056.42	1,934.71	9,856.44	1.69%	4.38%
2004					
1st Qtr.	1,133.29	2,041.95	10,488.43	1.64%	4.62%
2nd Qtr.	1,122.87	1,984.13	10,289.04	1.71%	4.92%
3rd Qtr.	1,104.15	1,872.90	10,129.85	1.79%	5.18%
4th Qtr.	1,162.07	2,050.22	10,362.25	1.75%	4.83%
2005					
1st Qtr.	1,191.98	2,056.01	10,648.48	1.77%	5.11%
2nd Qtr.	1,181.65	2,012.24	10,382.35	1.85%	5.32%
3rd Qtr.	1,224.14	2,149.20	10,544.06	1.83%	5.42%
4th Qtr.	1,230.47	2,178.67	10,615.78	1.86%	5.60%
2006					
1st Qtr.	1,283.04	2,287.97	10,996.04	1.85%	5.61%
2nd Qtr.	1,281.77	2,240.46	11,188.84	1.90%	

Source: Council of Economic Advisors, Economic Indicators, various issues.

Exhibit___(DCP-1)
Schedule 3

PINNACLE WEST CAPITAL CORP.
SEGMENT FINANCIAL INFORMATION
2002 - 2005
($millions)

Segment	Operating Revenue	Income From Continuing Operations	Net Income	Total Assets
		2002		
Regulated Electricity	$1,890 77.5%	$170 82.5%	$170 114.1%	$8,185 89.6%
Real Estate	$201 8.2%	$10 4.9%	$19 12.8%	$504 5.5%
Marketing and Trading	$287 11.8%	$58 28.2%	-$8 -5.4%	$414 4.5%
Other	$62 2.5%	-$32 -15.5%	-$32 -21.5%	$36 0.4%
Pinnacle West Capital Corp. (Consolidated)	$2,440	$206	$149	$9,139
		2003		
Regulated Electricity	$1,978 71.7%	$170 75.6%	$170 70.5%	$8,761 91.9%
Real Estate	$362 13.1%	$45 20.0%	$55 22.8%	$424 4.4%
Marketing and Trading	$391 14.2%	$8 3.6%	$9 3.7%	$324 3.4%
Other	$28 1.0%	$2 0.9%	$7 2.9%	$27 0.3%
Pinnacle West Capital Corp. (Consolidated)	$2,759	$225	$241	$9,536
		2004		
Regulated Electricity	$2,035 71.9%	$152 61.5%	$152 62.6%	$8,674 87.6%
Real Estate	$350 12.4%	$40 16.2%	$44 18.1%	$454 4.6%
Marketing and Trading	$401.0 14%	$29.0 12%	$17.0 7%	$746.0 8%
Other	$43 1.5%	$26 10.5%	$30 12.3%	$23 0.2%
Pinnacle West Capital Corp. (Consolidated)	$2,829	$247	$243	$9,897
		2005		
Regulated Electricity	$2,237 74.9%	$167 74.9%	$167 94.9%	$9,732 85.9%
Real Estate	$338 11.3%	$35 15.7%	$52 29.5%	$483 4.3%
Marketing and Trading	$352 11.8%	$16 7.2%	-$51 -29.0%	$1,070 9.4%
Other	$61 2.0%	$5 2.2%	$8 4.5%	$38 0.3%
Pinnacle West Capital Corp. (Consolidated)	$2,988	$223	$176	$11,323

Source: Pinnacle West Capital Corp., Form 10-K, various years, provided in response to Data

Exhibit___(DCP-1)
Schedule 4

BOND RATINGS

	Arizona Public Service		Pinnacle West Capital	
Date	Moody's	S&P	Moody's	S&P
2000	Baa2	BBB		
2001	Baa1	BBB	Baa2	BBB
2002	Baa1	BBB	Baa2	BBB-
2003	Baa1	BBB	Baa2	BBB-
2004	Baa1	BBB	Baa2	BBB-
2005	Baa1	BBB	Baa2	BB+
2006	Baa2	BBB-	Baa3 Provisional	BB+ Preliminary

Source: Response to Data Request TAI-3-4.

ARIZONA PUBLIC SERVICE COMPANY
CAPITAL STRUCTURE RATIOS
2001 - 2005
($Millions)

YEAR	COMMON EQUITY	PREFERRED SECURITIES	LONG-TERM DEBT 1/	SHORT-TERM DEBT
2001	$2,150.7	$0.0	$2,074.6	$171.2
	48.9%	0.0%	47.2%	3.9%
	50.9%	0.0%	49.1%	
2002	$2,159.3	$0.0	$2,220.8	$0.0
	49.3%	0.0%	50.7%	0.0%
	49.3%	0.0%	50.7%	
2003	$2,203.6	$0.0	$2,622.7	$0.0
	45.7%	0.0%	54.3%	0.0%
	45.7%	0.0%	54.3%	
2004	$2,232.4	$0.0	$2,718.3	$0.0
	45.1%	0.0%	54.9%	0.0%
	45.1%	0.0%	54.9%	
2005	$2,985.2	$0.0	$2,565.3	$0.0
	53.8%	0.0%	46.2%	0.0%
	53.8%	0.0%	46.2%	

1/ Includes current maturities.

Note: Percentages may not total 100.0% due to rounding.

Source: Response to Data Request TAI-3-20.

PINNACLE WEST CAPITAL CORP. (CONSOLIDATED)
CAPITAL STRUCTURE RATIOS
2001 - 2005
($millions)

YEAR	COMMON EQUITY	PREFERRED SECURITIES	LONG-TERM DEBT 1/	SHORT-TERM DEBT
2001	$2,499.3	$0.0	$2,799.2	$405.8
	43.8%	0.0%	49.1%	7.1%
	47.2%	0.0%	52.8%	
2002	$2,686.2	$0.0	$3,024.6	$227.7
	45.2%	0.0%	50.9%	3.8%
	47.0%	0.0%	53.0%	
2003	$2,829.8	$0.0	$3,321.5	$86.1
	45.4%	0.0%	53.3%	1.4%
	46.0%	0.0%	54.0%	
2004	$2,950.2	$0.0	$3,202.2	$71.0
	47.4%	0.0%	51.5%	1.1%
	48.0%	0.0%	52.0%	
2005	$3,425.0	$0.0	$2,993.4	$15.7
	53.2%	0.0%	46.5%	0.2%
	53.4%	0.0%	46.6%	

1/ Includes current maturities.

Note: Percentages may not total 100.0% due to rounding.

Source: Response to Data Request TAI-3-20.

Exhibit___(DCP-1)
Schedule 6

AUS UTILITY REPORTS
ELECTRIC UTILITY GROUPS
AVERAGE COMMON EQUITY RATIOS

Year	Electric	Combination Electric and Gas
2001	42%	38%
2002	38%	36%
2003	42%	38%
2004	47%	43%
2005	44%	47%

Note: Averages include short-term debt.

Source: AUS Utility Reports.

Exhibit___(DCP-1)
Schedule 7

COMPARISON COMPANIES
BASIS FOR SELECTION

Company	Market Cap (000)	Percent Revenues Electric	Common Equity Ratio	Value Line Safety	Moody's/ S&P Bond Rating	S&P Stock Ranking
Pinnacle West Capital	$4,000,000	74%	57%	1	BBB-/Baa1	A-
Comparison Group*						
Cleco Corp.	$1,100,000	95%	52%	3	BBB/Baa1	B+
DTE Energy	$7,500,000	55%	45%	3	BBB+/A3	B+
Energy East	$3,300,000	56%	44%	2	BBB+/A3	B+
Hawaiian Electric Industries	$2,200,000	82%	54%	2	NR/Baa2	B+
PNM Resources	$1,700,000	76%	42%	2	BBB/Baa2	B+
Puget Energy	$2,400,000	61%	46%	3	BBB/Baa2	B
Avera Proxy Group						
Black Hills Corp.	$1,200,000	22%	52%	3	BBB/Baa1	B
Edison International	$13,100,000	81%	41%	3	BBB+/A3	B
Hawaiian Electric	$2,200,000	82%	53%	2	NR/Baa2	B+
Idacorp	$1,500,000	98%	50%	3	A-/A3	B
MDU Resources Group	$4,400,000	5%	63%	1	A-/A2	A
PNM Resources Group	$1,700,000	76%	42%	2	BBB/Baa2	B+
Pinnacle West Capital	$4,000,000	74%	57%	1	BBB-/Baa1	A-
Puget Energy, Inc.	$2,400,000	61%	46%	3	BBB/Baa2	B
Sempra Energy	$12,000,000	45%	55%	2	A+/A1	B
Xcel Energy	$7,500,000	75%	47%	2	A-/A3	B

* Selected using following criteria:
Market cap of $1 billion to $8 billion.
Electric Revenues of 50% or greater.
Common Equity Ratio of 40% or greater.
Value Line Safety of 1, 2 or 3.
S&P and/or Moody's bond ratings of BBB.
S&P stock ranking of B, B, or A-..

Sources: C.A. Turner Utility Reports, Standard & Poor's Stock Guide, Value Line Investment Survey.

COMPARISON COMPANIES
DIVIDEND YIELD

COMPANY	DPS	May - July, 2006 HIGH	LOW	AVERAGE	YIELD
Comparison Group					
Cleco Corp.	$0.90	$25.09	$21.26	$23.18	3.9%
DTE Energy	$2.06	$43.63	$38.77	$41.20	5.0%
Energy East	$1.16	$24.75	$22.18	$23.47	4.9%
Hawaiian Electric Industries	$1.24	$28.74	$25.69	$27.22	4.6%
Pinnacle West Capital	$2.00	$44.20	$38.31	$41.26	4.8%
PNM Resources	$0.88	$27.84	$24.10	$25.97	3.4%
Puget Energy	$1.00	$22.45	$20.28	$21.37	4.7%
Average					**4.5%**
Avera Proxy Group					
Black Hills Corp.	$1.32	$37.52	$32.46	$34.99	3.8%
Edison International	$1.08	$42.40	$37.90	$40.15	2.7%
Hawaiian Electric	$1.24	$28.74	$25.69	$27.22	4.6%
Idacorp	$1.20	$37.47	$32.27	$34.87	3.4%
MDU Resources Group	$0.51	$37.25	$33.81	$35.53	1.4%
PNM Resources Group	$0.88	$27.84	$24.10	$25.97	3.4%
Pinnacle West Capital	$2.00	$44.20	$38.31	$41.26	4.8%
Puget Energy, Inc.	$1.00	$22.45	$20.28	$21.37	4.7%
Sempra Energy	$1.20	$48.64	$42.90	$45.77	2.6%
Xcel Energy	$0.89	$20.37	$18.10	$19.24	4.6%
Average					**3.6%**

Source: Yahoo! Finance.

COMPARISON COMPANIES
RETENTION GROWTH RATES

COMPANY	2001	2002	2003	2004	2005	Average	2006	2007	2009-2011	Average
Comparison Group										
Cleco Corp.	6.5%	5.6%	3.5%	3.9%	4.1%	4.7%	2.5%	3.0%	3.5%	3.0%
DTE Energy	0.1%	6.4%	2.5%	1.6%	3.7%	2.9%	0.0%	1.5%	4.5%	2.0%
Energy East	7.1%	2.9%	3.1%	3.8%	3.7%	4.1%	2.0%	2.0%	3.0%	2.3%
Hawaiian Electric Industries	4.4%	4.3%	3.9%	1.1%	1.5%	3.0%	1.5%	2.0%	3.0%	2.2%
Pinnacle West Capital	7.3%	2.9%	2.6%	2.3%	1.0%	3.2%	2.5%	3.5%	3.0%	3.0%
PNM Resources	12.3%	3.1%	3.0%	4.5%	4.3%	5.4%	4.0%	4.0%	3.5%	3.8%
Puget Energy	0.0%	1.3%	2.1%	2.8%	2.9%	1.8%	2.5%	3.0%	3.5%	3.0%
Average	5.4%	3.8%	3.0%	2.9%	3.0%	**3.6%**	2.1%	2.7%	3.4%	**2.8%**
Avera Proxy Group										
Black Hills Corp.	11.6%	6.0%	2.8%	2.3%	3.8%	5.3%	3.5%	4.0%	5.0%	4.2%
Edison International	13.6%	11.9%	13.6%	0.0%	12.3%	10.3%	9.0%	8.0%	6.0%	7.7%
Hawaiian Electric	4.4%	4.3%	3.9%	1.1%	1.5%	3.0%	1.5%	2.0%	3.0%	2.2%
Idacorp	6.3%	0.0%	0.0%	2.7%	1.3%	2.1%	2.5%	2.5%	3.0%	2.7%
MDU Resources Group	7.9%	5.0%	7.6%	7.9%	10.0%	7.7%	10.0%	9.0%	8.0%	9.0%
PNM Resources Group	12.3%	3.1%	3.0%	4.5%	4.3%	5.4%	4.0%	4.0%	3.5%	3.8%
Pinnacle West Capital	7.3%	2.9%	2.6%	2.3%	1.0%	3.2%	2.5%	3.5%	3.0%	3.0%
Puget Energy, Inc.	0.0%	1.3%	2.1%	2.8%	2.9%	1.8%	2.5%	3.0%	3.5%	3.0%
Sempra Energy	11.9%	13.1%	11.3%	14.9%	10.1%	12.3%	9.0%	8.5%	9.0%	8.8%
Xcel Energy	4.3%	0.0%	3.9%	3.9%	2.9%	3.0%	3.5%	3.5%	3.5%	3.5%
Average	8.0%	4.8%	5.1%	4.2%	5.0%	**5.4%**	4.8%	4.8%	4.8%	**4.8%**

Source: Value Line Investment Survey.

COMPARISON COMPANIES
PER SHARE GROWTH RATES

COMPANY	5-Year Historic Growth Rates				Est'd '03-'05 to '09-'11 Growth Rates			
	EPS	DPS	BVPS	Average	EPS	DPS	BVPS	Average
Comparison Group								
Cleco Corp.	1.0%	2.0%	4.0%	2.3%	4.5%	2.0%	8.0%	4.8%
DTE Energy	-2.0%	0.0%	3.5%	0.5%	4.5%	0.5%	2.0%	2.3%
Energy East	-2.5%	5.0%	6.0%	2.8%	4.0%	4.5%	2.5%	3.7%
Hawaiian Electric Industries	1.0%	0.0%	3.0%	1.3%	3.0%	0.0%	2.5%	1.8%
Pinnacle West Capital	-4.5%	6.5%	4.0%	2.0%	6.0%	5.0%	3.5%	4.8%
PNM Resources	-1.0%	5.0%	4.5%	2.8%	5.5%	8.5%	4.0%	6.0%
Puget Energy	-7.5%	-11.5%	0.5%	-6.2%	5.0%	1.5%	4.0%	3.5%
Average				**0.8%**				**3.9%**
Avera Proxy Group								
Black Hills Corp.		3.5%	16.0%	9.8%	6.5%	3.0%	4.0%	4.5%
Edison International		-9.0%	8.5%	-0.3%	7.0%		8.5%	7.8%
Hawaiian Electric	1.0%	0.0%	3.0%	1.3%	3.0%	0.0%	2.5%	1.8%
Idacorp	-11.0%	-6.0%	3.0%	-4.7%	4.5%	-2.0%	3.0%	1.8%
MDU Resources Group	12.5%	5.0%	12.5%	10.0%	8.0%	5.0%	10.5%	7.8%
PNM Resources Group	-1.0%	5.0%	4.5%	2.8%	5.5%	8.5%	4.0%	6.0%
Pinnacle West Capital	-4.5%	6.5%	4.0%	2.0%	6.0%	5.0%	3.5%	4.8%
Puget Energy, Inc.	-7.5%	-11.5%	0.5%	-6.2%	5.0%	1.5%	4.0%	3.5%
Sempra Energy	16.0%	-5.0%	10.5%	7.2%	5.5%	4.5%	11.0%	7.0%
Xcel Energy	-5.5%	-11.0%	-4.5%	-7.0%	6.0%	5.5%	3.0%	4.8%
Average				**1.5%**				**5.0%**

Source: Value Line Investment Survey.

COMPARISON COMPANIES
DCF COST RATES

COMPANY	ADJUSTED YIELD	HISTORIC RETENTION GROWTH	PROSPECTIVE RETENTION GROWTH	HISTORIC PER SHARE GROWTH	PROSPECTIVE PER SHARE GROWTH	FIRST CALL EPS GROWTH	AVERAGE GROWTH	DCF RATES
Comparison Group								
Cleco Corp.	4.0%	4.7%	3.0%	2.3%	4.8%	8.0%	4.6%	8.5%
DTE Energy	5.1%	2.9%	2.0%	0.5%	2.3%	4.5%	2.4%	7.5%
Energy East	5.0%	4.1%	2.3%	2.8%	3.7%	4.0%	3.4%	8.4%
Hawaiian Electric Industries	4.6%	3.0%	2.2%	1.3%	1.8%	3.0%	2.3%	6.9%
Pinnacle West Capital	4.9%	3.2%	3.0%	2.0%	4.8%	6.0%	3.8%	8.8%
PNM Resources	3.5%	5.4%	3.8%	2.8%	6.0%	8.5%	5.3%	8.8%
Puget Energy	4.8%	1.8%	3.0%		3.5%	4.0%	3.1%	7.8%
Average	4.5%	3.6%	2.8%	2.0%	3.9%	5.4%	3.6%	**8.1%**
Median								**8.4%**
Composite		8.2%	7.3%	6.5%	8.4%	**10.0%**	8.1%	
Avera Proxy Group								
Black Hills Corp.	3.9%	5.3%	4.2%	9.8%	4.5%	6.0%	5.9%	9.8%
Edison International	2.8%	10.3%	7.7%		7.8%	8.0%	8.4%	11.2%
Hawaiian Electric	4.6%	3.0%	2.2%	1.3%	1.8%	3.0%	2.3%	6.9%
Idacorp	3.5%	2.1%	2.7%		1.8%	5.0%	2.9%	6.4%
MDU Resources Group	1.5%	7.7%	9.0%	10.0%	7.8%	8.0%	8.5%	10.0%
PNM Resources Group	3.5%	5.4%	3.8%	2.8%	6.0%	8.5%	5.3%	8.8%
Pinnacle West Capital	4.9%	3.2%	3.0%	2.0%	4.8%	6.0%	3.8%	8.8%
Puget Energy, Inc.	4.8%	1.8%	3.0%		3.5%	4.0%	3.1%	7.8%
Sempra Energy	2.7%	12.3%	8.8%	7.2%	7.0%	5.3%	8.1%	10.8%
Xcel Energy	4.7%	3.0%	3.5%		4.8%	5.0%	4.1%	8.8%
Average	3.7%	5.4%	4.8%	5.5%	5.0%	5.9%	5.2%	**8.9%**
Median								**8.8%**
Composite		9.1%	8.5%	9.2%	8.7%	**9.6%**	8.9%	

Note: Negative average values not considered.

Sources: Prior pages of this schedule.

Exhibit___(DCP-1)
Schedule 9

STANDARD & POOR'S 500 COMPOSITE
20-YEAR U.S. TREASURY BOND YIELDS
RISK PREMIUMS

Year	EPS	BVPS	ROE	20-YEAR T-BOND	RISK PREMIUM
1977		$79.07			
1978	$12.33	$85.35	15.00%	7.90%	7.10%
1979	$14.86	$94.27	16.55%	8.86%	7.69%
1980	$14.82	$102.48	15.06%	9.97%	5.09%
1981	$15.36	$109.43	14.50%	11.55%	2.95%
1982	$12.64	$112.46	11.39%	13.50%	-2.11%
1983	$14.03	$116.93	12.23%	10.38%	1.85%
1984	$16.64	$122.47	13.90%	11.74%	2.16%
1985	$14.61	$125.20	11.80%	11.25%	0.55%
1986	$14.48	$126.82	11.49%	8.98%	2.51%
1987	$17.50	$134.04	13.42%	7.92%	5.50%
1988	$23.75	$141.32	17.25%	8.97%	8.28%
1989	$22.87	$147.26	15.85%	8.81%	7.04%
1990	$21.73	$153.01	14.47%	8.19%	6.28%
1991	$16.29	$158.85	10.45%	8.22%	2.23%
1992	$19.09	$149.74	12.37%	7.29%	5.08%
1993	$21.89	$180.88	13.24%	7.17%	6.07%
1994	$30.60	$193.06	16.37%	6.59%	9.78%
1995	$33.96	$215.51	16.62%	7.60%	9.02%
1996	$38.73	$237.08	17.11%	6.18%	10.93%
1997	$39.72	$249.52	16.33%	6.64%	9.69%
1998	$37.71	$266.40	14.62%	5.83%	8.79%
1999	$48.17	$290.68	17.29%	5.57%	11.72%
2000	$50.00	$325.80	16.22%	6.50%	9.72%
2001	$24.69	$338.37	7.43%	5.53%	1.90%
2002	$27.59	$321.72	8.36%	5.59%	2.77%
2003	$48.73	$367.17	14.15%	4.80%	9.35%
2004	$58.55	$414.75	14.98%	5.02%	9.96%
Average			**14.02%**	**8.02%**	**6.00%**

Sources: Standard & Poor's Analysts' Handbook and Ibbotson Associates 2006 Yearbook.

