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BEFORE THE ARIZONA CORPORATION CC

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AZ CORP COMMISSION
DOCKET CONTROL

COMMISSIONERS
GARY PIERCE- Chairman
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SANDRA D. KENNEDY
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BRENDA BURNS

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	DOCKET NO. E-01345A-11-0224 **STAFF'S NOTICE OF FILING DIRECT TESTIMONY AND REQUEST FOR SUBSTITUTION OF TESTIMONY**

On November 18, 2011, Staff filed its Direct Testimony in the above captioned docket. On November 22, 2011, Staff became aware that material labeled by Arizona Public Service Company as confidential had inadvertently been included within Staff's prefiled Direct Testimony. Staff hereby requests that the November 18th testimony be replaced with the attached substitute Staff Direct Testimony with the confidential material redacted. Staff has mailed parties only corrected copies of the individual witness testimony that required redaction rather than reproducing the entire prefiled Staff Direct Testimony for mailing.

RESPECTFULLY SUBMITTED this 25th day of November 2011.

Arizona Corporation Commission
DOCKETED
NOV 25 2011
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BEFORE THE ARIZONA CORPORATION COMMISSION

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Commissioner
SANDRA D. KENNEDY
Commissioner
PAUL NEWMAN
Commissioner
BRENDA BURNS
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	)	DOCKET NO. E-01345A-11-0224

PUBLIC

DIRECT

TESTIMONY

OF

RALPH C. SMITH

ON BEHALF OF THE

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

NOVEMBER 18, 2011

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Staff Accounting Schedules RCS-2
Copies of selected APS non-confidential responses to discovery and other documents that are referenced in my testimony RCS-3
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Excerpts of regulatory commission orders addressing ratepayer/shareholder sharing of Directors and Officers Liability Insurance Expense RCS-5

EXECUTIVE SUMMARY
ARIZONA PUBLIC SERVICE COMPANY
DOCKET NO. E-01345A-11-0224

The purpose of my testimony is to address the application for a general rate increase filed by APS. Specifically, I will be addressing the revenue requirement, rate base, net operating income, and selected other issues, including APS' proposal for new depreciation rates. I also discuss a potential cost recovery mechanism for the Commission's consideration to address Four Corners related cost changes.

APS' has requested a total base rate revenue increase of $95.493 million, which includes an increase of $54.610 million on original cost rate base and $40.883 million for additional revenue on the fair value increment. In an update filed by APS on October 26, 2011, APS has revised its base rate revenue increase request to $84.909 million, consisting of $42.646 million on original cost rate base and $42.263 million for the fair value increment.

On original cost rate base, including post-test year plant additions through March 31, 2012 and the rate of return recommended by Staff witness David Parcell, I have calculated a revenue sufficiency for APS of approximately $48.932 million. Staff is presenting the Commission with two alternatives for the revenue requirement change on fair value rate base ("FVRB") using the fair value rate of return ("FVROR") recommended by Staff witness Parcell. Under alternative 1, APS has a revenue sufficiency of approximately $48.932 million. Under FVROR alternative 2, the base rate revenue sufficiency is approximately $7.449 million. These amounts compare directly to the amounts in APS' filing on APS Schedule A-1. Staff is recommending the use of alternative 2 in this case, which results in a jurisdictional base rate decrease of approximately $7.449 million.

I recommend the following adjustments to the original cost and fair value rate base proposed by APS:

Summary of Staff Adjustments to Rate Base		**Original Cost**	**Fair Value**
Adj		Increase	Increase
No	Description	(Decrease)	(Decrease)
B-1	Post-Test Year Plant Additions - Through 3/31/2012 - Solar Plant	$ (35,406)	$ (35,406)
B-2	Post-Test Year Plant Additions - Through 3/31/2012 - Fossil Plant	$ (23,458)	$ (23,458)
B-3	Post-Test Year Plant Additions - Through 3/31/2012 - Nuclear Plant	$ (17,536)	$ (17,536)
B-4	Post-Test Year Plant Additions - Through 3/31/2012 - Distribution and General and Intangible Plant	$ (53,196)	$ (53,196)
B-5	Accumulated Depreciation - Post Test Year Adjustment Through 3/31/2012	$ 60,124	$ 60,124
B-6	Accumulated Deferred Income Taxes - Post Test Year Adjustment Through 3/31/2012	$ 1,726	$ 1,726
B-7	Cash Working Capital	$ 10,467	$ 10,467
	Total of Staff Adjustments	$ **(57,279)**	$ **(57,279)**
	APS Proposed Rate Base	$ 5,720,277	$ 8,224,405
	Staff Proposed Rate Base	$ **5,662,998**	$ **8,167,126**

Each of these adjustments is discussed in my testimony.

Staff's adjusted rate base and how it compares with APS' is summarized below:

$000's	APS	Staff	Difference
Summary of Rate Base	Schedule B-1	Schedule B	
Original Cost Rate Base	$ 5,720,277	$ 5,662,998	$ (57,279)
RCND Rate Base	$ 10,728,532	$ 10,671,253	$ (57,279)
Fair Value Rate Base	$ 8,224,405	$ 8,167,126	$ (57,279)

The adjusted fair value rate base has been used by Staff to compute the required base rate revenue requirement.

I also recommend several adjustments to net operating income. A summary Staff's adjustments and a reconciliation of the revenue deficiency on original cost rate base is presented in the following table:

Adj. No.	Description	Pre-Tax Revenue or Expense Adjustment	Net Operating Income Increase (Decrease)
C-1	Forensic Investigation of Grant-Funded Projects	$ (2,057)	$ 1,244
C-2	General Advertising Expense	$ (572)	$ 346
C-3	Property Tax Expense	$ (584)	$ 353
C-4	Solar Post Test Year Plant Depreciation and Property Tax Expense	$ (1,301)	$ 787
C-5	Fossil Post Test Year Plant Depreciation and Property Tax Expense	$ (783)	$ 473
C-6	Nuclear Post Test Year Plant Depreciation and Property Tax Expense	$ (363)	$ 220
C-7	Distribution and General and Intangible Post Test Year Plant Depreciation and Property	$ (2,664)	$ 1,611
C-8	Interest Synchronization	$ -	$ (638)
C-9	Base Fuel and Purchased Power	$ (9,575)	$ 5,792
C-10	Payroll Expense Adjustment - New Union Contract	$ 4,994	$ (3,021)
C-11	Depreciation Expense - New Depreciation Rates	$ (4,735)	$ 2,864
C-12	Prospective Amortization of 2010 Severance Costs	$ (3,128)	$ 1,892
C-13	Directors and Officers' Liability Insurance Expense	$ (550)	$ 333
C-14	Incentive Compensation	$ (18,930)	$ 11,451
C-15	Normalized Fossil Non-Plant Maintenance Expense	$ (266)	$ 161
C-16	Edison Electric Institute Dues	$ (216)	$ 131
Total of Staff's Adjustments		$ (40,730)	$ 23,999
	Adjusted Net Operating Income per APS		$ 474,356
	Adjusted Net Operating Income per Staff		$ 498,355

My testimony addresses the Company's proposed depreciation rates. The new depreciation rates proposed by APS are summarized in Company witness Dr. White's testimony and are shown in detail in his exhibit, Attachment REW-2 entitled "2011 Depreciation Rate Study" which was prepared by Dr. White's firm, Foster Associates, Inc. The Company's proposed rates were developed using a depreciation system composed of the straight-line method, vintage 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.

Based on December 31, 2010 plant investment, the new depreciation rates proposed by APS decrease depreciation expense by $41.301 million (from $305.37 million at present rates to $264.07 million at APS' proposed rates).[1] Of the 170 plant accounts studied, APS proposes depreciation rate reductions for 97 accounts and increases for 73 accounts. On a composite

[1] Approximately $24.630 million of this reduction relates to the prospective cessation of depreciation on Four Corners Units 1-3, as shown on APS' Attachment REW-2, Statement B, page 26.

basis, the Company's proposed new rates for APS plant produce a decrease of 0.37 percentage points, from the current composite rate of 2.77 percent to a composite at new rates of 2.40 percent.

With the exception of the meters account[2], the depreciation rates proposed by APS are generally appropriate and have been determined using depreciation methods consistent with how depreciation rates have been determined for APS in prior cases.

APS has appropriately incorporated the operating license extension into its development of new depreciation rates for the Palo Verde Nuclear Generating Station.

APS has also incorporated proposed changes to depreciation rates for the Four Corners steam generating station related to the acquisition by APS of Southern California Edison's ("SCE") share in Four Corners Units 4 and 5 and to APS' expectations for the operation of that plant and in view of environmental regulations. APS' proposal to acquire SCE's share of Four Corners Units 4 and 5 is currently pending before the Commission in Docket No. E-01345A-10-0474. APS' incorporation of the depreciable life changes for the Four Corners plant also incorporates a related assumption that Units 1-3 will be retired in 2012, thus APS' proposed annualized depreciation accrual for Four Corners Units 1-3 decreases from approximately $24.630 million at current depreciation rates to zero at APS' proposed depreciation rates.[3]

With respect to meters, APS' proposal to reduce the average service lives from 26 years (upon which the currently authorized depreciation rates for meters are based) to 15 years should be rejected. In APS' last rate case, the Company represented that: "The current projection life of 26 years for electronic meters is recommended for AMI meters pending sufficient retirement experience to estimate service lives for AMI metering technology."[4] That APS recommendation should continue to apply in the current case. The currently authorized depreciation rates for meters using a 26 year anticipated life are also in line with depreciation rates for meters that have been authorized for other Arizona utilities. The existing authorized rates for meters should continue to be applied. The issue of service lives for meters should be re-examined in APS' next rate case.

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[2] APS records its meters investment in sub-account 370.01 for electronic meters and 370.03 for AMI meters.
[3] See, e.g., APS' Exhibit REW-2, at page 28.
[4] See, e.g., Attachment REW-1 to APS witness Dr. White's direct testimony in Docket No. E-01345A-08-0172, at page 4.

INTRODUCTION

A. Background and Qualifications

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 31 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 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 attorneys general, 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, Indiana, Illinois, Kansas, 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, Virginia, Washington, Washington D.C.,

West Virginia 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 testified before the Arizona Corporation Commission ("ACC" or "Commission")?

A. Yes. I have previously testified before the Commission on a number of occasions. 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"), and APS' Docket Nos. E-01345A-05-0816, E-01345A-05-0826, E-01345A-05-0827, and E-01345A-08-0172 concerning proceedings involving APS base rates and other matters. I testified before the Commission in the Arizona-American Water Company in Docket Nos. W-01303A-09-0343 and SW-01303A-09-0343. I also testified before the Commission in the last UNS Gas, Inc. rate case, Docket Nos. G-04204A-06-0463, G-04204A-06-0013 and G-04204A-05-0831, and in the last UNS Electric, Inc. rate case Docket No. E-04204A-06-0783, as well as the Southwest Gas Corporation rate cases, G-01551A-07-0504 and G-01551A-10-0458.

B. Purpose of Testimony

Q. On whose behalf are you appearing?

A. I am appearing on behalf of the Commission's Utilities Division ("Staff").

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

A. The purpose of my testimony is to address the application for a general rate increase filed by APS. Specifically, I will be addressing the revenue requirement, rate base, net operating income, and selected other issues, including APS' proposal for new depreciation rates. I also discuss a potential cost recovery mechanism for the Commission's consideration to address Four Corners related cost changes.

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

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

C. Content of Attachments to Testimony

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

A. Yes, I have five attachments, Attachments RCS-1 through RCS-5.

Q. What is shown in each of those attachments?

A. Attachment RCS-1 presents by educational background and qualifications.

Attachment RCS-2 presents the results of my analysis including Staff's recommended revenue requirement, rate base and adjusted net operating income.

Attachment RCS-3 presents copies of non-confidential responses to data requests and selected non-confidential documents that are referenced in my testimony.

Attachment RCS-4 presents copies of selected APS confidential responses to discovery and other confidential documents that are referenced in my testimony.

Attachment RCS-5 presents excerpts of regulatory commission orders addressing ratepayer/shareholder sharing of Directors and Officers Liability Insurance Expense.

D. General Background to APS' Rate Request

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

A. APS is an Arizona utility providing electricity to more than 1 million customers in 11 of Arizona's 15 counties. With its headquarters in Phoenix, APS is the largest subsidiary of Pinnacle West Capital Corporation ("PWCC" or "PNW"[5]). APS is the largest electric utility in Arizona.

APS' current base rates became effective January 1, 2010 pursuant to Decision No. 71448 dated December 30, 2009. That case, Docket No. E-01345A-08-0172 used a test year ending December 31, 2007.

On June 1, 2011, APS filed with the Commission an application for a base rate increase of $95.5 million, using a test year ending December 31, 2010.

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

REVENUE REQUIREMENT

A. Summary of APS' Requested Increase

Q. Please briefly summarize APS' basis for its request for a rate increase.

A. Using a test year ending December 31, 2010, with pro forma adjustments, in its original filing, APS was seeking a base rate increase of $95 million. On October 26, 2011, APS filed certain updated information, which reduces the base rate increase APS is seeking to approximately $85 million. The Company's originally filed and updated base rate revenue increase request is summarized in the table below:

Summary of APS' As-Filed and Updated Base Rate Revenue Increase Request

Component (Millions of Dollars)	APS' Filed Base Rate Increase Request	APS' Updated Base Rate Increase Request
Non-Fuel Costs	$ 194	$ 196
AZ Sun Transfer	$ 45	$ 42
Fuel Costs	$ (144)	$ (153)
Base Rate Increase Request	**$ 95**	**$ 85**

B. Summary of Staff's Recommendation

Q. What revenue increase does Staff recommend?

A. Compared with APS' originally filed $95 million and revised $85 million base rate increases shown in the above table, Staff recommends a base rate revenue decrease of approximately $7.449 million on adjusted Fair Value rate base.

Q. What base cost of fuel is incorporated in Staff's recommendation?

A. APS' base cost of fuel has been reset to 3.2071 cents per kWh, based on APS' current forecast for 2012.[6] Staff and APS are both recommending in the current APS rate case that the 90/10 sharing provision of APS' existing Power Supply Adjustor ("PSA") be

[6] Staff's adjustment for the base cost of fuel and purchased power is presented on Attachment RCS-2, Schedule C-9.

eliminated.[7] This will help assure that the reductions in fuel and purchased power costs that APS may experience prospectively will be fully passed through to customers. APS estimates additional annual incremental fuel and purchased power cost savings of as much as $31.4 million if its proposed acquisition of Southern California Edison's ("SCE") share of Four Corners Units 4 and 5 is approved.[8]

Q. What calculations have you presented in support of that recommendation?

A. On Attachment RCS-2, Schedule A, page 1, I present a calculation of the revenue sufficiency for APS on original cost rate base ("OCRB"). As shown on Schedule A, page 1, column C, on OCRB my calculations show a jurisdictional base rate revenue sufficiency of $48.932 million. Column D presents a calculation on fair value rate base ("FVRB") similar to the one presented in APS' filing. Staff's recommended decrease of approximately $7.449 million represents a decrease from current base rate revenue from sales to ultimate customers of approximately 0.26 percent.

Staff is also presenting the Commission with two options for the Fair Value rate of return ("FVROR") for APS. On Schedule A, page 2, I present Staff's alternative calculations using adjusted FVRB. These calculations show FVRORs ranging from 5.74 percent to 6.05 percent. On adjusted FVRB under Staff's option 1, which uses a fair value rate of return of 5.74 percent, the base rate decrease is $48.932 million. Under option 2 the fair value rate of return for APS is 6.05 percent, and the jurisdictional base rate decrease is approximately $7.449 million.

[7] Staff witness Michael McGarry is addressing PSA issues in the current APS rate case for Staff.
[8] See, e.g., Attachment RCS-2, Schedule C-9, column F, line 10. This additional fuel cost savings is not reflected in Staff's presentation at this time because the Commission has not yet issued a decision on whether or not to approve APS' proposed acquisition of SCE's share in Four Corners Units 4 and 5. That proposed acquisition is pending before the Commission in Docket No. E-01345A-10-0474.

Attachment RCS-2, Schedule D, shows the development of Staff's recommended fair value rate of return to be applied to FVRB. The testimony of Staff witness David Parcell also addresses the determination of the fair value rate of return.

C. Test Year

Q. What test year is being used in this case?

A. APS' filing is based on the historic test year ended December 31, 2010. Staff's calculations use the same historic test year.

Q. Could you please discuss the test year concept?

A. Yes. In Arizona, a historic test year approach is used. In general, the test year concept is typically applied in the following manner. Various adjustments are made to the historic test year amounts to ensure that there is a matching of investment, revenues and expenses. Rate base items, such as plant in service and accumulated depreciation, are based on the actual level as of the end of the historic test year. Several rate base items that tend to fluctuate from month to month, such as materials and supplies and prepayments, are based on a test year average level. Since end of test year net plant in service is used, revenues are annualized based on end of test year customer levels. Additionally, certain expenses, such as depreciation and payroll costs, are commonly annualized based on end of test year levels.[9] This is to ensure that the going-forward revenue and expense levels are matched with the investment (net plant-in-service) used to serve those customers.

As time goes forward, changes in the Company's cost structure will occur. For example, rate base will increase as new plant is added to serve new customers, revenue will increase as customers are added, expenses will fluctuate, etc. It is very important to be consistent

[9] In the current APS base rate case, APS has extended the payroll annualization and the depreciation expense annualization to levels based on information beyond the end of the 2010 test year.

with a test period approach to ensure that there is a consistent matching between investment, revenues and costs. Any adjustments that reach beyond the end of the historic test year must be very carefully considered before being adopted.

Q. In the current APS rate case, do the Company's and Staff's filings reflect a significant modification to the 2010 test year information used to develop APS" jurisdictional rate base?

A. Yes. Both APS' and Staff's filing in the current APS rate case include adjustments to rate base and operating expenses for post-test year plant. APS' proposed adjustment is for estimated post-test year plant that APS projects will be in service by June 30, 2012, which is 18 months beyond December 31, 2010, the end of the test year. Staff's presentation reflects post test year plant that has either already been placed into service or which will have been placed into service and which can at a later point in the proceeding be verified as having been placed into service through March 31, 2012. APS has indicated in response to Staff discovery that it will have March 31, 2012 information available approximately 30 days after that date. The use of information through March 31, 2012 should therefore result in verifiable amounts being available for review in time for an open meeting at the Commission to consider APS' base rate increase request.

APS' presentation reflects changes in the balances from accumulated depreciation and certain changes to Accumulated Deferred Income Taxes ("ADIT") that are projected to occur through June 30, 2012. Staff's presentation includes changes in accumulated depreciation at current depreciation rates occurring through March 31, 2012. Staff also proposes to include changes in ADIT through that same date, pending satisfactory resolution of a potential tax normalization issue raised by APS.[10]

[10] See, e.g., APS' response to STF 15.13, and the discussion of ADIT in conjunction with Staff rate base adjustment B-6, herein.

Q. How does Staff propose to adjust for post test year plant, accumulated depreciation and ADIT at March 31, 2012?

A. Staff currently has placeholder adjustments for those items based on known information through August 2011, which was provided in APS' response to STF 6.55, and updated projections by APS for changes through March 31, 2012 that were provided by APS in response to other Staff discovery. As stated by APS in response to STF 27.2 concerning plant, STF 27.8 concerning accumulated depreciation and STF 27.9 concerning ADIT, APS anticipates having actual December 31, 2011 amounts available 30 days after the close of the year, and APS anticipates having March 31, 2012 amounts available 30 days after the close of that quarterly period. Staff currently intends to update its current placeholder adjustments for post test year plant, accumulated depreciation and ADIT to use those actual known amounts once they are provided by APS and can be reviewed by Staff. The incorporation of such actual information for March 31, 2012 post test year plant, accumulated depreciation and ADIT may require a compliance filing by APS to be made before a final decision is issued, and for an opportunity for Staff and other parties to review and comment upon such information, so that post test year amounts for plant, accumulated depreciation and ADIT can be incorporated into the APS base rate revenue requirement in time for a final decision on or about July 1, 2012.

D. Organization of Staff Accounting Schedules

Q. How are Staff's accounting schedules organized?

A. Staff's accounting schedules are presented in Attachment RCS-2. They are organized into summary schedules and adjustment schedules. The summary schedules consist of Schedules A, A-1, B, B.1, C, C.1 and D. Attachment RCS-2 also contains rate base adjustment Schedules B-1 through B-7 and net operating income adjustment Schedules C-

1 through C-16. The revenue requirement for APS was based upon the ACC jurisdictional adjusted results.

Q. What is shown on Schedule A of Attachment RCS-2?

A. Attachment RCS-2 presents the Staff Accounting Schedules and revenue requirement determination. Schedule A presents the overall financial summary, giving effect to all the adjustments I am recommending in my testimony. This schedule presents the change in the Company's gross revenue requirement needed for the Company to have the opportunity to earn Staff's recommended fair value rate of return on Staff's proposed FVRB. The rate base and operating income amounts are taken from Schedules B and C, respectively. The weighted average cost of capital of 8.28 percent, as presented in the prefiled testimony of Staff witness Parcell, is provided on Schedule D for convenience, as are the derivation of Staff's two options for the fair value rate of return. Schedule D presents the weighted average cost of capital and fair value rate of return recommended in the prefiled testimony of Mr. Parcell.

The operating income excess or deficiency shown on line 5 of Schedule A is obtained by subtracting the operating income available on line 4 (operating income as adjusted) from the required operating income on line 3. Line 7 represents the gross revenue requirement, which is obtained by multiplying the income deficiency by the gross revenue conversion factor ("GRCF"). The derivation of the GRCF is shown on Schedule A-1. Line 8 shows APS' requested additional base rate increase on the FVRB increment. Line 9 shows a comparison of the total base rate revenue deficiency or excess from APS' original filing using Staff's recommended adjustments.

Q. What is shown on Schedule A, page 1, lines 10 and 11?

A. Lines 10 and 11 of Schedule A show the amount of base rate revenues from sales to ultimate customers and the approximate percentage change in base rate revenue, based on APS' originally filed request and Staff's recommended adjustments.

Q. What is shown on Schedule A, page 2?

A. Schedule A, page 2, presents a reconciliation of the base rate revenue requirement change recommended by Staff with the corresponding amounts from APS' original filing. The approximate revenue requirement impact of each Staff adjustment is shown.

Q. What is shown on Schedule A-1?

A. Schedule A-1 shows the development of the gross revenue conversion factor.

Q. How does the GRCF recommended by Staff compare with the GRCF contained in APS' filing?

A. As shown on Schedule A-1, Staff recommends a GRCF of 1.6566, which compares with the GRCF of 1.6532 used in APS' filing. APS did not include a component for uncollectible revenue in its GRCF calculation. Staff updated the GRCF to include an uncollectible revenue component. Due to the variances that occur with uncollectibles based on the level of revenue, Staff believes it can be appropriate to include the uncollectible revenue component in the GRCF calculation. In the current rate case, APS has not proposed a pro forma adjustment for uncollectibles expense. APS' response to STF 25.11 notes that the uncollectible rate of 0.21 percent was applied to revenue in 2008, 2009 and 2010. As shown on Schedule A-1, Staff has used the uncollectibles rate of 0.21 percent in deriving the GRCF.

Q. What is shown on Schedule B?

A. Schedule B presents APS' proposed adjusted test year Original Cost and Fair Value rate bases and Staff's proposed adjusted test year Original Cost and Fair Value rate bases. The beginning rate base amounts presented on Schedule B are taken from the Company's amended filing for the test year, specifically APS Schedule B-1. Staff's recommended adjustments to rate base are summarized on Attachment RCS-2, Schedule B.1. Attachment RCS-2 includes a separate Schedule B.1 for adjustments to Original Cost rate base and for adjustments to Reconstruction Cost New Depreciated ("RCND") rate base. Each of these adjustments is discussed in this testimony.

Schedules B-1 through B-7 provide further support and calculations for the rate base adjustments Staff is recommending.

Q. What is shown on Schedule C?

A. The starting point on Schedule C is APS' adjusted test year net operating income, as provided on Company Schedule C-1. Staff's recommended adjustments to APS' adjusted test year revenues and expenses are summarized on Attachment RCS-2, Schedule C.1. Each of these adjustments is discussed in my testimony.

Schedules C-1 through C-16 provide further support and calculations for the net operating income adjustments Staff is recommending.

Q. What is shown on Schedule D?

A. Schedule D summarizes the capital structure and cost of capital that was proposed by APS and the capital structure and cost of capital that is recommended by Staff witness Parcell.

Schedule D also presents the derivation of Staff's recommended Fair Value rate of return for use with the Staff's adjusted Fair Value rate base.