COMPARISON COMPANIES
CAPM COST RATES
USING RISK PREMIUM

COMPANY	RISK-FREE RATE	BETA	MARKET PREMIUM	CAPM RATES
Comparison Group				
Cleco Corp.	5.30%	1.20	5.80%	12.3%
DTE Energy	5.30%	0.70	5.80%	9.4%
Energy East	5.30%	0.90	5.80%	10.5%
Hawaiian Electric Industries	5.30%	0.70	5.80%	9.4%
Pinnacle West Capital	5.30%	0.95	5.80%	10.8%
PNM Resources	5.30%	0.95	5.80%	10.8%
Puget Energy	5.30%	0.80	5.80%	9.9%
Average	5.30%	0.89	5.80%	**10.4%**
Median				**10.5%**
Avera Proxy Group				
Black Hills Corp.	5.30%	1.00	5.80%	11.1%
Edison International	5.30%	1.10	5.80%	11.7%
Hawaiian Electric	5.30%	0.70	5.80%	9.4%
Idacorp	5.30%	0.95	5.80%	10.8%
MDU Resources Group	5.30%	0.95	5.80%	10.8%
PNM Resources Group	5.30%	0.95	5.80%	10.8%
Pinnacle West Capital	5.30%	0.95	5.80%	10.8%
Puget Energy, Inc.	5.30%	0.80	5.80%	9.9%
Sempra Energy	5.30%	1.05	5.80%	11.4%
Xcel Energy	5.30%	0.85	5.80%	10.2%
Average	5.30%	0.93	5.80%	**10.7%**
Median				**10.8%**

Sources: Value Line Investment Survey, Standard & Poor's Analysts' Handbook, Federal Reserve.

COMPARISON COMPANIES
RATES OF RETURN ON AVERAGE COMMON EQUITY

Company	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	1992-2001 Average	2001-2005 Average	2006	2007	2009-2011
Comparison Group																			
Cleco Corp.	14.0%	12.4%	12.9%	13.4%	13.8%	12.8%	12.6%	12.9%	15.0%	14.6%	13.5%	11.5%	12.6%	11.6%	13.4%	12.8%	8.5%	8.5%	9.0%
DTE Energy	18.7%	15.3%	11.8%	13.0%	11.8%	11.9%	12.2%	12.7%	11.9%	7.6%	13.7%	9.7%	8.1%	10.2%	12.7%	9.9%	5.5%	6.0%	10.5%
Energy East	10.7%	9.1%	10.3%	10.5%	10.1%	9.9%	11.2%	14.4%	15.1%	13.4%	9.3%	8.3%	9.1%	9.3%	11.5%	9.9%	8.5%	8.5%	9.5%
Hawaiian Electric Industries	10.9%	10.5%	11.1%	11.0%	10.5%	10.9%	11.5%	11.1%	9.8%	12.4%	11.9%	11.1%	9.3%	9.7%	11.0%	10.9%	10.0%	10.0%	10.0%
Pinnacle West Capital	10.7%	10.9%	10.2%	10.6%	11.2%	11.9%	11.5%	12.3%	12.4%	12.8%	8.6%	8.3%	8.2%	6.9%	11.5%	9.0%	8.5%	9.0%	9.0%
PNM Resources	4.6%	8.6%	11.7%	8.5%	9.9%	10.0%	11.3%	9.1%	10.2%	15.8%	6.3%	6.7%	7.9%	8.6%	10.0%	9.1%	6.5%	6.5%	8.5%
Puget Energy	12.4%	11.0%	8.8%	10.2%	10.2%	7.4%	11.5%	11.8%	13.2%	7.6%	7.8%	7.4%	8.0%	8.4%	10.4%	7.6%	8.0%	8.5%	8.5%
Average	11.7%	11.1%	11.0%	11.0%	11.1%	10.7%	11.7%	12.0%	12.5%	12.0%	10.2%	9.0%	9.0%	9.2%	**11.5%**	**9.9%**	**8.2%**	**8.7%**	**9.3%**
Composite															**11.5%**	**9.9%**			
Avera Proxy Group																			
Black Hills Corp.	16.2%	14.7%	13.9%	14.4%	16.1%	16.2%	16.8%	17.2%	21.5%	22.1%	12.1%	6.9%	7.9%	9.4%	16.9%	12.1%	9.5%	9.5%	10.0%
Edison International	13.4%	11.8%	11.5%	11.8%	11.2%	11.6%	12.7%	13.7%	-52.0%	14.9%	15.4%	15.8%	3.9%	17.4%	6.1%	13.5%	14.0%	13.0%	11.0%
Hewaiian Electric	10.9%	10.5%	11.1%	11.0%	10.5%	10.9%	11.5%	11.1%	9.8%	12.4%	11.9%	11.1%	9.3%	9.7%	11.0%	10.9%	10.0%	10.0%	10.0%
Idacorp	9.0%	11.2%	10.1%	11.6%	12.1%	12.4%	12.4%	12.3%	16.7%	14.9%	7.1%	4.2%	8.2%	7.3%	12.3%	8.3%	7.5%	7.0%	7.0%
MDU Resources Group	11.5%	12.2%	12.1%	12.4%	13.0%	14.3%	14.7%	13.7%	14.2%	15.0%	11.1%	13.4%	13.5%	15.4%	13.3%	13.7%	14.0%	13.0%	11.5%
PNM Resources Group	4.6%	8.6%	11.7%	8.5%	9.9%	10.0%	11.3%	9.1%	10.2%	15.8%	6.3%	6.7%	7.9%	8.6%	10.0%	9.1%	8.5%	8.5%	8.5%
Pinnacle West Capital	10.7%	10.9%	10.2%	10.6%	11.2%	11.9%	11.5%	12.3%	12.4%	12.8%	8.6%	8.3%	8.2%	6.9%	11.5%	9.0%	8.5%	9.0%	9.0%
Puget Energy, Inc.	12.4%	11.0%	8.8%	10.2%	10.2%	7.4%	11.5%	11.8%	13.2%	7.6%	7.8%	7.4%	8.0%	6.4%	10.4%	7.8%	8.0%	8.5%	8.5%
Sempra Energy	14.3%	14.1%	13.6%	15.1%	14.9%	16.1%	9.5%	13.3%	16.5%	20.0%	20.7%	19.4%	20.7%	15.7%	14.7%	19.3%	13.5%	13.0%	12.5%
Xcel Energy	9.1%	11.3%	12.4%	13.5%	12.6%	10.3%	11.4%	8.8%	9.8%	13.2%	2.8%	10.0%	9.8%	9.1%	11.2%	9.0%	10.0%	9.5%	10.5%
Average	11.2%	11.6%	11.5%	11.9%	12.2%	12.1%	12.3%	12.3%	7.2%	14.9%	10.4%	10.5%	9.7%	10.8%	**11.7%**	**11.3%**	**10.4%**	**10.1%**	**9.9%**
Composite															**11.7%**	**11.3%**			

Source: Calculations made from data contained in Value Line Investment Survey.

COMPARISON COMPANIES
MARKET TO BOOK RATIOS

Company	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	1992-2001 Average	2001-2005 Average
Comparison Group																
Cleco Corp.	177%	175%	156%	162%	168%	171%	183%	172%	223%	224%	154%	134%	177%	177%	181%	173%
DTE Energy	162%	154%	120%	130%	137%	126%	165%	145%	126%	142%	145%	142%	132%	140%	141%	140%
Energy East	131%	143%	105%	96%	94%	108%	169%	186%	151%	131%	121%	119%	138%	141%	131%	130%
Hawaiian Electric Industries	171%	154%	141%	149%	147%	147%	154%	132%	127%	145%	153%	151%	179%	181%	147%	162%
Pinnacle West Capital	116%	125%	99%	116%	133%	152%	180%	143%	145%	154%	116%	114%	130%	130%	136%	129%
PNM Resources	72%	84%	87%	95%	108%	106%	106%	65%	94%	123%	95%	93%	124%	147%	96%	116%
Puget Energy	149%	146%	112%	119%	130%	155%	170%	146%	143%	143%	126%	129%	137%	133%	141%	134%
Average	140%	140%	117%	124%	131%	138%	161%	144%	144%	152%	130%	126%	145%	150%	**139%**	**141%**
Composite															**139%**	**141%**
Avera Proxy Group																
Black Hills Corp.	264%	221%	169%	185%	198%	228%	255%	237%	301%	273%	143%	134%	134%	165%	233%	170%
Edison International	167%	172%	122%	116%	120%	158%	192%	173%	197%	128%	117%	108%	153%	205%	155%	142%
Hawaiian Electric	171%	154%	141%	149%	147%	147%	154%	132%	127%	145%	153%	151%	179%	181%	147%	162%
Idacorp	155%	172%	146%	148%	168%	177%	177%	158%	189%	185%	134%	112%	125%	122%	168%	136%
MDU Resources Group	155%	180%	169%	173%	179%	209%	245%	208%	201%	213%	155%	168%	185%	210%	193%	186%
PNM Resources Group	72%	84%	87%	95%	108%	106%	106%	85%	94%	123%	95%	93%	124%	147%	96%	116%
Pinnacle West Capital	116%	125%	99%	116%	133%	152%	180%	143%	145%	154%	116%	114%	130%	130%	136%	129%
Puget Energy, Inc.	149%	146%	112%	119%	130%	155%	170%	146%	143%	143%	126%	129%	137%	133%	141%	134%
Sempra Energy	187%	200%	166%	167%	171%	178%	203%	173%	165%	180%	155%	172%	178%	186%	179%	174%
Xcel Energy	164%	165%	154%	159%	162%	165%	176%	144%	141%	163%	113%	113%	132%	139%	159%	132%
Average	160%	162%	137%	143%	152%	168%	186%	160%	170%	171%	131%	129%	148%	162%	**161%**	**148%**
Composite															**161%**	**148%**

Source: Calculations made from data contained in Value Line Investment Survey.

STANDARD & POOR'S 500 COMPOSITE RETURNS AND MARKET-TO-BOOK RATIOS 1992 -2004

YEAR	RETURN ON AVERAGE EQUITY	MARKET-TO BOOK RATIO
1992	12.2%	271%
1993	13.2%	272%
1994	16.4%	246%
1995	16.6%	264%
1996	17.1%	299%
1997	16.3%	354%
1998	14.6%	421%
1999	17.3%	481%
2000	16.2%	453%
2001	7.5%	353%
2002	8.4%	296%
2003	14.2%	278%
2004	15.0%	291%
Averages:		
1992-2001	14.7%	341%
2000-2004	12.3%	334%

Source: Standard & Poor's Analyst's Handbook, 2005 edition, page 1.

RISK INDICATORS

GROUP	VALUE LINE SAFETY	VALUE LINE BETA	VALUE LINE FIN STR	S & P STK RANK
S & P's 500 Composite	2.7	1.05	B++	B+
Comparison Group	2.3	0.89	B++	B
Avera Proxy Group	2.2	0.93	B++	B+
Pinnacle West Capital	1.0	0.95	A	B

Sources: Value Line Investment Survey, Standard & Poor's Stock Guide.

Definitions:

Safety rankings are in a range of 1 to 5, with 1 representing the highest safety or lowest risk.

Beta reflects the variability of a particular stock, relative to the market as a whole. A stock with a beta of 1.0 moves in concert with the market, a stock with a beta below 1.0 is less variable than the market, and a stock with a beta above 1.0 is more variable than the market.

Financial strengths range from C to A++, with the latter representing the highest level.

Common stock rankings range from D to A+, with the latter representing the highest level.

Exhibit___(DCP-1)
Schedule 14

ARIZONA PUBLIC SERVICE COMPANY
TOTAL COST OF CAPITAL

ITEM	PERCENT	COST RATE	WEIGHTED COST
Long-Term Debt	45.50%	5.41%	2.46%
Common Equity	54.50%	10.25%	5.59%
Total	100.00%		**8.05%**

Exhibit___(DCP-1)
Schedule 15

ARIZONA PUBLIC SERVICE COMPANY
PRE-TAX COVERAGE

ITEM	PERCENT	COST RATE	WEIGHTED COST	PRE-TAX COST	
Long-Term Debt	45.50%	5.41%	2.46%	2.46%	
Common Equity	54.50%	10.25%	5.59%	9.41%	(1)
TOTAL CAPITAL	100.00%		8.05%	11.87%	

(1) Post-tax weighted cost divided by .59345 (composite tax factor)

Pre-tax coverage = 11.87%/2.46%
4.82 X

Standard & Poor's Utility Benchmark Ratios:

	A	BBB
Pre-tax coverage (X) Business Position:		
6	3.5 - 4.3x	2.4 - 3.5x
Total Debt to Total Capital (%) Business Position		
5	42 - 50%	50 - 60%

Note: Since 2004, S&P no longer uses the ratio "Pre-tax Coverage" as one of its benchmark ratios. The benchmark levels shown above reflect the 1999 levels cited by S&P.

Staff Exhibit No. ____

BEFORE THE ARIZONA CORPORATION COMMISSION

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

DIRECT TESTIMONY

OF

RALPH C. SMITH

ON BEHALF OF
THE ARIZONA CORPORATION COMMISSION,
UTILITIES DIVISION STAFF

Phoenix, Arizona
August 18, 2006

Staff Exhibit No. ____

BEFORE THE ARIZONA CORPORATION COMMISSION

In the Matter of the Application of	)	
Arizona Public Service Company for a	)	Docket No. E-01345A-05-0816
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To Amend Decision No. 67744	)	

DIRECT TESTIMONY

OF

RALPH C. SMITH

ON BEHALF OF
THE ARIZONA CORPORATION COMMISSION,
UTILITIES DIVISION STAFF

Phoenix, Arizona
August 18, 2006

DIRECT TESTIMONY OF RALPH C. SMITH
EXECUTIVE SUMMARY

My testimony addresses the following issues:

- The Company's proposed depreciation rates.

My findings and recommendations for each of these areas are as follows:

- The depreciation rates proposed by APS presented in Mr. White's Attachments REW-1 and REW-2 should be adopted for use in this case. The depreciation rates proposed by APS were developed in a manner that is consistent with the Commission's rules for depreciation rates. My review of the details provided in Mr. White's Attachments REW-1 and REW-2 and other information indicates that those new rates proposed by APS are consistent with a "technical update" approach to the depreciation rates that the Commission approved in Decision 67744. The net change in percentage terms resulting from APS's technical update in composite terms is fairly small, an increase of 0.06 percentage points for APS plant and a decrease of 0.20 percentage points for plant that APS acquired from PWEC.

- Each of the new depreciation rates proposed by APS should be clearly broken out between (1) a service life rate and (2) a net salvage rate, similar to the rates shown in Appendix A to the Commission's Decision No. 67744. By doing this, the depreciation expense related to the inclusion of estimated future cost of removal in depreciation rates can be tracked and accounted for by plant account.

DIRECT TESTIMONY OF RALPH C. SMITH
TABLE OF CONTENTS

ATTACHMENTS:

RCS-1, Background and Qualifications
RCS-2, Commission Rule R14-2-102, Treatment of depreciation
RCS-3, Appendix A from Commission Decision No. 67744 showing APS's current depreciation rates by component.

I. INTRODUCTION

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

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

Q. Please describe Larkin & Associates.

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

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

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

professional and a Certified Rate of Return Analyst (CRRA). Since 1981, I have been a member of the Michigan Association of Certified Public Accountants. I am also a member of the Michigan Bar Association and the Society of Utility and Regulatory Financial Analysts (SURFA). I have also been a member of the American Bar Association (ABA), and the ABA sections on Public Utility Law and Taxation.

Q. Please summarize your professional experience.

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

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

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

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

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

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

A. Yes. Most recently I testified before the Delaware Public Service Commission on such issues in Docket No. 05-304, a Delmarva Power and Light Company rate case.

Q. On whose behalf are you appearing?

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

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

A. Yes. I have testified before the Commission previously on a number of occasions. Most recently, I testified before the Commission in Docket No. E-01345A-06-0009, involving an emergency rate increase request by Arizona Public Service Company ("APS" or "Company").

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

A. The purpose of my testimony is to address the depreciation rates proposed by APS in the current rate case.

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

A. Yes. Attachments RCS-2 and RCS-3 contain copies of selected documents that are referenced in my testimony.

II. DISCUSSION OF ISSUES

Q. What issues are addressed in your testimony?

A. My testimony addresses the Company's proposed depreciation rates and follows through on issues raised by the Staff concerning depreciation rates in the last APS rate case.

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

A. The information I reviewed included the Commission's rules regarding depreciation, testimony and exhibits from the prior APS rate case, Docket No. E-03145A-03-0437, APS's application and testimony in the current case, APS's responses to data requests of Staff and other parties, Excel files supporting APS witness Ronald White's "2005 Technical Update" of APS's depreciation rates, information provided to me by Staff, and other publicly available information.

A. The Company's Proposed Depreciation Rates

Q. Please provide some background for the request that APS has made in the current proceeding as it relates to the Company's depreciation rate proposals.

A. In APS's last rate case, Docket No. E-01345A-03-0437, APS presented a depreciation study prepared by Mr. John Wiedmayer of Gannett Fleming, Inc. The study contained recommended remaining life depreciation accrual rates as of December 31, 2002, and was attached to APS witness Laura Rockenberger's direct testimony in that proceeding as Attachment LLR-4. A witness on behalf of the Staff, Michael Majoros, raised a number of significant issues concerning the depreciation rates that had been proposed by APS. A settlement was ultimately reached among APS, Staff and other parties in Docket No. E-01345A-03-0437. That settlement provided as follows concerning Depreciation issues:

> "33. APS has agreed to adopt Staff's proposed service lives as set forth in Staff's direct testimony, including the service lives proposed by Staff for the PWEC Assets. The Parties further agree that APS shall be allowed a jurisdictional net salvage allowance as reflected in APS' direct testimony.

34. The attached Appendix A set forth the remaining service lives, net salvage allowance, annual depreciation rates, and reserve allocation for each category of APS depreciable property agreed to by the Parties for purposes of this proceeding and authorized by the Commission's approval of this agreement.

35. APS will separately record and account for net salvage such that it can be identified both as a component to annual depreciation expense and in accumulated reserves for depreciation.

36. Amortization rates currently in effect, which are shown in Appendix A are to remain in effect.

37. For purposes of this proceeding, the Parties agree that SFAS 143 shall not be adopted for ratemaking purposes."

Attachment RCS-3 reproduces for ease of reference Appendix A from Decision No. 61744. This contains the detailed depreciation rates by account that the parties agreed to in their stipulation in APS' last rate case.

Q. What did Commission Order 61744 state with respect to the depreciation rates?

A. Commission Order 61744, at page 19, stated as follows concerning Depreciation:

"The Settlement Agreement adopts Staff's recommended service lives, and Appendix A to the Settlement Agreement sets forth the remaining service lives, net salvage allowance, annual depreciation rates, and reserve allocation for each category of APS depreciable property

property as agreed to by the parties. The parties agree that the Statement of Financial Accounting Standards ("SFAS") 143 will not be adopted for ratemaking purposes."

Q. What Commission rules address the treatment of depreciation?

A. The Commission's rules at R14-02-102 address the treatment of depreciation. A copy of these rules are presented, for ease of reference, in Attachment RCS-2. The current version of the rules appear to have been adopted effective April 9, 1992. This pre-dates the adoption of Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations" which has resulted in revisions for financial reporting purposes, among other things, of the presentation of cost of removal information. I discuss SFAS No. 143 in more detail subsequently in my testimony.

Q. Did APS file a new depreciation study in the current rate case?

A. No. Instead of performing a full depreciation study in which asset lives and net salvage rates are estimated from a statistical analysis of recorded retirements and net salvage realized in the past, APS has presented a "2005 Technical Update." As described on page 7 of Dr. Ronald White's direct testimony on behalf of APS:

> "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."

Q. Please discuss the Company's proposed depreciation rates and how they were derived.

A. The new depreciation rates proposed by APS are summarized in Company witness Dr. White's testimony and are shown in detail in his exhibits, Attachments REW-1 (for APS plant) and REW-2 (for PWEC units acquired by APS). As noted above, APS' new depreciation rates were not the result of a complete depreciation study, but resulted from a "2005 technical update." The Company's proposed rates were developed using a depreciation system composed of the straight-line method, broad group procedure and remaining life technique. APS has developed its proposed depreciation rates for production facilities by unit and by type of plant in service at each unit. This appears consistent with the development of depreciation rates for APS that was accepted by the Commission in APS' last rate case, Docket No. E-01345A-03-0437.