E. Staff's Fair Value Rate of Return Presentation

Q. What information on the FVROR is Staff presenting to the Commission in this proceeding?

A. Staff is presenting the Commission with two alternatives for the FVROR to be applied to APS' adjusted Fair Value rate base. As shown in Schedule D, Staff alternative 1 applies a zero cost rate to the FV increment and produces a Fair Value rate of return of 5.74 percent. Under alternative 2, a return of 1.0 percent is applied to the FV increment and produces a Fair Value rate of return of 6.05 percent. The 1.0 percent is developed by Staff witness David Parcell and represents a point within a range from zero to a "real" risk-free rate of return *i.e.* a risk-free rate of return less inflation. The testimony of Staff Witness David Parcell addresses these alternative methods of deriving a FVROR.

F. Fair Value Rate of Return on Fair Value Rate Base

Q. How was the Fair Value rate base determined?

A. As shown on Attachment RCS-2, Schedule B, the Fair Value rate base was determined by averaging Original Cost and RCND rate base information. For purposes of this presentation, Staff has used the Company's RCND information as the starting point for the fair value rate base.

Q. How did APS determine the Fair Value rate of return to apply to Fair Value rate base in its filing?

A. As shown on Attachment RCS-2, Schedule A, in column B (which reproduces the revenue deficiency calculation from APS' Schedule A-1), the Company calculated a revenue deficiency of $54.610 million on its proposed Original Cost and FVRB base, and adds $40.883 million for an additional revenue requirement on the FVRB increment, based on a 1.0 percent return on the FVRB increment, to derive its total requested base rate revenue increase of $95.493 million.

RATE BASE

Q. Have you prepared a schedule that summarizes Staff's proposed adjustments to rate base?

A. Yes. As noted above, the adjusted rate base is shown on Attachment RCS-2, Schedule B and the adjustments to APS' proposed rate base are shown on Schedule B.1. Attachment RCS-2 contains a separate Schedule B.1 for adjustments to original cost rate base and to RCND rate base. A comparison of the Company's proposed rate base and Staff's recommended rate base on an Original Cost and Fair Value basis are presented below:

$000's	APS	Staff	Difference
Summary of Rate Base	Schedule B-1	Schedule B	
Original Cost Rate Base	$ 5,720,277	$ 5,662,998	$ (57,279)
RCND Rate Base	$ 10,728,532	$ 10,671,253	$ (57,279)
Fair Value Rate Base	$ 8,224,405	$ 8,167,126	$ (57,279)

Post-Test Year Plant

Q. How is inclusion of post-test year plant in rate base an issue in the current APS rate case?

A. As described below in more detail, APS has proposed to include several hundred million dollars in rate base for post-test year plant. Some of this amount relates to amounts that were included in construction work in progress ("CWIP") as of December 31, 2010, the end of the test year, which APS has since placed into service, or projects that would be placed into service, at various points in time before new base rates resulting from this proceeding are anticipated to become effective.

Q. Is the inclusion of post-test-year plant in rate base an exceptional ratemaking treatment and up to the discretion of the Commission?

A. Yes, it is. Staff's understanding is, in specific instances, the Commission has allowed a utility to include CWIP, or alternatively post-test year plant additions, in rate base, but the Commission's general practice has been to not allow CWIP to be included in rate base. That said, the inclusion of CWIP in rate base is an exceptional ratemaking treatment.

Q. Please elaborate on how including CWIP or post-test-year plant in rate base is an exceptional ratemaking treatment.

A. CWIP, as the title designates, is not plant that is completed and providing service to ratepayers during the test year. During the test year, it is not used or useful in providing electric service to a utility's customers. The ratemaking process is predicated on an examination of the operations of a utility to insure that the assets upon which ratepayers are required to provide the utility with a rate of return are prudently incurred and are both used and useful in providing services on a current basis. Facilities in the process of being built are not used or useful. The ratemaking process therefore excludes CWIP from rate

base until such projects are completed and providing service to ratepayers in the context of a test year that is being used for determining the utility's revenue requirement. In the current APS rate case, the test year is the twelve months ending December 31, 2010, and the construction projects the Company seeks to include in rate base were not providing service during that period. The Company claims that the construction projects it is requesting for inclusion in rate base will be in service by the time rates in this proceeding take effect. In APS' last base rate case, Docket No. E-01345A-08-0172, the Commission approved a Settlement Agreement, which allowed post test year plant beyond the historic test year. The Settlement Agreement (at ¶ 3.4) cited the Signatories' desire to enhance APS' ability to retain and improve its current investment grade rating, thereby allowing APS to attract capital at reasonable rates and to also optimize its operational flexibility. For purposes of this case, for the reasons just cited from the Settlement Agreement, Staff is proposing to include in rate base post-test-year plant that can be verified as being in service on or before March 31, 2012. Based on that determination, I have reflected a rate base adjustment for post-test-year plant that has been or will be placed into service by March 31, 2012, one full year and three months after the test year, as post-test year plant in rate base.

Q. What post-test year plant additions is APS requesting?

A. In its filing, APS has requested post-test year plant additions for plant it anticipates will be placed into service by June 30, 2012.

Q. What is Staff's position on the inclusion of post-test-year plant in rate base for APS?

A. As described above, Staff proposes to include plant that is placed into service by March 31, 2012 as post-test-year plant.

Q. Have you made any adjustments to APS' proposed rate base amounts for any of these items?

A. Yes. I have made adjustments to APS' proposed amounts for post-test year Plant in Service in Staff rate base Adjustments B-1 through B-4. I have also adjusted Accumulated Depreciation for changes occurring through March 31, 2012 in Staff rate base adjustment B-5, and have adjusted ADIT for some of the ADIT changes occurring through March 31, 2012 in Staff rate base adjustment B-6. Each of these adjustments is currently based on APS' estimates, and should therefore be viewed as a placeholder. As described above, ultimately, Staff proposes to use actual March 31, 2012 balances for post test year plant additions, accumulated depreciation and ADIT.

Q. What policy guidance are you following concerning the amount of post-test year plant additions that Staff proposes be included in rate base?

A. Staff has determined in the current APS base rate case that post-test-year plant additions that can be verified as having been placed into service by March 31, 2012 should be included in rate base as post-test-year plant.

Q. What rate base adjustments have you made to APS' proposed miscellaneous post-test year plant additions based on that guidance?

A. Staff Adjustments B-1 through B-4 reflect the impact of this recommendation for post test year plant. The amounts of post-test-year plant that APS has requested that are not in service or projected to be in service by March 31, 2012 have not been included in rate base as plant in service by Staff.

I have also made related adjustments for Depreciation and Property Tax Expense as it relates to those adjustments to post-test year plant.

B-1. Post-Test Year Plant Additions - Solar

Q. Please explain Staff's adjustment to APS' post-test year plant additions for Solar Plant.

A. The Company made a pro forma adjustment to increase its rate base by including solar plant additions totaling approximately $277.411 million on a total Company basis and $267.979 million on an ACC jurisdictional basis that APS originally expected would be placed into service by June 30, 2012. At the end of the test year, these projects had not been completed and were not recorded as Plant in Service. APS contends that these construction projects will close to Plant in Service by June 30, 2012, *i.e.* or by the time APS expects the new rates in this proceeding to take effect. APS claims that this justifies their inclusion in rate base in this proceeding. As shown on Attachment RCS-2, Schedule B-1, based on actual information through August 2011 that was provided in APS' response to STF 6.55 and updated projections from APS for solar plant additions through March 31, 2012 that APS provided in response to STF 27.4(a), Staff has reflected post test year solar plant additions through March 31, 2012 of $240.759 million on a total Company basis and $232.573 million on an ACC jurisdictional basis. This results in an adjustment to reduce APS' originally filed projection of post test year solar plant additions by $35.406 million, as shown on Schedule B-1, column F.

B-2. Post-Test Year Plant Additions - Fossil

Q. Please explain Staff's adjustment to APS' post-test year plant additions for Fossil Plant.

A. The Company made a pro forma adjustment to increase its rate base by including fossil plant additions totaling approximately $156.269 million on a total Company basis and $150.956 million on an ACC jurisdictional basis that APS originally expected would be placed into service by June 30, 2012. At the end of the test year, these projects had not

been completed and were not recorded as Plant in Service. APS contends that these construction projects will close to Plant in Service by June 30, 2012, *i.e.* or by the time APS expects the new rates in this proceeding to take effect. APS claims that this justifies their inclusion in rate base in this proceeding. As shown on Attachment RCS-2, Schedule B-2, based on actual information through August 2011 that was provided in APS' response to STF 6.55 and updated projections from APS for fossil plant additions through March 31, 2012 that APS provided in response to STF 27.4(c), Staff has reflected post test year fossil plant additions through March 31, 2012 of $131.985 million on a total Company basis and $127.498 million on an ACC jurisdictional basis. This results in an adjustment to reduce APS' originally filed projection of post test year fossil plant additions by $23.458 million, as shown on Schedule B-2, column F.

B-3. Post-Test Year Plant Additions - Nuclear

Q. Please explain Staff's adjustment to APS' post-test year plant additions for Nuclear Plant.

A. The Company made a pro forma adjustment to increase its rate base by including nuclear plant additions totaling approximately $120.103 million on a total Company basis and $116.019 million on an ACC jurisdictional basis that APS originally expected would be placed into service by June 30, 2012. At the end of the test year, these projects had not been completed and were not recorded as Plant in Service. APS contends that these construction projects will close to Plant in Service by June 30, 2012, *i.e.* or by the time APS expects the new rates in this proceeding to take effect. APS claims that this justifies their inclusion in rate base in this proceeding. As shown on Attachment RCS-2, Schedule B-3, based on actual information through August 2011 that was provided in APS' response to STF 6.55 and updated projections from APS for nuclear plant additions through March 31, 2012 that APS provided in response to STF 27.4(b), Staff has reflected

post test year nuclear plant additions through March 31, 2012 of $101.950 million on a total Company basis and $98.483 million on an ACC jurisdictional basis. This results in an adjustment to reduce APS' originally filed projection of post test year nuclear plant additions by $17.536 million, as shown on Schedule B-3, column F.

B-4. Post-Test Year Plant Additions – Distribution, General and Intangible

Q. Please explain Staff's adjustment to APS' post-test year plant additions for Distribution, General and Intangible Plant.

A. The Company made a pro forma adjustment to increase its rate base by including distribution, general and intangible plant additions totaling approximately $432.984 million on a total Company basis and $423.910 million on an ACC jurisdictional basis that APS originally expected would be placed into service by June 30, 2012. At the end of the test year, these projects had not been completed and were not recorded as Plant in Service. APS contends that these construction projects will close to Plant in Service by June 30, 2012, *i.e.* or by the time APS expects the new rates in this proceeding to take effect. APS claims that this justifies their inclusion in rate base in this proceeding. As shown on Attachment RCS-2, Schedule B-4, based on actual information through August 2011 that was provided in APS' response to STF 6.55 and updated projections from APS for distribution plant additions through March 31, 2012 that APS provided in response to STF 27.4(d) and (e), Staff has reflected post test year distribution, general and intangible plant additions through March 31, 2012 of $378.649 million on a total Company basis and $370.714 million on an ACC jurisdictional basis. This results in an adjustment to reduce APS' originally filed projection of post test year distribution, general and intangible plant additions by $53.196 million, as shown on Schedule B-4, column F.

Q. Are Staff rate base Adjustments B-1 through B-4 related to corresponding income statement adjustments?

A. Yes. Staff rate base adjustments B-1 through B-4 for post test year plant additions through March 31, 2012 are related to Staff's operating income statement adjustments C-4 through C-7, which reduces APS' proposed pro forma adjustment to Depreciation and Property Tax Expense as it relates to the post-test year plant additions removed from APS' proposed rate base as shown on Schedules B-1 through B-4.

End of Test Year Construction Work in Progress In-Service by March 31, 2012

Q. In APS' last base rate case, Docket No. E-01345A-08-0172, how was the post test year plant adjustment determined?

A. In APS' last rate case, the post test year plant adjustment was determined by reviewing the December 31, 2007 end of test year balance of CWIP and allowing post test year plant additions for the components of that balance that were being placed into service by a June 30, 2009 date that was eighteen months after the end of the test year. Specifically, in Docket No. E-01345A-08-0172, the portion of APS' December 31, 2007 CWIP projects that were projected to be placed into service by December 31, 2008 were included by Staff in rate base as post-test-year plant. Ultimately, the Settlement Agreement in that docket provided for a return on and of such post-test year through June 30, 2009, eighteen months beyond the test year ending December 31, 2007.[11]

Q. What is APS" CWIP balance at December 31, 2010?

A. According to APS' responses to STF 22.7 and 27.13, APS' December 31, 2010 CWIP balance, exclusive of nuclear fuel, was $369.413 million.

[11] This was noted in the Settlement Agreement at paragraph 3.4.

Q. Have some of the projects that were in CWIP at December 31, 2010 since been placed into service?

A. Yes. Many of the proposed post-test year plant additions that were in CWIP as of December 31, 2010 have been placed into service and closed to Plant in Service. For example, APS' responses to STF 22.7 and 27.13 identified the amount of December 31, 2010 CWIP that was placed into service by August 31, 2011 as $161.191 million.

Q. Does APS anticipate that some additional amounts of December 31, 2010 CWIP will be placed into service from September 1, 2011 through March 31, 2012?

A. Yes. APS' response to STF 27.13 shows that APS expects that $90.597 million of the December 31, 2010 CWIP will be placed into service between September 1 and December 31, 2011 and an additional $28.170 million will be placed into service by March 31, 2012.

Q. Does APS anticipate that some amounts of its December 31, 2010 CWIP balance will <u>not</u> be placed into service by March 31, 2012?

A. Yes. APS' response to STF 27.13 shows that APS expects that $89.455 million of the December 31, 2010 CWIP will <u>not</u> be placed into service by March 31, 2012.

Q. Is Staff making a specific adjustment for the portions of the December 31, 2010 CWIP balance that are anticipated to be placed into service by March 31, 2012 in the current APS rate case?

A. No, not at this time. As explained above, in the current APS rate case, Staff has followed a similar approach to addressing post test year plant additions that APS proposed in its filing, which involves reflecting post test year plant additions for plant that is placed into service by a certain date. For the date for post test year plant in the current APS rate case, APS proposes using June 30, 2012 and Staff has used March 31, 2012. The plant reflected

dramatically. ADIT represents the cumulative consequences of the differences between tax and book accounting.

Q. What is the main source of ADIT for utilities?

A. The main source of ADIT for utilities is depreciation. Financial reporting reflects the economic decline of an asset over its useful life. By contrast, the tax law reflects a conscious policy by Congress to promote the acquisition of certain types of assets. Congress implemented this policy by enacting accelerated depreciation, which allows the claiming of tax depreciation deductions using a pattern that is a good deal more rapid than the economic consumption of the asset. The accelerated deductions lower income taxes due and thereby produce a cash benefit to the company making the investment. Depreciation, both book and tax, is generally limited to the cost of an asset.[13] Accelerated tax depreciation essentially allows tax deductions that would have been claimed at a later point in time to an earlier point in time. It generally does not alter the total quantity of deductions. The primary purpose is to encourage investment by providing an income tax savings to the taxpayer.

Q. What is the nature of accelerated tax depreciation?

A. By accelerating deductions, Congress extended an interest-free loan from the Federal government to taxpayers who acquire business assets. This capital investment subsidy could have taken the form of a straight governmental loan program. Instead, Congress chose to use the tax system to extend and receive repayment of the loan. This is where ADIT comes in. ADIT represents the obligation on the part of the Company to repay the loan that was extended by the government. Conceptually, ADIT is funded by ratepayers

[13] The capitalized cost of an asset can be different for financial reporting and income tax purposes, due to different capitalization accounting methods.

through the payment of a utility's Deferred Income Tax Expense, which is included as an operating expense in establishing a utility's revenue requirement and base rates.

Q. Is ADIT unique to utilities?

A. No. Under GAAP, all companies reflect ADIT. This is because governmental loans are made to all types of enterprises and, in each case, the economics are the same. In the case of utilities, however, the ADIT is funded by ratepayers via the inclusion of Deferred Income Tax Expense in the setting of a utility's rates based on cost of service principles.

Q. What are the typical accounting entries for ADIT relating to accelerated tax depreciation?

A. For accelerated tax depreciation, the tax deduction typically exceeds the book depreciation expense, especially in the early years after the asset is placed into service. For illustrative purposes, if tax depreciation in a particular year exceeded book depreciation by $100 million, and the tax rate was 40%, a utility would make the following accounting entries to record the impact on ADIT:

Dr. Deferred Income Tax Expense	$40 million
Cr. Accumulated Deferred Income Taxes	$40 million

In this example, the Deferred Income Tax expense and ADIT are each increased by $40 million. Accounting for ADIT can be a complicated area. The above simplified illustration is not intended to explain the complexities, but rather to merely provide some basic content from an accounting perspective to help conceptualize the rate making treatment.

Q. How is ADIT treated in ratemaking?

A. Because ADIT represents a no-cost element of the financing of the asset being depreciated, ADIT associated with the assets included in rate base is reflected in Arizona ratemaking as a reduction in rate base (the predominant practice). (In some regulatory jurisdictions, the ADIT is reflected as a zero cost component of the capital structure.) In either case, ADIT associated with assets included in rate base reduces the return component of the cost of service.

Q. Ideally, should the ADIT amount be updated through the same date as post test year plant and accumulated depreciation, in the determination of rate base?

A. Yes. Because rate base is being adjusted to reflect post-test-year plant additions placed into service by March 31, 2012, ideally the related impacts on ADIT through that same date should also be reflected. This would reflect that the post test year plant has in part effectively been financed by a combination of growth in the accumulated depreciation balance and by cost free capital in the form of ADIT.

Q. How have additional tax deductions become available to APS as the result of changes in the federal income tax laws?

A. On December 17, 2010, President Obama signed legislation known as the Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act of 2010. That Act provides for 100 percent depreciation bonus for qualifying capital investments placed in service after September 8, 2010 through December 31, 2011. For equipment placed in service after December 31, 2011 and through December 31, 2012, the bill provides for 50 percent bonus tax depreciation. The Small Business Jobs Act of 2010, which contained 50 percent depreciation bonus, still applies to purchases made between January 1, 2010 and September 7, 2010. In summary:

- Bonus tax depreciation helps businesses that buy new equipment cut their tax bill.
- The bonus tax depreciation applies, among other things, to purchases of tangible personal property (including construction, mining, forestry, and agricultural equipment) with a MACRS recovery period of 20 years or less.
- To qualify, the equipment must have been purchased and placed in service.
- The bonus tax depreciation applies to new equipment only.
- This bonus tax depreciation is allowed for both regular and alternative minimum tax purposes.
- The bonus tax depreciation is discretionary; the taxpayer need not claim the depreciation bonus.
- The Depreciation Bonus will expire at the end of 2012.
- For 2011, the tax depreciation bonus is 100 percent for qualifying property.

Q. What are the implications for a regulated utility, such as APS?

A. For a regulated public utility, such as APS, that normalizes its federal income tax expense related to tax depreciation, the bonus federal income tax depreciation should reduce current federal income tax expense. There are also related impacts on deferred income tax expense and ADIT. Deferred federal income tax expense and ADIT, which is a rate base offset, are each increased by similar amounts. In general, the increase to deferred federal income tax expense and the increase to ADIT are the result of the same journal entries. In situations where the utility has adequate positive taxable income to fully utilize the deductions, for income statement purposes, the impacts on current and deferred income tax expense will generally offset each other, and there should be no net effect. For rate base, however, the substantially increased ADIT, which is non-investor supplied cost-free capital, provides a significant reduction.

Q. Has the task of updating the ADIT balance to March 31, 2012 been complicated in the current APS rate case by other factors?

A. Yes. As described in APS' responses to STF 15.13, AECC 1.11, STF 19.14 and 19.15, APS anticipates realizing substantial amounts of 2011 and 2012 bonus tax depreciation. APS' response to STF 15.13(c), for example, indicates that, based on the updated calculations for post test year plant provided in APS' supplemental response to STF 6.55, the estimated ADIT impacts from 2011 and 2012 bonus tax depreciation are anticipated by APS to be in a range of $79 million to $128 million, as shown at APS14831. APS has cautioned, however, that without guidance from the IRS that explicitly allows inclusion of ADIT balances in rate base, APS believes that using such a methodology would not be appropriate and could result in extremely unfavorable tax consequences for the Company and its customers.[14] APS' response to STF 19.14(a) addresses and explains the concerns in additional detail.

Additionally, APS' response to STF 19.15(c) indicates that, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

Q. How does a federal income tax net operating loss ("NOL") occur?

A. A NOL is created in any year in which the aggregate income reported on a taxpayer's tax return is exceeded by the aggregate deductions claimed on that return. An NOL results when a taxpayer's deductions exceed the taxable income in a tax year.

[14] See, e.g., APS' response to STF 15.13(c), (d), and (e), etc.

Q. How can an NOL provide for future tax savings?

A. A federal income tax NOL can be carried forward for 20 years and can be applied against future taxable income to reduce tax expense.

Q. In general, is it possible to relate specific deductions to a Company's NOL?

A. No. In order to relate specific deductions to the Company's NOLs, there would have to be deduction ordering rules. As a general matter, the tax law contains no ordering rules for deductions. Thus, for most purposes, it does not relate an NOL to any specific deductions. Consequently, as a general matter, it is not possible to relate any specific deductions to the NOL that APS anticipates for 2011.

Q. Did APS pay federal income tax for the 2010 test year?

A. APS' response to STF 19.15, concerning whether APS paid any federal income tax for 2010, states that **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

Q. You mentioned that in a number of responses to discovery, such as STF 15.13 and others, APS has cautioned about updating the ADIT balance to March 31, 2011 without guidance from the IRS that explicitly allows inclusion of those ADIT impacts in rate base. Has APS applied for any such guidance from the IRS on how the actual March 31, 2011 ADIT balance could be reflected in the determination of rate base to match the use of March 31, 2011 balances for plant and accumulated depreciation?

A. No. APS' response to STF 19.14(b) states that:

> A draft of the guidance (a Private Letter Ruling) that APS would need to seek from the IRS has not yet been prepared, and could take several months to draft. Additionally, outside tax counsel would be needed to properly draft and file such a request for guidance. APS believes that the associated

expenditures should not be made until it becomes readily apparent that no other options are available.

Q. What other options has APS suggested?

A. In response to STF 19.14(c), with regard to the reflection of ADIT associated with post test year plant, APS proposes one of two options[15]: (1) make the adjustment for post test year plant in a manner similar to the 2009 rate case settlement and do not reduce the post test year plant additions for post test year ADIT[16], or (2) permit APS to use a complete future test year period ending June 30, 2012 for all rate case items.

Q. Are those APS suggestions under consideration by Staff?

A. Only the first one. As explained above, Staff would consider making the rate base adjustment for post test year plant in a manner similar to how that was done in APS' last base rate case, Docket No. E-01345A-08-0172, which involved using the end-of-test-year CWIP balance for items within that balance placed into service within a certain time after the test year.

With respect to the second suggestion made by APS, APS does not explain how or when its filing would be updated for a "complete future test year period ending June 30, 2012," and does not address or explain how that would not constitute essentially filing an entirely new rate case with a different test year. Staff does not believe that alternative is feasible nor has any merit in the context of the current APS base rate case.

[15] A complete copy of APS' response to STF 19.14 is included in Attachment RCS-4, attached to this testimony.
[16] APS states that this would "allow post test year additions in a manner consistent with the 2009 rate settlement." However, as noted above, the 2009 rate settlement concerning post test year plant was based on allowing the specific components of the December 31, 2007 end-of-test year CWIP that were being placed into service by June 30, 2009. The proposal by APS for post test year plant and related changes to accumulated depreciation and ADIT in the current base rate case, as explained above, is somewhat different.

Q. Given the uncertainty regarding how to appropriately reflect the update to the ADIT balance to March 31, 2012 to match the post test year plant and accumulated depreciation adjustments, how have you reflected the post test year adjustment for ADIT at this time?

A. As shown on Attachment RCS-2, Schedule B-6, page 1, at this time, the adjustment of the rate base offset for ADIT only reflects removal of the April 1 through June 30, 2012 amounts for post test year ADIT contained in the APS rate base adjustments for post test year plant. This results in decreasing jurisdictional ADIT, and increasing rate base, by $1.726 million.

Q. What is shown on Schedule B-6, page 2?

A. Schedule B-6, page 2, shows total Company and ACC jurisdictional amounts for the ADIT components that are typically reflected in the determination of APS' rate base, and shows how the net credit-balance amount of ADIT has grown through actual data provided by APS at July 31, 2011, and is estimated by APS to increase further through March 31, 2012. APS' original filing reflected a jurisdictional offset to rate base for ADIT of approximately $1.615 billion.[17]

APS' October 26, 2011 update filing reflects a jurisdictional offset to rate base for ADIT of approximately $1.615 billion.[18] In comparison, as of July 31, 2011, the actual jurisdictional ADIT balance had grown to approximately $1.658 billion.[19] Additionally, the information provided by APS in response to STF 20.1 shows the estimated jurisdictional ADIT balance at March 31, 2012 of approximately $1.723 billion.[20] The differences between these amounts and the jurisdictional ADIT reflected in APS' filing

[17] See Attachment RCS-2, Schedule B-6, line 31.
[18] See Attachment RCS-2, Schedule B-6, line 33.
[19] See Attachment RCS-3, Schedule B-6, column A, line 30.
[20] Id, column I, line 30.

are large and highlight the importance of appropriately updating the ADIT balance to match the time frame with updating rate base for plant and accumulated depreciation.

Q. How did you determine the RCND adjustment for ADIT?

A. In this case, the RCND adjustment for ADIT is the same as the Original Cost rate base adjustment for ADIT.

B-7 Working Capital

Q. Have you reviewed the Company's request for a working capital allowance?

A. Yes. The Company's working capital request consists of six separate subcomponents. As shown on APS' Schedule B-5, the subcomponents are:

(1) a negative Cash Working Capital balance of negative $101.57 million based on a lead/lag study on a total company basis;

(2) a year-end Materials and Supplies balance of $181.414 million on a total company basis;

(3) a year-end Fuel (Coal and Oil) balance of $21.575 million on a total company basis;

(4) a year-end Fuel (Nuclear) balance of $108.794 million on a total company basis;

(5) a year-end Prepayments balance of $23.346 million on a total company basis; and

(6) a year-end Special Deposits & Working Funds balance of $219,000 on a total company basis.

As shown on Company Schedule B-5, APS' calculated a total company basis amount of Working Capital allowance of $233.778 million. On APS' Schedule B-1, line 19, APS has reduced the Cash Working Capital component of that by $14.220 million, bringing the

total company amount to $219.558 million. The corresponding ACC jurisdictional amount of rate base APS is requesting for Working Capital is $202.206 million, as shown on APS' Schedule B-1, page 1, column F, line 19.

Q. Has Staff adjusted any of those working capital components?

A. Yes, only one, the cash working capital component. Staff has accepted APS' working capital components which involve balances at December 31, 2010, the end of the test year, but has adjusted the Company's cash working capital request to reflect Staff adjustments to operating expenses. Staff's adjustment to cash working capital is discussed below.

B-7.1. Cash Working Capital

Q. What is cash working capital?

A. Cash working capital is the cash needed by the Company to cover its day-to-day operations. If the Company's payment of cash expenditures, on an aggregate basis, occurs before the cash receipt of utility revenue, investors must provide cash working capital. In that situation a positive cash working capital requirement exists. On the other hand, if revenues are typically received prior to when expenditures are made, on average, then ratepayers provide the cash working capital to the utility, and the negative cash working capital allowance is reflected as a reduction to rate base. In this case, the cash working capital requirement is a reduction to rate base as ratepayers are essentially supplying these funds.

Q. Does APS have a positive or negative cash working capital requirement?

A. APS has a negative cash working capital requirement. In other words, ratepayers are essentially supplying the funds used for the day-to-day operations of the Company. On

average, revenues from ratepayers are received prior to the time when the utility pays the associated expenditures.

Q. Did APS present a lead/lag study in support of its cash working capital requirement?

A. Yes, APS performed a lead/lag study to calculate the cash working capital requirement in this case. The Company provided its lead/lag study calculations with its work papers in this case.

Q. Are you recommending any revisions to APS' cash working capital request?

A. Yes. I have reflected the impact of Staff's adjustments to operating expenses. I have also synchronized the calculation of cash working capital with Staff's recommended revenue increase in terms of updating the cash expenses for income taxes and interest.

Q. What is the result of your cash working capital calculation?

A. As shown on Schedule B-7, page 1, APS' filed cash working capital request should be increased by approximately $10.467 million on an ACC jurisdictional basis.

Q. Were there certain Staff adjustments to APS' operating expenses that are primarily attributable to that increase in the allowance for cash working capital?

A. Yes. The increase in the allowance for cash working capital, as noted above, is shown on Attachment RCS-2, Schedule B-7, page 1. As shown on line 18, Staff's adjustment to incentive compensation expense increased the jurisdictional allowance for cash working capital by approximately $10.3 million. As shown on lines 41 and 42, Staff's adjustment to income tax expense increased the jurisdictional allowance for cash working capital by $851,000, and property tax expense increased the jurisdictional allowance for cash working capital by $646,000. Those were the largest impacts. As shown on Schedule B-

7, page 1, Staff's other adjustments to other operating expenses increased the cash working capital allowances in some instances and decreased it in others.

Other Rate Base Updates

Q. Please explain Staff's review of changes in APS' balance sheet accounts for Other Rate Base Updates.

A. As described above, Staff has reflected post test year changes for plant through March 31, 2012, and related adjustments for accumulated depreciation and ADIT through that same date.[21] In order to assure that rate base is updated for the use of actual March 31, 2012 information in a consistent and balanced manner, Staff proposes to review, and may propose adjustments for changes in, other balance sheet accounts through that date that are currently reflected in APS' rate base on the basis of December 31, 2010, end-of-test year recorded balances.

ADJUSTMENTS TO OPERATING INCOME

Discussion of selected company adjustments

Q. Are there certain Company proposed adjustments that you would like to address before discussing Staff's adjustments?

A. Yes. There are two Company adjustments that relate to provisions contained in the Settlement Agreement that was reached by the parties in APS' last rate case, Docket No. E-01345A-08-0172. APS' adjustment 17 removes Schedule 3 revenue and the Company's adjustment 23 amortizes deferred pension and other post employment benefit (OPEB) costs. Both of these adjustments relate to special accounting treatments that were

[21] As noted above, the ultimate amounts of these adjustments will depend on actual information to be provided by APS, which APS anticipates having available by April 30, 2012. Additionally, an adjustment to fully reflect ADIT changes through March 31, 2012 is pending additional information concerning how a normalization concern raised by APS in discovery responses can be resolved.

provided for in the Settlement Agreement that was approved by the Commission in No. E-01345A-08-0172.

APS' filing also reflects the Company making two adjustments, to remove expense for supplemental executive retirement plan and stock-based compensation, which appear to be consistent with prior Commission orders, and which are the types of adjustments that would typically be made by Staff and/or RUCO in recent utility rate cases, and would be made in the current case by Staff if such costs were not already being removed by APS in the current case.

Finally, APS proposed a new adjustment in its October 26, 2011 update, related to transmission costs, upon which Staff has reserved judgment on this new adjustment at this time.

Schedule 3 Revenues

Q. What are Schedule 3 revenues?

A. Schedule 3 of APS' tariff relates to fees that are collected by the Company for line extensions.

Q. What unusual accounting was provided for Schedule 3 revenues in the Settlement Agreement that was approved by the Commission in No. E-01345A-08-0172?

A. Section X of the Settlement Agreement at paragraph 10.1 provided for APS to record Schedule 3 receipts as revenue during the period January 1, 2010 through the earlier of December 31, 2012 or the conclusion of APS' next general rate case. Prior to that, APS had recorded Schedule 3 receipts as Contributions in Aid to Construction ("CIAC").

Recording receipts for line extensions as CIAC is the standard way of accounting for such receipts under the Uniform System of Accounts for electric utilities.

Q. Please discuss the Company's adjustment to remove Schedule 3 revenues.

A. APS proposes to discontinue the special accounting treatment – i.e., recording Schedule 3 receipts as revenue – that had been provided by the Settlement Agreement that was approved by the Commission in Docket No. E-01345A-08-0172, and to again resume the standard accounting for such receipts as CIAC. Accordingly, the Company's adjustment no. 12 removes $18.660 million of Schedule 3 revenues from revenues.

Q. How is CIAC typically treated for ratemaking purposes?

A. CIAC is typically treated for ratemaking purposes as an offset to rate base. The rate base offset amount related to CIAC is typically based on the unamortized CIAC balance, less an income tax impact that is accounted for in the balance of ADIT.

As a simplified example, if a utility had $100 million of unamortized CIAC (and there was a 40 percent combined state and federal income tax rate), rate base would be reduced by approximately $60 million ($100 million of CIAC less $40 million of ADIT).

The amortization of CIAC is typically reflected for ratemaking purposes as an offset to a utility's depreciation expense.

Q. What amounts did APS expect for Schedule 3 receipts in Docket No. E-01345A-08-0172?

A. As stated in paragraph 10.2 of the Settlement Agreement in Docket No. E-01345A-08-0172, APS estimated that its Schedule 3 revenues would be $23 million in 2010, $25 million in 2011 and $49 million in 2012.

Q. What amount of Schedule 3 receipts did APS record as revenue in the 2010 test year?

A. In the 2010 test year, APS recorded $18.660 million of Schedule 3 receipts as revenue.

Q. Does Staff agree with the Company's proposed adjustment to remove the Schedule 3 revenue?

A. Yes. The recording of Schedule 3 receipts as revenue represented an unusual accounting treatment and was instituted in the context of the Settlement Agreement that was approved by the Commission in Docket No. E-01345A-08-0172 primarily as a temporary measure to help APS manage its earnings and support its credit rating during the period between base rate cases. Under ordinary circumstances, Staff supports the recording of receipts that utilities receive for line extensions in accordance with the standard accounting, i.e., recording such receipts as CIAC. Consequently, Staff agrees with the conversion back to standard accounting, as CIAC, for Schedule 3 receipts. Additionally, the $18.660 million amount by which revenues are reduced in the current APS rate case is somewhat lower than the amounts of Schedule 3 revenues that APS was expected to receive from Docket No. E-01345A-08-0172, so transitioning back to the normal accounting treatment at this time, i.e., in the context of the 2010 test year when APS' Schedule 3 receipts were relatively low, will help to minimize the rate impacts of the transition. Consequently, Staff has accepted APS' proposed adjustment no. 17 to remove the Schedule 3 revenues.

Amortization of Deferred Pension and OPEB Costs

Q. What was provided for in the Settlement Agreement that was approved by the Commission in Docket No. E-01345A-08-0172 concerning deferrals of pension and OPEB costs?

A. Section IX of that Settlement Agreement provided for limited deferrals of Pension and OPEB costs by APS in 2011 and 2012 if such costs exceed the Docket No. E-01345A-08-0172 test year level, which the Signatories to the Settlement Agreement identified as $23.949 million.

Q. What has APS proposed in the current rate case related to that provision?

A. APS proposes in Company adjustment no. 23 to increase pre-tax operating expenses by ~~$8.740 million in total and by $8.122 million on an ACC jurisdictional basis to reflect the~~ recovery via amortization over a three-year period of the pension and OPEB cost deferral authorized in Decision No. 71448.

Q. Does Staff agree with that APS adjustment in principle?

A. Yes. Staff agrees that the adjustment proposed by APS is consistent in theory and concept with the Settlement Agreement provision for limited deferrals of Pension and OPEB in 2011 and 2012 if such costs exceed the test year level used in Docket No. E-01345A-08-0172.

Q. Does Staff have any concerns about the amounts used by APS?

A. Yes. APS' proposed adjustment is based on 2011 and 2012 estimates of pension and OPEB costs that were available to APS when APS prepared its filing. Staff has not been able to verify the amounts of APS' actually incurred 2011 or 2012 pension and OPEB costs, as those accounting periods have not yet closed. Moreover, the 2011 information

used by APS to compute its adjustment does not appear to reflect the latest actuarial valuation, which was presented to the Company on May 20, 2011 by Towers Watson, as described in APS' response to STF 27.1(i).

Q. How does Staff propose to address such concerns in the context of the current APS rate case?

A. Staff proposes to address such verifiability concerns in the context of the current APS rate case by seeking updated information from APS on actual 2011 and 2012 pension and OPEB costs, and may adjust the estimated amounts used by APS, if such an adjustment becomes warranted.

Supplemental Executive Retirement Benefits

Q. Please discuss APS' proposed adjustment to remove expense for Supplemental Executive Retirement Benefits.

A. APS' adjustment No. 25 reduces pre-tax operating expenses by $8.492 million in total and $7.892 million on an ACC jurisdictional basis to remove expense for benefits under the Supplemental Executive Retirement Plan ("SERP").

Q. Can you please provide a general description of SERPs?

A. The SERP provides supplemental retirement benefits for select executives. Generally, SERPs are implemented for executives to provide retirement benefits that exceed amounts limited in qualified plans by Internal Revenue Service ("IRS") limitations. Companies usually maintain that providing such supplemental retirement benefits to executives is necessary in order to ensure attraction and retention of qualified employees. Typically, SERPs provide for retirement benefits in excess of the limits placed by IRS regulations on pension plan calculations for salaries in excess of specified amounts. IRS restrictions can

also limit the Company 401(k) contributions such that the Company 401(k) contribution as a percent of salary may be smaller for a highly paid executive than for other employees.

Q. Is the removal of expense for SERPs consistent with Commission precedent?

A. Yes. The removal of expense for SERP is consistent with a series of Commission decisions in which the SERP expense has been removed from utility rates, including Commission decisions in rate cases involving APS and other utilities that are regulated by the Commission. In Decision No. 68487, in a Southwest Gas Corporation rate case, the Commission adopted a recommendation by RUCO to remove SERP expense. In reaching its conclusion regarding SERP, the Commission stated on page 19 of Decision No. 68487 that:

> Although we rejected RUCO's arguments on this issue in the Company's last rate proceeding, we believe that the record in this case supports a finding that the provision of additional compensation to Southwest Gas' highest paid employees to remedy a perceived deficiency in retirement benefits relative to the Company's other employees is not a reasonable expense that should be recovered in rates. Without the SERP, the Company's officers still enjoy the same retirement benefits available to any other Southwest Gas employee and the attempt to make these executives 'whole' in the sense of allowing a greater percentage of retirement benefits does not meet the test of reasonableness. If the Company wishes to provide additional retirement benefits above the level permitted by IRS regulations applicable to all other employees it may do so at the expense of its shareholders. However, it is not reasonable to place this additional burden on ratepayers.

In a UNS Gas, Inc. rate case, in Decision No. 71623 at pages 33-34, the Commission stated:

> [I]n Decision No. 69663, we disallowed SERP expenses for APS based on the finding made in the earlier Southwest Gas proceeding. (Decision No. 69663, at 26-27.) In the prior UNS Electric case (Decision No. 70360, at 22), we also excluded SERP costs stating '[w]e see no reason to depart

> from the rationale on this issue in the most recent UNS Gas rate case...' In the most recent Southwest Gas case (Decision No. 70665, at 17-18), we again found that SERP expenses should not be recoverable from ratepayers.
>
> We see no reason to depart from the rationale on this issue in all of the recent cases cited above, that ratepayers should not be required to fund the retirement benefits of a few select executives whose salaries exceed current IRS limits (currently $240,000). As has been stated in prior cases, the Company's shareholders may provide these additional retirement benefits but ratepayers should not be subject to this additional burden.
>
> We therefore adopt the recommendations of Staff and RUCO and disallow...SERP expenses proposed by UNS Gas.[22]

At page 28 of that Decision, the Commission stated:

> ... the issue is not whether UNS may provide compensation to select executives in excess of the retirement limits allowed by the IRS, but whether ratepayers should be saddled with costs of executive benefits that exceed the treatment allowed for all other employees. If the Company chooses to do so, shareholders rather than ratepayers should be responsible for the retirement benefits afforded only to those executives. We see no reason to depart from the rationale on this issue in the most recent Southwest Gas rate case [See also Arizona Public Service Co., Decision No. 69663, at 27 (June 28, 2007), wherein SERP costs were excluded in their entirety.], and we therefore adopt the recommendations of Staff and RUCO and disallow the requested SERP costs.

In Decision No. 71914 (September 30, 2010), the Commission also disallowed UNS Electric's SERP cost in Docket No. E-04204A-09-0206, stating at page 31 that:

> We see no reason to depart from the rationale on this issue in all of the recent cases cited above, that ratepayers should not be required to fund the retirement benefits of a few select executives whose salaries exceed current IRS limits (currently $240,000). As has been stated in prior cases, the Company's shareholders may provide these additional retirement benefits but ratepayers should not be subject to this additional burden.
>
> We therefore adopt the recommendations of Staff and RUCO and disallow ... SERP expense proposed by UNSE.

[22] See Decision No. 70011 at pages 27-29.

SERP expense was also removed by Staff in APS' last rate case, Docket No. E-01345A-08-0172 and such removal was incorporated into the Settlement Agreement revenue requirement that was approved by the Commission in Decision No. 71448 (December 30, 2009).

Q. Does Staff agree with the Company's adjustment to remove SERP expense?

A. Yes. The removal of SERP expense is consistent with several Commission orders, including those noted above, which have required the removal of such expense.

Stock Compensation

Q. What adjustment has APS proposed in the current case with regard to stock-based compensation?

A. The Company's adjustment no. 26 reduces pre-tax operating expenses by $12.421 million in total and by $11.543 million on an ACC jurisdictional basis to remove expense related to stock-based compensation.

Q. Has stock-based compensation been removed in other cases?

A. Yes. In Decision No. 69663, from a prior APS rate case, Docket No. E-01345A-05-0816 et al, the Commission adopted a Staff recommendation in that case where cash-based incentive compensation expense was allowed and stock-based compensation was disallowed. Additionally, page 36 of Decision No. 69663 indicates that the Commission rejected an argument by APS that the Commission not look at how compensation is determined or its individual components:

> APS argues that the issue is whether APS compensation, including incentives, is reasonable. APS does not believe that the Commission should look at how that compensation is determined or its individual components, but rather should just look at the total compensation. The

> Company argues that the interests of investors and consumers are not in fundamental conflict over the issue of financial performance, because both want the Company to be able to attract needed capital at a reasonable cost.
>
> We agree with Staff that APS' stock-based incentive compensation expense should not be included in the cost of service used to set rates. Contrary to APS' argument that we should not look at how compensation is determined, we do not believe rates paid by ratepayers should include costs of a program where an employee has an incentive to perform in a manner that could negatively affect the Company's provision of safe, reliable utility service at a reasonable rate. As testified to by Staff witness Dittmer and set out in Staff's Initial brief, "[e]nhanced earnings levels can sometimes be achieved by short-term management decisions that may not encourage the development of safe and reliable utility service at the lowest long-term cost. ... For example, some maintenance can be temporarily deferred, thereby boosting earnings. ... But delaying maintenance can lead to safety concerns or higher subsequent 'catch-up' costs." [cite omitted] To the extent that Pinnacle West shareholders wish to compensate APS management for its enhanced earnings, they may do so, but it is not appropriate for the utility's ratepayers to provide such incentive and compensation.

Thus, in Decision No. 69663, the Commission made an adjustment to disallow a portion of APS' incentive compensation expense, specifically the stock-based compensation.

Q. Was stock-based compensation expense also disallowed in the Commission's decisions in other rate cases?

A. Yes, it was. In Decision No. 70360 at page 22, in a rate case involving UNS Electric, the Commission, in referencing a similar decision regarding Southwest Gas Corporation as well as a prior APS rate case stated:

> For these same reasons, we agree with Staff that test year expenses should be reduced to remove stock-based compensation to officers and employees...The disallowance of stock-based compensation is consistent with the most recent rate case for Arizona Public Service Company (Decision No. 69663).

In Decision No. 71914 (September 30, 2010), the Commission also disallowed UNS Electric's stock-based compensation expense in Docket No. E-04204A-09-0206, stating at pages 29-30, among other things, that:

> We agree with RUCO that UNSE's proposal to include the costs of stock-based compensation should be denied. ...
>
> The Company has not presented a compelling reason to depart from previous and recent determinations on this issue.

Q. Please discuss the reasons for removing stock-based compensation.

A. Ratepayers should not be required to pay executive or management compensation that is based on the performance of the Company's (or its parent company's) stock price.

Q. Does Staff agree with the Company's adjustment to remove the expense for stock-based compensation?

A. Yes.

APS' October 26, 2011 New Update Adjustment to "Sync-Up Transformers Excluded from the FERC Formula Rate"

Q. Has APS presented a new operating expense adjustment in conjunction with its October 26, 2011 update that Staff has not reflected at this time, which you would like to discuss?

A. Yes. In particular I would like to briefly discuss one new adjustment APS made in its October 26, 2011 update, which is not being incorporated at this time into Staff's derivation of the base rate revenue requirement for APS. The new adjustment proposed by APS (APS adjustment no. 35) is described as an adjustment to "sync up the step-up transformers excluded from the FERC formula rate." This new APS adjustment does not

appear to relate to any information provided by APS in discovery, nor does it appear to be supported by any APS testimony that Staff has been able to identify. Staff is also unclear at this time how this new APS adjustment relates to the continuation of APS' existing Transmission Cost Adjustment ("TCA") rider, which is recommended by Staff witness McGarry, versus implementing prospectively an expanded TCA that APS has requested. Consequently, Staff is reserving judgment on this new APS adjustment until an explanation and additional supporting information has been provided. Accordingly, Staff has not reflected it in the determination of the base rate revenue requirement for APS at this time.

STAFF ADJUSTMENTS

Q. Please describe how you have summarized Staff's proposed adjustments to operating income.

A. Attachment RCS-2, Schedule C summarizes Staff's recommended net operating income. Schedule C.1 (ACC) presents Staff's recommended adjustments to test year revenues and expenses on an Arizona jurisdictional basis. The impact on state and federal income taxes associated with each of the recommended adjustments to operating income are also reflected on Schedule C.1. APS' proposed adjusted test year net operating income is $474.356 million, whereas Staff's recommended adjusted net operating income is $498.355 million. The recommended adjustments to operating income are discussed below in the same order as they appear on Schedule C.1.

C-1. Forensic Investigation of Grant-Funded Projects

Q. Please explain Staff's adjustment for costs related to a forensic investigation of grant-funded projects.

A. Staff Adjustment C-1 removes expense incurred by APS during the 2010 test year related to a forensic investigation conducted for APS into matters pertaining to projects funded with Department of Energy ("DOE") grants. APS' responses to STF 9.2, 9.3, 9.4, 9.7, 9.8, 9.9, 19.21, 20.2, 20.3 and 20.4, many of which contain confidential information, relate to Staff's investigation into such costs. APS' response to STF 9.2 describes that $1 million of such costs had been removed by APS in its original filing, and in that response, APS has also agreed to the removal of the remaining expenses, amounting to $2.129 million, associated with the Integrated Energy System ("IES") project, the Substitute Natural Gas ("SNG") project and the related legal and audit expenses that APS recorded during the 2010 test year. APS' October 26, 2011 update includes an adjustment (APS adjustment no. 34) on APS' Schedule C-2, page 12 to remove the $2.129 million of O&M expense on a total Company basis, and $2.057 million on an ACC jurisdictional basis. Attachment RCS-2, Schedule C-1 reflects the removal of these costs.

Q. Is there a need for a corresponding rate base adjustment related to these DOE grant-funded projects?

A. No. APS' response to STF 9.2 states that APS has not included any costs in rate base associated with the IES or SNG projects.

C-2. General Advertising Expense

Q. How does APS" test year General Advertising Expense compare with 2009?

A. APS" 2010 test year General Advertising Expense in Account 930.1 of $3.549 million exceeds the 2009 recorded amount of $1.808 million by $1.741 million or 96 percent.

Q. Please explain Staff's adjustment to General Advertising Expense.

A. This adjustment decreases APS' General Advertising Expense by approximately $572,000 on an ACC jurisdictional basis to remove general advertising expense that was not specifically related to energy conservation and sustainability, and to provide for a normalized allowance for general advertising expense. In its last rate case, Docket No. E-01345A-11-0224, the Company's response to STF 6.93, had agreed to remove advertising expense that was not specifically related to energy conservation and sustainability. A similar adjustment should be made in the current rate case.

Q. What amount of APS' 2010 general advertising expense was not related to conservation and sustainability?

A. APS' responses to Pre-filed 1.40, APS14082, and to STF 21.1 through 21.5, and to STF 27.10 indicate that $40,688 was incurred for "Breakfast at the Zoo" expense. This was for an employee event, which APS indicates was attended by approximately 2,000 APS employees and their families. APS' response to STF 21.1(p) indicates that the Breakfast at the Zoo charges did not encompass advertising and no advertising copy is available. That APS response also states that this expense should have been recorded to Account 930.2, instead of 930.1. This $40,688 expense for Breakfast at the Zoo is not necessary for the provision of safe and reliable utility service and is not for Commission-approved advertising and has therefore been removed.

Q. Did APS provide copies of the advertisements it ran in 2010?

A. Yes. APS' response to STF 21.1 included copies of advertisements. In general APS' advertisements appear to be consistent with promoting the sustainability objectives. Accordingly, Staff is not proposing to disallow APS' advertising expense related to specific advertisements.

Q. Please explain how you determined a normalized level for general advertising expense.

A. As noted above, APS' 2010 test year General Advertising Expense in Account 930.1 of $3.549 million exceeded the 2009 recorded amount of $1.808 million by $1.741 million or 96 percent. As shown on Attachment RCS-2, Schedule C-2, a three-year average of 2008 through 2010 actual advertising expense is $2.917 million. APS' 2010 general advertising expense, exclusive of the $40,688 Breakfast at the Zoo item, is adjusted to a normalized allowance of $2.917 million. This reduces total Company expense by approximately $631,489 and reduces ACC jurisdictional expense by $572,363.