Q. What impact do the new depreciation rates proposed by APS have?

A. As summarized on page 10 of Dr. White's testimony, based on December 31, 2004 plant investment, the new depreciation rates proposed by APS for APS plant <u>increase</u> depreciation expense by $5,222,168 (from $221,616,212 at present rates to $226,838,380 at APS' proposed rates). For the Pinnacle West Energy Company ("PWEC") units acquired by APS, the new depreciation rates decrease depreciation expense by $1,980,690 (from $28,789,932 at present rates to $26,809,242 at APS' proposed rates). The combined impact for APS plant and the PWEC units acquired by APS is a net increase of approximately $3.241 million in depreciation expense on December 31, 2004 plant.

On a composite basis[1], the Company's proposed new rates for APS plant produce an increase of 0.06 percentage points, from the current composite rate of 2.89% to a composite at new rates of 2.95%. For the PWEC units, the new depreciation rates proposed by APS produce a composite rate of 2.67%, which is 0.20 percentage points less that the equivalent present composite rate of 2.87%.

Q. Did APS add plant since the last case that was not considered in the development of its depreciation rates in that proceeding?

A. Yes. The following power plants were transferred from PWEC to APS on July 29, 2005: Redhawk Units 1 and 2, West Phoenix Units 4 and 5 and Saguaro Unit 3. Of these transferred assets, West Phoenix Unit 5 was not considered in the establishment of depreciation rates in Docket No. E-01345A-03-0437. As described in the Company's response to data request STF-11-5:

"The depreciation rates used for each PWEC unit before the units were transferred to APS were approved as part of Decision No.

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[1] APS does not apply its depreciations on a composite basis; this information is for comparative purposes only.

> 67744. (See Appendix A to that Decision, pages 20-21.) Note that West Phoenix CC5 was under construction during the 2003 rate case. Therefore, there are no rates for that unit in Decision No. 67744. The rates used for West Phoenix CC5 were based on the service life statistic and net salvage rates approved for Redhawk."

Redhawk Units 1 and 2 are a matching pair of 530-megawatt combined cycle plants near the Palo Verde switchyard. West Phoenix Unit 5 is also a 530-megawatt combined cycle unit.

Q. Before discussing specific issues associated with APS' proposed depreciation rates, could you please provide your understanding of some basic depreciation terminology?

A. Yes, of course.

Q. What is depreciation?

A. The Commission's rules at R14-2-102(A)(3) define "depreciation" as "an accounting process which will permit the recovery of the original cost of an asset less its net salvage over the service life."

Q. What is net salvage?

A. The Commission's rules at R14-2-102(A)(5) define "net salvage" as "the salvage value of property less the cost of removal."

Q. What is "salvage value"?

A. The Commission's rules at R14-2-102(A)(5) define "salvage value" as:

> "the amount received for assets retired, less any expenses incurred in selling or preparing the assets for sale; of if retained, the amount at

which the material recoverable is chargeable to materials and supplies, or other appropriate accounts."

Q. What is the "cost of removal"?

A. The Commission's rules at R14-2-102(A)(5) define the "cost of removal" as "the cost of demolishing, dismantling, removing, tearing down, or abandoning of physical assets, including the cost of transportation and handling incidental thereto."

Q. What is depreciation expense?

A. Depreciation expense is a charge to operating expense to reflect the recovery of depreciable utility plant. Depreciation rates are applied to a utility's depreciable utility plant to determine the amount of depreciation expense. Public utility depreciation expense is typically straight-line over the service life which results in an equal share of the cost of assets being assigned or allocated to expense each year over the service life of the assets. A service life is the period of time during which depreciable plant and equipment is in service. [2]

Q. What is depreciable utility plant?

A. Public utilities record their plant investment activity in the individual plant accounts set-forth in the Federal Energy Regulatory Commission's ("FERC") Uniform System of Accounts ("USOA"). Plant additions, retirements and balances are maintained by plant account. An annual addition is the original

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[2] National Association of Regulatory Utility Commissioners Public Utility Depreciation Practices, August, 1996. ("NARUC Depreciation Manual"), p. 321. Also, Commission Rule R14-2-102, which

cost of plant added to the account during the year. A retirement is recorded in the plant account by removing the original cost of a prior addition when such plant is removed from service. The plant balance is what is left at the end of an accounting period after accounting for additions and retirements.

Q. How is the annual depreciation expense calculated?

A. Annual depreciation expense, called an accrual, is calculated by applying a depreciation rate to plant balances.

Q. Is the depreciation accrual a cash expense?

A. No. Depreciation is considered a non-cash expense.

Q. Please explain the distinction between a cash and non-cash expense.

A. Depreciation expense is considered a non-cash accrual. This contrasts with payroll expense, for example, which involves the current outlay of cash. Depreciation expense does not involve a specific payment during the test-year. Both depreciation and payroll are included as expenses in the income statement and revenue requirement, but no cash flows out of the company for depreciation expense. Instead of reducing the cash account, depreciation expense is recorded on the income statement as an expense and is simultaneously recorded on the balance sheet in the accumulated depreciation account; which is shown as an offset to plant in service. The following accounting entries illustrate the difference:

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defines "service life" as "the period between the date an asset is first devoted to public service and the date of its retirement from service."

Account	Description	Amount Dr. (Cr.)
403	Depreciation Expense	$ 1,000
108	Accumulated Depreciation	$ (1,000)
	To record depreciation	

various	Payroll Expense	$ 1,000
131	Cash	$ (1,000)
	To record payroll expense	

Q. What is the Accumulated Depreciation account?

A. Accumulated Depreciation, Account 108 in the USOA, is a record of the previously recorded depreciation expense. At any point in time, the accumulated depreciation account represents the net accumulated amount of the original cost of assets and net salvage that has been recovered to date. From a regulatory perspective, Accumulated Depreciation can be considered a measure of the depreciation recovered from ratepayers. Commission Rule R14-2-102 defines "accumulated depreciation" as "the sum of the annual provision for depreciation from the time that the asset is first devoted to public service."

Q. How does depreciation expense impact a utility's revenue requirement?

A. Annual depreciation expense is a cost that is included in a public utility's revenue requirement. Because public utilities tend to be capital intensive, depreciation expense can be a significant component of the utility's revenue requirement.

Q. What is the objective of depreciation expense?

A. From a regulatory perspective, the objective of public utility depreciation is straight-line capital recovery. This is accomplished by allocating the original cost of assets to expense over the lives of those assets through the application of depreciation rates to plant balances. Additionally, many state regulatory commissions, including the ACC, have allowed utilities to recover through the commission-authorized depreciation rates, the utility's estimated future cost of removal, which is part of the net salvage component of the depreciation rates.

Q. Please illustrate how depreciation rates are developed.

A. The following calculation shows a straight-line whole-life depreciation rate assuming a 10-year average service life and a $1 million plant investment, and the whole life method. Each year the 10% depreciation rate would be applied to plant in service to produce an annual depreciation expense and an entry to accumulated depreciation:

Straight-Line Whole-Life Depreciation Rate
Assuming $1 Million Investment and a 10-Year Life
Depreciation Rate: 100% / 10 Years = 10% Per Year

Year	Annual Depreciation Expense	End-of-Year Accumulated Depreciation
1	$ 100,000	$ (100,000)
2	$ 100,000	$ (200,000)
3	$ 100,000	$ (300,000)
4	$ 100,000	$ (400,000)
5	$ 100,000	$ (500,000)
6	$ 100,000	$ (600,000)
7	$ 100,000	$ (700,000)
8	$ 100,000	$ (800,000)
9	$ 100,000	$ (900,000)
10	$ 100,000	$ (1,000,000)
TOTAL	$ 1,000,000	

Q. What happens at the end of an asset's life under this scenario?

A. All things equal, at the end of 10 years, the plant balance will be 100% (or $1 million), and the accumulated depreciation balance will also be 100% (also

$1 million). This equality is important to understanding issues relating to the cost of removal/negative net salvage.

Q. What is negative net salvage?

A. Negative net salvage is the difference between any salvage value and the cost of removal of the asset after completion of its service life. If the cost of removal exceeds the salvage amount, this produces negative net salvage. In this testimony I will use the terms negative net salvage and net cost of removal interchangeably. The ratemaking treatment of negative net salvage was raised as an issue by a Staff witness (Mr. Majoros) in the last APS rate case, Docket No. E-01345A-03-0437. Negative net salvage can have a significant impact on a utility's depreciation rates and revenue requirement.

Q. What happens if estimated future negative net salvage is included in the calculation?

A. Assume a negative 55 percent (-55%) net salvage ratio. The above whole-life example with a 55% value for negative net salvage is as follows:

Straight-Line Whole-Life Depreciation Rate
Assuming $1 Million Investment, a 10-Year Life
And Negative Net Salvage of 55%
Depreciation Rate: [100% - (-55%)] / 10 Years = 15.5% Per Year

Year	Annual Depreciation Expense	End-of-Year Accumulated Depreciation	Annual Negative Net Salvage Charge	FAS 143 Regulatory Liability
1	$ 100,000	$ (100,000)	$ 55,000	$ (55,000)
2	$ 100,000	$ (200,000)	$ 55,000	$ (110,000)
3	$ 100,000	$ (300,000)	$ 55,000	$ (165,000)
4	$ 100,000	$ (400,000)	$ 55,000	$ (220,000)
5	$ 100,000	$ (500,000)	$ 55,000	$ (275,000)
6	$ 100,000	$ (600,000)	$ 55,000	$ (330,000)
7	$ 100,000	$ (700,000)	$ 55,000	$ (385,000)
8	$ 100,000	$ (800,000)	$ 55,000	$ (440,000)
9	$ 100,000	$ (900,000)	$ 55,000	$ (495,000)
10	$ 100,000	$ (1,000,000)	$ 55,000	$ (550,000)
TOTAL	$ 1,000,000		$ 550,000	

In this example, negative net salvage increases the resulting whole -life depreciation rate from 10% to 15.5%, i.e., by 55%. This increase results from the inclusion of estimated future net cost of removal, including estimated future inflation.

Q. Please explain the "FAS 143 Regulatory Liability" column in the above example.

A. Because the Company has no current legal obligation to pay the estimated future inflated cost of removal (negative net salvage) amounts (i.e., has no asset retirement obligation), the excess amounts recovered through depreciation rates are accumulated in a regulatory liability account for financial reporting purposes, pursuant to Statement of Financial Accounting Standards No. 143. (SFAS 143) I will explain certain provisions in SFAS 143 that require such treatment in more detail later in my testimony.

Q. Why does negative net salvage increase the depreciation rate?

A. It increases the depreciation rate because negative salvage is, in effect, added to the original cost of the plant. Instead of 100% (which represents the original cost of assets), the numerator becomes 155%. This is equivalent to capitalizing or adding the estimated cost of removal to the original cost of the asset. In the above example, instead of recovering the original plant cost of $1 million, the depreciation rates would recover $1.55 million.

Q. What happens at the end of life under this scenario?

A. The plant balance will be 100% but the sum of the accumulated depreciation balance and the regulatory liability account will be 155%. Consequently, unlike the "zero net salvage scenario" shown above, when negative net salvage is included in a depreciation rate, there will not be an equality of plant and reserve at the end of an asset's life because the Company will have charged more depreciation than it paid for the original cost of the asset. Under these circumstances, equality will only be achieved if the Company actually spends additional money at the end of the asset's life.

Q. Is the Company required to pre-collect from ratepayers estimated future amounts of money that it might spend at the end of plant useful life?

A. While for some of its assets APS has no current legal liability to spend money for estimated future cost of removal, the Commission rules at R14-2-102(B)(3) require that: "The cost of depreciable plant adjusted for net salvage shall be distributed in a rational and systematic manner over the estimated service life of the plant." As discussed above, the Commission's rules define "net salvage" to include the cost of removal. Consequently, I conclude that the Commission's rules require cost of removal to be included in the utility's depreciation rates.

Q. If the Company does incur an obligation at the end of an asset's service life that requires spending money for removal, can the Company take the money out of accumulated depreciation?

A. No. Accumulated Depreciation is an unfunded account. Even though the Company collected money from ratepayers for future removal cost that had been included in past depreciation rates, it will have already spent that money on whatever it chose in the past: salaries, dividends, etc.

Q. Please explain the concept of remaining life depreciation.

A. The remaining life technique is similar to the whole-life technique, but it incorporates accumulated depreciation into the numerator of the equation, and the denominator becomes the remaining life rather that the whole life of the asset.

Q. What happens when accumulated depreciation is incorporated into the numerator of the basic depreciation calculation?

A. If the 10-year asset is 3 years old, its remaining life would be 7 years (10 – 3 = 7). The accumulated depreciation account would be 30% of the original cost because the 10% depreciation rate would have been applied for three years (3 x 10% = 30%). The remaining life depreciation rate would then be 10%, calculated as follows:

Straight-Line Remaining-Life Depreciation Rate
Assuming $1 Million Investment and a 10-Year Life
Depreciation Rate: [100% - 30%] / [10 - 3 Years] = 10% Per Year

Year	Annual Depreciation Expense	End-of-Year Accumulated Depreciation
3		$ (300,000)
4	$ 100,000	$ (400,000)
5	$ 100,000	$ (500,000)
6	$ 100,000	$ (600,000)
7	$ 100,000	$ (700,000)
8	$ 100,000	$ (800,000)
9	$ 100,000	$ (900,000)
10	$ 100,000	$ (1,000,000)
TOTAL	$ 700,000	

Under the example with the assumed 55% negative net salvage, and a 7-year remaining life, the results would be a 15.5% depreciation rate, as shown below:

Straight-Line Remaining-Life Depreciation Rate
Assuming $1 Million Investment, a 10-Year Life
And Negative Net Salvage of 55%
Depreciation Rate: [(100% - (-55%)) - (3 x 15.5%)] / [10 - 3 Years] = 15.5% Per Year
Depreciation Rate: [(108.5%)] / [7 Years] = 15.5% Per Year

Year	Annual Depreciation Expense	End-of-Year Accumulated Depreciation	Annual Negative Net Salvage Charge	FAS 143 Regulatory Liability
3		$ (300,000)		$ (165,000)
4	$ 100,000	$ (400,000)	$ 55,000	$ (220,000)
5	$ 100,000	$ (500,000)	$ 55,000	$ (275,000)
6	$ 100,000	$ (600,000)	$ 55,000	$ (330,000)
7	$ 100,000	$ (700,000)	$ 55,000	$ (385,000)
8	$ 100,000	$ (800,000)	$ 55,000	$ (440,000)
9	$ 100,000	$ (900,000)	$ 55,000	$ (495,000)
10	$ 100,000	$ (1,000,000)	$ 55,000	$ (550,000)
TOTAL	$ 700,000		$ 385,000	

Q. Why would the whole-life depreciation rate in the example with negative net salvage and the remaining life depreciation rate in the negative net salvage example both be 15.5 percent?

A. In these examples, the remaining life depreciation rate and the whole-life depreciation rates are the same (15.5 percent) because I have assumed that the accumulated depreciation account is in balance. In other words, based on a continuation of the fundamental parameters, i.e., the 10-year service life and the negative 55% net salvage ratio, exactly the right amount of depreciation has been charged and collected in the past.

Q. What would happen if either of these fundamental parameters were to change?

A. If either the service life or net salvage parameter changes during the life of the plant, the accumulated depreciation account will be out of balance, and the remaining life rate will be either higher or lower than whole-life rate depending on the direction of the imbalance. That is because the Company will have collected either too much depreciation or not enough depreciation in the past, given the current estimates of lives or future net salvage. The difference between the actual amount recovered, as included in the book depreciation reserve, and a theoretical estimate of what should be in the book reserve, is called a "reserve imbalance." The remaining life technique is often used to deal with such reserve imbalances.

Q. Since the last revision to the Commission's rules regarding the treatment of depreciation, has a significant accounting pronouncement been issued?

A. Yes. As noted above, it appears that the Commission's rules concerning the treatment of depreciation were last revised and became effective April 9, 1992. Since that date, generally accepted accounting principles (GAAP), specifically SFAS 143, highlight the amounts associated with estimated future cost of removal for which no current legal obligation exists and require that they be reported as Regulatory Liabilities for financial reporting purposes. A regulatory liability can be viewed as an amount owed to ratepayers.

Q. What is SFAS 143?

A. The Financial Accounting Standards Board ("FASB") is a standards-setting body for the public accounting profession. In June 2001, the FASB promulgated Statement of Financial Accounting Standards No. 143 (FAS

143). This pronouncement addresses the appropriate accounting for long-lived assets. It is effective for all fiscal years beginning after June 15, 2002. However, earlier application was encouraged. Pursuant to SFAS 143, all companies, both unregulated (e.g., Walmart) and regulated (e.g., APS) must review all of their long-lived assets to determine whether or not they have actual legal obligations to remove retired assets. For some plant and equipment, companies have a legal obligation to remove the asset at the end of the service life. These legal obligations for future removal are called asset retirement obligations ("AROs"). For other assets, no such obligation exists.

If a company does have an ARO, the fair value of the future retirement cost, which is determined using net present value techniques, is considered to be part of the original cost of the asset. That ARO is therefore capitalized (included in the original cost) and depreciated over the life of the asset. In essence, if a Company incurs a legal liability to spend money to remove an asset at the end of its life, that liability is part of the cost of the asset.

In contrast, if a company does <u>not</u> have such legal obligations, the future cost of removal will <u>not</u> be capitalized as part of the asset cost and will <u>not</u> be included in depreciation expense. Only the initial cost of the asset (which does not include estimated inflated future cost of removal for which no current liability exists), will be depreciated.

At the end of the asset's life, for assets without AROs, the accumulated depreciation account will equal the plant balance. In other words, under SFAS 143, there is symmetry between assets with and without

AROs. In both cases, the accumulated depreciation will equal the original cost of the asset at the end of its life.

Q. How are AROs measured?

A. AROs are measured at their net present value, not their inflated future value.

Q How are AROs recorded for accounting purposes?

A. As stated above, AROs are capitalized as a cost of the related asset and simultaneously recorded as a liability for those companies with a legal obligation to remove a retired asset. To illustrate, assuming an ARO of $500, the $500 would be debited (i.e., added) to plant and simultaneously credited (i.e., added) to the regulatory liability account. Each year, as the liability increases due to inflation, the increase is charged to accretion expense and credited to the liability, but the asset value remains the same. In other words, just as the original cost of the asset does not increase, neither does the capitalized asset retirement cost.

Q. What happens if a company does not have an asset retirement obligation pursuant to SFAS 143?

A. If a company does not have such obligations, the estimated future inflated cost of removal is not considered as a cost of the asset, and therefore it will not be included in the company's depreciation expense on its general purpose financial statements. SFAS 143, therefore, unbundles net salvage from depreciation rates. It does this in two ways: (1) by incorporating the net present value of an ARO in the cost of the asset, or (2) by excluding non-AROs from the depreciation rate calculations.

Q. What is the accounting impact of SFAS 143 for electric utilities?

A. Under Generally Accepted Accounting Principles ("GAAP"), electric utilities are required to review all of their assets to determine if they have any AROs. If a utility has any AROs, they are capitalized. Paragraph B73 of SFAS 143 provides an exception for regulated utilities, which allows them to continue to incorporate net salvage factors ("non-legal AROs") in depreciation rates even if they do not have AROs. Utilities are also required to determine the amount of any prior cost of removal collections relating to non- AROs that is now included in their accumulated depreciation accounts, and reclassify these and any such future charges as a regulatory liability in their financial statements. In other words, even with the paragraph B73 exception, SFAS 143 provides transparency through reporting disclosure requirements.

Q. What is the impact of SFAS 143 on electric regulatory accounting?

A. FERC addressed SFAS 143 in Docket RM02-7-000 which resulted in Order No. 631. FERC Order 631 essentially adopts SFAS 143 and integrates it into the Uniform System of Accounts. Utilities are required to review their long - lived assets to determine if they have any AROs. Where utilities do not have AROs, any charges for such amounts must be separately identified. FERC Order 631 defines cost of removal allowances for which there is no legal asset retirement obligation, as "non-legal retirement obligations." Past and future "non- legal AROs" must be specifically identified and accounted for separately in the depreciation studies, depreciation expense and the accumulated depreciation account. In Order 631, FERC maintains the transparency resulting from the "separation principle" for non-legal AROs that was established in paragraph B73 of SFAS 143. Paragraph 38 of Order 631 explains FERC's new requirements for non-legal AROs:

> "Instead, we will require jurisdictional entities to maintain separate subsidiary records for cost of removal for non-legal retirement obligations that are included as specific identifiable allowances recorded in accumulated depreciation in order to separately identify such information to facilitate external reporting and for regulatory analysis, and rate setting purposes. Therefore, the Commission is amending the instructions of accounts 108 and 110 in Parts 101, 201 and account 31, Accrued depreciation - Carrier property, in Part 352 to require jurisdictional entities to maintain separate subsidiary records for the purpose of identifying the amount of specific allowances collected in rates for non-legal retirement obligations included in the depreciation accruals."