Q. What is APS' 2011 budget for advertising expense?

A. APS' 2011 advertising budget was stated in response to STF 27.10(j) to be $171,583.33 per month, or $2.059 million for the year. APS' response to STF 27.10(j) at APS14964 states that APS is expected to be on budget by the end of 2011. That response shows that APS was under-budget for YTD September 2009 results.

Q. What explanation did APS provide as to why its 2011 budget of $2.059 million for advertising is so much lower than APS' 2010 actual advertising expense of $3.549 million?

A. APS' response to STF 27.10(h) stated that in 2010, the General Advertising Expense budget included $1.6 million to fund production costs for a new sustainability TV and radio campaign and these ads continued to run in 2011.

Q. How does the normalized annual allowance of $2.917 million for general advertising expense compare with APS' 2011 budget, and with a four-year average including the 2011 budget?

A. The normalized annual allowance of $2.917 million for general advertising expense exceeds APS' 2011 budget by $858,261 or 41.7 percent. A four-year average, 2008 through 2010 actual, and including the 2011 budget, which APS expects to be on by the end of the year, is $2.703 million. The normalized annual allowance of $2.917 million exceeds that four-year average amount by $214,565, or 7.9 percent.

Q. Please summarize the adjustment for General Advertising Expense.

A. As shown on Attachment RCS-2, Schedule C-2, General Advertising Expense should be reduced on an ACC jurisdictional basis by $572,363 to remove an expense for Breakfast at the Zoo and to provide for a normalized annual allowance, based on a three-year average of actual advertising expense for 2008 through 2010.

C-3. Property Tax Expense

Q. Please explain Staff Adjustment C-3.

A. This adjustment uses information provided by APS in its October 26, 2011 Update of its property tax expense adjustment detail, specifically APS14932, page 4 of 5, to adjust pro forma property tax expense to reflect more current information. Attachment RCS-2, Schedule C-3, column A shows the amounts reflected in APS' original filing. Column B shows the updated amounts from APS14932, page 4 of 5. Column C shows the resultant adjustment amounts. As shown on Schedule C-3, line 1, the full cash value of APS' plant has been updated to $7.871 billion (from $7.874 billion in APS' original filing). Also, on Schedule C-3, line 10, the effective property tax rate has been updated from the 9.00 percent used in APS' original filing to the more current rate of 8.96 percent. As shown on

Attachment RCS-2, Schedule C-3, this adjustment reduces property tax expense by $695,000 on a total Company basis and by $584,000 on an ACC jurisdictional basis to reflect more current information on the assessment and effective property tax rate.

C-4. Solar Post-Test-Year Plant Depreciation and Property Tax Expense

Q. Please explain Staff Adjustment C-4.

A. This adjustment is shown on Attachment RCS-2, Schedule C-4. Column A shows the amounts contained in APS' original filing. Column B shows the Staff adjusted amounts which reflect updates to APS' estimated amount of post test year solar plant and the removal of APS' estimated solar plant additions for April 1 through June 30, 2012, to correspond with Staff's use of post test year plant additions through March 31, 2012, as previously addressed in conjunction with Staff rate base adjustment B-1. Column C shows the adjustment amounts.

As shown on Attachment RCS-2, Schedule C-4, this adjustment decreases ACC jurisdictional depreciation expense by $1.170 million and property tax expense by $131,000, based on differences between Staff's and APS' proposed amounts of post-test-year solar plant additions.

C-5. Fossil Post-Test-Year Plant Depreciation and Property Tax Expense

Q. Please explain Staff Adjustment C-5.

A. This adjustment is shown on Attachment RCS-2, Schedule C-5. Column A shows the amounts contained in APS' original filing. Column B shows the Staff adjusted amounts which reflect updates to APS' estimated amount of post test year fossil plant and the removal of APS' estimated fossil plant additions for April 1 through June 30, 2012, to correspond with Staff's use of post test year plant additions through March 31, 2012, as

previously addressed in conjunction with Staff rate base adjustment B-2. Column C shows the adjustment amounts.

As shown on Attachment RCS-2, Schedule C-5, this adjustment decreases ACC jurisdictional depreciation expense by $637,000 and property tax expense by $146,000, based on differences between Staff's and APS' proposed amounts of post-test-year fossil-fueled generation plant additions.

C-6. Nuclear Post-Test-Year Plant Depreciation and Property Tax Expense

Q. Please explain Staff Adjustment C-6.

A. This adjustment is shown on Attachment RCS-2, Schedule C-6. Column A shows the amounts contained in APS' original filing. Column B shows the Staff adjusted amounts which reflect updates to APS' estimated amount of post test year nuclear plant and the removal of APS' estimated nuclear plant additions for April 1 through June 30, 2012, to correspond with Staff's use of post test year plant additions through March 31, 2012, as previously addressed in conjunction with Staff rate base adjustment B-3. Column C shows the adjustment amounts.

As shown on Attachment RCS-2, Schedule C-6, this adjustment decreases ACC jurisdictional depreciation expense by $253,000 and property tax expense by $110,000, based on differences between Staff's and APS' proposed amounts of post-test-year nuclear generation plant additions.

C-7. Distribution and General Post-Test-Year Plant Depreciation and Property Tax Expense

Q. Please explain Staff Adjustment C-7.

A. This adjustment is shown on Attachment RCS-2, Schedule C-7. Column A shows the amounts contained in APS' original filing. Column B shows the Staff adjusted amounts which reflect updates to APS' estimated amount of post test year distribution and general plant and the removal of APS' estimated distribution and general plant additions for April 1 through June 30, 2012, to correspond with Staff's use of post test year plant additions through March 31, 2012, as previously addressed in conjunction with Staff rate base adjustment B-4. Column C shows the adjustment amounts.

As shown on Attachment RCS-2, Schedule C-6, this adjustment decreases ACC jurisdictional depreciation expense by $1.693 million and property tax expense by $971,000 based on differences between Staff's and APS' proposed amounts of post-test-year distribution and general plant additions.

C-8. Interest Synchronization

Q. Please explain your interest synchronization adjustment.

A. The interest synchronization adjustment applies the weighted cost of debt to the adjusted rate base to derive a pro forma interest expense deduction that is used in the calculation of test year income expense. After adjustments, Staff's proposed rate base differs from that of the Company. This results in an adjustment to the amount of synchronized interest included in the tax calculation. The calculation of the interest synchronization adjustment is shown on Attachment RCS-2, Schedule C-8. This adjustment increases income tax expense by the amount shown on Schedule C-8, line 7 and decreases the Company's achieved operating income by a similar amount.

C-9. Base Cost of Fuel and Purchased Power

Q. What has APS proposed in the current case for the base cost of fuel and purchased power?

A. In its original filing, APS proposed to reduce the base fuel rate from 3.7571 cents per kWh, that was authorized by the Commission in Decision No. 71448, to 3.2415 cents per kWh, based on a projection APS had made of 2012 fuel and purchased power costs, net of an off system sales margin credit.

Q. What was APS' actual base cost of fuel for the 2010 test year?

A. For the test year ending December 31, 2010, APS' actual base cost of fuel and purchased power expense was approximately 3.3486 cents per kWh.[23]

Q. What is the basis for APS' requested base fuel rate?

A. APS' requested base fuel rate is based on a projection of 2012 fuel and purchased power costs made by APS that used March 31, 2011 market prices. Details of APS' proposed 3.2415 cents per kWh are shown at Mr. Ewen's Attachment PME-3. APS' 2012 forecast of fuel expense included assumptions for:

1. Increased electricity sales due to continued growth.
2. Lower commodity market prices for natural gas and power.
3. Higher coal and nuclear prices due to standard contract escalators.
4. Normalized maintenance and unplanned outage times.
5. Cancellation by Salt River Project ("SRP") of a capacity contract with APS.
6. Additional renewable resources consistent with the Company's Renewable Energy Standard ("RES") requirements.

[23] See APS witness Ewen's direct testimony, Attachment PME-4, page 1 of 4.

7. Miscellaneous items, such as broker fees, third-party wheeling expense, and short-term and long-term capacity costs.

Using those assumptions, as shown on APS' Attachment PME-3, page 2 of 4, APS had projected $945.9 million of fuel and purchased power expense for 2012, offset by $16.9 million of off-system sales margin credit, for a net retail fuel cost of $929.0 million. Dividing this cost amount by 28,186 GWh of projected native load sales for 2010 produced the base fuel rate of 3.2415 cents per kWh that APS reflected in its original filing.

Q. Has APS provided an alternative calculation that includes the impact of APS acquiring Southern California Edison's (SCE) share of Four Corners Units 4 and 5?

A. Yes. APS' Attachment PME-3, page 3 of 4, shows the Company's proposed base cost of fuel and purchased power, including the effects of acquiring SCE's share of Four Corners Units 4 and 5. This reflects total fuel and purchased power expense of $917.422 million, less off-system margin credits of $20.459 million for a net retail fuel cost of $896.963 million. Dividing the $896.963 million by the 28,658 GWh of projected native load sales for 2010 produces APS' alternative proposed base fuel rate of 3.1298 cents per kWh.

Q. How does APS' base cost of fuel interact with its Power Supply Adjustor ("PSA") mechanism?

A. APS' current PSA includes a 90/10 sharing provision for increases in certain fuel and purchased power costs above the base cost of fuel and purchased power. In the Company's filing, APS' annual base rate revenue requirement has been reduced by approximately $144 million (at test year sales levels). Under the 90/10 provision in the PSA, approximately $20.7 million of that decrease would not be passed onto customers.

As explained by APS witness Ewen in his direct testimony at page 4, concerning the impact of the Company's proposed decrease in the base cost of fuel:

> This adjustment reduces the annual base rate revenue requirement by approximately $144 million (at Test Year sales levels). But for the 90/10 sharing arrangement in the PSA, this would amount to no difference in the revenues actually collected from customers. With that sharing arrangement, the impact of the reduction in the base fuel rate amounts to a $21 million net increase in revenues, or about 0.7%. It is important to update the Company's base fuel rate both so that the attendant impact on class rate design can be accounted for and to avoid the 90/10 sharing becoming, in essence, an automatic 10% penalty or reward. Attachment PME-1 shows the results of the proposed adjustments on Test Year revenues. However, as will be discussed later in my testimony, the Company is proposing to remove the 90/10 sharing provision.

Q. Is another Staff witness addressing APS' proposal to remove the 90/10 sharing provision from the PSA?

A. Yes. APS' proposal to remove the 90/10 sharing provision from the PSA is being addressed in the current case by Staff witness Michael McGarry.

Q. How has Staff revised APS' proposed base cost of fuel and purchased power at this time?

A. Staff adjustment C-9 removes APS' pro forma adjustment of $29.810 million related to projected 2012 fuel and purchased power expense and replaced it with a reduction of $39.385 million based on APS' revised forecast of 2012 fuel cost. This adjustment decreases APS' proposed fuel cost by $9.575 million.

Q. What is shown in column F?

A. Column F shows the estimated fuel cost savings that APS projects related to its proposed acquisition of SCE's share of Four Corners Units 4 and 5. As shown on line 10, based on

APS' updated estimates, acquiring SCE's share of Four Corners Units 4 and 5 would reduce fuel and purchased power costs by approximately $31.4 million, versus the amount Staff has used. APS' proposed acquisition of SCE's share of Four Corners Units 4 and 5 is being addressed in another proceeding and has not yet been ruled on by the Commission. Consequently, no incremental fuel savings related to that acquisition are being reflected currently in Staff's (or APS') determination of the base cost of fuel and purchased power.

Q. Might a revision to the base cost of fuel and purchased power be needed if more accurate fuel forecast information for 2012 becomes available at a later point in the processing of the APS rate case?

A. Possibly. Staff is monitoring APS' PSA forecast filings and the concurrent proceeding dealing with APS' request to acquire Four Corners, Units 4 and 5. The impact on base fuel costs resulting from APS' proposed acquisition of SCE's share of Four Corners Units 4 and 5 may need to be revised if that transaction is approved and/or if other significant changes in base fuel costs occur.

C-10. Payroll Expense Adjustment

Q. Please explain the payroll expense adjustment.

A. APS' October 26, 2011 update substantially revised APS' originally filed payroll expense annualization adjustment. The APS update to that adjustment increases O&M expense by $4.855 million on a total Company basis, and by $4.512 million on an ACC jurisdictional basis.

APS' October 26, 2011 update filing, on the Company's revised Schedule C-3, for APS adjustment no. 11, shows an increase to pre-tax O&M expense of $4.512 million on an

ACC jurisdictional basis. In APS' original filing, this same adjustment had decreased O&M expense by $482,000 on an ACC jurisdictional basis. That is a net increase of approximately $4.994 million in jurisdictional O&M expense.

The APS update essentially reflects the impact of two items: (1) correction by APS of errors it discovered in its originally filed adjustment, which increases total Company O&M expense by $3.178 million, and (2) the impact of a new union contract, which increases total Company O&M expense by $2.196 million.

APS indicates that its revised adjustment reflects the impact of a new union contract. APS' workpapers (APS14945, pages 2 and 4 of 10) show a 1.5 percent and 2.5 percent union pay increase for Union 387 for 2011 and 2012, respectively, which cumulatively produce a 4.04 percent increase for the two years combined.[24] That compares to an increase of 1.0 percent only for 2011 that was reflected in APS' originally calculated adjustment. The pay increases resulting from a union contract included in APS' revised payroll annualization adjustment have been accepted by Staff to incorporate the impact of the known and measureable union pay increases into the O&M expenses, based on the Commission's historical practice of reflecting pay increases associated with union contracts.

APS was asked in discovery[25] to explain the other changes which impacted the payroll annualization adjustment. After obtaining and reviewing APS' response to STF 32.1, Staff has also reflected the impact of the error corrections contained in APS' revised payroll annualization adjustment. APS' response to STF 32.1 explains the corrections to the original APS payroll annualization adjustment, which includes revisions to 2010 recorded amounts and March 2011 annualized amounts. APS has indicated that its

[24] 1.015 x 1.025 = 1.0404.
[25] Staff set 32, issued November 7, 2011.

original adjustment had mistakenly included in test year base pay amounts related to the selling of paid time off and paid earned and accrued vacation, which had overstated the test year base pay and related payroll tax expense, and understated the amount of the payroll annualization adjustment.

In summary, as shown on Attachment RCS-2, Schedule C-10, this adjustment increases jurisdictional O&M expense by $4.994 million.

C-11. Depreciation Expense – New Depreciation Rates for Meters

Q. Please explain Staff Adjustment C-11.

A. This adjustment reflects the rejection of APS' proposed new depreciation rate proposal for Account 370.01, electronic meters, and Account 370.03, AMI meters. APS proposes to increase the annual depreciation for electronic meters, from $2.289 million at the currently authorized depreciation rate of 3.68 percent, to $3.863 million, for a proposed new depreciation rate of 6.21 percent, per its 2011 Depreciation Study.[26] That is an increase of $1.574 million, or 68.7 percent.

For AMI meters, APS proposes to increase the annual depreciation from $4.497 million at the currently authorized depreciation rate of 3.82 percent, to $7.687 million for a proposed new depreciation rate of 6.53 percent, per its 2011 Depreciation Study. That is an increase of $3.190 million, or 70.9 percent.

[26] See Exhibit REW-2, pages 18 and 26. The annual depreciation accrual amounts are based on December 31, 2010 plant.

Q. How do the depreciable lives reflected in the currently authorized depreciation rates for these accounts compare with APS' proposal for new depreciation rates?

A. The currently authorized depreciation rates for these accounts are based upon a 26 year average service life for each type of meters. In contrast, APS' proposal for new depreciation rates has reflected average service lives of only 15 years for each type of meters.

Q. Has APS discontinued the purchase and installation of electronic meters?

A. No. Electronic meters are not obsolete and APS has added significant amounts of new plant to Account 370.01 in recent years.

Q. What was the net plant balance at December 31, 2010?

A. As of December 31, 2010, the end of the test year, the plant balance, accumulated depreciation, and net plant amounts were as follows:

Description	Original Plant Cost @ 12/31/2010	Accumulated Depreciation at 12/31/2010	Net Plant Balance
Using Recorded Depreciation Reserve	(E)	(F)	(G)
Electronic Meters - Plant Account 370 01	$ 62,207,543	$ (19,681,616)	$ 42,525,927

Q. What significant additions has APS made to the electronic meters account in recent years?

A. As examples, APS added $11.936 million to this account in 2007 and another $11.953 million had been added in 2005.[27]

[27] See APS' response to STF 12.27(d) in APS' last rate case, Docket No. E-01345A-08-0172. A copy of that response is included in Attachment RCS-3, attached to my testimony.

Q. Has APS projected further substantial additions to Account 370.01 in years beyond the 2007 test year used in its last rate case?

A. Yes. APS' response to STF 12.27(h) in Docket No. E-01345A-08-0172 stated that APS estimated meter additions for Account 370.01 of $12.5 million in 2008, $8.9 million in 2009 and $4.2 million in 2010.

Q. What depreciation rates had APS been using for Account 370.01?

A. The depreciation rates that APS has used for these accounts from 1998 through the present were identified in the response to STF 17.7(h) in Docket E-01345A-08-0172[28] as follows:

Account 370.01, Electronic Meters	Depreciation Rate
1998 to March 2005:	4.54%
April 2005 to June 2007:	3.61%
July 2007 to present:	3.68%

Q. How does APS' existing depreciation rate for electronic meters, Account 370.01, compare with the depreciation being used by other Arizona electric utilities?

A. The present depreciation rate used by APS for Account 370.01, electronic meters, is 3.68 percent. Tucson Electric Power Company ("TEP") uses a depreciation rate of 2.99 percent for Account 370.00, Meters.[29] UNS Electric, Inc. ("UNSE") used a rate of 3.11 percent for Account 370.00, Meters.[30] TEP and UNSE do not break out their investment in Meters into separate sub-accounts. APS' existing 3.68 percent depreciation rate for electronic meters is higher (i.e., produces more depreciation in each year) than the recently approved revised rates being used by TEP and UNSE in Docket Nos. E-01933A-07-0402

[28] A copy of that response is included in Attachment RCS-3.
[29] See, e.g., Docket No. E-01933A-07-0402, direct testimony of TEP witness, Dr. Kimbugwe Kateregga, Exhibit KAK-1, 2007 Depreciation Rate Study, page 60.
[30] See, e.g., Docket No. E-04204A-06-0783, direct testimony of UNSE witness, Dr. Ronald White, Exhibit REW-2, 2006 Depreciation Rate Revenue, page 15.

and E-04204A-06-0783, respectively. UNSE also filed a technical update of its depreciation rates in Docket No. E-04204A-09-0206, sponsored by Dr. White. UNSE's depreciation rates in that case were accepted and reflected a 3.01 percent depreciation rate for meters. The 3.01 percent rate was a decrease from the previous 3.11 percent depreciation rate used by UNSE for meters. Page 18 of Dr. White's depreciation study for UNSE in Docket No. E-04204A-09-0206[31] shows that the average service life for UNSE's meters (Account 370.00) at the previous and revised depreciation rates was 34 years. The remaining life for UNSE's meters account increased from 24.14 years to 25.56 years.

Q. APS is proposing to substantially increase the annual depreciation expense for Account 370.01, electronic meters. You mentioned the depreciation rates for Meters, Account 370, that were authorized for TEP and UNSE in their most recent rate cases. How were the then-existing depreciation rates for Meters changed in those TEP and UNSE rate cases?

A. In Docket No. E-01933A-07-0402, TEP's depreciation rate for Account 370, Meters, was reduced from 3.79 percent to 2.99 percent.[32] In Docket No. E-04204A-06-0783, UNSE's depreciation rate for Meters was reduced from 3.25 percent to 3.11 percent. These reductions in the depreciation rate for Meters for the other two Arizona electric utilities contrast with APS' proposal for a substantial increase. In Docket No. E-04204A-09-0206, UNSE's depreciation rate for Meters was reduced from 3.11 percent to 3.01 percent.

[31] A copy of selected pages from Dr. White's Attachment REW-2, 2009 Technical Update, for UNS Electric in E-04204A-09-0206, relating to the average service lives, remaining life, and depreciation rates for UNSE meters is included in Attachment RCS-3 to my testimony.

[32] See, e.g., Docket No. E-01933A-07-0402, direct testimony of TEP witness, Dr. Kimbugwe Kateregga, Exhibit KAK-1, 2007 Depreciation Rate Study, page 60. Cost of removal for distribution plant was broken out as a separate depreciation rate component in the approved depreciation rates. TEP's existing depreciation rate for Meters prior to Docket No. E-01933A-07-0402 had included a provision for negative net salvage.

Q. What other concerns does Staff have regarding APS proposed replacement of electronic meters?

A. APS has not demonstrated that it is economical, cost-effective or even prudent to purchase and then replace electronic meters within only a few years of their initial installation. Moreover, electronic meters that are new or only a few years old should have significant salvage value, yet APS has reflected salvage value of only 0.03 percent[33] (i.e., only 3 cents of value for every $1 invested) for electronic meters in its proposed depreciation rates.

Q. How should APS' proposed depreciation for Account 370.01 be adjusted?

A. The existing depreciation rate of 3.68% should be applied. As shown on Attachment RCS-2, Schedule C-11, this produces annual depreciation of $2.289 million. APS' proposal for $3.863 million of depreciation expense for this account should be rejected. The jurisdictional adjustment reduces depreciation expense by $1.564 million.

Q. What did APS state in its last depreciation rate study concerning the appropriate depreciation period for AMI meters?

A. Page 4 of APS' 2008 Depreciation Rate Study[34] stated that:

> Amortization accounting is also recommended for Account 370.01 (Meters-Electronic) and Account 370.02 (Meters-Electromechanical). APS has committed to a program of replacing electronic and electromechanical meters with AMI (Advanced Metering Infrastructure) meters by 2012. Accordingly, a 5-year amortization period is recommended for Accounts 370.01 and 370.02. **The current projection life of 26 years for electronic meters is recommended for AMI meters pending sufficient retirement experience to estimate service lives for AMI metering technology.** Reserve imbalances associated with the proposed meter amortization accounts were distributed to the remaining depreciable accounts in the Distribution plant function. (Emphasis supplied.)

[33] See, e.g., Exhibit REW-2, at page 18.
[34] See Attachment REW-1 to APS witness Dr. White's direct testimony in Docket No. E-01345A-08-0172

Q. Does that same situation exist in the current APS rate case?

A. Yes. The current projection life of 26 years for electronic meters is recommended for AMI meters pending sufficient retirement experience to estimate service lives for AMI metering technology. The 26 year average service life period that has traditionally been applied to meter investment should continue for AMI meters.

Q. How should APS' proposed depreciation of AMI meters be adjusted?

A. As shown on Attachment RCS-2, Schedule C-11, the existing authorized depreciation rate of 3.82 percent should continue to be applied. This reduces APS' requested depreciation expense for Account 370.3, AMI meters, by $3.171 million on an ACC jurisdictional basis.

Q. Is another Staff witness addressing the useful lives of electronic and AMI meters from an engineering perspective?

A. Yes. Staff witness Michael Lewis is addressing the useful lives of electronic and AMI meters from an engineering perspective. He has concluded that there is no reason from an engineering perspective why AMI meters should not last as long as older meters.

Q. Should the issue of APS' meter replacement program and its impact on the service lives of investment in Account 370.01, electronic meters, and 370.03, AMI meters, be reviewed in APS' next rate case?

A. Yes. The issue of APS' meter replacement program and its impact on Account 370.01, electronic meters, should be reviewed in APS' next rate case. APS should be directed to present evidence demonstrating that its continuing purchase and installation of tens of millions of dollars of electronic meters in conjunction with its apparent plans to then replace them within a few years with more advanced "smart meters" is economical, cost-

effective and prudent. APS should also be directed to present updated information on retirement experience necessary to re-evaluate the depreciation rate for Accounts 370.01, electronic meters, and 370.03, AMI meters, at that time.[35] In that case, APS should also present updated information concerning the useful life of AMI meters.

C-12. Prospective Amortization of 2010 Severance Costs

Q. Please explain Staff Adjustment C-12.

A. This adjustment is shown on Attachment RCS-2, Schedule C-12, and removes the $3.366 million total Company and $3.128 million ACC jurisdictional expense requested by APS for amortization over a three-year period of the $10.099 million cost of APS' 2010 non-voluntary severance program.[36] As explained in the response to STF 25.6(d), APS has requested that $3.366 million of the $10.099 million associated with the 2010 non-voluntary severance program remain in the test year, for one year of an APS-proposed three-year amortization of such severance costs.

Staff has removed this prospective amortization because the first year savings identified by APS of $23.446 million in total, and approximately $11.5 million of APS O&M expense savings and $3.9 million of APS capital savings, are sufficient to have fully amortized the $10.099 million severance cost during the first full annual period during which such savings were realized. Staff's analysis indicates that a one-year amortization from April 2011 through March 2012 is sufficient to fully amortize such cost against the realized savings. Consequently, no remaining unamortized balance should remain by July 1, 2012, the approximate date on which new base rates for APS from the current APS rate case would become effective. The APS request for $3.366 million of prospective

[35] This need not take the form of a complete new depreciation rate study, but could be in the form of a Technical Update, focusing on Account 370 (and any other accounts that had experienced significant changes).
[36] These amounts are confirmed in APS' response to STF 25.8.

amortization of this cost is unwarranted because the savings realized by APS will have enabled the full amortization of the severance costs prior to the effective date of new rates in the current APS base rate case.

Q. Did APS file a request for an accounting deferral or establish a regulatory asset related to the $10.099 million of 2010 non-voluntary severance program cost?

A. No. As explained in the Company's response to STF 25.5(k), APS did not file a request for accounting deferrals or establish a regulatory asset related to the $10.099 million. APS has requested that the $10.099 million be amortized over a 3-year period to match the cost against the benefit.

Q. When did APS experience the benefit of the 2010 non-voluntary severance program?

A. APS began experiencing the benefit of the 2010 non-voluntary severance program as its work force was down-sized during the period January 2010 through March 2011. APS' response to STF 25.5(a) identifies the monthly work force changes and states that during the period January 2010 through March 2011 the total number of APS/PNW regular employees was reduced by a net 259 employees, as a combination of voluntary employee terminations and non-voluntary terminations, offset by employee new hires.

Q. What amount of total first year savings for the severance program has APS identified?

A. APS' response to STF 25.5(b) has identified first year savings of $23.446 million.

Q. What calendar period has APS identified as the "first year" in which APS is realizing those savings?

A. APS' response to STF 25.5(d) states that the first full year of savings is for the 12 month period April 2011 through March 2012.

Q. How much O&M expense and capital cost savings attributable to the severance is being realized by APS during that "first year" period of April 2011 through March 2012?

A. APS' response to STF 25.5(g) indicates that of the $23.446 million total savings, approximately $11.5 million relates to APS O&M savings and $3.9 million relates to APS capital savings, with the remainder relating to amounts billed to participants in jointly owned facilities.

Q. What does Staff propose?

A. Staff proposes that the amortization of the $10.099 million 2010 non-voluntary severance program cost commence when APS began realizing the savings. Coordinating the amortization of the 2010 severance cost with the realization by APS of such savings results in a conclusion that there is no remaining unamortized amount left when new base rates for APS in the current rate case would take effect. The $11.5 million APS O&M savings and $3.9 million APS capital savings identified by the Company as being realized for the first year, April 2011 through March 2012, are sufficient to fully amortize the $10.099 million cost by March 2012, if not sooner, indicating that there should be no remaining unamortized cost existing by July 1, 2012 when new base rates for APS have been anticipated to be in effect. Consequently, the prospective $3.366 million amortization proposed by APS, which is $3.128 million on an ACC jurisdictional basis, has been

removed from test year operating expenses, as shown on Attachment RCS-2, Schedule C-12.

C-13. Directors and Officers' Liability Insurance Expense

Q. Please explain Staff Adjustment C-13.

A. This adjustment is shown on Attachment RCS-2, Schedule C-13 and removes one-half of the Directors and Officers' Liability Insurance expense and reduces jurisdictional test year O&M expense by $550,000. The removal of one-half of this expense reflects an equal (i.e., 50/50) sharing of the cost for this insurance between shareholders and ratepayers.

Q. Why should the cost of the D&O insurance expense be shared between shareholders and ratepayers?

A. This type of insurance coverage usually comes into play when a shareholder sues the officers and directors of a public company, such as APS' parent company, Pinnacle West. Thus, it helps protect the officers and directors from the costs of a shareholder lawsuit. Shareholders benefit from payouts under the policy that would reduce the cost not recoverable from ratepayers. On the other hand, ratepayers benefit from this because having such insurance improves the ability of the publicly traded parent corporation to attract and retain qualified directors and officers and enables the directors and officers to make decisions without fear of personal liability. Consequently, it is reasonable for shareholders to bear some of the cost for the D&O Insurance.

Q. Was this adjustment made in APS' last rate case?

A. To my knowledge it was not.

Q. Did Staff recommend a similar adjustment in Southwest Gas' most recent Arizona rate case?

A. Yes. A similar adjustment was also made in Southwest Gas' most recent Nevada rate case, Nevada PSC Docket No. 09-04003, and adopted by the Nevada Commission in an order dated October 29, 2009. Southwest's D&O Insurance expense is a "system allocable" expense, meaning that it is incurred at Southwest's corporate headquarters and the cost is allocated to the divisions. Thus, a portion of the same Southwest D&O Insurance expense that was recently disallowed in Nevada was being allocated to Arizona, and was adjusted for 50/50 sharing by Staff in SWG's most recent Arizona rate case, Docket No. G-01151A-10-0458.[37]

Q. Have other regulatory commissions besides Nevada made a similar adjustment for sharing of D&O Liability Insurance Expense between shareholders and ratepayers?

A. Yes. The Nevada Commission order in Southwest Gas' last rate case, at page 47, paragraph 157, cites two states (Arkansas and California) that have required a sharing of D&O Liability Insurance Expense between ratepayers and shareholders on a 50-50 basis.[38] We are aware that at least two other commissions (Connecticut and Florida) have made adjustments for a ratepayer and shareholder sharing of D&O Insurance expense. Connecticut has required shareholders to share a portion of the cost of D&O Insurance expense, with the shareholder portion varying from 50 percent to 75 percent in different cases.

[37] Southwest Gas' most recent rate case resulted in a settlement being reached by most of the parties to that case, which incorporated this Staff adjustment; however, a final decision has not yet been issued by the Commission in that case.

[38] To date, we have not located the Arkansas and California commission orders which required that sharing.

Q. Have you included an attachment with excerpts from the orders of which you are aware which have made such findings concerning sharing of D&O Insurance Expense between shareholders and ratepayers?

A. Yes. Attachment RCS-5 contains excerpts from such orders that we have currently located.

Q. Please summarize the adjustment to expense for D&O Insurance sharing between shareholders and ratepayers.

A. As shown on Schedule C-13, APS' proposed test year expense for D&O Insurance of $1.170 million should be reduced by $585,000 to reflect an allocation of 50 percent of this expense to shareholders. The ACC jurisdictional adjustment to expense is a reduction of $550,000.

Q. Is there a related adjustment to rate base?

A. No. APS' response to STF 21.6(a) indicated that it expenses D&O Insurance as incurred and did not include a rate base item for prepaid D&O insurance.

C-14. Annual Incentive Compensation

Q. Please explain Staff Adjustment C-14.

A. This adjustment is shown on Attachment RCS-2, Schedule C-14. The adjustment first normalizes the test year annual incentive compensation expense amount based on an average of the last three years, 2008 through 2010. In comparison with the average, the 2010 test year amount was significantly higher. This adjustment then removes 50% of a normalized level of expense related to APS' annual incentive compensation to reflect the sharing of that expense between shareholders and ratepayers.

Q. Please explain the reason for removing 50 percent of the normalized incentive compensation expense.

A. In general, incentive compensation programs can provide benefits to both shareholders and ratepayers. The removal of 50 percent of the incentive compensation expense, in essence, provides an equal sharing of such cost, and therefore provides an appropriate balance between the benefits attained by both shareholders and ratepayers. Both shareholders and ratepayers stand to benefit from the achievement of performance goals. Moreover, there is no assurance that the award levels included in the Company's proposed or Staff's normalized expense (before sharing) will be repeated in future years.

Q. What is the result of Staff adjustment C-14?

A. Test year expense for incentive compensation proposed by APS is reduced by $20.370 million on a total Company basis and by $18.930 million on an ACC jurisdictional basis.

Q. What was APS' incentive compensation expense in the 2010 test year, and how did that compare with prior years?

A. The table below shows the amounts of incentive compensation charged to O&M for each year 2005 through 2007, which were provided in APS' response to STF 19.17 from APS' last rate case and for years 2008 through 2010 as provided in APS' response to STF 22.2 in the current case:

Year	Total Company	ACC Jurisdictional
2005	$21.752 million	$20.522 million
2006	$21.005 million	$19.842 million
2007	$28.342 million	$26.470 million

[BEGIN CONFIDENTIAL]

[redacted] [redacted] [redacted]

[END CONFIDENTIAL]

The 2010 test year amount is significantly higher than the comparable amounts from prior years.

Q. How much of APS' 2010 test year incentive compensation expense was for Officers and Senior Management?

A. It appears that the officers' portion of test year incentive compensation expense was approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

Q. Has APS identified the amount of incentive compensation related to front line and non-senior management?

A. APS has identified that **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** is for front line and non-senior management.

Q. Please briefly discuss the key provisions of APS' Annual Incentive Plan.

A. APS' 2011 Annual Incentive Award Program (AIA) was provided in response to STF 1.16 as CONFIDENTIAL APS14212. The 2011 AIA is comprised of **[BEGIN CONFIDENTIAL]** [redacted]

[39] Per APS' response to STF 20.8, APS14893.

[redacted]

[redacted] **[END CONFIDENTIAL]**

Q. You stated that the AIA is comprised of three components. Please discuss the [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

A. Per APS14212, page 2 of 17:

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

Q. Please discuss the [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] of APS' 2011 AIA.

A. The **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** is described in APS14212, page 2 of 17, as follows:

[BEGIN CONFIDENTIAL]

[redacted]

[redacted]

[END CONFIDENTIAL]

Q. How does the third component, the [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] affect the calculated total incentive award?

A. It doesn't. The achievement of the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** goals determines the total calculated incentive award, and the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** affects the amounts received by individual employees.

Q. Has APS listed the [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] on which the [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] of the AIA is predicated?

A. Yes, those items are listed on APS14212, pages 4-7 of 17, which is reproduced in Attachment RCS-4.

Q. Do APS' shareholders and customers both benefit from its AIA goals?

A. Yes. As noted above, the primary purpose of the APS performance portion of the AIA is to emphasize the importance of the Company's earnings. For an AIA award to occur, APS' earnings must exceed a threshold level. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** measures include a variety of measures, including shareholder value-oriented goals and customer satisfaction,

indicating that there are benefits to both shareholders and customers from the achievement of AIA Business Unit goals that result in the payment of incentive compensation.

Q. Was an equal sharing of APS' cash-based incentive compensation expense required in APS' last litigated rate case?

A. No. In APS' last litigated base rate case, Docket No. E-01345A-05-0816, only stock-based compensation was removed. However, in APS' last base rate case, Docket No. E-01345A-08-0172, Staff made an adjustment to share on a 50/50 basis between shareholders and ratepayers APS' cash-based incentive compensation expense. That Staff adjustment was incorporated into the development of the allowed revenue requirement for APS in that proceeding.

Q. Was an equal sharing of incentive compensation expense ordered in Commission decisions in other rate cases involving Arizona utilities?

A. Yes. In Decision No. 70011 (November 27, 2007), in the UNS Gas, Inc. rate case, Docket No. G-04204A-06-0463, the Commission stated on page 27 that:

> We believe that Staff's recommendation provides a reasonable balancing of the interests between ratepayers and shareholders by requiring each group to bear half the cost of the incentive program.

In Decision No. 70360 (May 27, 2008), in a UNS Electric, Inc. rate case, Docket No. E-04204A-06-0783, the Commission stated at page 21 that:

> Consistent with our finding in the UNS Gas rate case (Decision No. 70011, at 26-27), we believe that Staff's recommendation provides a reasonable balancing of the interests between ratepayers and shareholders by requiring each group to bear half the cost of the incentive program...Given that the arguments raised in the UNS Gas case are virtually identical to those

> presented in this case, we see no reason to deviate from that recent decision.

In Decision No. 68487 (February 23, 2006), in a Southwest Gas Company rate case, Docket No. G-01551A-04-0876, the Commission stated at page 18 that:

> We believe that Staff's recommendation for an equal sharing of the costs associated with MIP compensation provides an appropriate balance between the benefits attained by both shareholders and ratepayers.

In Decision No. 70665 (December 24, 2008) in a Southwest Gas rate case, Docket No. G-01551A-07-0504, the Commission stated at page 16:

> In the last Southwest Gas rate case, as well as several subsequent cases,[3] we disallowed 50 percent of management incentive compensation on the basis that such programs provide approximately equal benefits to shareholders and ratepayers because the performance goals relate to financial performance and cost containment goals as well as customer service elements. (Decision No. 68487 at 18.) In that Decision, we stated:
>
> > In Decision No. 64172, the Commission adopted Staff's recommendation regarding MIP expenses based on Staff's claim that two of the five performance goals were tied to return on equity and thus primarily benefited shareholders. We believe that Staff's recommendation for an equal sharing of the costs associated with MIP compensation provides an appropriate balance between the benefits attained by both shareholders and ratepayers. Although achievement of the performance goals in the MIP, and the benefits attendant thereto, cannot be precisely quantified there is little doubt that both shareholders and ratepayers derive some benefit from incentive goals. Therefore, the costs of the program should be borne by both groups and we find Staff's equal sharing recommendation to be a reasonable resolution.
>
> (Id.) We believe the same rationale exists in this case to adopt the position advocated by Staff and RUCO to disallow 50 percent of the Company's proposed MIP costs.[4]

[3]See UNS Gas, Inc., Decision No. 70011 (November 27, 2007) at 27; Arizona Public Service Co., Decision No. 69663 (June 28, 2007) at 27; and UNS Electric, Inc., Decision No. 70360 (May 27, 2008) at 21.

[4]On the same basis, we will also disallow 100 percent of the Southwest Gas stock incentive plan ("SIP"). The costs related to similar incentive plans were recently rejected for APS and UNS Electric. (See Ex. S-12 at 32-34.) As was noted in the APS case, stock performance incentive goals have the potential to negatively affect customer service, and ratepayers should not be required to pay executive compensation that is based on the performance of the Company's stock price. (Decision No. 69663 at 36.)

In Decision No. 71623 (April 14, 2010) in a UNS Gas rate case, Docket No. G-04204A-08-0571, the Commission stated at 30-31:

> We believe that the Staff and RUCO recommendations, to require a 50/50 sharing of incentive compensation costs, provides a reasonable balancing of the interests between ratepayers and shareholders. The equal sharing of such costs recognizes that the program in comprised of elements that relate to the parent company's financial performance and cost containment goals, matters that primarily benefit shareholders, while at the same time recognizing that approximately 40 percent of the program's incentive compensation is based on meeting customer service goals. This offers the opportunity for the Company's customers to benefit from improved performance in that area.
>
> Therefore, consistent with the recent cases cited above, we will adopt the recommendation of Staff and RUCO on this issue.

In Decision No. 71914 (September 30, 2010), in a UNS Electric, Inc. rate case, Docket No. E-04204A-09-0206, the Commission stated at pages 28-29 that:

> UNSE ... argues that its PEP is very similar to Arizona Public Service Company's (APS) cash-based incentive compensation plan which the Commission allowed recovery of in Decision No. 69663 (June 28, 2007).
>
> Staff and RUCO recommended that the Commission disallow 50 percent of the PEP costs, consistent with the Commission's previous treatment of this expense. ...

> We believe that the Staff and RUCO recommendations, to require a 50/50 sharing of incentive compensation costs, provide a reasonable balancing of the interests between ratepayers and shareholders. The equal sharing of such costs recognizes that the program is comprised of elements that relate to the parent company's financial performance and cost containment goals, matters that primarily benefit shareholders, while at the same time recognizing that a portion of the program's incentive compensation is based on meeting customer service goals. This offers the opportunity for the Company's customers to benefit from improved performance in that area.
>
> Therefore, consistent with the recent cases cited above, we will adopt the recommendation of Staff and RUCO on this issue ....

In Decision No. 71914, the Commission also disallowed UNSE's expense for stock-based compensation.

Q. Please summarize Staff's recommendation concerning APS' annual incentive plan compensation expense.

A. Staff recommends a 50 percent sharing of normalized incentive compensation expense between shareholders and ratepayers. As shown on Attachment RCS-2, Schedule C-14, this results in a reduction to test year expense of $20.37 million on a total Company basis and $18.930 million on an ACC jurisdictional basis.

C-15. Fossil Non-Plant Maintenance Expense

Q. Please explain the adjustment for Fossil Non-Plant Maintenance Expense.

A. As part of its adjustment to normalize fossil plant maintenance expense, using a six-year average of 2005 through 2010, APS had included an adjustment to increase O&M expense by $882,000 for fossil non-plant maintenance. This is maintenance that is not associated with a specific fossil-fuel fired generating plant. APS' proposed adjustment represents a 660 percent increase over the 2010 recorded amount of $116,000:

Fossil Non-Plant Maintenance Expense		
Year	Amount ($000)	Percent Increase Over 2010
2005	$ 2,246	1836%
2006	$ 999	761%
2007	$ 660	469%
2008	$ 495	327%
2009	$ 773	566%
2010	$ 116	0%
Averages:		
Six Years	$ 882	660%
Five Years	$ 609	425%

The 2005 amount used in APS' average for that of $2.246 million does not appear to be representative of current or ongoing experience, and includes costs that are not typically incurred. APS' response to STF 25.21 states, for example, that:

> Year 2005 was $900,000 higher than other years because of $657,000 in incentive charged in that year plus a higher than average payroll accrual charged that year to department 9960 of $235,000 compared to the six year average of $55,000.

The Staff adjustment shown on Attachment RCS-2, Schedule C-15, page 1, uses a five-year average of 2006 through 2010 for this, for a normalized allowance of $609,000. That reduces APS' requested amount by $273,000 in total and by $266,000 on an ACC jurisdictional basis.

Fossil Plant Maintenance Expense for Four Corners Plant

Q. Does Staff have any other concerns about APS' requested amount for fossil plant maintenance expense?

A. Yes. As shown on Attachment RCS-2, Schedule C-15, page 2, APS has requested an annual normalized O&M expense allowance of $22.759 million for maintenance on the Four Corners plant, including $16.775 million for Four Corners Units 1-3. The $16.775 million Four Corners Units 1-3 maintenance expense amount includes $8.002 million for plant overhauls and $8.773 million for routine maintenance. APS has treated Four Corners Units 1-3 in other respects in its filing as units that are to be retired by the end of 2012.[40] Since APS has represented that Four Corners Units 1-3 may be retired by the end of 2012, Staff is concerned about the $16.775 million annual maintenance expense amount that APS has requested for Four Corners Units 1-3 in terms of whether that expense is representative of ongoing operations.

Q. Does the normal overhaul and maintenance expense typically cease after a fossil unit is retired?

A. Yes. APS' response to STF 25.22(f), for example, states that:

> The normal overhaul and ongoing maintenance cycles would cease after a fossil unit has been retired. However, costs will be incurred after a plant ceases operation in order to perform activities to secure the unit in a safe condition until dismantlement and decommissioning.

Q. Are APS' maintenance costs on the Four Corners plant a subject that is pending before the Commission in another docket?

A. Yes. As explained in APS' response to STF 25.22(e):

[40] See, e.g., APS' response to data request STF 27.11, and APS' depreciation rate study, sponsored by APS witness Ronald White, and the Direct Testimony of Dr. White at page 10.

APS' deferral order proposed in Docket No. E-01345A-10-0474, would net any reduced costs of Units 1-3 with the acquisition of SCE's share of Units 4-5, thus providing customers the benefit of any cost offsets. Also, as stated in that Docket, Units 1-3 could continue running past the acquisition date to (1) allow for a transition period and (2) if favorable market conditions exist, APS could sell the output as off-system sales, crediting margins to customers through the PSA.

Q. Has Staff made any pro forma adjustment to address Four Corners maintenance expense at this time?

A. No. Given the uncertain status of the continued operation of Four Corners, particularly Units 1-3, and the related issues that are being addressed in Docket No. E-01345A-10-0474, including the accounting deferral sought by APS in that proceeding, Staff is not making any pro forma adjustment to address Four Corners maintenance expense at this time.

C-17. Edison Electric Institute Dues

Q. Please explain the adjustment for Edison Electric Institute ("EEI") Dues.

A. This adjustment is shown on Attachment RCS-2, Schedule C-17 and reduces test year expense by $230,252 on a total Company basis and $216,273 on an ACC jurisdictional basis.

Q. How does your adjustment for Edison Electric Institute Dues compare with APS' proposed treatment of such dues?

A. It reflects the removal of 49.93 percent of EEI core dues, or $338,830 versus APS' adjustment to only remove the lobbying portion, or $108,578, of such EEI core dues. APS indicated in its response to STF 1.36 on the workpaper designated APS14209, page 4 of 4, that it removed 16 percent of the EEI core dues (apparently only the direct lobbying portion).

Q. How did you determine the portion of EEI core dues that should not be charged to ratepayers?

A. I obtained a classification by NARUC category for EEI Core Dues activities for the year ended December 31, 2005. This is shown on Schedule C-17, page 2. EEI Core Dues relating to the following activities should be excluded from rates:

- Legislative Advocacy
- Regulatory Advocacy
- Advertising
- Marketing
- Public Relations

The sum of EEI Core Dues activities for these NARUC categories totals 49.93 percent, as shown on Schedule C-17, page 2.

Q. Why is 2005 EEI information being used as the basis for the disallowance percentage?

A. In STF set 22, APS was asked to provide current information, but did not provide it. STF 22.5 specifically asked APS to provide the following information:

a) Please provide the EEI budget for each year 2008, 2009, 2010 and 2011.

b) Please provide the EEI financial statements for each year 2008, 2009, 2010 and 2011.

c) Does APS have any information breaking out EEI core dues activities by NARUC operating expense category, i.e., legislative advocacy; legislative policy research; regulatory advocacy; regulatory policy research; advertising; marketing; utility operations and engineering; financial, legal planning and customer service;

> public relations; and other? If not, explain fully why not. If so, please provide the most current information APS has.

APS' response stated that:

a) APS does not receive copies of EEI's budget.

b) APS does not receive copies of EEI's financial statements.

c) EEI does not prepare a schedule of expenses by NARUC Category. Instead EEI provides a copy of a letter that identifies the percent of dues spent on legislative advocacy, which APS previously provided in response to Staff 1.36 as ASP14209.

As a result of APS' failure to provide the information requested in STF 22.5, Staff has concluded that APS has failed to justify inclusion in rates of any amount of EEI dues for regular activities above the 49.93 percent that is shown on Schedule C-13, page 2, and was the basis for Staff's recommended disallowance of EEI core dues in APS' last rate case, Docket No. E-01345A-08-0172.

Q. What is the purpose of the NARUC-designated categorization of EEI expenditures?

A. The purpose of the NARUC-designated categorization of EEI expenditures is to provide regulatory commissions with information that is useful in helping them decide which, if any, of the costs of the association should be approved for inclusion in utility rates. Often, state commissioners review the costs of the association charged or allocated to the utilities in their jurisdiction in accordance with the policies of their commission for treatment of costs directly incurred by the state's utilities for similar activities. Certain expense categories may be viewed by some State commissions as potential vehicles for charging ratepayers with such costs as lobbying, advocacy or promotional activities which may not be to their benefit. The NARUC-designated categories of EEI expenditures are thus intended to be helpful to state utility regulatory commissions.

Q. Was this same percentage for the EEI core dues disallowance used in any other electric utility rate cases of which you are aware?

A. Yes. The Arkansas Public Service Commission in Docket No. 06-101-U, an Entergy Arkansas, Inc., rate case, in Order No. 10 (6/15/07) adopted a similar adjustment to reflect the disallowance of 49.93 percent of EEI core dues.

In addition, in a proceeding before the Arizona Corporation Commission in Docket No. E-04204A-06-0783, a UNS Electric, Inc., rate case, in Order No. 70360 dated May 27, 2008, the Commission stated in part:

> We agree with Mr. Smith's assessment that the portions of the EEI dues related to legislative and regulatory advocacy, advertising, marketing and public relations should not be included in recoverable test year expenses in this case. We believe Staff raises a valid point regarding the nature of EEI core dues, and whether a higher percentage of such dues should be disallowed as related to activities that are not necessary for the provision of service to UNSE customers. We therefore adopt Staff's position on this issue.

This 49.93 percent disallowance of EEI core dues corresponds to the above-identified activity categories.

THE COMPANY'S PROPOSED DEPRECIATION RATES

Depreciation Terminology and Concepts

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 Commission rules address the treatment of depreciation?

A. The Commission's rules at R14-02-102 address the treatment of depreciation. The current version of the rules appear to have been adopted effective April 9, 1992.

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.[41]

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 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 <u>non-cash</u> expense.

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[41] National Association of Regulatory Utility Commissioners Public Utility Depreciation Practices, August, 1996. ("NARUC Depreciation Manual"), p. 321. Also, Commission Rule R14-2-102, which 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."

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:

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 explain the concept of remaining life depreciation.

A. The remaining life technique 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. Can you provide a similar illustration of how accumulated depreciation is incorporated into the numerator of the basic depreciation calculation?