Q. Does FERC provide any additional insight as to the interpretation of these new rules?

A. Yes, at paragraph 39 of the order, FERC states:

> "Jurisdictional entities must identify and quantify in separate subsidiary records the amounts, if any, of previous and current accumulated removal costs for other than legal retirement obligations recorded as part of the depreciation accrual in accounts 108 and 110 for public utilities and licensees, account 108 for natural gas

companies, and account 31 for oil pipeline companies. If jurisdictional entities do not have the required records to separately identify such prior accruals for specific identifiable allowances collected in rates for non-legal asset retirement obligations recorded in accumulated depreciation, the Commission will require that the jurisdictional entities separately identify and quantify prospectively the amount of current accruals for specific allowances collected in rates for non-legal retirement obligations."

Q. Does FERC make any policy calls concerning the appropriate treatment of the disposition of prior and future collections contained in these separate allowances?

A. No. As indicated at paragraph 64 of the Order, FERC declined to make such calls on a policy basis. Rather, FERC will resolve the appropriate treatment of the dispositions of prior and future collections on a case-by-case basis.

Q. Does FERC's Order require anything new or more with respect to its requirement for detailed depreciation studies?

A. No. At paragraph 65 of the Order, FERC states that:

"... this rule requires nothing new and nothing more with respect to the requirement for a detailed study. Complex depreciation and negative salvage studies are routinely filed or otherwise made available for review in rate proceedings. When utilities perform depreciation studies, a certain amount of detail is expected. It is incumbent upon the utility to provide sufficient detail to support depreciation rates, cost of removal, and salvage estimates in rates."

Additionally, footnote 45 states:

"When an electric utility files for a change in its jurisdictional rates, the Commission requires detailed studies in support of changes in annual depreciation rates if they are different from those supporting the utility's prior approved jurisdictional rate."

Thus, FERC recognizes distinctions between legal and non-legal AROs just as SFAS 143 recognizes those distinctions. On a going-forward basis, jurisdictional entities must be prepared to specifically identify and justify any non-legal AROs that they propose to include in rates.

Q. Has APS implemented SFAS 143?

A. Yes. The Company implemented SFAS 143 on January 1, 2003. Footnote 11 from APS's 2003 SEC Form 10-K states with respect to the initial adoption of this accounting, that on January 1, 2003 the Company adopted SFAS No. 143, "Accounting for Asset Retirement Obligations." In its 2003 SEC Form 10-K, APS states further that:

"In accordance with SFAS No. 71, we will continue to accrue for removal costs for our regulated assets, even if there is no legal obligation for removal. At December 31, 2003, regulatory liabilities shown on our Balance Sheets included approximately $480 million of estimated future removal costs that are not considered legal obligations."

Moreover, consistent with adopting this accounting principle for financial reporting purposes, APS "reclassified prior year removal costs of approximately $557 million previously included in accumulated depreciation to the liability for asset retirements and removals in our Balance Sheets. In 2003, we reclassified the portion of this liability for which no legal obligation for removal costs exists to a regulatory liability."

When initially adopting SFAS 143, companies such as APS, reclassified for financial statement reporting purposes their accumulated cost of removal for which there is no current legal obligation for removal, from Accumulated Depreciation and reported this as a Regulatory Liability.

As described on page 78 of the Company's 2005 Securities and Exchange Commission ("SEC") Form 10-K:

> "APS records a regulatory liability for the asset retirement obligations related to its regulated assets. This regulatory liability represents the difference between the amount that has been recovered in regulated rates and the amount calculated under SFAS No. 143 'Accounting for Asset Obligations,' as interpreted by FIN 47. APS believes it can recover in regulated rates the costs calculated in accordance with SFAS No. 143."

Under "Regulatory Liabilities" on its 2005 SEC Form 10-K, APS reported a "regulatory liability related to asset retirement obligations" of $86 million and $101 million as of December 31, 2004 and 2005, respectively. Under "Regulatory Liabilities" on its 2005 SEC Form 10-K, APS also reported a regulatory liability of $376 million and $385 million as of December 31, 2004 and 2005, respectively, related to removal costs, with this note: "In accordance with SFAS No. 71, APS accrues for removal costs for its regulated assets, even if there is no legal obligation for removal."

Q. Are the "costs of removal" that were reclassified as a regulatory liability for financial reporting purposes the result of APS's past depreciation rates?

A. Essentially, yes. APS's past depreciation rates have included negative net salvage. This has resulted in APS pre-collecting from ratepayers estimated future costs of removal for non-legal AROs, which under SFAS 143, have been reclassified for financial reporting purposes as a regulatory liability.

Plant and equipment are retired from service at the end of their useful life. Sometimes the retired plant and equipment may be physically removed and can be resold for value. This is called gross salvage. The cost of removal net of the value received for the salvage constitutes net salvage. In more technical terms, gross salvage is the amount recorded for the property retired due to the sale, reimbursement, or reuse of the property. Cost of removal is the cost incurred in connection with the retirement from service and the disposition of depreciable plant. As discussed above, net salvage is the difference between gross salvage and cost of removal.

Q. Are net salvage ratios included in the Company's depreciation rate calculations?

A. Yes. Substantial negative net salvage ratios are included in several of APS's depreciation rates. The inclusion of negative future net salvage ratios in APS's proposed depreciation rates result in depreciation rates that are significantly higher in many instances than if no cost of removal had been included. As noted above, the inclusion of net salvage in depreciation rates appears to be consistent with past practices of the utility and Commission, and appears to be required by Commission rule R14-2-102(B)(3).

Q. Do APS's proposed depreciation rates include estimated future removal costs?

A. Yes. As noted above, APS's proposed depreciation rates include estimated future removal costs, including estimated future inflation. APS has done this by including negative net salvage ratios in the development of depreciation rates for many, but not all, of its depreciable plant assets.

Q. Where does APS develop its estimated future cost of removal that are included in its proposed depreciation rates?

A. These are developed in Mr. White's Attachments REW-1 and REW-2, on Statement D (average net salvage), Statement E (future net salvage and Statement F (dismantlement costs) of those attachments.

Q. Did you request APS to provide its <u>actual</u> cost of removal and net salvage information by plant account?

A. Yes. This was requested in data request STF-11-30 for years 2000 through 2005.

Q. Did APS provide that requested information plant account?

A. No. APS' response to data request STF-11-30 stated: "APS did not record cost of removal and salvage at the plant account level for the periods requested." APS did provide total amounts by year.

Q. How much actual negative net salvage has the Company been experiencing in total?

A. The following table summarizes the annual cost of removal and salvage information that was provided by APS in response to data request STF-11-30:

Annual Net Salvage
Per APS' Response to Data Request STF-11-30

Year		Annual Cost of Removal		Annual Gross Salvage	Annual Net Salvage
2000	$	4,796,643	$	(10,694,073)	$ (5,897,430)
2001	$	14,136,598	$	(7,230,051)	$ 6,906,547
2002	$	11,046,897	$	(9,119,972)	$ 1,926,925
2003	$	14,270,117	$	(4,956,898)	$ 9,313,219
2004	$	8,697,802	$	(10,318,654)	$ (1,620,852)
2005	$	15,910,845	$	(10,444,823)	$ 5,466,022
Averages:					
2000-04	$	10,589,611	$	(8,463,930)	$ 2,125,682
2001-05	$	12,812,452	$	(8,414,080)	$ 4,398,372

Q. Have you made a comparison of how much APS's proposed depreciation rates would collect annually for estimated future cost of removal with the Company's recent actual cost of removal?

A. No. During the course of my analysis, I started to make such a comparison, but concluded that it was not necessary for purposes of this case because the Commission's rules at R14-2-102 require net salvage to be included in the development of the utility's depreciation rates. Since I am not recommending an adjustment to reflect an alternative treatment of cost of removal in this case, the comparative calculation related to quantifying such an adjustment was not pursued as it would have been if an adjustment to the Company's approach was being recommended.

Q. Has APS's approach to including net salvage in depreciation rates been widely used in the utility industry?

A. Yes. Many regulated utilities have used this approach. It is even addressed in the NARUC's 1996 Public Utilities Depreciation Practices Manual as a recommended approach. On the other hand, the same NARUC Manual at page 157 also states:

> "Some commissions have abandoned the above procedure [gross salvage and cost of removal reflected in depreciation rates] and moved to current-period accounting for gross salvage and/or cost of removal. In some jurisdictions gross salvage and cost of removal are accounted for as income and expense, respectively, when they are realized. Other jurisdictions consider only gross salvage in depreciation rates, with the cost of removal being expensed in the year incurred."

Q. In your opinion, is there a reasonable alternative to the approach used by APS?

A. Yes. Instead of incorporating estimated future cost of removal along with estimated future inflation into depreciation rates, providing a normalized level of removal cost as a current-period expense is a reasonable alternative for ratemaking purposes, in my opinion.

Q. Does the NARUC Manual indicate that some utility commissions are using this alternative approach?

A. Yes. The NARUC Manual at page 158 states that:

> It is frequently the case that net salvage for a class of property is negative, that is, cost of removal exceeds gross salvage. This circumstance has increasingly become dominant over the past 20 to 30 years; in some cases negative net salvage even exceeds the original cost of plant. Today few utility plant categories experience positive net salvage; this means that most depreciation rates must be designed to recover more than the original cost of plant. The predominance of this circumstance is another reason why some utility commissions have switched to current period accounting for gross salvage and, particularly, cost of removal.

Q. Could APS's approach result in accumulated depreciation exceeding the original cost of plant in service?

A. Yes. One of the mechanical problems with APS's approach is that it can result in a depreciation reserve actually exceeding the gross plant balance. That is because the depreciation rates proposed by APS for distribution plant include estimated future cost of removal, and therefore produce higher depreciation rates than are necessary to fully depreciate the original cost of the plant. Therefore, at the end of its life, the accumulated depreciation account exceeds the plant account balance. Referring back to the hypothetical illustration that I presented earlier, with a 55% negative net salvage assumption, at the end of the 10-year assumed useful life, the utility has recorded $1.55 million in depreciation on a depreciable asset of $1 million. During the plant's depreciable life, the utility had no asset retirement obligation, but it would have collected an extra $550,000.

Q. How should the allowance for cost of removal be calculated?

A. Because the Commission's rules at R14-2-102 in their current form clearly require the inclusion of net salvage in the development of the utility's depreciation rates, and this is what APS has done, I am not in this proceeding recommending an alternative. Were it not for those rules, I believe there is substantial merit in the alternative recommended by the witness for Staff in the prior APS rate case, which would provide for a normalized allowance for cost of removal based on the average of the most recent five years worth of actual net salvage activity. Essentially, the cost of removal is treated just as any other normalized operating expense.

Q. Are you aware of whether other regulatory commissions use that alternative approach for utility recovery of cost of removal?

A. Yes. A five-year average net salvage allowance approach has been used for many years by the Pennsylvania Public Utility Commission. In recent years, some other state regulatory commissions have used similar approaches that exclude estimated future cost of removal from the development of depreciation rates, and provide an allowance for the cost of removal based on an average of a utility's actual incurred cost.

Q. What are the advantages of that approach?

A. The five-year rolling average for recovery of cost of removal provides a reasonable method for addressing this controversial aspect of depreciation. APS's proposed development of depreciation rates essentially treats estimated future costs of removal (including estimated future inflation) as a current period expense, even when there is no current legal obligation to incur such cost. In contrast with APS's approach, a normalized expense allowance approach better conforms with the generally accepted accounting principles articulated in SFAS 143 by not treating estimated inflated future removal costs as if they were a current obligation and a current expense. Additional advantages offered by the normalized expense allowance approach include that it is simple, straight-forward and easy to implement, provides an opportunity for the Company to recover a normalized allowance for cost of removal based on recent actual cost, and avoids charging current customers for estimated future inflation. However, the Commission's rules at R14-2-102 in their present state would appear to preclude this alternative for purposes of this case.

Rule R14-2-102 is a rule of general applicability to electric utilities in the state of Arizona. Because I believe there is no compelling reason to treat cost of removal (where there is no current obligation to incur such cost) differently from other normalized operating expenses, I recommend that the Commission consider amending Rule R14-2-102 to allow treatment of cost of removal in the manner recommended by Staff's consultant in the prior APS rate case.

Q. Should the depreciation rates proposed by APS be adopted for use in this case?

A. Yes. The depreciation rates proposed by APS presented in Mr. White's Attachments REW-1 and REW-2 should be adopted for use in this case. The depreciation rates proposed by APS were developed in a manner that is consistent with the Commission's rules for depreciation rates. My review of the details provided in Mr. White's Attachments REW-1 and REW-2 and other information indicates that those new rates proposed by APS are consistent with a "technical update" approach to the depreciation rates that the Commission approved in Decision 67744. As noted above in my testimony, the net change in percentage terms resulting from APS's technical update in composite terms is fairly small, an increase of 0.06 percentage points for APS plant and a decrease of 0.20 percentage points for plant that APS acquired from PWEC.

Q. Do you have any other recommendations concerning the depreciation rates proposed by APS?

A. Yes. Each of the new depreciation rates proposed by APS should be clearly broken out between (1) a service life rate and (2) a net salvage rate, similar to the rates shown in Appendix A to the Commission's Decision No. 67744. By doing this, the depreciation expense related to the inclusion of estimated future cost of removal in depreciation rates can be tracked and accounted for by plant account.

Q. Does this conclude your testimony?

A. Yes, it does.

Attachment RCS-1
QUALIFICATIONS OF RALPH C. SMITH

Accomplishments

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Previous Positions

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

Installed computerized accounting system for a realty management firm.

Education

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

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

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

Continuing education required to maintain CPA license and CFP certificate.

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

Michigan Bar Association.

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

Partial list of utility cases participated in:

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

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

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

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

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

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

R14-2-102. Treatment of depreciation

A. The following definitions shall apply in this Section unless the context otherwise requires:

1. "Accumulated depreciation" means the summation of the annual provision for depreciation from the time that the asset is first devoted to public service.
2. "Cost of removal" means the cost of demolishing, dismantling, removing, tearing down, or abandoning of physical assets, including the cost of transportation and handling incidental thereto.
3. "Depreciation" means an accounting process which will permit the recovery of the original cost of an asset less its net salvage over the service life.
4. "Depreciation rate" means the percentage rate applied to the original cost of an asset to yield the annual provision for depreciation.
5. "Net salvage" means the salvage value of property retired less the cost of removal.
6. "Original cost" means the cost of property at the time it was first devoted to public service.
7. "Property retired" means assets which have been removed, sold, abandoned, destroyed, or which for any cause have been withdrawn from service and books of account.
8. "Salvage value" means the amount received for assets retired, less any expenses incurred in selling or preparing the assets for sale; or if retained, the amount at which the material recoverable is chargeable to materials and supplies, or other appropriate accounts.
9. "Service life" means the period between the date an asset is first devoted to public service and the date of its retirement from service.

B. All public service corporations shall maintain adequate accounts and records related to depreciation practices, subject to the following:

1. Annual depreciation accruals shall be recorded.
2. A separate reserve for each account or functional account shall be maintained.
3. The cost of depreciable plant adjusted for net salvage shall be distributed in a rational and systemic manner over the estimated service life of such plant.
4. Public service corporations having less than $250,000 in annual revenue shall not be required to maintain depreciation records by separate accounts but shall make annual composite accruals to accumulated depreciation for total depreciable plant.

C. Requests for depreciation rate changes and methods for estimating depreciation rates shall be as follows:

1. If a public service corporation seeks a change in its depreciation rates, it shall submit a request for such as part of a rate application in accordance with the requirements of R14-2-103.
2. A public service corporation may propose any reasonable method for estimating service lives, salvage values, and cost of removal. The method shall be fully described in a request to change depreciation rates.
3. Data and analyses supporting the change shall be submitted, including engineering data and assessment of the impact and appropriateness of the change for ratemaking purposes.
4. Changed depreciation rates shall not become effective until the Commission authorizes such changes.

D. Upon the motion of any party or upon its own motion, the Commission may determine that good cause exists for granting a waiver from one or more of the requirements of this Section.

Historical Note

Former Section R14-2-102 repealed, former Section R14-2-127 renumbered as Section R14-2-102 without change effective March 2, 1982 (Supp. 82-2). Forward to the rule corrected as filed April 13, 1973 (Supp. 89-1). Section R14-2-102 repealed, new Section adopted effective April 9, 1992 (Supp. 92-2).

APPENDIX A

ARIZONA PUBLIC SERVICE
Depreciation Rate Summary
Related to Electric Plant at December 31, 2002

	Depreciable Group	Depreciation Rate (A)	Service Life Rate (B)	Net Salvage Rate (C)
		A = (B + C)		
STEAM PRODUCTION PLANT				
FERC 311	Structures and Improvements	2.84%	2.37%	0.47%
FERC 312	Boiler Plant Equipment	3.50%	2.92%	0.58%
FERC 314	Turbogenerator Units	2.98%	2.49%	0.50%
FERC 315	Accessory Electric Equipment	2.70%	2.25%	0.45%
FERC 316	Miscellaneous Power Plant Equipment	4.14%	3.45%	0.69%
NUCLEAR PRODUCTION PLANT				
FERC 321	Structures and Improvements	2.60%	2.60%	0.00%
FERC 322	Reactor Plant Equipment	2.86%	2.80%	0.06%
FERC 322.1	Reactor Plant Equipment - Steam Generators	10.32%	8.82%	1.50%
FERC 323	Turbogenerator Units	2.90%	2.84%	0.06%
FERC 324	Accessory Electric Equipment	2.78%	2.73%	0.05%
FERC 325	Miscellaneous Power Plant Equipment	3.59%	3.52%	0.07%
OTHER PRODUCTION PLANT				
FERC 341	Structures and Improvements	2.69%	2.56%	0.13%
FERC 342	Fuel Holders, Products and Accessories	2.87%	2.74%	0.14%
FERC 343	Prime Movers	1.25%	1.25%	0.00%
FERC 344	Generators and Devices	3.38%	3.38%	0.00%
FERC 345	Accessory Electric Equipment	2.26%	2.26%	0.00%
FERC 346	Miscellaneous Power Plant Equipment	2.58%	2.58%	0.00%
TRANSMISSION PLANT (1)				
FERC 353	Station Equipment	1.52%	1.52%	0.00%
FERC 354	Towers and Fixtures	2.08%	1.54%	0.54%
FERC 356	Overhead Conductors and Devices	2.32%	1.72%	0.60%
	(1) Rates will apply to ACC Jurisdictional Assets in these Accounts			
DISTRIBUTION PLANT				
FERC 361	Structures and Improvements	2.10%	1.91%	0.19%
FERC 362	Station Equipment	2.04%	2.04%	0.00%
FERC 364	Poles, Towers and Fixtures - Wood	2.64%	2.40%	0.24%
FERC 364.1	Poles, Towers and Fixtures - Steel	2.03%	1.93%	0.10%
FERC 365	Overhead Conductors and Devices	1.99%	1.81%	0.18%
FERC 366	Underground Conduit	1.20%	1.14%	0.06%
FERC 367	Underground Conductors and Devices	3.18%	3.03%	0.15%
FERC 368	Line Transformers	2.30%	2.19%	0.11%
FERC 369	Services	2.60%	2.36%	0.24%
FERC 370	Meters	2.84%	2.84%	0.00%

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ARIZONA PUBLIC SERVICE
Depreciation Rate *Summary*
Related to Electric Plant at December 31, 2002

		Depreciable Group	Depreciation Rate (A) A = (B+C)	Service Life Rate (B)	Net Salvage Rate (C)
FERC	370.1	Electronic Meters	3.61%	3.61%	0.00%
FERC	371	installations On Customers Premises	2.33%	1.94%	0.39%
FERC	373	Street Lighting and Signal Systems	3.10%	2.58%	0.52%
GENERAL PLANT					
FERC	390	Structures and Improvements	2.93%	2.55%	0.38%
FERC	391	Office Furniture and Equipment - Furniture	4.16%	4.16%	0.00%
FERC	391.1	Office Furniture and Equipment - PC Equipme	11.43%	11.43%	0.00%
FERC	391.2	Office Furniture and Equipment - Equipment	4.17%	4.17%	0.00%
FERC	393	Stores Equipment	0.00%	0.00%	0.00%
FERC	394	Tools. Shop and Garage Equipment	4.61%	4.61%	0.00%
FERC	395	Laboratory Equipment	5.07%	5.07%	0.00%
FERC	397	Communication Equipment	4.74%	4.74%	0.00%
FERC	398	Miscellaneous Equipment	3.85%	3.85%	0.00%

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ARIZONA PUBLIC SERVICE
Amortization Rate Summary
Related to Electric Plant at December 31,2002

Amortization Group			Amortization Rate
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 8 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

(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.

DECISION NO. 67744

ARIZONA PUBLIC SERVICE COMPANY
PROPOSED AND CURRENTLY USED RATES

Transportation Equipment (392)

Class	Description	Proposed Rates for 2004	(1995) Current Rates
01	Passenger Sedans	15.00%	15.00%
03	Compact Autos	13.33%	13.33%
09	Compact Pickup	11.43%	11.43%
10	Commerical Vehicles to 5 Ton	9.25%	9.25%
11	Commerical Vehides, 4-Wheel Drive	10.57%	10.57%
12	Conv. Dr. 5-10 Ton, Truck	7.50%	7.50%
13	Conv. Dr. 2 1/2 Ton w/Single-Person Aerial	7.27%	7.27%
14	4-Wheel Dr. 5-10 Ton, Truck	7.00%	7.00%
15	'Conv. Dr. 10-15 Ton, Tractor, Dump Truck, Backhoe	5.38%	5.38%
16	Conv. Dr. 18-32Ton, Line Construction with Aerial	5.33%	5.33%
17	4-Wheel Dr. 10-15 Ton, Truck	6.92%	6.92%
19	Trucks, 18-32Ton, Tractor. Platform Dump, Hydrolift	5.83%	5.83%
22	Trucks, 15-25 Ton 6X6	6.54%	6.54%
26	Fork Lift, Electric, to 4,000#	6.67%	6.67%
27	Fork Lift, Gasoline, to 4,000#	4.69%	4.69%
28	Fork Lift, 8-10 Ton Capacity	6.67%	6.67%
29	Wheeled Backhoe/Loader & Backfiller	5.83%	5.83%
30	Motor Grader	10.00%	10.00%
32	D4 Caterpillar (Small)	7.50%	7.50%
35	Trailer, to 5,000# GVW	3.25%	3.25%
36	Trailer, 5,000-10,000# GVW	4.11%	4.11%
37	Trailer, 10,000-20,000# GVW	3.75%	3.75%
38	Trailer, 20,000-50,000# GVW	4.69%	4.69%
39	Trailer, Over 50,000# GVW	5.00%	5.00%
41	Trailer-Mounted Industrial Equipment	4.93%	4.93%
42	Mobile Crane 45 Ton	10.00%	10.00%

Note: The depreciation study did not include accounts 392 or 396, therefore no changes are being proposed.

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ARIZONA PUBLIC SERVICE COMPANY
PROPOSED AND CURRENTLY USED RATES

. Power Operated Equipment (396)

Class	Description	Proposed Rates for 2004	(1995) Current Rates
12	Conv. Dr. 5-10 Ton. Truck	7.50%	7.50%
13	Conv. Dr. 2 112 Ton w/Single-Person Aerial	7.27%	7.27%
14	4-Wheel Dr. 5-10 Ton. Truck	7.00%	7.00%
15	Conv. Dr. 10-15 Ton, Tractor, Dump Truck, Backhoe	5.38%	5.38%
16	Conv. Dr. 18-32 Ton, Line Construction with Aerial	5.33%	5.33%
17	4-Wheel Dr. 10-15 Ton, Truck	6.92%	6.92%
78	4-Wheel Or. 15-20 Ton, Truck	6.92%	6.92%
19	Trucks, 18-32 Ton, Tractor, Platform Dump, Hydrolift	5.83%	5.83%
20	Truck. 18-32 Ton, Hole Digger, Hydrocrane & Carrier	7.00%	7.00%
22	Trucks, 15-25 Ton 6X6	6.54%	6.54%
23	Small Trencher	10.00%	10.00%
24	Medium Trencher	6.25%	6.25%
26	Fork Lift, Electric, to 4,000#	6.67%	6.67%
27	Fork Lift, Gasoline. to 4,000#	4.69%	4.69%
28	Fork Lift, 8-10 Ton Capacity	6.67%	6.67%
29	Wheeled Backhoe/Loader & Backfiller	5.83%	5.83%
30	Motor Grader	10.00%	10.00%
31	Snow Vehicles-Crawlers	10.00%	10.00%
32	04 Caterpillar (Small)	7.50%	7.50%
33	07 Caterpillar (Medium)	7.50%	7.60%
34	D8 Caterpillar (Heavy)	7.50%	7.50%
35	Trailer. to 5,000# GVW	3.25%	3.25%
38	Trailer, 20,000-50,000# GVW	4.69%	489%
40	Wire Tensioners	8.50%	8.50%
41	Trailer-Mounted Industrial Equipment	4.93%	4.93%
42	Mobiie Crane 45 Ton	10.00%	10.00%

Note: The depreciation study did not include Accounts 392 and 396, therefore no changes are being proposed.

DECISION NO. 67744

PINNACLE WEST ENERGY CORPORATION
Depreciation Rate Summary
Related to Electric Plant at December 31,2002

	Depreciable Group	Depreciation Rate (A) A = (B + C)	Service Life Kate (E)	Net Salvage Rate (C)
OTHER PRODUCTION				
FERC 341	Structures and Improvements	2.08%	1.98%	0.10%
FERC 342	Fuel Holder;, Products & Accessories	2.14%	2.04%	0.10%
FERC 343	Prime Movers	2.14%	2.10%	0.04%
FERC 344	Generators and Devices	2.94%	2.86%	0.08%
TRANSMISSION				
FERC 353	Station Equipment	1.74%	1.74%	0
FERC 355	Poles and Fixtures - Steel	2.08%	1.81%	0.27%
FERC 356	Overhead Conductors and Devices	2.45%	1.81%	0.63%

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ARIZONA PUBLIC SERVICE COMPANY
Schedule 1. Summary of Service Life and Net Salvage Estimates and Calculated Remaining Life Annual Accruals
Related to Electric Plant at December 31, 2002

	Depreciable Group	Probable Retirement Year	Estimated Survivor Curve	Net Salvage Percent	Original Cost at 12/31/02	Book Accumulated Depreciation	Future Accruals	Composite Remaining Life	Calculated Annual Accrual Amount	Calculated Annual Accrual Rate
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)=(9)/(5)
PLANT IN SERVICE										
STEAM PRODUCTION PLANT										
311	Structures and Improvements									
	Cholla Unit 1	06-2017	75 - S1.5	(20)	2,144,789	1,841,738	732,009	14.0	52,286	2.44%
	Cholla Unit 2	06-2033	75 - S1.5	(20)	5,022,179	2,101,615	3,925,000	29.0	135,345	2.69%
	Cholla Unit 3	06-2035	75 - S1.5	(20)	9,583,277	5,184,966	6,314,966	29.9	211,203	2.20%
	Cholla Common	06-2035	75 - S1.5	(20)	36,234,550	19,318,431	24,163,029	29.9	808,128	2.23%
	Four Corners Units 1-3	06-2016	75 - S1.5	(20)	15,972,927	10,628,079	8,539,433	13.3	642,063	4.02%
	Four Corners Units 4-5	06-2031	75 - S1.5	(20)	9,195,585	5,124,992	5,909,710	26.8	220,512	2.40%
	Four Corners Common	06-2031	75 - S1.5	(20)	3,946,871	2,227,796	2,508,449	26.8	93,599	2.37%
	Navajo Units 1-3	06-2026	75 - S1.5	(20)	27,152,517	12,197,389	20,385,831	22.8	894,107	3.29%
	Ocotillo Units 1-2	06-2020	75 - S1.5	(20)	3,787,972	2,084,288	2,461,278	17.1	143,934	3.80%
	Saguaro Units 1-2	06-2014	75 - S1.5	(20)	2,446,832	1,989,759	946,439	11.3	83,756	3.42%
	Yucca Unit 1	06-2016	75 - S1.5	(20)	462,587	452,608	102,472	13.1	7,822	1.69%
	Total Account 311				115,950,066	63,151,661	75,988,418		3,292,754	2.84%
312	Boiler Plant Equipment									
	Cholla Unit 1	06-2017	48 - L2	(20)	26,431,681	17,605,653	14,112,364	13.4	1,053,162	3.98%
	Cholla Unit 2	06-2033	48 - L2	(20)	140,612,492	86,692,363	82,042,627	22.0	3,729,210	2.65%
	Cholla Unit 3	06-2035	48 - L2	(20)	100,448,965	60,203,467	60,335,291	22.9	2,634,729	2.62%
	Cholla Common	06-2035	48 - L2	(20)	22,626,051	11,328,185	15,823,076	24.8	638,027	2.82%
	Four Corners Units 1-3	06-2016	48 - L2	(20)	197,139,757	115,304,816	121,262,892	12.7	9,548,259	4.84%
	Four Corners Units 4-5	06-2031	48 - L2	(20)	111,591,873	64,306,071	69,604,177	22.1	3,149,510	2.82%
	Four Corners Common	06-2031	48 - L2	(20)	3,290,391	2,152,160	1,796,309	22.8	78,785	2.39%
	Navajo Units 1-3	06-2026	48 - L2	(20)	149,350,243	69,950,378	109,269,914	20.6	5,304,365	3.55%
	Ocotillo Units 1-2	06-2020	48 - L2	(20)	24,152,351	17,905,382	11,077,439	15.2	728,779	3.02%
	Saguaro Units 1-2	06-2014	48 - L2	(20)	24,387,712	16,566,160	12,699,094	11.1	1,144,063	4.69%
	Total Account 312				800,031,516	462,014,635	498,023,184		28,008,889	3.50%
314	Turbogenerator Units									
	Cholla Unit 1	06-2017	65 - R2	(20)	10,417,373	7,459,687	5,041,161	14.0	360,083	3.46%
	Cholla Unit 2	06-2033	65 - R2	(20)	28,551,889	15,518,951	18,743,316	27.5	681,575	2.39%
	Cholla Unit 3	06-2035	65 - R2	(20)	39,626,197	16,959,280	30,592,156	29.7	1,030,039	2.60%
	Cholla Common	06-2035	65 - R2	(20)	631,278	335,591	421,943	29.0	14,550	2.30%
	Four Corners Units 1-3	06-2018	65 - R2	(20)	36,412,926	24,829,283	18,866,228	13.1	1,440,170	3.96%
	Four Corners Units 4-5	06-2031	65 - R2	(20)	14,488,238	7,086,302	10,299,584	26.3	391,619	2.70%
	Four Corners Common	06-2031	65 - R2	(20)	1,726,164	1,349,968	721,429	23.3	30,963	1.79%
	Navajo Units 1-3	06-2026	65 - R2	(20)	24,387,110	14,479,672	14,784,860	22.0	672,039	2.76%
	Ocotillo Units 1-2	06-2020	65 - R2	(20)	15,517,601	11,437,238	7,183,883	16.8	427,612	2.76%
	Saguaro Units 1-2	06-2014	65 - R2	(20)	16,259,698	13,244,927	6,266,711	11.2	559,528	3.44%

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ARIZONA PUBLIC SERVICE COMPANY
Schedule 1. Summary of Service Life and Net Salvage Estimates and Calculated Remaining Life Annual Accruals
Related to Electric Plant at December 31, 2002

	Depreciable Group	Probable Retirement Year	Estimated Survivor Curve	Net Salvage Percent	Original Cost at 12/31/02	Book Accumulated Depreciation	Future Accruals	Composite Remaining Life	Calculated Annual Accrual Amount	Calculated Annual Accrual Rate
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)=(9)/(5)
	Total Account 314				188,018,474	112,700,899	112,921,270		5,608,177	2.98%
315	Accessory Electric Equipment									
	Cholla Unit 1	06-2017	60 - R2.5	(20)	4,756,906	3,592,717	2,115,570	13.9	152,199	3.20%
	Cholla Unit 2	06-2033	60 - R2.5	(20)	42,235,616	25,070,631	25,612,111	26.8	955,676	2.26%
	Cholla Unit 3	06-2035	60 - R2.5	(20)	29,917,206	16,267,820	19,632,827	28.5	688,871	2.30%
	Cholla Common	06-2035	60 - R2.5	(20)	4,476,001	2,380,788	2,990,413	28.7	104,196	2.33%
	Four Corners Units 1-3	06-2016	60 - R2.5	(20)	16,353,282	9,525,599	10,098,339	13.2	765,026	4.68%
	Four Corners Units 4-5	06-2031	60 - R2.5	(20)	9,183,206	5,039,778	5,980,069	25.9	230,891	2.51%
	Four Corners Common	06-2031	60 - R2.5	(20)	2,596,719	2,104,631	1,011,432	21.0	48,163	1.85%
	Navajo Units 1-3	06-2026	60 - R2.5	(20)	20,226,194	11,727,970	12,543,463	22.0	570,157	2.82%
	Ocotillo Units 1-2	06-2020	60 - R2.5	(20)	2,407,622	2,023,821	865,325	16.3	53,087	2.20%
	Saguaro Units 1-2	06-2014	60 - R2.5	(20)	2,654,661	2,355,021	830,572	11.2	74,158	2.79%
	Total Account 315				134,807,415	80,088,776	81,880,122		3,642,425	2.70%
316	Miscellaneous Power Plant Equipment									
	Cholla Unit 1	06-2017	40 - R2	(20)	2,316,189	1,189,333	1,588,894	13.5	117,696	5.08%
	Cholla Unit 2	06-2033	40 - R2	(20)	4,848,431	2,631,492	3,184,225	22.1	144,083	2.97%
	Cholla Unit 3	06-2035	40 - R2	(20)	4,138,531	1,990,199	2,976,038	23.8	125,044	3.02%
	Cholla Common	06-2035	40 - R2	(20)	7,096,069	2,439,747	6,075,536	25.8	235,486	3.32%
	Four Corners Units 1-3	06-2016	40 - R2	(20)	4,330,612	925,502	4,271,232	13.1	326,048	7.53%
	Four Corners Units 4-5	06-2031	40 - R2	(20)	3,304,340	1,402,561	2,562,647	23.0	111,419	3.37%
	Four Corners Common	06-2031	40 - R2	(20)	8,133,224	3,483,659	6,276,210	23.2	270,526	3.33%
	Navajo Units 1-3	06-2026	40 - R2	(20)	11,805,250	5,248,830	8,917,470	20.2	441,459	3.74%
	Ocotillo Units 1-2	06-2020	40 - R2	(20)	3,711,192	1,301,603	3,151,827	16.2	194,557	5.24%
	Saguaro Units 1-2	06-2014	40 - R2	(20)	3,191,024	1,340,385	2,488,844	10.9	228,334	7.16%
	Yucca Unit 1	06-2016	40 - R2	(20)	452,868	359,801	183,641	12.2	15,053	3.32%
	Total Account 316				53,324,730	22,313,112	41,676,564		2,209,705	4.14%
TOTAL STEAM PRODUCTION PLANT					1,292,132,201	740,269,083	810,289,558		42,761,950	
NUCLEAR PRODUCTION PLANT										
321	Structures and Improvements									
	Palo Verde Unit 1	12-2024	65 - R2.5	0	161,039,432	69,557,944	91,481,488	21.2	4,315,165	2.68%
	Palo Verde Unit 2	12-2025	65 - R2.5	0	88,415,270	38,859,061	49,556,209	22.0	2,252,555	2.55%
	Palo Verde Unit 3	03-2027	65 - R2.5	0	159,591,077	63,133,223	96,457,854	23.3	4,139,822	2.59%
	Palo Verde Water Reclamati	03-2027	65 - R2.5	0	125,593,913	51,122,827	74,471,086	23.2	3,209,961	2.56%
	Palo Verde Common	03-2027	65 - R2.5	0	98,127,309	39,316,906	58,810,403	23.2	2,534,931	2.58%
	Total Account 321				632,767,001	261,989,961	370,777,040		16,452,433	2.60%
322	Reactor Plant Equipment									
	Palo Verde Unit 1	12-2024	70 - R1	(2)	359,545,213	153,616,828	213,119,289	20.6	10,345,597	2.88%

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ARIZONA PUBLIC SERVICE COMPANY
Schedule 1. Summary of Service Life and Net Salvage Estimates and Calculated Remaining Life Annual Accruals
Related to Electric Plant at December 31, 2002

	Depreciable Group	Probable Retirement Year	Estimated Survivor Curve	Net Salvage Percent	Original Cost at 12/31/02	Book Accumulated Depreciation	Future Accruals	Composite Remaining Life	Calculated Annual Accrual Amount	Calculated Annual Accrual Rate
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)=(9)/(5)
	Palo Verde Unit 2	12-2025	70 - R1	(2)	176,362,235	72,582,559	107,306,921	21.5	4,991,020	2.83%
	Palo Verde Unit 3	03-2027	70 - R1	(2)	322,750,700	121,218,478	207,987,236	22.6	9,202,975	2.85%
	Palo Verde Water Reclamati	03-2027	70 - R1	(2)	123,313	7,176	118,603	23.0	5,157	4.18%
	Palo Verde Common	03-2027	70 - R1	(2)	26,449,873	9,583,436	17,395,434	22.6	769,709	2.91%
	Total Account 322				885,231,334	357,008,477	545,927,484		25,314,457	2.86%
322.1	Reactor Plant Equipment - Steam Generators									
	Palo Verde Unit 1	12-2005	Square	(17)	30,722,375	27,569,149	8,376,030	3.0	2,792,010	9.09%
	Palo Verde Unit 2	12-2003	Square	(17)	15,870,053	15,868,835	2,699,327	1.0	2,699,327	17.01%
	Palo Verde Unit 3	12-2007	Square	(17)	25,413,317	20,039,935	9,693,646	5.0	1,938,729	7.63%
	Total Account 322.1				72,005,745	63,477,719	20,769,003		7,430,066	10.32%
323	Turbogenerator Units									
	Palo Verde Unit 1	12-2024	60 - S0	(2)	117,808,078	51,570,896	68,593,344	19.9	3,446,902	2.93%
	Palo Verde Unit 2	12-2025	60 - S0	(2)	76,754,224	32,432,468	45,858,840	20.8	2,204,656	2.87%
	Palo Verde Unit 3	03-2027	60 - S0	(2)	142,895,088	55,838,987	89,914,003	21.8	4,124,496	2.89%
	Palo Verde Water Reclamati	03-2027	60 - S0	(2)	217,707	76,585	145,476	22.0	6,613	3.04%
	Palo Verde Common	03-2027	60 - S0	(2)	1,223,879	346,554	901,803	22.2	40,622	3.32%
	Total Account 323				338,898,976	140,265,490	205,411,466		9,823,287	2.90%
324	Accessory Electric Equipment									
	Palo Verde Unit 1	12-2024	45 - R3	(2)	115,495,170	53,444,066	64,361,007	20.0	3,218,050	2.79%
	Palo Verde Unit 2	12-2025	45 - R3	(2)	50,119,388	21,982,186	29,139,590	20.9	1,394,239	2.78%
	Palo Verde Unit 3	03-2027	45 - R3	(2)	89,143,623	36,343,481	54,583,014	22.1	2,469,820	2.77%
	Palo Verde Common	03-2027	45 - R3	(2)	17,918,193	7,299,463	10,977,094	22.0	498,959	2.78%
	Total Account 324				272,676,374	119,069,196	159,060,705		7,581,068	2.78%
325	Miscellaneous Power Plant Equipment									
	Palo Verde Unit 1	12-2024	35 - R0.5	(2)	29,671,405	11,770,905	18,493,928	17.7	1,044,855	3.52%
	Palo Verde Unit 2	12-2025	35 - R0.5	(2)	26,389,406	8,702,844	18,214,350	18.7	974,029	3.69%
	Palo Verde Unit 3	03-2027	35 - R0.5	(2)	27,284,046	9,445,478	18,384,249	19.2	957,513	3.51%
	Palo Verde Water Reclamati	03-2027	35 - R0.5	(2)	88,819	27,706	62,889	19.5	3,225	3.63%
	Palo Verde Common	03-2027	35 - R0.5	(2)	48,459,510	15,382,218	34,046,482	19.4	1,754,973	3.62%
	Total Account 325				131,893,186	45,329,151	89,201,899		4,734,595	3.59%
	TOTAL NUCLEAR PRODUCTION PLANT				2,333,472,616	987,139,984	1,391,147,598		71,335,907	
	HYDRO PRODUCTION PLANT									
331	Structures and Improvement	12-2004	200-SQ	0	100,878	100,878	0	0.0	0	0.00
332	Reservoirs, Dams and Water	12-2004	200-SQ	0	991,936	1,105,086	(113,150)	0.0	0	0.00

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Attachment RCS-3
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ARIZONA PUBLIC SERVICE COMPANY

Schedule 1. Summary of Service Life and Net Salvage Estimates and Calculated Remaining Life Annual Accruals