A. If a 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 an example with an 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	

APS' Proposed New Depreciation Rates

Q. How has APS requested new depreciation rates in the current case?

A. APS witness Ronald White sponsors a 2011 Depreciation Rate Study for APS, which is presented in Attachment REW-2 to his direct testimony.

Q. How were APS' depreciation rates modified in its last rate case, Docket No. E-01345A-08-0172?

A. In its last rate case, APS' depreciation rates were modified in a depreciation study sponsored by APS witness Dr. White. In that case, Staff concluded that, with the exception of the Company's proposed depreciation rates for account 370.01, electronic meters, the depreciation rates proposed by APS were developed in a manner that is consistent with the Commission's rules for depreciation rates. Additionally, APS applied for and was granted an operating license extension for the Palo Verde Nuclear Generating Station. The estimated impact of that license extension on Palo Verde depreciation rates was addressed in the Settlement Agreement in Docket No. E-01345A-08-0172.[42]

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 exhibit, Attachment REW-2. APS' new depreciation rates are the result of a depreciation study prepared by Dr. White's firm, Foster Associates, Inc., entitled "2011 Depreciation Rate Study" which is Attachment REW-2. With the exception of selected general support asset categories for which amortization accounting has been approved, the Company's proposed rates were developed using a depreciation system composed of the straight-line method, vintage 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' prior rate cases, Docket Nos. E-01345A-03-0437 and E-01345A-08-0172.

[42] See, e.g., Decision No. 71448, Settlement Agreement, Section XI at page 10.

APS' proposed depreciation rates also reflect a redistribution of recorded reserves. It is generally considered appropriate and consistent with group depreciation theory to periodically redistribute or rebalance recorded reserves among the various primary accounts based upon more current estimates of retirement dispersion and net salvage rates. Statement C of Exhibit REW-2 provides a comparison of recorded, computed and redistributed reserves at December 31, 2010. The recorded reserve of $4.210 billion was 38.2 percent of the depreciable plant investment. The corresponding computed reserve of $3.367 billion is 30.6 percent of the depreciable plant investment. A proportionate amount of the measured reserve imbalance of $842.1 million is amortized over the composite weighted-average remaining life of each rate category using the remaining life depreciation proposed in the study.

APS' depreciation rates also include amortization accounting for various general plant accounts.

Q. What impact do the new depreciation rates proposed by APS have?

A. As summarized on page 13 of Dr. White's testimony, based on December 31, 2010 plant investment, the new depreciation rates proposed by APS for APS plant decrease depreciation expense by $41.301 million (from $305.368 million at present rates to $264.067 million at APS' proposed rates). Of the 170 plant accounts studied in the 2011 study, APS proposes depreciation rate reductions for 97 accounts and increases for 73 accounts.[43]

[43] *See*, e.g., Attachment REW-2, 2011 Depreciation Rate Study, page 4.

On a composite basis[44], the Company's proposed new rates for APS plant produce a decrease of 0.37 percentage points, from the current composite rate of 2.77 percent to a composite at new rates of 2.40 percent.

Q. Are there particular aspects of APS' proposed depreciation rates which warrant further discussion?

A. Yes. In particular, APS' proposed new depreciation rates for meters, APS' depreciation changes related to the Four Corners plant, and depreciation changes related to the operating license extension obtained by APS for the Palo Verde Nuclear Generating Station would appear to warrant further discussion. I address each of these areas below.

APS Proposed Depreciation Rates for Meters

Q. Please discuss APS' depreciation proposal for meters.

A. As discussed in APS' last rate case, Docket No. E-01345A-08-0172, APS has committed to a program of replacing electronic and electromechanical meters (Accounts 370.01 and 370.02, respectively) with Advanced Metering Infrastructure (Meters-AMI, Account 370.03).

APS' 2011 depreciation study shows no investment remaining in Account 370.02, electromechanical meters.

APS proposes to reduce the depreciable life for electronic meters (Account 370.01) and for Meters-AMI (account 370.3) from the current life of 26 years to a new life of only 15 years. Primarily related to this proposed service life shortening, APS proposes to increase the depreciation rate for electronic meters (Account 370.01) and for Meters-AMI (account

[44] Id, at page 3. APS does not apply its depreciations on a composite basis; this information is for comparative purposes only.

370.3) from the current rates of 3.68 percent and 3.82 percent, respectively, to new APS-proposed rates of 6.21 percent and 6.53 percent, respectively.[45]

Q. Does Staff agree with APS' proposal to shorten the average service life for meters from the current life of 26 years to a new life of only 15 years?

A. No. Staff disagrees with that proposed change and recommends that the current average service life of 26 years for meters continue to be used. Section C-11 of my testimony, on pages 61-67, presents the reasons for this recommendation, and the related Staff adjustment to depreciation expense.

Four Corners Related Depreciation Changes

Q. What ownership changes for the Four Corners coal-fired power plant are currently pending?

A. Four Corners is a five-unit coal-fired power plant located in the northwestern corner of New Mexico. APS owns 100 percent of Four Corners Units 1-3 and 15 percent of Four Corners Units 4 and 5. In November 2010, APS and Southern California Edison entered into an asset purchase agreement providing for the purchase by APS of SCE's 48 percent interest in Units 4 and 5. APS has indicated that completion of the purchase by APS is expected to occur in the second half of 2012, and is conditioned upon receipt of regulatory approval by the ACC, the California Public Utilities Commission and the FERC, and the execution of a new coal supply contract, and other typical closing conditions.

APS has announced that, if APS' purchase of the SCE interests in Four Corners Units 4 and 5 is consummated, APS will close Units 1, 2 and 3 at the plant. These events will

[45] See, e.g., Attachment REW-2, page 18. The new APS proposed depreciation rate for electronic meters is based on a 6.24 percent rate for investment cost recovery and a negative 0.03 percent net salvage rate.

change the plant's overall generating capacity from 2,100 MW to 1,540 MW and APS' entitlement from the plant from 791 MW to 970 MW.

Q. How did the APS depreciation study reflect the proposed purchase of Four Corners Units 4 and 5, and the subsequent shutdown of Units 1 through 3?

A. The APS depreciation study only uses the Four Corners plant balances for the current APS ownership share. APS reflected the proposed closure of Four Corners Units 1-3 by setting the rebalanced depreciation reserves for Four Corners Units 1-3 equal to computed reserves derived from an estimated 2012 year of shutdown. Estimated dismantlement costs for Units 1-3 were added to the estimated dismantlement costs for Units 4 and 5, and reserves were rebalanced over all steam production units. This treatment marginally increased the unrecovered investment in plants other than Four Corners and allocated the unrecovered investment in Four Corners Units 1-3 over the longer estimated average remaining lives of other steam units.[46] Based on the proposed retirement of Four Corners Units 1-3 by the end of 2012, APS decreased the annual depreciation accrual for those units from $24.630 million at current depreciation rates to zero at APS' proposed rates.[47]

As shown on page 75 of the depreciation study, the anticipated year of retirement for Four Corners Units 1-3 was adjusted from 2016 to 2012. With respect to Four Corners Units 4 and 5 and Four Corners common plant, the APS depreciation study, at page 75, reflected a revision of the anticipated retirement year from 2016 to 2038.

As shown on page 28 of the depreciation study, APS has reduced the annualized depreciation accrued for Four Corners, Units 1-3, from $24.630 million at current rates to zero at proposed depreciation rates.

[46] *See*, e.g., Direct Testimony of APS witness Ronald White at page 10.
[47] *See*, e.g., Attachment REW-2, page 28.

Q. Does Staff generally agree with APS' proposed depreciation changes relating to Four Corners?

A. Yes. While there continues to be some uncertainty as to the ownership changes related to Four Corners which will likely affect the remaining service lives, APS' proposed depreciation changes relating to Four Corners appear to be generally reasonable based on currently available information. The depreciation changes APS has proposed related to Four Corners also appear to be consistent with APS' announced closure of Four Corners Units 1-3 and a life extension of Four Corners Units 4 and 5, if APS' proposed purchase of SCE's interests in Units 4 and 5 is consummated. However, if that purchase is not consummated or if other information becomes available indicating that a different operating life scenario is more likely, the Four Corners depreciation impacts may need to be revised.

Palo Verde Nuclear Generating Station Operating License Extension

Q. How did the APS depreciation study reflect the Palo Verde Nuclear Generating Station operating license extension?

A. As shown on pages 76-77 of the depreciation study, the anticipated year of retirement for each of the Palo Verde generation units, and for the Palo Verde water reclamation system and common plant was also extended by 20 years beyond the retirement dates that had been used prior to the operating license extension.

Q. Does Staff concur with the Palo Verde related depreciation changes proposed by APS?

A. Yes.

Staff Recommendation on Depreciation Rates

Q. How should the depreciation rates proposed by APS be adopted for use in this case?

A. With the exception of Account 370.01, Electronic Meters, and Account 370.03, AMI Meters, the depreciation rates proposed by APS presented in Dr. White's Attachment REW-2 should be adopted for use in this case.[48] 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 Dr. White's Attachment REW-2 and other information indicates that those new rates proposed by APS are consistent with a reasonable approach to updating the depreciation rates that the Commission approved in Decision Nos. 67744, 69663 and 71448. I discuss the reasons for rejecting APS' proposed depreciation rate changes for electronic and AMI meter plant in Accounts 370.01 and 370.03, respectively, in my testimony on pages 61-67, in conjunction with Staff adjustment C-11.

SPECIAL RATEMAKING TREATMENT FOR IMPACT OF APS' ACQUISITION OF SCE'S OWNERSHIP INTEREST IN FOUR CORNERS UNITS 4 AND 5

Q. How could APS' ownership in Four Corners generating units be affected by its potential acquisition from Southern California Edison of SCE's interests in Four Corners, Units 4 and 5?

A. As described above in my discussion of depreciation rates, APS currently owns 15 percent of Four Corners Units 4 and 5, and has announced an agreement with SCE to acquire SCE's 48 percent interest in those units. APS owns 100 percent of Four Corners Units 1, 2, and 3, which are older less efficient generating units, and has announced its intention to retire those older units if its acquisition of SCE's ownership interests in Four Corners Units 4 and 5 is consummated.

[48] An additional adjustment may also be needed for the prospective annual depreciation of the Four Corners generating plant if APS' proposed acquisition of SCE's interest in Four Corners Units 4 and 5 is not consummated.

Q. What ratemaking treatment has APS requested related to its potential acquisition of SCE's interests in Four Corners, Units 4 and 5?

A. APS has asked for approval of new depreciation rates which reflect an extended service life for Four Corners, Units 4 and 5, that would apply in the event that APS acquires these units. APS has also reflected the cessation of annual depreciation accruals for Four Corners Units 1-3 based on its proposal to retire those units by the end of 2012.

In the current base rate case, APS has included in rate base only the cost for the share of Four Corners that APS already owns. APS has not proposed to include its cost of purchasing the SCE 48 percent interest in Four Corners Units 4 and 5 in its rate base in the current base rate case.

However, APS proposes in its rate case that the costs associated with acquiring SCE's ownership interest in those units would be recovered through APS' proposed Environmental and Reliability Account ("ERA") mechanism. Pursuant to that mechanism, APS' rates would be adjusted in the year after the units were acquired.

Q. Is Staff recommending approval of APS' proposed ERA?

A. No, as described in the Direct Testimony of Staff witness McGarry, Staff recommends that the Company's proposed ERA should be rejected.

Q. Is APS' acquisition of SCE's interest in Four Corners Units 4 and 5 a "known and measurable" change for purposes of determining APS' rate base in this proceeding?

A. No. APS' application (Docket No. E-01345A-10-0474) to acquire SCE's interest in Units 4 and 5 and its related proposal to shut down Units 1, 2, and 3 has not yet been approved. APS projects that the proposed transaction may be consummated in the second half of

2012, pending receipt of regulatory approvals. Because of the uncertainty associated with APS' acquisition and the resultant fate of the Four Corners plant, it would be inappropriate to include costs for APS' acquisition of SCE's ownership interests in Units 4 and 5 in (or to correspondingly remove Units 1, 2, and 3 from) APS' rate base at this time.

Q. How does this affect the timing of APS' ability to recover the costs of these units if APS proceeds with the acquisition?

A. Ordinarily, APS would have to wait until its next rate case, at which time the Company would ask to have its cost of acquiring SCE's ownership interests in Four Corners Units 4 and 5 included in rate base and presumably to have Units 1, 2, and 3 removed from rate base. Assuming that the transaction was found to be prudent, APS would begin recovering the costs of the acquired units at the close of its next rate case, *i.e.,* once its new rates from that case become final. This is the normal procedure for ratemaking, and it would not be an inappropriate result in this situation.

I would note that, in Docket No. E-01345A-10-0474, APS has requested a deferral order for certain costs related to Four Corners, Units 4 and 5. In that application, APS has also asked to defer certain costs related to the shutdown of Four Corners Units 1, 2 and 3. If that request were approved, APS would be able to seek recovery of those deferred costs in its next rate case as well.

Q. Is Staff recommending that the Commission consider another alternative for the ratemaking treatment for Four Corners, Units 4 and 5?

A. Yes. For a number of reasons, Staff is recommending that the Commission consider holding this case open solely for the purpose of addressing the ratemaking treatment of

Four Corners. This would allow APS to seek to include the costs of these units in rates once it has acquired them, instead of waiting until its next rate case.

Q. Why is Staff making this recommendation?

A. Staff believes that the posture of this case and the circumstances presented by it warrant consideration of this treatment. I would note that this recommendation is a departure from ordinary ratemaking procedures, and Staff would not make this recommendation absent compelling circumstances.

Q. What are the compelling circumstances?

A. In the past, APS has had less than ideal credit ratings. In the last rate case, the parties entered a Settlement Agreement, which, among other things, sought to position APS to be able to improve its financial metrics. I would note that APS' financial metrics appear to have improved, as discussed in the testimony of Staff witness Parcell.

Q. Are there benefits to ratepayers of APS' maintaining an investment-grade credit rating?

A. Yes. An investment-grade credit rating enables the Company to obtain capital at lower interest rates. These capital-cost savings are passed on to ratepayers in the form of lower rates.

Q. If APS' credit metrics have improved, as you noted above, why is Staff recommending that the Commission consider special ratemaking treatment in the current APS rate case for the Four Corner's acquisition?

A. In this case, Staff has calculated a small revenue sufficiency, which would result in a base rate decrease for APS. On the other hand, if APS were to acquire SCE's interest in Four

Corners, Units 4 and 5, the Company could be subject to increased costs, which would not be recoverable under normal circumstances until APS' next rate case. Providing for a special ratemaking treatment may help APS not only in maintaining its investment grade bond ratings but also to acquire a resource that could produce substantial net benefits for APS' ratepayers versus other alternatives. Overall net savings are anticipated by APS to result from that acquisition.[49]

Some of the cost decreases resulting from that acquisition, such as the lower fuel costs that APS projects[50], would commence providing benefits to ratepayers through the operation of the PSA mechanism. However, as noted above, under ordinary ratemaking procedures, the Company would not be able to recover its cost of plant investment and related costs such as depreciation and property taxes until the conclusion of its next rate case. A special ratemaking treatment would provide for the non-fuel cost recovery issues related to Four Corners to be addressed on a more timely basis.

Additionally, the accounting deferrals being addressed in Docket No. E-01345A-10-0474 would have less time to grow, and thus would likely become less of a future burden upon ratepayers if such deferrals are addressed promptly after APS' acquisition of the SCE interests in Four Corners Units 4 and 5 is consummated, rather than allowing such deferrals to grow until they can be considered in the context of APS' next base rate case.

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[49] Testimony in Docket No. E-01345A-10-0474 describes how the proposed transaction is a genuine, unanticipated opportunity for APS to acquire a power resource that APS anticipates will provide unique value to APS' customers. APS has stated that the proposed transaction results in a system-wide revenue requirement that has net present value that is $488 million less than the next least expensive alternative of replacing 791 MW with combined-cycle natural gas generation and $1.08 billion less than the alternative of investing in environmental upgrades for Four Corners Units 1-3. See, e.g., APS witness Dinkel's Direct Testimony in that docket, at page 7.

[50] See, e.g., Attachment RCS-2, Schedule C-9, column F, line 10, which shows the incremental fuel cost savings that APS estimates with Four Corners 4&5 acquisition of $31.4 million. Reduced fuel costs reflect in part the higher efficiency of Four Corners Units 4&5 over Units 1 through 3.

Under these circumstances, Staff believes that a means of reducing the regulatory lag associated with cost recovery for the acquisition of SCE's interest in the Four Corners Units 4 and 5 (if the acquisition is determined to be prudent) is an option worthy of consideration in the current APS case due to the unique circumstances involved.

Q. Would it be unreasonable for the Commission to reject the special ratemaking procedure that you have described above?

A. This issue is essentially a policy matter for the Commission's consideration. It would not be *unreasonable* for the Commission to reject this proposal and instead go forward with routine ratemaking procedures. Staff offers this opinion to provide the Commission with a means to balance the effects of a modest rate decrease with the effects of a proposed acquisition that, if executed, will likely increase APS' plant investment and related costs.[51]

Q. Should the case be held open indefinitely?

A. No. This rate case is anticipated to be completed sometime in the summer of 2012. The Four Corners acquisition is anticipated to occur no later than October, 2012, and is conditioned upon APS receiving required regulatory approvals.[52] If APS wishes to take advantage of this proposal, Staff recommends that it file its ratemaking request related to its acquisition of Four Corners no later than December 30, 2012. Staff recommends that the rate case be held open solely on the Four Corners acquisition issue.

[51] As described in Docket No. E-01345A-10-0474, all proposed alternatives related to Four Corners would cause customer bills to rise; however, APS has represented that the proposed transaction would cause customer bills to increase by the least amount. See, e.g., Direct Testimony of Staff witness Laura Furrey, at pages 21-22.
[52] See, e.g., APS Schedule E-9 (SEC Form 10-K- for period ending 12/31/2010), pages 11-12 of 374.

Q. What would APS' filing, upon the Company's consummation of the acquisition of SCE's interest in Four Corners, Units 4 and 5, and the related proceeding entail?

A. The proceeding would include consideration of the rate base and expense effects associated with the acquisition of Units 4 and 5 as well as rate base and expense effects associated with the retirement of Units 1, 2, and 3. A very important matter to note is that this filing would include a prudence review of the transaction and of any deferred costs for which the Company would seek recovery. Any rate adjustment would be contingent upon the Commission finding that the acquisition and related costs were prudent.

Q. Does this conclude your Direct 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 Certified Rate of Return Analyst, 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, public service commission staffs, state attorney generals, municipalities, and consumer groups concerning regulatory matters before regulatory agencies in Alabama, Alaska, Arizona, Arkansas, California, Connecticut, Delaware, Florida, Georgia, Hawaii, Illinois, Indiana, Kansas, Kentucky, Louisiana, Maine, Michigan, Minnesota, Mississippi, Missouri, New Jersey, New Mexico, New York, Nevada, North Carolina, North Dakota, Ohio, Pennsylvania, South Carolina, South Dakota, Texas, Utah, Vermont, Virginia, Washington, Washington DC, West Virginia, 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 were 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. (Michigan PSC)
83-662	Continental Telephone Company of California, (Nevada 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)
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) Phase II of	Investigation of 1999 Intrastate Access Charge filing (Alaska PUC)
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)
Docket No. E-01345A-06-009	Arizona Public Service Company (Arizona Corporation Commission)
Case No. 05-1278-E-PC-PW-42T	Appalachian Power Company and Wheeling Power Company both d/b/a American Electric Power (West Virginia PSC)
Docket No. 04-0113	Hawaiian Electric Company (Hawaii PUC)
Case No. U-14347	Consumers Energy Company (Michigan PSC)
Case No. 05-725-EL-UNC	Cincinnati Gas & Electric Company (PUC of Ohio)
Docket No. 21229-U	Savannah Electric & Power Company (Georgia PSC)
Docket No. 19142-U	Georgia Power Company (Georgia PSC)
Docket No. 03-07-01RE01	Connecticut Light & Power Company (CT DPUC)
Docket No. 19042-U	Savannah Electric & Power Company (Georgia PSC)
Docket No. 2004-178-E	South Carolina Electric & Gas Company (South Carolina PSC)
Docket No. 03-07-02	Connecticut Light & Power Company (CT DPUC)
Docket No. EX02060363, Phases I&II	Rockland Electric Company (NJ BPU)
Docket No. U-00-88	ENSTAR Natural Gas Company and Alaska Pipeline Company (Regulatory Commission of Alaska)
Phase 1-2002 IERM, Docket No. U-02-075	Interior Telephone Company, Inc. (Regulatory Commission of Alaska)
Docket No. 05-SCNT-1048-AUD	South Central Telephone Company (Kansas CC)
Docket No. 05-TRCT-607-KSF	Tri-County Telephone Company (Kansas CC)
Docket No. 05-KOKT-060-AUD	Kan Okla Telephone Company (Kansas CC)
Docket No. 2002-747	Northland Telephone Company of Maine (Maine PUC)
Docket No. 2003-34	Sidney Telephone Company (Maine PUC)

Docket No. 2003-35	Maine Telephone Company (Maine PUC)
Docket No. 2003-36	China Telephone Company (Maine PUC)
Docket No. 2003-37	Standish Telephone Company (Maine PUC)
Docket Nos. U-04-022, U-04-023	Anchorage Water and Wastewater Utility (Regulatory Commission of Alaska)
Case 05-116-U/06-055-U	Entergy Arkansas, Inc. EFC (Arkansas Public Service Commission)
Case 04-137-U	Southwest Power Pool RTO (Arkansas Public Service Commission)
Case No. 7109/7160	Vermont Gas Systems (Department of Public Service)
Case No. ER-2006-0315	Empire District Electric Company (Missouri PSC)
Case No. ER-2006-0314	Kansas City Power & Light Company (Missouri PSC)
Docket No. U-05-043,44	Golden Heart Utilities/College Park Utilities (Regulatory Commission of Alaska)
A-122250F5000	Equitable Resources, Inc. and The Peoples Natural Gas Company, d/b/a Dominion Peoples (Pennsylvania PUC)
E-01345A-05-0816	Arizona Public Service Company (Arizona CC)
Docket No. 05-304	Delmarva Power & Light Company (Delaware PSC)
05-806-EL-UNC	Cincinnati Gas & Electric Company (Ohio PUC)
U-06-45	Anchorage Water Utility (Regulatory Commission of Alaska)
03-93-EL-ATA, 06-1068-EL-UNC	Duke Energy Ohio (Ohio PUC)
PUE-2006-00065	Appalachian Power Company (Virginia Corporation Commission)
G-04204A-06-0463 et. al	UNS Gas, Inc. (Arizona CC)
Docket No. 2006-0386	Hawaiian Electric Company, Inc (Hawaii PUC)
E-01933A-07-0402	Tucson Electric Power Company (Arizona CC)
G-01551A-07-0504	Southwest Gas Corporation (Arizona CC)
Docket No.UE-072300	Puget Sound Energy, Inc. (Washington UTC)
PUE-2008-00009	Virginia-American Water Company (Virginia SCC)
PUE-2008-00046	Appalachian Power Company (Virginia SCC)
E-01345A-08-0172	Arizona Public Service Company (Arizona CC)
A-2008-2063737	Babcock & Brown Infrastructure Fund North America, LP. and The Peoples Natural Gas Company, d/b/a Dominion Peoples (Pennsylvania PUC)
08-1783-G-42T	Hope Gas, Inc., dba Dominion Hope (West Virginia PSC)
08-1761-G-PC	Hope Gas, Inc., dba Dominion Hope, Dominion Resources, Inc., and Peoples Hope Gas Companies (West Virginia PSC)
Docket No. 2008-0085	Hawaiian Electric Company, Inc. (Hawaii PUC)
Docket No. 2008-0266	Young Brothers, Limited (Hawaii PUC)
G-04024A-08-0571	UNS Gas, Inc. (Arizona CC)
Docket No. 09-29	Tidewater Utilities, Inc. (Delaware PSC)
Docket No. UE-090704	Puget Sound Energy, Inc. (Washington UTC)
09-0878-G-42T	Mountaineer Gas Company (West Virginia PSC)
2009-UA-0014	Mississippi Power Company (Mississippi PSC)
Docket No. 09-0319	Illinois-American Water Company (Illinois CC)
Docket No. 09-414	Delmarva Power & Light Company (Delaware PSC)
R-2009-2132019	Aqua Pennsylvania, Inc. (Pennsylvania PUC)
Docket Nos. U-09-069, U-09-070	ENSTAR Natural Gas Company (Regulatory Commission of Alaska)
Docket Nos. U-04-023, U-04-024	Anchorage Water and Wastewater Utility - Remand (Regulatory Commission of Alaska)
W-01303A-09-0343 & SW-01303A-09-0343	Arizona-American Water Company (Arizona CC)
09-872-EL-FAC & 09-873-EL-FAC	Financial Audits of the FAC of the Columbus Southern Power Company and the Ohio Power Company - Audit I (Ohio PUC)
2010-00036	Kentucky-American Water Company (Kentucky PSC)
E-04100A-09-0496	Southwest Transmission Cooperative, Inc. (Arizona CC)
E-01773A-09-0496	Arizona Electric Power Cooperative, Inc. (Arizona CC)

R-2010-2166208, R-2010-2166210, R-2010-2166212, & R-2010-2166214	Pennsylvania-American Water Company (Pennsylvania PUC)
PSC Docket No. 09-0602	Central Illinois Light Company D/B/A AmerenCILCO; Central Illinois Public Service Company D/B/A AmerenCIPS; Illinois Power Company D/B/A AmerenIP (Illinois CC)
10-0713-E-PC	Allegheny Power and FirstEnergy Corp. (West Virginia PSC)
Docket No. 31958	Georgia Power Company (Georgia PSC)
Docket No. 10-0467	Commonwealth Edison Company (Illinois CC)
PSC Docket No. 10-237	Delmarva Power & Light Company (Delaware PSC)
U-10-51	Cook Inlet Natural Gas Storage Alaska, LLC (Regulatory Commission of Alaska)
10-0699-E-42T	Appalachian Power Company and Wheeling Power Company (West Virginia PSC)
10-0920-W-42T	West Virginia-American Water Company (West Virginia PSC)
A.10-07-007	California-American Water Company (California
A-2010-2210326	TWP Acquisition (Pennsylvania PUC)
08-1012-EL-FAC	Financial, Management, and Performance Audit of the FAC for Dayton Power and Light – Audit 1 (Ohio PUC)
10-268-EL FAC et al.	Financial Audit of the FAC of the Columbus Southern Power Company and the Ohio Power Company – Audit II (Ohio PUC)
Docket No. 2010-0080	Hawaiian Electric Company, Inc. (Hawaii PUC)
G-01551A-10-0458	Southwest Gas Corporation (Arizona CC)
10-KCPE-415-RTS	Kansas City Power & Light Company – Remand (Kansas CC)

Arizona Public Service Company
Docket No. E-01345A-11-0224
Attachment RCS-2
Staff Accounting Schedules
Accompanying the Direct Testimony of Ralph C. Smith

****APS Confidential Information Has Been Redacted****

Schedule	Description	Pages	Confidential	Exhibit Page No.
	Revenue Requirement Summary Schedules			
A	Calculation of Revenue Deficiency (Sufficiency)	2	No	2-3
A-1	Gross Revenue Conversion Factor	1	No	4
B	Adjusted Rate Base	1	No	5
B.1	Summary of Adjustments to Rate Base	2	No	6-7
C	Adjusted Net Operating Income	1	No	8
C.1	Summary of Net Operating Income Adjustments	3	No	9-11
D	Capital Structure and Cost Rates	1	No	12
	Rate Base Adjustments			
B-1	Post-Test Year Plant Additions - Through 3/31/2012 - Solar Plant	1	No	13
B-2	Post-Test Year Plant Additions - Through 3/31/2012 - Fossil Plant	1	No	14
B-3	Post-Test Year Plant Additions - Through 3/31/2012 - Nuclear Plant	1	No	15
B-4	Post-Test Year Plant Additions - Through 3/31/2012 - Distribution and General and Intangible Plant	1	No	16
B-5	Accumulated Depreciation - Post Test Year Adjustment Through 3/31/2012	1	No	17
B-6	Accumulated Deferred Income Taxes - Post Test Year Adjustment Through 3/31/2012	2	No	18-19
B-7	Cash Working Capital	3	No	20-22
	Net Operating Income Adjustments			
C-1	Forensic Investigation of Grant-Funded Projects	1	No	23
C-2	General Advertising Expense	1	No	24
C-3	Property Tax Expense	1	No	25
C-4	Solar Post Test Year Plant Depreciation and Property Tax Expense	1	No	26
C-5	Fossil Post Test Year Plant Depreciation and Property Tax Expense	1	No	27
C-6	Nuclear Post Test Year Plant Depreciation and Property Tax Expense	1	No	28
C-7	Distribution and General and Intangible Post Test Year Plant Depreciation and Property Tax Expense	1	No	29
C-8	Interest Synchronization	1	No	30
C-9	Base Fuel and Purchased Power	1	No	31
C-10	Payroll Expense Adjustment - New Union Contract	1	No	32
C-11	Depreciation Expense - New Depreciation Rates	1	No	33
C-12	Prospective Amortization of 2010 Severance Costs	1	No	34
C-13	Directors and Officers' Liability Insurance Expense	1	No	35
C-14	Incentive Compensation	1	Yes	36
C-15	Normalized Fossil Non-Plant Maintenance Expense	2	No	37-38
C-16	Edison Electric Institute Dues	2	No	39-40
	Total Pages, Including Content Listing	40		

Arizona Public Service Company
Computation of Increase in Gross Revenue Requirement

Test Year Ended December 31, 2010
(Thousands of Dollars)

Staff ROE: 9.90%

Line No.	Description	Reference	APS Proposed Original Cost (A)	APS Proposed Fair Value (B)	Staff Proposed Original Cost (C)	Staff Proposed Fair Value Alt 1 (D1)	Staff Proposed Fair Value Alt 2 (D2)	Difference Fair Value (E)=D2-B
1	Adjusted Rate Base	Sch. B	$ 5,720,277	$ 8,224,405	$ 5,662,998	$ 8,167,126	$8,167,126	$ (57,279)
2	Rate of Return	Sch. D	8.87%	6.17%	8.28%	5.74%	6.05%	
3	Operating Income Required		$ 507,389	$ 507,389	$ 468,818	$ 468,818	$ 493,859	$ (13,530)
4	Net Operating Income Available	Sch. C	$ 474,356	$ 474,356	$ 498,355	$ 498,355	$ 498,355	$ 23,999
5	Operating Income Excess/Deficiency		$ 33,033	$ 33,033	$ (29,537)	$ (29,538)	$ (4,496)	$ (37,529)
6	Gross Revenue Conversion Factor	Sch. A-1	1.6532	1.6532	1.6566	1.6566	1.6566	
7	Revenue Deficiency (Sufficiency)		$ 54,610	$ 54,610	$ (48,932)	$ (48,932)	$ (7,449)	$ (62,059)
8	Fair Value Increment			$ 40,883				$ (40,883)
9	Total Revenue Deficiency (Sufficiency)			$ 95,493		$ (48,932)	$ (7,449)	$ (102,942)
	Percentage Increase Over Current Rates							
10	Revenue from Sales to Ultimate Retail Customers	Sch C, L.1		$ 2,868,858		$ 2,868,858	$2,868,858	
11	Percentage Increase - Total	L9/L15		3.33%		-1.71%	-0.26%	

Notes and Source
Cols. A & B taken from APS filing, Schedule A-1

Arizona Public Service Company
Revenue Requirement Reconciliation
Test Year Ended December 31, 2010

Docket No. E-01345A-11-0224
Schedule A
Page 2 of 2

(Thousands of Dollars)

Line No.	Description	Schedule	Staff Adjustments (A)	Conversion Factor (B)	Equivalent Revenue Requirement Amount (C)
1	**Rate of return difference**	D		-0.59%	
2	Staff GRCF	A-1		1.6566	
3	**Rate Base**			-0.982843%	
4	Original Cost Rate Base per APS' Filing	B	$ 5,720,277		$ (56,221)
5	Staff ROR	D		8.28%	
6	Staff ROR x GRCF			13.71%	
	Effect of Staff adjustments to Rate Base				
7	Post-Test Year Plant Additions - Through 3/31/2012 - Solar Plant	B-1	$ (35,406)	13.71%	$ (4,856)
8	Post-Test Year Plant Additions - Through 3/31/2012 - Fossil Plant	B-2	$ (23,458)	13.71%	$ (3,217)
9	Post-Test Year Plant Additions - Through 3/31/2012 - Nuclear Plant	B-3	$ (17,536)	13.71%	$ (2,405)
10	Post-Test Year Plant Additions - Through 3/31/2012 - Distribution and General and Intangible Plant	B-4	$ (53,196)	13.71%	$ (7,295)
11	Accumulated Depreciation - Post Test Year Adjustment Through 3/31/2012	B-5	$ 60,124	13.71%	$ 8,246
12	Accumulated Deferred Income Taxes - Post Test Year Adjustment Through 3/31/2012	B-6	$ 1,726	13.71%	$ 237
13	Cash Working Capital	B-7	$ 10,467	13.71%	$ 1,436
12	Total Staff Original Cost Rate Base Adjustments		$ (57,279)		
13	**Staff Adjusted Original Cost Rate Base**		$ 5,662,998		
	Net Operating Income				
14	Net Operating Income per APS' Filing		$ 474,356		
15	**Effect of Staff Adjustments on NOI**			GRCF	
16	Forensic Investigation of Grant-Funded Projects	C-1	$ 1,244	1.65660	$ (2,061)
17	General Advertising Expense	C-2	$ 346	1.65660	$ (573)
18	Property Tax Expense	C-3	$ 353	1.65660	$ (585)
19	Solar Post Test Year Plant Depreciation and Property Tax Expense	C-4	$ 787	1.65660	$ (1,304)
20	Fossil Post Test Year Plant Depreciation and Property Tax Expense	C-5	$ 473	1.65660	$ (784)
21	Nuclear Post Test Year Plant Depreciation and Property Tax Expense	C-6	$ 220	1.65660	$ (364)
22	Distribution and General and Intangible Post Test Year Plant Depreciation and Property Tax Expense	C-7	$ 1,611	1.65660	$ (2,669)
23	Interest Synchronization	C-8	$ (638)	1.65660	$ 1,057
24	Base Fuel and Purchased Power	C-9	$ 5,792	1.65660	$ (9,595)
25	Payroll Expense Adjustment - New Union Contract	C-10	$ (3,021)	1.65660	$ 5,005
26	Depreciation Expense - New Depreciation Rates	C-11	$ 2,864	1.65660	$ (4,744)
27	Prospective Amortization of 2010 Severance Costs	C-12	$ 1,892	1.65660	$ (3,134)
28	Directors and Officers' Liability Insurance Expense	C-13	$ 333	1.65660	$ (551)
29	Incentive Compensation	C-14	$ 11,451	1.65660	$ (18,970)
30	Normalized Fossil Non-Plant Maintenance Expense	C-15	$ 161	1.65660	$ (267)
31	Edison Electric Institute Dues	C-16	$ 131	1.65660	$ (217)
32	Total Staff Adjustments to Operating Income		$ 23,999		
33	**Staff Adjusted Net Operating Income**		$ 498,355		
	Gross Revenue Conversion Factor Difference:				
34	Per Staff			1.65660	
35	Per Company			1.65320	
36	Difference			0.00340	
37	Company adjusted NOI deficiency			$ 33,033	
38	GRCF difference				$ 112
39	STAFF REVENUE REQUIREMENT ADJUSTMENTS IDENTIFIED ABOVE				$ (103,719)
40	Company requested Base Rate Revenue Increase on OCRB	Schedule A, page 1, column A, line 9			$ 54,610
41	Reconciled Revenue Requirement				$ (49,109)
42	Revenue Requirement Calculated on OCRB	Schedule A, page 1, column C, line 9			$ (48,932)
43	Difference				$ (177)
44	Difference Attributed to APS Rate of Return Rounding	Line 50, below			$ (180)
45	Unidentified Difference				$ 3

Notes and Source

Pre-tax return computed using Gross Revenue Conversion Factor

Difference related to rounding in calculation of Company requested Base Rate Revenue Increase on OCRB

	Component	Per APS (ROR Rounded)	Per APS Without Rounding	Difference
46	Rate Base	$ 5,720,277	$ 5,720,277	
47	Rate of Return	8.87%	8.87190%	
48	Required Return	$ 507,389	$ 507,497	$ (109)
49	GRCF			1.6532
50	Revenue Requirement Impact of APS Rate of Return Rounding			$ (180)

Arizona Public Service Company
Computation of Gross Revenue Conversion Factor

Docket No. E-01345A-11-0224
Schedule A-1
Page 1 of 1

Test Year Ended December 31, 2010
(Thousands of Dollars)

Line No.	Description	Company (A)	Staff Proposed (B)
1	Gross Revenue	100.00%	100.00%
2	Less: Uncollectible Revenue		0.21%
3	Taxable Income as a Percent	100.00%	99.79%
4	Less: Federal Income Taxes	32.57%	32.50%
5	Taxable Income as a Percent	67.43%	67.29%
6	Less: State Income Taxes	6.94%	6.93%
7	Change in Net Operating Income	60.49%	60.36%
8	Gross Revenue Conversion Factor	1.6532	1.6566
9	Combined state and federal income tax rate	39.51%	39.51%

Notes and Source

Col.A: APS Filing, Schedule C-3
Col.B: Staff included the uncollectible rate of 0.21% based on APS' response to data request Staff 25.11.

Components of Revenue Requirement Increase ($000's)

		Percent (C)	Fair Value Alt 1 (D)	Fair Value Alt 2 (E)
10	Net Income	60.36%	(29,537)	(4,496)
11	Federal Income Taxes	32.50%	(15,904)	(2,421)
12	State Income Taxes	6.93%	(3,389)	(516)
13	Uncollectibles	0.21%	(103)	(16)
14	Total Revenue Increase	100.00%	(48,932)	(7,449)
15	Total Revenue Increase per Schedule A		$ (48,932)	$ (7,449)
14	Difference		-	(0)

Arizona Public Service Company
Original Cost and RCND Adjusted Rate Base
ACC Jurisdiction
Test Year Ended December 31, 2010
(Thousand of Dollars)

Docket No. E-01345A-11-0224
Schedule B
Page 1 of 1

Line No.	Description	Original Cost by APS (A)	Original Cost Staff Adjustments (B)	Original Cost As Adjusted by Staff (C)	RCND As Adjusted by APS (D)	RCND Staff Adjustments (E)	RCND As Adjusted by Staff (F)
1	Gross Utility Plant in Service	$ 12,467,614	$ (129,596)	$ 12,338,018	$ 23,201,276	$ (129,596)	$ 23,071,680
2	Less: Accumulated Depreciation	$ (5,015,939)	$ 60,124	$ (4,955,815)	$ (9,014,923)	$ 60,124	$ (8,954,799)
3	Net Utility Plant in Service	$ 7,451,675	$ (69,472)	$ 7,382,203	$ 14,186,353	$ (69,472)	$ 14,116,881
	Deductions:						
4	Deferred Income Taxes	$ (1,615,133)	$ 1,726	$ (1,613,407)	$ (3,341,556)	$ 1,726	$ (3,339,830)
5	Investment Tax Credits	$ (876)	$ -	$ (876)	$ (876)	$ -	$ (876)
6	Customer Advances for Construction	$ (121,645)	$ -	$ (121,645)	$ (121,645)	$ -	$ (121,645)
7	Customer Deposits	$ (68,084)	$ -	$ (68,084)	$ (68,084)	$ -	$ (68,084)
8	Pension and Other Postretirement Liabilities	$ (661,518)	$ -	$ (661,518)	$ (661,518)	$ -	$ (661,518)
9	Liability For Asset Retirement	$ (320,592)	$ -	$ (320,592)	$ (320,592)	$ -	$ (320,592)
10	Other Deferred Credits	$ (64,107)	$ -	$ (64,107)	$ (64,107)	$ -	$ (64,107)
11	Coal mine reclamation	$ (114,396)		$ (114,396)	$ (114,396)		$ (114,396)
12	Unamortized Gain-Sale of Utility Plant	$ (53,961)	$ -	$ (53,961)	$ (53,961)	$ -	$ (53,961)
13	Regulatory Liabilities	$ (253,750)	$ -	$ (253,750)	$ (253,750)	$ -	$ (253,750)
14	Total Deductions	$ (3,274,062)	$ 1,726	$ (3,272,336)	$ (5,000,485)	$ 1,726	$ (4,998,759)
	Additions:						
14	Construction Work in Progress	$ -	$ -	$ -	$ -	$ -	$ -
15	Regulatory Assets	$ 746,508	$ -	$ 746,508	$ 746,508	$ -	$ 746,508
16	Deferred debit income tax receivable	$ 63,271		$ 63,271	$ 63,271		$ 63,271
17	Other Deferred Debits	$ 72,203	$ -	$ 72,203	$ 72,203	$ -	$ 72,203
18	Decommissioning Trust Accounts	$ 458,476	$ -	$ 458,476	$ 458,476	$ -	$ 458,476
19	Allowance For Working Capital	$ 202,206	$ 10,467	$ 212,673	$ 202,206	$ 10,467	$ 212,673
20	Total Additions	$ 1,542,664	$ 10,467	$ 1,553,131	$ 1,542,664	$ 10,467	$ 1,553,131
20	Total Rate Base	$ 5,720,277	$ (57,279)	$ 5,662,998	$ 10,728,532	$ (57,279)	$ 10,671,253

Notes and Source
Cols. A and D: APS filing, Schedule B-1

Fair Value Calculation (Per Company)

Original Cost	$ 5,720,277	
RCND	$ 10,728,532	
Total	$ 16,448,809	
Average (Fair Value)	$ 8,224,405	See Sch. A

Fair Value Calculation (Per Staff)

Original Cost	$ 5,662,998	
RCND	$ 10,671,253	
Total	$ 16,334,251	
Average (Fair Value)	$ 8,167,126	See Sch. A

Arizona Public Service Company
Summary of Rate Base Adjustments
ACC Jurisdiction
Test Year Ended December 31, 2010
(Thousand of Dollars)

Line No.	Description	Staff Adjustments	Post-Test Year Plant Additions - Through 3/31/2012 - Solar Plant B-1	Post-Test Year Plant Additions - Through 3/31/2012 - Fossil Plant B-2	Post-Test Year Plant Additions - Through 3/31/2012 - Nuclear Plant B-3	Post-Test Year Plant Additions - Through 3/31/2012 - Distribution and General and Intangible Plant B-4	Accumulated Depreciation - Post Test Year Adjustment Through 3/31/2012 B-5	Accumulated Deferred Income Taxes - Post Test Year Adjustment Through 3/31/2012 B-6	Cash Working Capital B-7
1	Gross Utility Plant in Service	$ (129,596)	$ (35,406)	$ (23,458)	$ (17,536)	$ (53,196)			$ -
2	Less: Accumulated Depreciation	$ 60,124					$ 60,124		
3	Net Utility Plant in Service	$ (69,472)	$ (35,406)	$ (23,458)	$ (17,536)	$ (53,196)	$ 60,124	$ -	$ -
	Deductions:								
4	Deferred Income Taxes	$ 1,726						$ 1,726	
5	Investment Tax Credits	$ -							
6	Customer Advances for Construction	$ -							
7	Customer Deposits	$ -							
8	Pension and Other Postretirement Liabilities	$ -							
9	Liability For Asset Retirement	$ -							
10	Other Deferred Credits	$ -							
11	Unamortized Gain-Sale of Utility Plant	$ -							
12	Regulatory Liabilities	$ -							
13	**Total Deductions**	$ 1,726	$ -	$ -	$ -	$ -	$ -	$ 1,726	$ -
	Additions:								
14	Construction Work in Progress	$ -							
15	Regulatory Assets	$ -							
16	Other Deferred Debits	$ -							
17	Decommissioning Trust Accounts	$ -							$ 10,467
18	Allowance For Working Capital	$ 10,467							
19	**Total Additions**	$ 10,467	$ -	$ -	$ -	$ -	$ -	$ -	$ 10,467
20	Total Rate Base	$ -							
		$ (57,279)	$ (35,406)	$ (23,458)	$ (17,536)	$ (53,196)	$ 60,124	$ 1,726	$ 10,467

Arizona Public Service Company
Summary of Rate Base Adjustments
Reconstruction Cost New Depreciated - ACC Jurisdiction
Test Year Ended December 31, 2010
(Thousand of Dollars)

Line No.	Description	Staff Adjustments	Post-Test Year Plant Additions - Through 3/31/2012 - Solar Plant B-1	Post-Test Year Plant Additions - Through 3/31/2012 - Fossil Plant B-2	Post-Test Year Plant Additions - Through 3/31/2012 - Nuclear Plant B-3	Post-Test Year Plant Additions - Through 3/31/2012 - Distribution and General and Intangible B-4	Accumulated Depreciation - Post Test Year Adjustment Through 3/31/2012 B-5	Accumulated Deferred Income Taxes - Post Test Year Adjustment Through 3/31/2012 B-6	Cash Working Capital B-7
1	Gross Utility Plant in Service	$ (129,596)	$ (35,406)	$ (23,458)	$ (17,536)	$ (53,196)	$ -		
2	Less: Accumulated Depreciation	$ 60,124	$ -				$ 60,124		
3	Net Utility Plant in Service	$ (69,472)	$ (35,406)	$ (23,458)	$ (17,536)	$ (53,196)	$ 60,124		$ -
	Deductions:								
4	Deferred Income Taxes	$ 1,726		$ -				$ 1,726	
5	Investment Tax Credits	$ -							
6	Customer Advances for Construction	$ -							
7	Customer Deposits	$ -							
8	Pension and Other Postretirement Liabilities	$ -							
9	Liability For Asset Retirement	$ -							
10	Other Deferred Credits	$ -							
11	Unamortized Gain-Sale of Utility Plant	$ -							
12	Regulatory Liabilities	$ -							
13	**Total Deductions**	$ 1,726	$ -	$ -	$ -	$ -	$ -	$ 1,726	$ -
	Additions:								
14	Construction Work in Progress	$ -							
15	Regulatory Assets	$ -							
16	Other Deferred Debits	$ -							
17	Decommissioning Trust Accounts	$ -							$ 10,467
18	Allowance For Working Capital	$ 10,467							$ 10,467
19	**Total Additions**	$ 10,467	$ -	$ -	$ -	$ -	$ -		
20	Total Rate Base	$ (57,279)	$ (35,406)	$ (23,458)	$ (17,536)	$ (53,196)	$ 60,124	$ 1,726	$ 10,467

Arizona Public Service Company
Adjusted Net Operating Income
ACC Jurisdictional
Test Year Ended December 31, 2010
(Thousand of Dollars)

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Schedule C
Page 1 of 1

Line No.	Description	As Adjusted by APS (A)	Staff Adjustments (B)	As Adjusted by Staff (C)
	Operating Revenues			
1	Revenues From Base Rates	$ 2,868,858	$ -	$ 2,868,858
2	Revenues From Surcharges	$ -	$ -	$ -
3	Other Electric Revenues	$ 121,013	$ -	$ 121,013
4	Total Operating Revenues	$ 2,989,871	$ -	$ 2,989,871
	Operating Expenses			
5	Electric Fuel and Purchased Power	$ 1,015,598	$ (9,575)	$ 1,006,023
6	O&M Excluding Fuel Expenses	$ 808,018	$ (20,725)	$ 787,293
7	Depreciation & Amortization	$ 352,026	$ (8,488)	$ 343,538
8	Income Taxes	$ 200,456	$ 16,731	$ 217,187
9	Other Taxes	$ 139,417	$ (1,943)	$ 137,474
10	Total Operating Expenses	$ 2,515,515	$ (23,999)	$ 2,491,516
11	Net Operating Income	$ 474,356	$ 23,999	$ 498,355

Notes and Source

Col. A: APS Schedule C-1, page 2 of 2
Col. B: Staff Schedule C.1

Arizona Public Service Company
Summary of Net Operating Income Adjustments
ACC Jurisdiction
Test Year Ended December 31, 2010
(Thousand of Dollars)

Line No.	Description	Staff Adjustments	Forensic Investigation of Grant-Funded Projects	General Advertising Expense	Property Tax Expense	Solar Post Test Year Plant Depreciation and Property Tax Expense	Fossil Post Test Year Plant Depreciation and Property Tax Expense	Nuclear Post Test Year Plant Depreciation and Property Tax Expense
			C-1	C-2	C-3	C-4	C-5	C-6
	Operating Revenues							
1	Revenues From Base Rates	$ -						
2	Revenues From Surcharges	$ -						
3	Other Electric Revenues	$ -						
4	Total Operating Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Operating Expenses							
5	Electric Fuel and Purchased Power	$ (9,575)						
6	O&M Excluding Fuel Expenses	$ (20,725)	$ (2,057)	$ (572)		$ -	$ -	$ -
7	Depreciation & Amortization	$ (8,488)				$ (1,170)	$ (637)	$ (253)
8	Other Taxes	$ (1,943)			$ (584)	$ (131)	$ (146)	$ (110)
9	PRE-TAX OPERATING EXPENSES	$ (40,730)	$ (2,057)	$ (572)	$ (584)	$ (1,301)	$ (783)	$ (363)
10	PRE-TAX OPERATING INCOME	$ 40,730	$ 2,057	$ 572	$ 584	$ 1,301	$ 783	$ 363
11	Income Taxes	$ 16,731	$ 813	$ 226	$ 231	$ 514	$ 310	$ 143
12	TOTAL OPERATING EXPENSES	$ (23,999)	$ (1,244)	$ (346)	$ (353)	$ (787)	$ (473)	$ (220)
13	OPERATING INCOME	$ 23,999	$ 1,244	$ 346	$ 353	$ 787	$ 473	$ 220