Related to Electric Plant at December 31, 2002

	Depreciable Group	Probable Retirement Year	Estimated Survivor Curve	Net Salvage Percent	Original Cost at 12/31/02	Book Accumulated Depreciation	Future Accruals	Composite Remaining Life	Calculated Annual Accrual Amount	Calculated Annual Accrual Rate	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)=(9)/(5)	
333	Water Wheels, Turbines and	12-2004	200-SQ	0	157,196	157,196	0	0.0	0	0.00	
334	Accessory Electric Equipmer	12-2004	200-SQ	0	627,611	627,611	0	0.0	0	0.00	
335	Miscellaneous Power Plant E	12-2004	200-SQ	0	126,018	126,018	0	0.0	0	0.00	
336	Roads, Railroads and Bridge	12-2004	200-SQ	0	77,427	77,427	0	0.0	0	0.00	
	Hydro Decomissioning Costs				-	7,884,531	5,335,469	2.0	2,667,735		
TOTAL HYDRO PRODUCTION PLANT					2,081,066	10,058,747	5,222,319		2,667,735		
OTHER PRODUCTION PLANT											
341	Structures and Improvements										
	Douglas CT	06-2017	80 - S1	(5)	4,562	4,146	642	13.9	46	1.01%	
	Ocotillo CT 1 - 2	06-2017	80 - S1	(5)	328,749	230,819	114,367	14.5	7,887	2.40%	
	Saguaro CT	06-2017	80 - S1	(5)	1,288,525	466,971	885,980	14.4	61,526	4.77%	
	Solar Unit 1		12 - SQ	0	375,512	383,809	(8,297)	3.6	0	0.00%	(2)
	West Phoenix CT 1 - 2	06-2017	80 - S1	(5)	510,951	419,492	117,007	14.2	8,240	1.61%	
	West Phoenix Combined Cyc	06-2031	80 - S1	(5)	6,706,722	2,438,522	4,603,536	28.1	163,827	2.44%	
	Yucca CT 1 - 4	06-2016	80 - S1	(5)	452,751	222,815	252,574	13.4	18,849	4.16%	
	Total Account 341				9,667,772	4,166,576	5,965,809		260,376	2.69%	
342	Fuel Holders, Products and Accessories										
	Douglas CT	06-2017	70 - S1	(5)	137,759	100,065	44,582	14.0	3,184	2.31%	
	Ocotillo CT 1 - 2	06-2017	70 - S1	(5)	719,859	517,984	237,868	14.0	16,991	2.36%	
	Saguaro CT	06-2017	70 - S1	(5)	1,304,977	1,019,500	350,726	14.0	25,052	1.92%	
	West Phoenix CT 1 - 2	06-2017	70 - S1	(5)	1,437,533	1,123,270	386,140	14.0	27,581	1.92%	
	West Phoenix Combined Cyc	06-2031	70 - S1	(5)	19,343,993	2,649,135	17,662,058	27.7	637,619	3.30%	
	Yucca CT 1 - 4	06-2016	70 - S1	(5)	3,232,217	2,859,228	534,600	12.9	41,442	1.28%	
	Total Account 342				26,176,338	8,269,182	19,215,973		751,870	2.87%	
343	Prime Movers										
	Douglas CT	06-2017	70 - L1.5	0	1,101,449	999,227	102,222	14.2	7,199	0.65%	(1)
	Ocotillo CT 1 - 2	06-2017	70 - L1.5	0	6,679,324	5,679,469	999,855	14.1	70,912	1.06%	
	Saguaro CT	06-2017	70 - L1.5	0	8,102,651	6,657,234	1,445,417	13.8	104,740	1.29%	
	West Phoenix CT 1 - 2	06-2017	70 - L1.5	0	8,802,636	6,220,272	2,582,364	14.2	181,857	2.07%	
	Yucca CT 1 - 4	06-2016	70 - L1.5	0	7,920,584	7,302,457	618,127	14.2	43,530	0.55%	(1)
	Total Account 343				32,606,644	28,858,659	5,747,985		408,237	1.25%	
344	Generators and Devices										
	Douglas CT	06-2017	37 - R3	0	551,765	542,840	8,925	9.7	920	0.17%	
	Ocotillo CT 1 - 2	06-2017	37 - R3	0	6,402,044	3,500,409	2,901,635	13.6	213,356	3.33%	
	Saguaro CT	06-2017	37 - R3	0	4,185,247	2,504,957	1,680,290	13.0	129,253	3.09%	
	Solar Unit 1		12 - SQ	0	6,933,081	3,289,918	3,643,163	7.8	467,072	6.74%	
	West Phoenix CT 1 - 2	06-2017	37 - R3	0	4,115,901	3,202,560	913,341	12.3	74,255	1.80%	

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ARIZONA PUBLIC SERVICE COMPANY
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Related to Electric Plant at December 31, 2002

	Depreciable Group	Probable Retirement Year	Estimated Survivor Curve	Net Salvage Percent	Original Cost at 12/31/02	Book Accumulated Depreciation	Future Accruals	Composite Remaining Life	Calculated Annual Accrual Amount	Calculated Annual Accrual Rate
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)=(9)/(5)
	West Phoenix Combined Cy	06-2031	37 - R3	(2)	81,920,222	11,983,119	71,575,507	26.2	2,731,890	3.33%
	Yucca CT 1 - 4	06-2016	37 - R3	0	5,395,818	4,370,148	1,025,670	11.6	88,420	1.64%
	Total Account 344				109,504,078	28,393,951	81,748,531		3,705,186	3.38%
345	Accessory Electric Equipment									
	Douglas CT	06-2017	50 - S2	0	353,277	313,549	39,728	13.1	3,033	0.86%
	Ocotillo CT 1 - 2	06-2017	50 - S2	0	1,494,636	1,281,843	212,793	13.2	16,121	1.08%
	Saguaro CT	06-2017	50 - S2	0	1,715,774	1,389,500	326,274	13.4	24,349	1.42%
	Solar Unit 1		12 - SQ	0	169,527	40,179	129,348	9.9	13,065	7.71%
	West Phoenix CT 1 - 2	06-2017	50 - S2	0	1,557,744	1,315,426	242,318	13.2	18,357	1.18%
	West Phoenix Combined Cy	06-2031	50 - S2	0	11,925,645	2,562,942	9,362,703	27.8	336,788	2.82%
	Yucca CT 1 - 4	06-2016	50 - S2	0	2,166,526	1,817,969	348,557	13.0	26,812	1.24%
	Total Account 345				19,383,129	8,721,408	10,661,721		438,525	2.26%
346	Miscellaneous Power Plant Equipment									
	Douglas CT	06-2017	70 - L1	0	40,913	30,160	10,753	13.8	779	1.90%
	Ocotillo CT 1 - 2	06-2017	70 - L1	0	553,173	418,696	134,477	14.0	9,606	1.74%
	Saguaro CT	06-2017	70 - L1	0	790,906	410,357	380,549	14.1	26,989	3.41%
	West Phoenix CT 1 - 2	06-2017	70 - L1	0	957,431	508,533	448,898	14.1	31,837	3.33%
	West Phoenix Combined Cy	06-2031	70 - L1	0	2,608,877	895,856	1,713,021	26.6	64,399	2.47%
	Yucca CT 1 - 4	06-2016	70 - L1	0	427,175	357,633	69,542	13.2	5,268	1.23%
	Total Account 346				5,378,475	2,621,235	2,757,240		138,878	2.58%
	TOTAL OTHER PRODUCTION PLANT				202,716,436	80,031,011	126,097,259		5,703,052	

(1) Staff's reallocation of reserves caused account to have a remaining Net Book Value. APS selected the longest life of other plant in that FERC account to calculate remaining life.
(2) Account is fully depreciated and, therefore, should have zero depreciation, not negative depreciation.

TRANSMISSION PLANT

352	Structures and Improvements		50 - R4	(5)	27,618,299	12,484,016	16,515,198	35.2	469,182	1.70%
352.5	Structures and Improvements - SCE 500 KV Line				409,725	424,897	(15,172)		13,316	3.25% (a)
353	Station Equipment		57 - R1.5	0	428,736,305	130,140,054	298,596,251	45.7	6,538,127	1.52%
353.5	Station Equipment - SCE 500 I				7,747,282	7,349,363	397,919		251,787	3.25% (a)
354	Towers and Fixtures		60 - R3	(35)	83,464,531	46,097,366	66,579,751	38.3	1,738,375	2.08%
354.5	Towers and Fixtures - SCE 50(				13,752,584	17,477,965	(3,725,381)		446,959	3.25% (a)
355	Poles and Fixtures - Wood		48 - R1.5	(35)	91,126,939	27,541,958	95,479,410	38.5	2,479,985	2.72%
355.1	Poles and Fixtures - Steel		55 - R3	(15)	83,067,888	22,833,440	72,694,631	45.1	1,611,854	1.94%
355.5	Poles and Fixtures - SCE 500 I				930,308	692,575	237,733		30,235	3.25% (a)
356	Overhead Conductors and Dev		55 - R3	(35)	205,771,417	94,269,666	183,521,747	38.5	4,766,799	2.32%
356.5	Overhead Conductors and Devices - SCE 500 KV Line				22,653,515	28,947,611	(6,294,096)		736,239	3.25% (a)
357	Underground Conduit		48 - S1.5	(10)	10,444,362	4,087,064	7,401,734	35.7	207,331	1.99%
358	Underground Conductors and I		40 - R3	(10)	18,551,254	9,702,854	10,703,525	26.3	406,978	2.19%

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ARIZONA PUBLIC SERVICE COMPANY
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Related to Electric Plant at December 31, 2002

	Depreciable Group	Probable Retirement Year	Estimated Survivor Curve	Net Salvage Percent	Original Cost at 12/31/02	Book Accumulated Depreciation	Future Accruals	Composite Remaining Life	Calculated Annual Accrual Amount	Calculated Annual Accrual Rate	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)=(9)/(5)	
TOTAL TRANSMISSION PLANT					994,274,409	402,048,829	742,093,250		19,897,167		
DISTRIBUTION PLANT											
361	Structures and Improvements		45 - R2.5	(10)	25,815,042	10,429,908	17,968,638	33.1	542,799	2.10%	
362	Station Equipment		44 - L0.5	0	212,357,577	52,722,295	159,635,282	36.9	4,332,029	2.04%	
364	Poles, Towers and Fixtures - V		38 - R0.5	(10)	264,200,711	61,128,434	231,492,348	30.9	7,491,662	2.84%	
364.1	Poles, Towers and Fixtures - S		50 - R3	(5)	53,919,851	5,601,620	51,013,814	46.6	1,094,717	2.03%	
365	Overhead Conductors and Dev		53 - O1	(10)	218,856,780	33,437,453	207,305,005	47.7	4,346,017	1.99%	
366	Underground Conduit		86 - O1	(5)	425,723,116	26,924,767	420,084,505	82.4	5,098,113	1.20%	
367	Underground Conductors and I		29 - L1	(5)	805,505,783	258,865,205	586,915,867	22.9	25,629,514	3.18%	
368	Line Transformers		36 - R3	(5)	486,837,053	235,537,009	275,641,897	24.6	11,204,955	2.30%	
369	Services		37 - S2	(10)	242,404,812	91,086,515	175,558,778	27.9	6,292,429	2.60%	
370	Meters		29 - L0	0	91,330,710	34,836,184	56,494,526	21.8	2,596,256	2.84%	
370.1	Electronic Meters		26 - R1.5	0	54,691,249	8,612,961	46,078,288	23.3	1,975,913	3.61%	
371	Installations On Customers Pr		50 - O2	(20)	25,335,831	3,863,126	26,539,871	45.0	589,775	2.33%	
373	Street Lighting and Signal Syst		35 - R2	(20)	57,185,737	22,716,125	45,906,759	25.9	1,772,462	3.10%	
TOTAL DISTRIBUTION PLANT					2,964,164,052	865,761,802	2,300,833,578		72,966,640		
GENERAL PLANT											
390	Structures and Improvements		39 - R1	(15)	96,667,435	24,085,116	87,082,434	30.7	2,836,561	2.93%	
391	Office Furniture and Equipmen		20 - SQ	0	19,919,640	11,543,613	8,376,027	10.1	829,310	4.16%	
391.1	Office Furniture and Equipmen		8 - R3	0	38,654,946	15,103,632	23,551,314	5.3	4,418,633	11.43%	
391.2	Office Furniture and Equipmen		22 - R4	0	7,652,923	2,932,191	4,720,732	14.8	318,968	4.17%	
393	Stores Equipment		20 - SQ	0	1,227,371	1,235,746	(8,375)	2.8	0	0.00%	(2)
394	Tools, Shop and Garage Equip		20 - SQ	0	12,673,031	4,673,542	7,999,489	13.7	583,904	4.61%	
395	Laboratory Equipment		20 - L1	0	1,350,583	531,270	819,313	12.0	68,504	5.07%	
397	Communication Equipment		19 - S1.5	0	94,309,691	40,677,647	53,632,044	12.0	4,469,337	4.74%	
398	Miscellaneous Equipment		24 - S1.5	0	1,336,404	481,755	854,649	16.6	51,454	3.85%	
TOTAL GENERAL PLANT					273,792,024	101,264,512	187,027,827		13,576,872		
TOTAL DEPRECIABLE PLANT STUDIED					8,082,832,804	3,186,573,978	5,562,511,188		228,709,123		

(2) Account is fully depreciated and, therefore, should have zero depreciation, not negative depreciation.

(a) Assets related to the 500 KV SCE Transmission Line are Depreciated at a rate of 3.25%.

	STEAM PRODUCTION PLANT NOT STUDIED	Original Cost at 12/31/02	Book Accumulated Depreciation
311	Structures and Improvements - West Phoenix	0	80,895
312	Boiler Plant Equipment - West Phoenix Units	0	300,097
312	Boiler Plant Equipment - Yucca Unit 1	425,323	441,994
314	Turbogenerator Units - West Phoenix Units 4	0	314,612
314	Turbogenerator Units - Yucca Unit 1	184,916	188,319

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	Depreciable Group	Probable Retirement Year	Estimated Survivor Curve	Net Salvage Percent	Original Cost at 12/31/02	Book Accumulated Depreciation	Future Accruals	Composite Remaining Life	Calculated Annual Accrual Amount	Calculated Annual Accrual Rate
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)=(9)/(5)
315	Accessory Electric Equipment - West Phoenix				33,968	83,338				
315	Accessory Electric Equipment - Yucca Unit 1				182,084	185,435				
316	Misc. Power Plant Equipment-West Phoenix U				17,267	0				
	TOTAL STEAM PRODUCTION PLANT NOT STUDIED				843,558	1,594,590				
	GENERAL PLANT NOT STUDIED									
392	Vehicles				28,410,886	20,605,998				
396	Power Operated Equipment				27,947,651	18,603,989				
	TOTAL GENERAL PLANT NOT STUDIED				56,358,537	39,209,987				
	OTHER PROPERTY NOT STUDIED									
	Intangible Plant									
301	Organization				73,639					
302	Franchises and Consents				883,584					
303	Miscellaneous Intangible Plant				201,550,375					
	Leased Property									
321	Structures and Improvements				1,833,193					
322	Reactor Plant Equipment				9,670,223					
323	Turbogenerator Units				2,705,885					
324	Accessory Electric Equipment				944,788					
325	Miscellaneous Power Plant Equipment				563,135					
361	Structures and Improvements				195,512					
368	Line Transformers				179,394					
371	Installations On Customers Premises				60,386					
390	Structures and Improvements				11,160,324					
397	Communication Equipment				245,938					
	TOTAL OTHER PROPERTY NOT STUDIED				229,866,377	120,727,768				
	TOTAL DEPRECIABLE PLANT IN SERVICE				8,369,701,276	3,348,106,323				
	NONDEPRECIABLE PLANT									
310	Land and Land Rights				3,295,288					
320	Land and Land Rights				3,399,728					
330	Land and Land Rights				64,500					
340	Land and Land Rights				28,192					
350	Land and Land Rights				50,808,274					
360	Land and Land Rights				26,755,119					
389	Land and Land Rights				7,327,436					
	TOTAL NONDEPRECIABLE				91,678,517					
	TOTAL PLANT IN SERVICE				8,461,379,793					

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ARIZONA PUBLIC SERVICE COMPANY
Schedule 1. Summary of Service Life and Net Salvage Estimates and Calculated Remaining Life Annual Accruals
Related to Electric Plant at December 31, 2002

The Calculated annual accrual (9) is made up of two depreciation components - service life and net salvage

Depreciable Group (1)		Probable Retirement Year (2)	Estimated Survivor Curve (3)	Net Salvage Percent (4)	Original Cost at 12/31/02 (5)	Book Accumulated Depreciation (6)	Future Accruals (7)	Composite Remaining Life (8)	Calculated Annual Accrual Amount (9)	Calculated Annual Accrual Rate (10)=(9)/(5)	Annual Accrual Service Life Amount (11) = (9)*100/(100+(-4))	Annual Accrual Service Life Rate (12)=(11)/(5)	Annual Accrual Net Salvage Amount (13) = (9) *(-4)/100+(-4)	Annual Accrual Net Salvage Rate (14)=(13)/(5)
PLANT IN SERVICE														
STEAM PRODUCTION PLANT														
311	Structures and Improvements													
	Cholla Unit 1	06-2017	75 - S1.5	(20)	2,144,769	1,841,738	732,009	14.0	52,286	2.44%	43,572	2.03%	8,714	0.41%
	Cholla Unit 2	06-2033	75 - S1.5	(20)	5,022,179	2,101,615	3,926,000	29.0	135,345	2.69%	112,787	2.25%	22,557	0.45%
	Cholla Unit 3	06-2035	75 - S1.5	(20)	9,583,277	5,184,966	6,314,966	29.9	211,203	2.20%	176,002	1.84%	35,200	0.37%
	Cholla Common	06-2035	75 - S1.5	(20)	36,234,650	19,318,431	24,163,029	29.9	808,128	2.23%	673,440	1.86%	134,688	0.37%
	Four Corners Units 1-3	06-2016	75 - S1.5	(20)	15,972,927	10,628,079	8,539,433	13.3	642,063	4.02%	535,052	3.35%	107,010	0.67%
	Four Corners Units 4-5	06-2031	75 - S1.5	(20)	9,195,585	5,124,992	5,909,710	26.8	220,512	2.40%	183,760	2.00%	36,752	0.40%
	Four Corners Common	06-2031	75 - S1.5	(20)	3,946,871	2,227,706	2,508,449	26.8	93,599	2.37%	77,999	1.98%	15,600	0.40%
	Navajo Units 1-3	06-2026	75 - S1.5	(20)	27,152,517	12,197,389	20,385,631	22.8	894,107	3.29%	745,089	2.74%	149,018	0.55%
	Ocotillo Units 1-2	06-2020	75 - S1.5	(20)	3,787,972	2,084,288	2,461,278	17.1	143,934	3.80%	119,945	3.17%	23,989	0.63%
	Saguaro Units 1-2	06-2014	75 - S1.5	(20)	2,446,832	1,989,759	948,439	11.3	83,756	3.42%	69,796	2.85%	13,959	0.57%
	Yucca Unit 1	06-2016	75 - S1.5	(20)	482,587	452,608	102,472	13.1	7,822	1.89%	6,519	1.41%	1,304	0.28%
	Total Account 311				115,950,068	63,151,661	75,988,416		3,292,754	2.84%	2,743,962	2.37%	548,792	0.47%
312	Boiler Plant Equipment													
	Cholla Unit 1	06-2017	48 - L2	(20)	28,431,681	17,605,653	14,112,364	13.4	1,053,182	3.98%	877,835	3.32%	175,527	0.66%
	Cholla Unit 2	06-2033	48 - L2	(20)	140,612,492	86,692,363	82,042,627	22.0	3,729,210	2.65%	3,107,675	2.21%	621,535	0.44%
	Cholla Unit 3	06-2035	48 - L2	(20)	100,448,965	60,203,487	60,335,291	22.8	2,634,729	2.62%	2,195,607	2.19%	439,121	0.44%
	Cholla Common	06-2035	48 - L2	(20)	22,626,051	11,328,185	15,823,076	24.8	638,027	2.82%	531,689	2.35%	106,338	0.47%
	Four Corners Units 1-3	06-2016	48 - L2	(20)	197,139,757	115,304,816	121,262,892	12.7	9,548,259	4.84%	7,956,883	4.04%	1,591,377	0.81%
	Four Corners Units 4-5	06-2031	48 - L2	(20)	111,591,873	64,306,071	69,604,177	22.1	3,149,510	2.82%	2,624,592	2.35%	524,918	0.47%
	Four Corners Common	06-2031	48 - L2	(20)	3,290,391	2,152,160	1,796,309	22.8	78,785	2.39%	65,655	2.00%	13,131	0.40%
	Navajo Units 1-3	06-2026	48 - L2	(20)	149,350,243	69,950,378	109,269,914	20.6	5,304,385	3.55%	4,420,304	2.96%	884,061	0.59%
	Ocotillo Units 1-2	06-2020	48 - L2	(20)	24,152,351	17,905,382	11,077,439	15.2	728,779	3.02%	607,316	2.51%	121,463	0.50%
	Saguaro Units 1-2	06-2014	48 - L2	(20)	24,387,712	16,666,160	12,699,094	11.1	1,144,063	4.69%	953,385	3.91%	190,677	0.78%
	Total Account 312				800,031,516	462,014,635	498,023,184		28,006,869	3.50%	23,340,741	2.92%	4,668,148	0.58%
314	Turbogenerator Units													
	Cholla Unit 1	06-2017	65 - R2	(20)	10,417,373	7,459,687	5,041,161	14.0	360,083	3.46%	300,069	2.88%	60,014	0.58%
	Cholla Unit 2	06-2033	65 - R2	(20)	28,551,889	15,518,951	18,743,316	27.5	681,575	2.39%	567,979	1.99%	113,596	0.40%
	Cholla Unit 3	06-2035	65 - R2	(20)	39,626,197	16,959,280	30,592,156	29.7	1,030,039	2.60%	858,366	2.17%	171,673	0.43%
	Cholla Common	06-2035	65 - R2	(20)	631,278	335,591	421,943	29.0	14,550	2.30%	12,125	1.92%	2,425	0.38%
	Four Corners Units 1-3	06-2016	65 - R2	(20)	36,412,926	24,829,283	18,866,228	13.1	1,440,170	3.96%	1,200,142	3.30%	240,028	0.66%
	Four Corners Units 4-5	06-2031	65 - R2	(20)	14,488,238	7,086,302	10,299,584	26.3	391,619	2.70%	326,349	2.25%	65,270	0.45%
	Four Corners Common	06-2031	65 - R2	(20)	1,726,164	1,349,968	721,429	23.3	30,963	1.79%	25,802	1.49%	5,160	0.30%
	Navajo Units 1-3	06-2026	65 - R2	(20)	24,387,110	14,479,672	14,784,860	22.0	672,039	2.76%	560,033	2.30%	112,007	0.46%
	Ocotillo Units 1-2	06-2020	65 - R2	(20)	15,517,801	11,437,238	7,183,683	16.8	427,612	2.76%	356,343	2.30%	71,269	0.46%
	Saguaro Units 1-2	06-2014	65 - R2	(20)	16,259,696	13,244,927	6,266,711	11.2	559,528	3.44%	466,273	2.87%	93,255	0.57%
	Total Account 314				188,018,474	112,700,899	112,921,270		5,608,177	2.98%	4,673,481	2.49%	934,696	0.50%
	Accessory Electric Equipment													
	Cholla Unit 1	06-2017	60 - R2.5	(20)	4,756,906	3,592,717	2,115,570	13.9	152,199	3.20%	126,833	2.67%	25,367	0.53%
	Cholla Unit 2	06-2033	60 - R2.5	(20)	42,235,618	25,070,831	25,612,111	26.8	955,676	2.26%	796,396	1.89%	159,279	0.38%
	Cholla Unit 3	06-2035	60 - R2.5	(20)	29,917,206	16,267,820	19,632,827	28.5	688,871	2.30%	574,059	1.92%	114,812	0.38%
	Cholla Common	06-2035	60 - R2.5	(20)	4,476,001	2,380,788	2,990,413	28.7	104,196	2.33%	86,830	1.94%	17,366	0.39%
	Four Corners Units 1-3	06-2016	60 - R2.5	(20)	16,353,282	9,625,599	10,098,339	13.2	765,026	4.68%	637,521	3.90%	127,504	0.78%
	Four Corners Units 4-5	06-2031	60 - R2.5	(20)	9,163,206	5,039,778	5,980,069	25.9	230,891	2.51%	192,409	2.10%	38,482	0.42%
	Four Corners Common	06-2031	60 - R2.5	(20)	2,596,719	2,104,631	1,011,432	21.0	48,163	1.85%	40,136	1.55%	8,027	0.31%
	Navajo Units 1-3	06-2026	60 - R2.5	(20)	20,226,194	11,727,970	12,543,463	22.0	570,157	2.82%	475,131	2.35%	95,026	0.47%
	Ocotillo Units 1-2	06-2020	60 - R2.5	(20)	2,407,622	2,023,821	865,325	16.3	53,087	2.20%	44,240	1.84%	8,848	0.37%

DECISION NO. 67744

ARIZONA PUBLIC SERVICE COMPANY
Schedule 1. Summary of Service Life and Net Salvage Estimates and Calculated Remaining Life Annual Accruals
Related to Electric Plant at December 31, 2002

The Calculated annual accrual (9) is made up of two depreciation components - service life and net salvage

	Depreciable Group	Probable Retirement Year	Estimated Survivor Curve	Net Salvage Percent	Original Cost at 12/31/02	Book Accumulated Depreciation	Future Accruals	Composite Remaining Life	Calculated Annual Accrual Amount	Calculated Annual Accrual Rate	Annual Accrual Service Life Amount	Annual Accrual Service Life Rate	Annual Accrual Net Salvage Amount	Annual Accrual Net Salvage Rate
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)=(9)/(5)	(11) =	(12)=(11)/(5)	(13) =	(14)=(13)/(5)
	Saguaro Units 1-2	06-2014	60 - R2.5	(20)	2,654,661	2,355,021	830,672	11.2	74,158	2.79%	61,799	2.33%	12,360	0.47%
	Total Account 315				134,807,415	80,088,778	81,680,122		3,642,426	2.70%	3,035,354	2.25%	607,071	0.45%
316	Miscellaneous Power Plant Equipment													
	Cholla Unit 1	06-2017	40 - R2	(20)	2,315,189	1,189,333	1,588,894	13.5	117,696	5.08%	98,080	4.24%	19,616	0.85%
	Cholla Unit 2	06-2033	40 - R2	(20)	4,848,431	2,631,492	3,184,225	22.1	144,083	2.97%	120,069	2.48%	24,014	0.50%
	Cholla Unit 3	06-2035	40 - R2	(20)	4,138,531	1,990,199	2,976,038	23.8	125,044	3.02%	104,203	2.52%	20,841	0.50%
	Cholla Common	06-2035	40 - R2	(20)	7,096,069	2,439,747	6,075,536	25.8	235,486	3.32%	196,238	2.77%	39,248	0.55%
	Four Corners Units 1-3	06-2016	40 - R2	(20)	4,330,612	925,502	4,271,232	13.1	326,048	7.53%	271,707	6.27%	54,341	1.25%
	Four Corners Units 4-5	06-2031	40 - R2	(20)	3,304,340	1,402,561	2,562,847	23.0	111,419	3.37%	92,850	2.81%	18,570	0.56%
	Four Corners Common	06-2031	40 - R2	(20)	8,133,224	3,483,659	6,276,210	23.2	270,526	3.33%	225,438	2.77%	45,088	0.55%
	Navajo Units 1-3	06-2026	40 - R2	(20)	11,805,250	5,248,830	8,917,470	20.2	441,459	3.74%	367,882	3.12%	73,676	0.62%
	Ocotillo Units 1-2	06-2020	40 - R2	(20)	3,711,192	1,301,603	3,151,827	16.2	194,557	5.24%	162,131	4.37%	32,426	0.87%
	Saguaro Units 1-2	06-2014	40 - R2	(20)	3,191,024	1,340,385	2,488,844	10.9	228,334	7.16%	190,279	5.96%	38,056	1.19%
	Yucca Unit 1	06-2016	40 - R2	(20)	452,868	359,801	183,641	12.2	15,053	3.32%	12,544	2.77%	2,509	0.55%
	Total Account 316				53,324,730	22,313,112	41,876,564		2,209,705	4.14%	1,841,421	3.45%	368,284	0.69%
	TOTAL STEAM PRODUCTION PLANT				1,292,132,201	746,269,083	816,288,558		42,761,850		35,634,959		7,126,992	
	NUCLEAR PRODUCTION PLANT													
321	Structures and Improvements													
	Palo Verde Unit 1	12-2024	65 - R2.5	0	161,039,432	69,557,944	91,481,488	21.2	4,315,165	2.68%	4,315,165	2.68%	0	0.00%
	Palo Verde Unit 2	12-2025	65 - R2.5	0	88,415,270	38,859,061	49,556,209	22.0	2,252,555	2.55%	2,252,555	2.55%	0	0.00%
	Palo Verde Unit 3	03-2027	65 - R2.5	0	159,591,077	63,133,223	96,457,854	23.3	4,139,822	2.59%	4,139,822	2.59%	0	0.00%
	Palo Verde Water Reclamati	03-2027	65 - R2.5	0	125,593,913	51,122,827	74,471,086	23.2	3,209,961	2.56%	3,209,961	2.56%	0	0.00%
	Palo Verde Common	03-2027	65 - R2.5	0	98,127,309	39,316,906	58,810,403	23.2	2,534,931	2.58%	2,534,931	2.58%	0	0.00%
	Total Account 321				632,767,001	261,989,961	370,777,040		16,452,433	2.60%	16,452,433	2.60%	0	0.00%
322	Reactor Plant Equipment													
	Palo Verde Unit 1	12-2024	70 - R1	(2)	359,545,213	153,816,828	213,119,289	20.6	10,345,597	2.88%	10,142,742	2.82%	202,855	0.06%
	Palo Verde Unit 2	12-2025	70 - R1	(2)	176,362,235	72,682,559	107,306,921	21.5	4,991,020	2.83%	4,893,156	2.77%	97,863	0.06%
	Palo Verde Unit 3	03-2027	70 - R1	(2)	322,750,700	121,218,478	207,987,236	22.6	9,202,976	2.85%	9,022,525	2.80%	180,450	0.06%
	Palo Verde Water Reclamati	03-2027	70 - R1	(2)	123,313	7,176	118,603	23.0	5,157	4.18%	5,056	4.10%	101	0.08%
	Palo Verde Common	03-2027	70 - R1	(2)	26,449,873	9,583,436	17,395,434	22.8	769,709	2.91%	754,617	2.85%	15,092	0.06%
	Total Account 322				885,231,334	357,008,477	545,927,484		25,314,457	2.86%	24,818,095	2.80%	496,362	0.06%
322.1	Reactor Plant Equipment - Steam Generators													
	Palo Verde Unit 1	12-2005	Square	(17)	30,722,376	27,569,149	8,376,030	3.0	2,792,010	9.09%	2,386,333	7.77%	405,677	1.32%
	Palo Verde Unit 2	12-2003	Square	(17)	15,870,063	15,868,635	2,699,327	1.0	2,699,327	17.01%	2,307,117	14.54%	392,210	2.47%
	Palo Verde Unit 3	12-2007	Square	(17)	25,413,317	20,039,935	9,693,646	5.0	1,938,729	7.63%	1,657,033	6.52%	281,696	1.11%
	Total Account 322.1				72,005,745	63,477,719	20,769,003		7,430,066	10.32%	6,350,464	8.82%	1,079,582	1.50%
323	Turbogenerator Units													
	Palo Verde Unit 1	12-2024	60 - S0	(2)	117,808,078	61,570,896	68,593,344	19.9	3,446,902	2.93%	3,379,316	2.87%	67,586	0.06%
	Palo Verde Unit 2	12-2025	60 - S0	(2)	78,764,224	32,432,468	45,856,840	20.8	2,204,656	2.87%	2,161,427	2.82%	43,229	0.06%
	Palo Verde Unit 3	03-2027	60 - S0	(2)	142,895,086	55,838,987	89,914,003	21.8	4,124,496	2.89%	4,043,623	2.83%	80,872	0.06%
	Palo Verde Water Reclamati	03-2027	60 - S0	(2)	217,707	76,585	145,476	22.0	6,613	3.04%	6,483	2.98%	130	0.06%
	Palo Verde Common	03-2027	60 - S0	(2)	1,223,879	346,554	901,803	22.2	40,622	3.32%	39,825	3.25%	797	0.07%
	Total Account 323				338,898,976	140,265,490	205,411,466		9,823,287	2.90%	9,630,674	2.84%	192,613	0.06%
324	Accessory Electric Equipment													

DECISION NO. 67744

ARIZONA PUBLIC SERVICE COMPANY
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Related to Electric Plant at December 31, 2002

The Calculated annual accrual (9) is made up of two depreciation components - service life and net salvage

	Depreciable Group	Probable Retirement Year	Estimated Survivor Curve	Net Salvage Percent	Original Cost at 12/31/02	Book Accumulated Depreciation	Future Accruals	Composite Remaining Life	Calculated Annual Accrual Amount	Calculated Annual Accrual Rate		Annual Accrual Service Life Amount	Annual Accrual Service Life Rate	Annual Accrual Net Salvage Amount	Annual Accrual Net Salvage Rate
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)=(9)/(5)		(11) =	(12)=(11)/(5)	(13) =	(14)=(13)/(5)
	Palo Verde Unit 1	12-2024	45 - R3	(2)	115,495,170	53,444,066	64,361,007	20.0	3,218,050	2.79%		3,154,951	2.73%	63,099	0.05%
	Palo Verde Unit 2	12-2025	45 - R3	(2)	50,119,358	21,982,186	29,139,590	20.9	1,394,238	2.78%		1,366,901	2.73%	27,338	0.05%
	Palo Verde Unit 3	03-2027	45 - R3	(2)	89,143,623	36,343,481	54,583,014	22.1	2,469,820	2.77%		2,421,392	2.72%	48,428	0.05%
	Palo Verde Common	03-2027	45 - R3	(2)	17,918,193	7,299,463	10,977,094	22.0	498,959	2.78%		489,175	2.73%	9,784	0.05%
	Total Account 324				272,676,374	119,069,196	159,060,705		7,581,068	2.78%		7,432,419	2.73%	148,648	0.05%
325	Miscellaneous Power Plant Equipment														
	Palo Verde Unit 1	12-2024	35 - R0.5	(2)	29,671,405	11,770,905	18,493,928	17.7	1,044,855	3.52%		1,024,367	3.45%	20,487	0.07%
	Palo Verde Unit 2	12-2025	35 - R0.5	(2)	26,389,406	8,702,844	18,214,350	18.7	974,029	3.69%		954,931	3.62%	19,099	0.07%
	Palo Verde Unit 3	03-2027	35 - R0.5	(2)	27,284,046	9,445,478	18,384,249	19.2	957,513	3.51%		938,738	3.44%	18,775	0.07%
	Palo Verde Water Reclamati	03-2027	35 - R0.5	(2)	88,819	27,708	62,889	19.5	3,225	3.63%		3,162	3.56%	63	0.07%
	Palo Verde Common	03-2027	35 - R0.5	(2)	48,459,510	15,382,218	34,046,482	19.4	1,754,973	3.62%		1,720,562	3.55%	34,411	0.07%
	Total Account 325				131,893,186	45,329,151	89,201,899		4,734,595	3.59%		4,641,760	3.52%	92,835	0.07%
	TOTAL NUCLEAR PRODUCTION PLANT				2,333,472,816	987,139,994	1,391,147,596		71,335,907			69,325,844		,010,041	
HYDRO PRODUCTION PLANT															
331	Structures and Improvement	12-2004	200-SQ	0	100,878	100,878	0	0.0	0	0.00		0	0.00%	0	0.00%
332	Reservoirs, Dams and Wate	12-2004	200-SQ	0	991,936	1,105,066	(13,1 0	0.0	0	0.00		0	0.00%	0	0.00%
333	Water Wheels, Turbines and	12-2004	200-SQ	0	157,196	157,196	0	0.0	0	0.00		0	0.00%	0	0.00%
334	Accessory Electric Equipme	12-2004	200-SQ	0	627,611	627,611	0	0.0	0	0.00		0	0.00%	0	0.00%
335	Miscellaneous Power Plant I	12-2004	200-SQ	0	126,018	126,018	0	0.0	0	0.00		0	0.00%	0	0.00%
336	Roads, Railroads and Bridge	12-2004	200-SQ	0	77,427	77,427	0	0.0	0	0.00		0	0.00%	0	0.00%
	Hydro Decommissioning Costs				-	7,684,531	5,335,469	2.0	2,667,735			2,667,735	100.00%	0	0.00%
	TOTAL HYDRO PRODUCTION PLANT				2,081,066	10,658,747	5,222,319		2,667,735			2,667,735		0	
OTHER PRODUCTION PLANT															
341	Structures and Improvements														
	Douglas CT	06-2017	80 - S1	(5)	4,562	4,146	642	13.9	46	1.01%		44	0.96%	2	0.05%
	Ocotillo CT 1 - 2	06-2017	80 - S1	(5)	328,749	230,819	114,367	14.5	7,887	2.40%		7,512	2.28%	376	0.11%
	Saguaro CT	06-2017	80 - S1	(5)	1,288,525	466,971	885,980	14.4	61,526	4.77%		58,597	4.55%	2,930	0.23%
	Solar Unit 1		12 - SQ	0	375,512	383,809	(8,297)	3.8	0	0.00%	(2)	0	0.00%	0	0.00%
	West Phoenix CT 1 - 2	06-2017	80 - S1	(5)	510,951	419,492	117,007	14.2	8,240	1.61%		7,848	1.54%	392	0.08%
	West Phoenix Combined Cy	06-2031	80 - S1	(5)	6,706,722	2,438,522	4,603,538	28.1	163,827	2.44%		156,026	2.33%	7,801	0.12%
	Yucca CT 1 - 4	06-2016	80 - S1	(5)	452,751	222,815	252,574	13.4	18,849	4.16%		17,951	3.96%	898	0.20%
	Total Account 341				9,667,772	4,166,576	5,965,809		260,376	2.69%		247,977	2.56%	12,399	0.13%
342	Fuel Holders, Products and Accessories														
	Douglas CT	06-2017	70 - S1	(5)	137,759	100,065	44,582	14.0	3,184	2.31%		3,033	2.20%	152	0.11%
	Ocotillo CT 1 - 2	06-2017	70 - S1	(5)	718,859	517,984	237,868	14.0	16,991	2.36%		16,181	2.25%	809	0.11%
	Saguaro CT	06-2017	70 - S1	(5)	1,304,977	1,019,500	350,726	14.0	25,052	1.92%		23,859	1.83%	1,193	0.09%
	West Phoenix CT 1 - 2	06-2017	70 - S1	(5)	1,437,533	1,123,270	386,140	14.0	27,581	1.92%		26,268	1.83%	1,313	0.09%
	West Phoenix Combined Cy	06-2031	70 - S1	(5)	19,343,993	2,849,135	17,662,058	27.0	637,619	3.30%		607,257	3.14%	30,363	0.16%
	Yucca CT 1 - 4	06-2016	70 - S1	(5)	3,232,217	2,859,228	534,600	12.9	41,442	1.28%		39,468	1.22%	1,973	0.06%
	Total Account 342				26,175,338	8,269,182	19,215,973		751,870	2.87%		716,066	2.74%	35,803	0.14%
343	Prime Movers														
	Douglas CT	06-2017	70 - L1.5	0	1,101,449	999,227	102,222	14.2	7,199	0.65%	(1)	7,199	0.65%	0	0.00%
	Ocotillo CT 1 - 2	06-2017	70 - L1.5	0	6,679,324	5,679,469	999,855	14.1	70,912	1.06%		70,912	1.06%	0	0.00%
	Saguaro CT	06-2017	70 - L1.5	0	8,102,651	6,657,234	1,445,417	13.8	104,740	1.29%		104,740	1.29%	0	0.00%
	West Phoenix CT 1 - 2	06-2017	70 - L1.5	0	8,802,636	6,220,272	2,582,364	14.2	181,857	2.07%		181,857	2.07%	0	0.00%
	Yucca CT 1 - 4	06-2016	70 - L1.5	0	7,920,584	7,302,457	618,127	14.2	43,530	0.55%	(1)	43,530	0.55%	0	0.00%

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ARIZONA PUBLIC SERVICE COMPANY
Schedule 1. Summary of Service Life and Net Salvage Estimates and Calculated Remaining Life Annual Accruals
Related to Electric Plant at December 31, 2002

	Depreciable Group	Probable Retirement Year	Estimated Survivor Curve	Net Salvage Percent	Original Cost at 12/31/02	Book Accumulated Depreciation	Future Accruals	Composite Remaining Life	Calculated Annual Accrual Amount	Calculated Annual Accrual Rate	The Calculated annual accrual (9) is made up of two depreciation components - service life and net salvage: Annual Accrual Service Life Amount	Annual Accrual Service Life Rate	Annual Accrual Net Salvage Amount	Annual Accrual Net Salvage Rate
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)=(9)/(5)	(11) =	(12)=(11)/(5)	(13) =	(14)=(13)/(5)
	Total Account 343				32,606,644	26,858,659	5,747,985		408,237	1.25%	408,237	1.25%	0	0.00%
344	Generators and Devices													
	Douglas CT	06-2017	37 - R3	0	551,765	542,840	8,925	9.7	920	0.17%	920	0.17%	0	0.00%
	Ocotillo CT 1 - 2	06-2017	37 - R3	0	6,402,044	3,500,409	2,901,635	13.6	213,356	3.33%	213,356	3.33%	0	0.00%
	Saguaro CT	06-2017	37 - R3	0	4,185,247	2,504,957	1,680,290	13.0	129,253	3.09%	129,253	3.09%	0	0.00%
	Solar Unit 1		12 - SQ	0	6,933,081	3,289,918	3,643,163	7.8	467,072	6.74%	467,072	6.74%	0	0.00%
	West Phoenix CT 1 - 2	06-2017	37 - R3	0	4,115,901	3,202,560	913,341	12.3	74,255	1.80%	74,255	1.80%	0	0.00%
	West Phoenix Combined Cy	06-2031	37 - R3	(2)	81,920,222	11,983,119	71,575,507	26.2	2,731,890	3.33%	2,731,890	3.33%	0	0.00%
	Yucca CT 1 - 4	06-2016	37 - R3	0	5,395,818	4,370,148	1,025,670	11.6	88,420	1.64%	88,420	1.64%	0	0.00%
	Total Account 344				109,504,078	29,393,951	81,748,531		3,705,166	3.38%	3,705,166	3.38%	0	0.00%
345	Accessory Electric Equipment													
	Douglas CT	06-2017	50 - S2	0	353,277	313,549	39,728	13.1	3,033	0.86%	3,033	0.86%	0	0.00%
	Ocotillo CT 1 - 2	06-2017	50 - S2	0	1,494,636	1,281,843	212,793	13.2	16,121	1.08%	16,121	1.08%	0	0.00%
	Saguaro CT	06-2017	50 - S2	0	1,715,774	1,389,500	326,274	13.4	24,349	1.42%	24,349	1.42%	0	0.00%
	Solar Unit 1		12 - SQ	0	169,527	40,179	129,348	9.9	13,065	7.71%	13,065	7.71%	0	0.00%
	West Phoenix CT 1 - 2	06-2017	50 - S2	0	1,557,744	1,315,426	242,318	13.2	18,357	1.18%	18,357	1.18%	0	0.00%
	West Phoenix Combined Cy	06-2031	50 - S2	0	11,925,645	2,562,942	9,362,703	27.8	336,788	2.82%	336,788	2.82%	0	0.00%
	Yucca CT 1 - 4	06-2016	50 - S2	0	2,166,526	1,817,969	348,557	13.0	26,812	1.24%	26,812	1.24%	0	0.00%
	Total Account 345				19,383,129	8,721,408	10,661,721		438,525	2.26%	438,525	2.26%	0	0.00%
346	Miscellaneous Power Plant Equipment													
	Douglas CT	06-2017	70 - L1	0	40,913	30,160	10,753	13.8	779	1.90%	779	1.90%	0	0.00%
	Ocotillo CT 1 - 2	06-2017	70 - L1	0	553,173	418,696	134,477	14.0	9,606	1.74%	9,606	1.74%	0	0.00%
	Saguaro CT	06-2017	70 - L1	0	790,906	410,357	380,549	14.1	26,969	3.41%	26,969	3.41%	0	0.00%
	West Phoenix CT 1 - 2	06-2017	70 - L1	0	957,431	508,533	448,898	14.1	31,837	3.33%	31,837	3.33%	0	0.00%
	West Phoenix Combined Cy	06-2031	70 - L1	0	2,608,877	895,856	1,713,021	26.6	64,399	2.47%	64,399	2.47%	0	0.00%
	Yucca CT 1 - 4	06-2016	70 - L1	0	427,175	357,633	69,542	13.2	5,268	1.23%	5,268	1.23%	0	0.00%
	Total Account 346				[illegible]	2,621,235	2,757,240		138,878	2.58%	138,878	2.58%	0	0.00%
	TOTAL OTHER PRODUCTION PLANT				202,716,436	80,631,011	128,097,258		5,703,852		5,664,849		48,202	

(1) Staff's reallocation of reserves caused account to have a remaining Net Book Value. APS selected the longest life of other plant in that FERC account to calculate remaining life.
(2) Account is fully depreciated and, therefore, should have zero depreciation, not negative depreciation.

	TRANSMISSION PLANT													
352	Structures and Improvements		50 - R4	(5)	27,618,299	12,484,016	16,515,198	35.2	469,182	1.70%	446,840	1.62%	22,342	0.08%
352.5	Structures and Improvements - SCE 500 KV Line				409,725	424,897	(15,172)		13,316	3.25% (a)	13,316	3.25%	0	0.00%
353	Station Equipment		57 - R1.5	0	428,736,305	130,140,054	298,596,251	45.7	6,538,127	1.52%	6,538,127	1.52%	0	0.00%
353.5	Station Equipment - SCE 500 I				7,747,282	7,349,363	397,919		251,787	3.25% (a)	251,787	3.25%	0	0.00%
354	Towers and Fixtures		60 - R3	(35)	83,464,531	46,097,366	66,579,751	38.3	1,738,375	2.08%	1,287,685	1.54%	450,690	0.54%
354.5	Towers and Fixtures - SCE 50				13,752,584	17,477,965	(3,725,381)		446,959	3.25% (a)	446,959	3.25%	0	0.00%
355	Poles and Fixtures - Wood		48 - R1.5	(35)	91,126,939	27,541,958	95,479,410	38.5	2,479,985	2.72%	1,837,026	2.02%	642,959	0.71%
355.1	Poles and Fixtures - Steel		55 - R3	(15)	83,067,868	22,833,440	72,694,631	45.1	1,611,854	1.94%	1,401,612	1.69%	210,242	0.25%
355.5	Poles and Fixtures - SCE 500				930,308	692,575	237,733		30,235	3.25% (a)	30,235	3.25%	0	0.00%
356	Overhead Conductors and De		55 - R3	(35)	205,771,417	94,269,686	183,521,747	38.5	4,766,799	2.32%	3,530,962	1.72%	1,235,837	0.60%
356.5	Overhead Conductors and Devices - SCE 500 KV Line				22,653,515	28,947,611	(6,294,096)		736,239	3.25% (a)	736,239	3.25%	0	0.00%
357	Underground Conduit		45 - S1.5	(10)	10,444,362	4,087,064	7,401,734	35.7	207,331	1.99%	188,483	1.80%	18,848	0.18%
358	Underground Conductors and		40 - R3	(10)	18,551,254	9,702,854	10,703,526	26.3	406,978	2.19%	369,980	1.99%	36,998	0.20%
	TOTAL TRANSMISSION PLANT				994,274,409	402,048,829	742,093,250		19,697,167		17,079,251		2,617,916	

DECISION NO. 67744

ARIZONA PUBLIC SERVICE COMPANY
Schedule 1. Summary of Service Life and Net Salvage Estimates and Calculated Remaining Life Annual Accruals
Related to Electric Plant at December 31, 2002

The Calculated annual accrual (9) is made up of two depreciation components - service life and net salvage

	Depreciable Group	Probable Retirement Year	Estimated Survivor Curve	Net Salvage Percent	Original Cost at 12/31/02	Book Accumulated Depreciation	Future Accruals	Composite Remaining Life	Calculated Annual Accrual Amount	Calculated Annual Accrual Rate		Annual Accrual Service Life Amount	Annual Accrual Service Life Rate	Annual Accrual Net Salvage Amount	Annual Accrual Net Salvage Rate
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)=(9)/(5)		(11) =	(12)=(11)/(5)	(13) =	(14)=(13)/(5)
DISTRIBUTION PLANT															
361	Structures and Improvements		45 - R2.5	(10)	25,815,042	10,429,908	17,966,838	33.1	542,799	2.10%		493,453	1.91%	49,345	0.19%
362	Station Equipment		44 - L0.5	0	212,357,577	52,722,295	159,635,282	36.9	4,332,029	2.04%		4,332,029	2.04%	0	0.00%
364	Poles, Towers and Fixtures - V		38 - R0.5	(10)	284,200,711	81,128,434	231,492,348	30.9	7,491,662	2.64%		6,810,602	2.40%	681,060	0.24%
364.1	Poles, Towers and Fixtures - S		50 - R3	(5)	53,919,851	5,601,820	51,013,814	46.6	1,094,717	2.03%		1,042,588	1.93%	52,129	0.10%
365	Overhead Conductors and De		53 - O1	(10)	218,856,780	33,437,453	207,305,005	47.7	4,346,017	1.99%		3,950,924	1.81%	395,092	0.18%
366	Underground Conduit		86 - O1	(5)	425,723,118	26,924,767	420,084,506	82.4	5,098,113	1.20%		4,855,348	1.14%	242,767	0.06%
367	Underground Conductors and		29 - L1	(5)	805,505,763	258,665,205	586,915,867	22.9	25,629,514	3.18%		24,409,061	3.03%	1,220,453	0.15%
368	Line Transformers		36 - R3	(5)	486,837,053	235,537,009	275,641,897	24.6	11,204,955	2.30%		10,671,366	2.19%	533,569	0.11%
369	Services		37 - S2	(10)	242,404,812	91,086,518	175,558,776	27.9	6,292,429	2.60%		5,720,390	2.36%	672,039	0.24%
370	Meters		29 - L0	0	91,330,710	34,836,184	56,494,526	21.8	2,598,256	2.84%		2,598,256	2.84%	0	0.00%
370.1	Electronic Meters		26 - R1.5	0	54,691,249	8,612,961	46,078,288	23.3	1,975,913	3.61%		1,975,913	3.61%	0	0.00%
371	Installations On Customers Pr		50 - O2	(20)	25,335,631	3,863,126	26,539,871	45.0	589,775	2.33%		491,479	1.94%	98,296	0.39%
373	Street Lighting and Signal Sys		35 - R2	(20)	57,165,737	22,716,125	45,906,759	25.9	1,772,462	3.10%		1,477,051	2.58%	295,410	0.52%
TOTAL DISTRIBUTION PLANT					2,984,184,052	865,761,602	2,300,833,578		72,966,840			68,826,478		4,140,162	
GENERAL PLANT															
390	Structures and Improvements		39 - R1	(15)	96,667,435	24,085,116	87,082,434	30.7	2,836,561	2.93%		2,466,575	2.55%	369,986	0.38%
391	Office Furniture and Equipmer		20 - SQ	0	19,919,640	11,543,613	8,376,027	10.1	829,310	4.16%		829,310	4.16%	0	0.00%
391.1	Office Furniture and Equipmer		8 - R3	0	38,654,946	15,103,632	23,551,314	5.3	4,418,633	11.43%		4,418,633	11.43%	0	0.00%
391.2	Office Furniture and Equipmer		22 - R4	0	7,652,923	2,932,191	4,720,732	14.8	318,968	4.17%		318,968	4.17%	0	0.00%
393	Stores Equipment		20 - SQ	0	1,227,371	1,235,746	(8,375)	2.8	0	0.00%	(2)	0	0.00%	0	0.00%
394	Tools, Shop and Garage Equi		20 - SQ	0	12,673,031	4,673,542	7,999,489	13.7	583,904	4.61%		583,904	4.61%	0	0.00%
395	Laboratory Equipment		20 - L1	0	1,350,583	531,270	819,313	12.0	68,504	5.07%		68,504	5.07%	0	0.00%
397	Communication Equipment		19 - S1.5	0	94,309,691	40,677,647	53,632,044	12.0	4,469,337	4.74%		4,469,337	4.74%	0	0.00%
398	Miscellaneous Equipment		24 - S1.5	0	1,336,404	481,756	854,649	16.6	51,454	3.85%		51,454	3.85%	0	0.00%
TOTAL GENERAL PLANT					273,792,024	101,264,512	187,027,627		13,578,872			13,208,685		369,986	
TOTAL DEPRECIABLE PLANT STUDIED					8,082,632,904	3,186,573,878	5,582,511,184		228,788,123			212,385,824		16,313,299	

(2) Account is fully depreciated and, therefore, should have zero depreciation, not negative depreciation.

(a) ... related to the 500 KV SCE Transmission Line are Depreciated at ... of 3.5%.

		Original Cost at 12/31/02	Book Accumulated Depreciation
STEAM PRODUCTION PLANT NOT STUDIED			
311	Structures and Improvements - West Phoenix	0	60,895
312	Boiler Plant Equipment - West Phoenix Units	0	300,097
312	Boiler Plant Equipment - Yucca Unit 1	425,323	441,994
314	Turbogenerator Units - West Phoenix Units 4	0	314,512
314	Turbogenerator Units - Yucca Unit 1	184,916	188,319
315	Accessory Electric Equipment - West Phoeni	33,966	83,338
315	Accessory Electric Equipment - Yucca Unit 1	182,084	185,435
316	Misc. Power Plant Equipment-West Phoenix U	17,267	0
TOTAL STEAM PRODUCTION PLANT NOT STUDIED		843,556	1,594,590
GENERAL PLANT NOT STUDIED			
392	Vehicles	28,410,886	20,605,998
396	Power Operated Equipment	27,947,651	18,603,989
TOTAL GENERAL PLANT NOT STUDIED		56,358,537	39,209,987
OTHER PROPERTY NOT STUDIED			
Intangible Plant			
301	Organization	73,839	

DECISION NO. 67744

ARIZONA PUBLIC SERVICE COMPANY
Schedule 1 Summary of Service Life and Net Salvage Estimates and Calculated Remaining Life Annual Accruals
Related to Electric Plant at December 31, 2002

The Calculated annual accrual (9) is made up of two depreciation components - service life and net salvage

	Depreciable Group	Probable Retirement Year	Estimated Survivor Curve	Net Salvage Percent	Original Cost at 12/31/02	Book Accumulated Depreciation	Future Accruals	Composite Remaining Life	Calculated Annual Accrual Amount	Calculated Annual Accrual Rate	Annual Accrual Service Life Amount	Annual Accrual Service Life Rate	Annual Accrual Net Salvage Amount	Annual Accrual Net Salvage Rate
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)=(9)/(5)	(11) =	(12)=(11)/(5)	(13) =	(14)=(13)/(5)
302	Franchises and Consents				683,584									
303	Miscellaneous Intangible Plant				201,550,375									
	Leased Property													
321	Structures and Improvements				1,833,193									
322	Reactor Plant Equipment				9,670,223									
323	Turbogenerator Units				2,705,885									
324	Accessory Electric Equipment				944,788									
325	Miscellaneous Power Plant Equipment				563,135									
361	Structures and Improvements				195,512									
368	Line Transformers				179,394									
371	Installations On Customers Premises				60,386									
390	Structures and Improvements				11,180,324									
397	Communication Equipment				246,938									
	TOTAL OTHER PROPERTY NOT STUDIED				228,866,377	120,727,788								
	TOTAL DEPRECIABLE PLANT IN SERVICE				8,389,701,276	3,348,106,323								
	NONDEPRECIABLE PLANT													
310	Land and Land Rights				3,295,268									
320	Land and Land Rights				3,399,728									
330	Land and Land Rights				84,500									
340	Land and Land Rights				28,192									
350	Land and Land Rights				50,808,274									
360	Land and Land Rights				26,755,119									
389	Land and Land Rights				7,327,436									
	TOTAL NONDEPRECIABLE				91,678,517									
	TOTAL PLANT IN SERVICE				8,481,379,793									

DECISION NO. 67744

PINNACLE WEST ENERGY CORPORATION

Summary of Service Life and Net Salvage Estimates and Calculated Remaining Life Annual Accruals
Related to Electric Plant at December 31, 2002

Depreciable Group (1)	Probable Retirement Year (2)	Estimated Survivor Curve (3)	Net Salvage Percent (4)	Original Cost at 12/31/02 (5)	Book Accumulated Depreciation (6)	Future Accruals (7)	Composite Remaining Life (8)	Calculated Annual Accrual Amount (9)	Calculated Annual Accrual Rate (10)=(9)/(5)
OTHER PRODUCTION									
341 Structures and Improvements									
West Phoenix CC 4	6-2056	80 - S1	(5)	3,768,898	69,749	3,887,594	49.71	78,205	2.08%
342 Fuel Holders, Products and Accessories									
West Phoenix CC 4	6-2056	70 - S1	(5)	4,135,109	62,598	4,279,266	48.32	88,561	2.14%
343 Prime Movers									
West Phoenix CC 4	6-2056	70 - L1.5	(2)	57,116,985	919,686	57,339,639	46.94	1,221,552	2.14%
344 Generators and Devices									
Redhawk CC Units 1 & 2	6-2057	70 - O4	(3)	546,899,426	13,736,086	549,570,323	34.03	16,149,583	2.95%
West Phoenix CC 4	6-2056	37 - R3	(2)	14,296,553	28,896	14,553,588	35.47	410,307	2.87%
Saguaro CT 3	6-2047	37 - R3	0	37,659,176	75,121	37,584,055	35.49	1,059,004	2.81%
Total Account 344				598,855,155	13,840,103	601,707,966		17,618,894	2.94%
TOTAL OTHER PRODUCTION PLANT				663,876,147	14,892,136	667,214,465		19,007,213	
TRANSMISSION									
353 Station Equipment									
Redhawk CC Units 1 & 2		57 - R1.5	0	46,000,000	569,193	45,430,807	56.59	802,806	1.75%
West Phoenix CC 4		57 - R1.5	0	1,953,105	72,502	1,880,603	55.77	33,721	1.73%
Total Account 353				47,953,105	641,695	47,311,410		836,527	1.74%
355 Poles and Fixtures- Steel									
Redhawk CC Units 1 & 2		55 - R3	(5)	1,500,000	23,458	1,701,542	54.50	31,221	2.08%
356 Overhead Conductors and De[illegible]									
Redhawk CC Units 1 & 2		5 ∞	(35)	1,500,000	23,458	2,001,542	54.50	36,726	2.45%
TOTAL TRANSMISSION PLANT				50,953,105	688,611	51,014,494		904,473	
Depreciate Property Totals				714,829,252	15,580,747	718,228,959		19,911,686	
NONDEPRECIABLE PLANT									
340 Land									
Redhawk CC Common				2,246,597					
West Phoenix CC 4				32,909	70				
TOTAL NONDEPRECIABLE PLANT				2,279,507	70				
TOTAL PWE PLANT IN SERVICE				717,108,759	15,580,817				

DECISION NO. 67744

PINNACLE WEST ENERGY CORPORATION

Summary of Service Life and Net Salvage Estimates and Calculated Remaining Life Annual Accruals
Related to Electric Plant at December 31, 2002

The Calculated Annual Accrual (9) is made up of two depreciation components - service life and net salvage

Depreciable Group (1)	Probable Retirement Year (2)	Estimated Survivor Curve (3)	Net Salvage Percent (4)	Original Cost at 12/31/02 (5)	Book Accumulated Depreciation (6)	Future Accruals (7)	Composite Remaining Life (8)	Calculated Annual Accrual Amount (9)	Calculated Annual Accrual Rate (10)=(9)/(5)	Annual Accrual Service Life Amount (11) = (9) * 100/100+(-4))	Annual Accrual Service Life Rate (12)=(11)/(5)	Annual Accrual Net Salvage Amount (13) = (9) * (-4)/100+(-4))	Annual Accrual Net Salvage Rate (14)=(13)/(5)
OTHER PRODUCTION													
341 Structures and Improvements													
West Phoenix CC 4	6-2056	80 - S1	(5)	$3,768,898	$69,749	$3,887,594	49.71	$78,205	2.08%	$74,481	1.98%	$3,724	0.10%
342 Fuel Holders, Products and Accessories													
West Phoenix CC 4	6-2056	70 - S1	(5)	4,135,109	62,598	4,279,266	48.32	88,561	2.14%	$84,344	2.04%	$4,217	0.10%
343 Prime Movers													
West Phoenix CC 4	6-2056	70 - L1.5	(2)	57,118,985	919,858	57,339,839	46.94	1,221,552	2.14%	$1,197,600	2.10%	$23,952	0.04%
344 Generators and Devices													
Redhawk CC Units 1 & 2	6-2057	70 - O4	(3)	546,899,426	13,736,088	549,570,323	34.03	16,149,583	2.95%	$15,679,207	2.87%	$470,376	0.09%
West Phoenix CC 4	6-2058	37 - R3	(2)	14,296,553	28,898	14,553,568	35.47	410,307	2.87%	$402,262	2.81%	$8,045	0.06%
Saguaro CT 3	6-2047	37 - R3	0	37,659,176	75,121	37,584,055	35.49	1,059,004	2.81%	$1,059,004	2.81%	$0	0.00%
Total Account 344				598,855,155	13,840,103	601,707,966		17,618,894	2.94%	$17,140,473	2.86%	$478,421	0.08%
TOTAL OTHER PRODUCTION PLANT				663,876,147	14,892,138	667,214,485		19,007,213		18,496,898		510,315	
TRANSMISSION													
353 Station Equipment													
Redhawk CC Units 1 & 2		57 - R1.5	0	46,000,000	569,193	45,430,807	56.59	802,806	1.75%	$802,806	1.75%	$0	0.00%
West Phoenix CC 4		57 - R1.5	0	1,953,105	72,502	1,880,803	55.77	33,721	1.73%	$33,721	1.73%	$0	0.00%
Total Account 353				47,953,105	641,695	47,311,410		836,527	1.74%	$836,527	1.74%	$0	
355 Poles and Fixtures - Steel													
Redhawk CC Units 1 & 2		55 - R3	(15)	1,500,000	23,458	1,701,542	54.50	31,221	2.08%	$27,149	1.81%	$4,072	0.27%
356 Overhead Conductors and Devices													
Redhawk CC Units 1 & 2		55 - R3	(35)	1,500,000	23,458	2,001,542	54.50	36,726	2.45%	$27,204	1.81%	$9,521	0.63%
TOTAL TRANSMISSION PLANT				50,953,105	688,611	51,014,494		904,473		890,880		13,594	
Depreciable Property Totals				$714,829,252	$15,580,747	$718,228,959		$19,911,686		$19,387,778		$523,909	
NONDEPRECIABLE PLANT													
340 Land													
Redhawk CC Common				2,246,597									
West Phoenix CC 4				32,909	70								
TOTAL NONDEPRECIABLE PLANT				2,279,507	70								
TOTAL PWE PLANT IN SERVICE				$717,108,759	$15,580,817								

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