Notes and Source

Combined Effective Tax Rate* 39.51%

* Per APS filing, Schedule C-3

Arizona Public Service Company
Summary of Net Operating Income Adjustments
ACC Jurisdiction
Test Year Ended December 31, 2010
(Thousand of Dollars)

Line No.	Description	Distribution and General and Intangible Post Test Year Plant Depreciation and Property Tax Expense C-7	Interest Synchronization C-8	Base Fuel and Purchased Power C-9	Payroll Expense Adjustment - New Union Contract C-10	Depreciation Expense - New Depreciation Rates C-11	Prospective Amortization of 2010 Severance Costs C-12
	Operating Revenues						
1	Revenues From Base Rates					$ -	
2	Revenues From Surcharges						
3	Other Electric Revenues						
4	Total Operating Revenues	$ -	$ -	$ -	$ -	$ -	$ -
	Operating Expenses						
5	Electric Fuel and Purchased Power			$ (9,575)	$ 4,994		$ (3,128)
6	O&M Excluding Fuel Expenses	$ -				$ (4,735)	
7	Depreciation & Amortization	$ (1,693)	$ -	$ -			
8	Other Taxes	$ (971)	$ -	$ -			
9	PRE-TAX OPERATING EXPENSES	$ (2,664)	$ -	$ (9,575)	$ 4,994	$ (4,735)	$ (3,128)
10	PRE-TAX OPERATING INCOME	$ 2,664	$ -	$ 9,575	$ (4,994)	$ 4,735	$ 3,128
11	Income Taxes	$ 1,053	$ 638	$ 3,783	$ (1,973)	$ 1,871	$ 1,236
12	TOTAL OPERATING EXPENSES	$ (1,611)	$ 638	$ (5,792)	$ 3,021	$ (2,864)	$ (1,892)
13	OPERATING INCOME	$ 1,611	$ (638)	$ 5,792	$ (3,021)	$ 2,864	$ 1,892

Notes and Source

Combined Effective Tax Rate* 39.51%

* Per APS filing, Schedule C-3

Arizona Public Service Company
Summary of Net Operating Income Adjustments
ACC Jurisdiction
Test Year Ended December 31, 2010
(Thousand of Dollars)

Line No.	Description	Directors and Officers' Liability Insurance Expense C-13	Incentive Compensation C-14	Normalized Fossil Non-Plant Maintenance Expense C-15	Edison Electric Institute Dues C-16
	Operating Revenues				
1	Revenues From Base Rates				
2	Revenues From Surcharges				
3	Other Electric Revenues				
4	Total Operating Revenues	$ -	$ -	$ -	$ -
	Operating Expenses				
5	Electric Fuel and Purchased Power				
6	O&M Excluding Fuel Expenses	$ (550)	$ (18,930)	$ (266)	$ (216)
7	Depreciation & Amortization				
8	Other Taxes				
9	PRE-TAX OPERATING EXPENSES	$ (550)	$ (18,930)	$ (266)	$ (216)
10	PRE-TAX OPERATING INCOME	$ 550	$ 18,930	$ 266	$ 216
11	Income Taxes	$ 217	$ 7,479	$ 105	$ 85
12	TOTAL OPERATING EXPENSES	$ (333)	$ (11,451)	$ (161)	$ (131)
13	OPERATING INCOME	$ 333	$ 11,451	$ 161	$ 131

Notes and Source
Combined Effective Tax Rate* 39.51%
* Per APS filing, Schedule C-3

Arizona Public Service Company
Capital Structure & Cost Rates

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Schedule D
Page 1 of 1

Test Year Ended December 31, 2010
(Thousands of Dollars)

Line No.	Capital Source	Capitalization Amount (A)	Capitalization Percent (B)	Cost Rate (C)	Weighted Avg. Cost of Capital (D)
	APS - Proposed				
1	Short-Term Debt	$ -			0.00%
2	Long-Term Debt	$ 3,382,856	46.06%	6.38%	2.94%
3	Common Stock Equity	$ 3,961,248	53.94%	11.00%	5.93%
4	Total Capital	$ 7,344,104	100.00%		8.87%
	ACC Staff - Proposed				
5	Short-Term Debt	$ -			0.00%
6	Long-Term Debt	$ 3,382,856	46.06%	6.38%	2.94%
7	Common Stock Equity	$ 3,961,248	53.94%	9.90%	5.34%
8	Total Capital	$ 7,344,104	100.00%		8.28%
9	Difference				-0.59%
10	Weighted Cost of Debt				2.94%
	ACC Staff - Proposed Fair Value Rate of Return - Alternative 1				
11	Short-Term Debt	$ -	0.00%	0.00%	0.00%
12	Long-Term Debt	$ 2,608,502	31.94%	6.38%	2.04%
13	Common Stock Equity	$ 3,054,497	37.40%	9.90%	3.70%
14	Capital financing OCRB	$ 5,662,998			
15	Appreciation above OCRB not recognized on utility's books	$ 2,504,128	30.66%	0% [a]	0.00%
16	Total capital supporting FVRB	$ 8,167,126	100.00%		5.74%
	ACC Staff - Proposed Fair Value Rate of Return - Alternative 2				
17	Short-Term Debt	$ -	0.00%	0.00%	0.00%
18	Long-Term Debt	$ 2,608,502	31.94%	6.38%	2.04%
19	Common Stock Equity	$ 3,054,497	37.40%	9.90%	3.70%
20	Capital financing OCRB	$ 5,662,998			
21	Appreciation above OCRB not recognized on utility's books	$ 2,504,128	30.66%	1.00% [b]	0.31%
22	Total capital supporting FVRB	$ 8,167,126	100.00%		6.05%

Notes and Source

Lines 1-4, APS filing D-1.

Line 15, Col.A:

23	Fair Value Rate Base	$ 8,167,126	Schedule A
24	Original Cost Rate Base	$ 5,662,998	Schedule A
25	Difference	$ 2,504,128	

Difference is appreciation of Fair Value over Original Cost that is not recognized on the utility's books.

[a] The appreciation of Fair Value over Original Cost has not been recognized on the utility's books. Such off-book appreciation has not been financed by debt or equity capital recorded on the utility's books. The appreciation over Original Cost book value is therefore recognized for cost of capital purposes at zero cost.

[b] Per Staff witness David Parcell

Arizona Public Service Company
Solar Post-Test Year Plant Additions

Test Year Ended December 31, 2010
(Thousands of Dollars)

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Schedule B-1
Page 1 of 1

Line No.	Description	Per Company Through 6/30/2012 Total Company (A)	Per Company Through 6/30/2012 ACC (B)	Per Staff Through 3/31/2012 Total Company (C)	Per Staff Through 3/31/2012 ACC (D)	Staff Adjustment Total Company (E)	Staff Adjustment ACC (F)
1	Post Test Year Plant Additions	277,411	267,979	240,759	232,573	(36,652)	(35,406)

Notes and Source:
Cols A and B: Per APS Filing Schedule B-2
Cols C and D: APS witness Jeffrey B Guldner workpaper JBG_WP1
As updated by APS in response to STF 6.55, APS14743 and APS' response to STF 27.4(a):

		Total Company (G)	ACC Jurisdictional (H)	Staff Jurisdictional Adjustment Components (I)	Staff Jurisdictional Adjustment Components Percent (J)
2	Additions from 1/1/2011 to 6/30/2012	$ 260,765	$ 251,899	$ (16,080)	45.42%
3	Additions from 4/1/2012 to 6/30/2012	$ 20,006	$ 19,326	$ (19,326)	54.58%
4	Additions from 1/1/2011 to 3/31/2012	$ 240,759	$ 232,573	$ (35,406)	100.00%

Arizona Public Service Company
Fossil Post-Test Year Plant Additions

Test Year Ended December 31, 2010
(Thousands of Dollars)

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Schedule B-2
Page 1 of 1

Line No.	Description	Per Company Through 6/30/2012 Total Company (A)	Per Company Through 6/30/2012 ACC (B)	Per Staff Through 3/31/2012 Total Company (C)	Per Staff Through 3/31/2012 ACC (D)	Staff Adjustment Total Company (E)	Staff Adjustment ACC (F)
1	Post Test Year Plant Additions	$ 156,269	$ 150,956	$ 131,985	$ 127,498	$ (24,284)	$ (23,458)

Notes and Source:
Cols A and B: Per APS Filing Schedule B-2
Cols C and D: APS witness Mark A Schiavoni workpaper MAS_WP1
As updated by APS in response to STF 6.55, APS14744, and APS' response to STF 27.4(c):

		Total Company (G)	ACC (H)	Staff Jurisdictional Adjustment Components (I)	Staff Jurisdictional Adjustment Components Percent (J)
2	Additions from 1/1/2011 to 6/30/2012	$ 154,606	$ 149,350	$ (1,606)	6.85%
3	Additions from 4/1/2012 to 6/30/2012	$ 22,621	$ 21,852	$ (21,852)	93.15%
4	Additions from 1/1/2011 to 3/31/2012	$ 131,985	$ 127,498	$ (23,458)	100.00%

Arizona Public Service Company
Nuclear Post-Test Year Plant Additions

Test Year Ended December 31, 2010
(Thousands of Dollars)

Line No.	Description	Per Company Through 6/30/2012 Total Company (A)	Per Company Through 6/30/2012 ACC (B)	Per Staff Through 3/31/2012 Total Company (C)	Per Staff Through 3/31/2012 ACC (D)	Staff Adjustment Total Company (E)	Staff Adjustment ACC (F)
1	Post Test Year Plant Additions	$ 120,103	$ 116,019	$ 101,950	$ 98,483	$ (18,153)	$ (17,536)

Notes and Source:
Cols A and B: Per APS Filing Schedule B-2
Cols C and D: APS witness Randy K Edington workpaper RKE_WP1
As updated by APS in response to STF 6.55, APS14745 and APS' response to STF 27.4(b):

		Total Company (G)	ACC (H)	Staff Jurisdictional Adjustment Components (I)	Staff Jurisdictional Adjustment Components Percent (J)
2	Additions from 1/1/2011 to 6/30/2012	$ 111,397	$ 107,609	$ (8,410)	47.96%
3	Additions from 4/1/2012 to 6/30/2012	$ 9,447	$ 9,126	$ (9,126)	52.04%
4	Additions from 1/1/2011 to 3/31/2012	$ 101,950	$ 98,483	$ (17,536)	100.00%

Arizona Public Service Company
Distribution, General and Intangible Post-Test Year Plant Additions

Docket No. E-01345A-11-0224
Schedule B-4

Test Year Ended December 31, 2010
(Thousands of Dollars)

Line No.	Description	Per Company Through 6/30/2012 Total Company (A)	Per Company Through 6/30/2012 ACC (B)	Per Staff Through 3/31/2012 Total Company (C)	Per Staff Through 3/31/2012 ACC (D)	Staff Adjustment Total Company (E)	Staff Adjustment ACC (F)
1	Post Test Year Plant Additions	$ 432,984	$ 423,910	$ 378,649	$ 370,714	$ (54,335)	$ (53,196)

Notes and Source:
Cols A and B: Per APS Filing Schedule B-2
Cols C and D: APS witness Daniel T Froetscher workpaper DTF_WP1
As updated by APS in response to STF 6.55, APS14746 and APS' response to STF 27.4(d) and (e):

		Total Company (G)	ACC (I)	Staff Jurisdictional Adjustment Components (I)	Staff Jurisdictional Adjustment Components Percent (J)
2	Additions from 1/1/2011 to 6/30/2012	$ 422,758	$ 413,898	$ (10,012)	18.82%
3	Additions from 4/1/2012 to 6/30/2012	$ 44,109	$ 43,184	$ (43,184)	81.18%
4	Additions from 1/1/2011 to 3/31/2012	$ 378,649	$ 370,714	$ (53,196)	100.00%

Arizona Public Services
Accumulated Depreciation
ACC Jurisdictional

Docket No. E-01345A-11-0224
Schedule B-5

Test Year Ended December 31, 2010

(Thousands of Dollars)

Line No.	Description	APS Original Filing, Change Through 6/30/2012	APS Update, Filing Change Through 6/30/2012	APS Update, Change Through 3/31/2012	Staff Adjustment
		(A)	(B)	(C)	(D) = C-A
1	Solar	$ (5,602)	$ (5,403)	$ (3,391)	$ 2,211
2	Fossil	$ (128,710)	$ (128,710)	$ (113,349)	$ 15,361
3	Nuclear	$ (92,675)	$ (92,675)	$ (94,045)	$ (1,370)
4	Distribution and General and Intangible	$ (263,596)	$ (263,596)	$ (219,674)	$ 43,922
5	Total	$ (490,583)	$ (490,384)	$ (430,459)	$ 60,124

Notes and Source

Amounts represent a decrease (increase) to the jurisdictional Accumulated Depreciation balance and (decrease) increase to rate base
Col A: APS Original Filing Schedule B-2, Pages 1 and 2 of 3
Col B: APS October 26, 2011 Update Schedule B-2 Pages 1 and 2 of 3
Col C: APS response to STF 27.6

Arizona Public Services
Accumulated Deferred Income Tax
ACC Jurisdictional

Docket No. E-01345A-11-0224
Schedule B-6
Page 1 of 2

Test Year Ended December 31, 2010
(Thousands of Dollars)

Line No.	Description	APS Original Filing, Change Through 6/30/2012	APS Update Filing, Change Through 6/30/2012	APS Update, Change Through 3/31/2012	Staff Adjustment
		(A)	(B)	(C)	(D) = C-A
1	Solar	$ (3,844)	$ (3,218)	$ (2,476)	$ 1,368
2	Fossil	$ (12,155)	$ (12,155)	$ (12,344)	$ (189)
3	Nuclear	$ (28,331)	$ (28,331)	$ (30,226)	$ (1,895)
4	Distribution and General and Intangible	$ (4,320)	$ (4,320)	$ (1,878)	$ 2,442
5	Total	$ (48,650)	$ (48,024)	$ (46,924)	$ 1,726

Notes and Source

Amounts represent a decrease (increase) to the jurisdictional ADIT balance and (decrease) increase to rate base

Col A: APS Original Filing Schedule B-2, Pages 1 and 2 of 3

Col B: APS October 26, 2011 Update Schedule B-2 Pages 1 and 2 of 3

Col C: APS response to STF 27.7

Note: the adjustment shown in column D is a temporary placeholder pending receipt of APS' actual March 31, 2012 ADIT balance similar to the information provided in APS' response to Staff 20.1, APS14858 and resolution of concerns about coordinating the rate base update to March 31, 2012 in a manner that will not implicate tax normalization concerns described in APS' responses to AECC 1.11, Staff 15.13, Staff 19.14 and other responses concerning the rate base update for ADIT balances.

Arizona Public Service Company
Accumulated Deferred Income Taxes - Accounts 190, 282, and 283

Test Year Ended December 31, 2010

(Thousands of Dollars)

Line No.	Account Description	Actuals Increase (Decrease) RATE BASE 7/31/11	Actuals Increase (Decrease) RATE BASE 8/31/11	Forecast Increase (Decrease) RATE BASE 9/30/11	Forecast Increase (Decrease) RATE BASE 10/31/11	Forecast Increase (Decrease) RATE BASE 11/30/11	Forecast Increase (Decrease) RATE BASE 12/31/11	Forecast Increase (Decrease) RATE BASE 1/31/12	Forecast Increase (Decrease) RATE BASE 2/29/12	Forecast Increase (Decrease) RATE BASE 3/31/12
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
	Total Company									
1	Total Deferred Taxes per General Ledger	$(1,819,235)	$(1,887,398)	$(1,888,657)	$(1,893,263)	$(1,891,763)	$ (1,893,834)	$(1,895,722)	$ (1,891,506)	$ (1,881,995)
	Exclude									
2	Reg Asset-Power Supply Adjustor Mark to Market	(24,929)	(24,929)	(18,418)	(17,861)	(18,042)	(17,792)	(17,719)	(17,882)	(18,323)
3	Reg Asset-Transmission Vegetation Management	(17,857)	(17,747)	(17,701)	(17,685)	(17,690)	(17,683)	(17,680)	(17,687)	(17,708)
4	Reg Asset-Unamortized Loss on Reaquired Debt	(8,346)	(8,187)	(8,120)	(8,097)	(8,105)	(8,094)	(8,089)	(8,100)	(8,130)
5	Option II Benefits (Includes Reg Asset and Def Comp)	4,272	3,879	3,712	3,653	3,672	3,646	3,640	3,653	3,689
6	Reg Asset-Demand Side Management	(4,351)	(2,806)	(2,151)	(1,922)	(1,997)	(1,894)	(1,876)	(1,916)	(2,025)
7	Reg Liab-Renewable Energy Standard	20,208	21,054	21,412	21,538	21,497	21,553	21,580	21,520	21,359
8	Reg Liab-Power Supply Adjustor	9,129	1,041	(2,391)	(3,588)	(3,198)	(3,736)	(3,703)	(3,776)	(3,974)
9	Renewable Energy Incentives	47,539	53,456	55,966	56,841	56,556	56,950	57,066	56,807	56,107
10	Mark to Market	74,908	64,472	82,448	81,877	82,063	81,806	81,730	81,900	82,362
11	OCI-Pension Taxes	22,123	22,123	22,123	22,123	22,123	22,123	22,123	22,123	22,123
12	Superfund	1,758	1,711	1,691	1,684	1,686	1,683	1,682	1,685	1,694
13	Other	1,039	1,039	1,039	1,039	1,039	1,039	1,039	1,039	1,039
14	Total Excluded	125,494	115,103	139,609	139,602	139,604	139,601	139,792	139,365	138,212
15	Total Accumulated Deferred Income Taxes	$(1,944,729)	$(2,002,501)	$(2,028,266)	$(2,032,865)	$(2,031,367)	$ (2,033,434)	$(2,035,514)	$ (2,030,872)	$ (2,020,207)
	ACC Jurisdictional									
16	Total Deferred Taxes per General Ledger	$(1,519,663)	$(1,576,602)	$(1,577,653)	$(1,581,501)	$(1,580,248)	$ (1,581,978)	$(1,583,556)	$ (1,580,034)	$ (1,572,089)
	Exclude									
17	Reg Asset-Power Supply Adjustor Mark to Market	(24,323)	(24,323)	(17,971)	(17,427)	(17,604)	(17,360)	(17,288)	(17,447)	(17,878)
18	Reg Asset-Transmission Vegetation Management	-	-	-	-	-	-	-	-	-
19	Reg Asset-Unamortized Loss on Reaquired Debt	(8,062)	(7,909)	(7,844)	(7,822)	(7,829)	(7,819)	(7,814)	(7,825)	(7,854)
20	Option II Benefits (Includes Reg Asset and Def Comp)	3,970	3,604	3,449	3,395	3,413	3,388	3,383	3,395	3,428
21	Reg Asset-Demand Side Management	(4,203)	(2,711)	(2,078)	(1,857)	(1,929)	(1,830)	(1,812)	(1,851)	(1,956)
22	Reg Liab-Renewable Energy Standard	19,521	20,338	20,684	20,805	20,766	20,820	20,846	20,788	20,633
23	Reg Liab-Power Supply Adjustor	8,908	1,015	(2,333)	(3,501)	(3,120)	(3,645)	(3,613)	(3,685)	(3,878)
24	Renewable Energy Incentives	46,383	52,157	54,606	55,460	55,182	55,566	55,679	55,427	54,744
25	Mark to Market	73,088	62,905	80,444	79,887	80,069	79,818	79,744	79,910	80,360
26	OCI-Pension Taxes	20,559	20,559	20,559	20,559	20,559	20,559	20,559	20,559	20,559
27	Superfund	1,634	1,590	1,571	1,565	1,567	1,564	1,563	1,566	1,574
28	Other	966	966	966	966	966	966	966	966	966
29	Total Excluded	138,441	128,191	152,053	152,030	152,040	152,027	152,213	151,803	$ 150,698
30	Total Accumulated Deferred Income Taxes	$(1,658,104)	$(1,704,793)	$(1,729,706)	$(1,733,531)	$(1,732,288)	$ (1,734,005)	$(1,735,769)	$ (1,731,837)	$ (1,722,787)
31	APS original filing, adjusted ACC jurisdictional ADIT									$ (1,615,133)
32	Difference									$ (107,654)
33	APS October 26, 2011 update filing, jurisdicitonal ADIT									$ (1,614,507)
34	Difference									$ (108,280)

Notes and Source:
Lines 1 - 13: APS response to STF 15.7
Lines 16-30: APS response to STF 20.1 Bates No APS 14858
Line 31: APS' original filing, Schedule B-1, page 1 of 2, line 4, column F
Line 33: APS' October 26, 2011 update filing, Schedule B-1, page 1 of 2, line 4, column F

Arizona Public Service Company
Cash Working Capital

Docket No. E-01345A-11-0224
Schedule B-7
Page 1 of 3

Test Year Ended December 31, 2010
(Thousands of Dollars)

Line No.	Description	Staff Income Statement Adjustments (A)	CWC FACTOR (B)	Staff Adjustments to Cash Working Capital (C)
	Fuel For Electric Generation:			
1	Coal	$ 14,653	0.01082	$ 159
2	Natural Gas	$ (24,102)	0.01120	$ (270)
3	Gas Mtm And Futures		0.00000	
4	Handling	$ (72)	0.06251	$ (4)
5	Fuel Oil		-0.00290	
6	Nuclear:			
7	Amortization	$ 3,889	0.00000	$ -
8	Spent Fuel		-0.10669	
9	Total Nuclear Fuel	$ 3,889		$ -
10	Total Fuel	$ (5,632)		$ (116)
11	Purchased Power	$ (5,605)	0.00889	$ (50)
12	Power Mtm		0.00000	
13	Power Supply Adjuster		0.00000	
14	Transmission By Others	$ 1,663	-0.00170	$ (3)
15	Total Purchased Power & Transmission	$ (3,943)		$ (53)
16	Subtotal Fuel and Purchased Power	$ (9,575)		
	Other Operations & Maintenance:			
17	Payroll	$ 4,994	0.06251	
18	Incentive	$ (18,930)	-0.54541	$ 10,325
19	Stock Compensation	$ -	0.00000	
20	Severance (Excludes Pension)	$ (3,128)	-0.11090	$ 347
21	Pension and OPEB	$ -	-0.00025	
22	Employee Benefits	$ -	0.06708	
23	Payroll Taxes	$ -	-0.00520	
24	Materials & Supplies	$ -	0.03579	
25	Vehicle Lease Payments	$ -	0.06704	
26	Prepaid Vehicle Licenses	$ -	0.00000	
27	Rents	$ -	0.07045	
28	Prepaid Rents	$ -	0.00000	
29	Palo Verde Lease	$ -	-0.21133	
30	Palo Verde S/L Gain Amort	$ -	0.00000	
31	Insurance	$ (550)	0.00000	$ -
32	Other	$ (3,112)	0.02812	$ (87)
33	Total Other O&M	$ (20,725)		$ 10,584
34	Depreciation & Amortization	$ (8,488)	0.00000	$ -
35	Amort Of Prop Losses & Reg Study Costs		0.00000	
36	Total	$ (8,488)		$ -
	Income Taxes:			
37	Current:			
38	Federal	$ 11,372	-0.05897	$ (671)
39	State	$ 2,423	-0.07443	$ (180)
40	Deferred		0.00000	
41	Total	$ 13,795		$ (851)
	Other Taxes:			
42	Property Taxes	$ (1,359)	-0.47517	$ 646
43	Sales Taxes		-0.06151	
44	Franchise Taxes		-0.10132	
45	Total	$ (1,359)		$ 646
46	Interest Expense - Synchronized	$ (1,614)	-0.15924	$ 257
47	Total	$ (27,965)		$ 10,467

Arizona Public Service Company
Cash Working Capital

Docket No. E-01345A-11-0224
Schedule B-7
Page 2 of 3

Test Year Ended December 31, 2010
(Thousands of Dollars)

Line No	Description	Federal Income Tax (A)	State Income Tax (B)	Total Income Tax (C)	Reference
	I. Change in Current Income Taxes				
1	Income Tax Rate	32.57%	6.94%	39.51%	Schedule A-1
2	Income Taxes at Present Rates			$ 16,731	Schedule C.1, line 11
	Adjustments to Income Tax Expense:				
3	Income Taxes at Present Rates	$ 13,792	$ 2,939	16,731	
4	Income Taxes at Proposed Rate	(2,421)	(516)	(2,937)	Schedule A-1, Col.E
5	Income Taxes Expense Adjustment	$ 11,371	$ 2,423	$ 13,794	

	II. Allocation for Base Fuel and Purchase Power	APS Adjustment (D)	Percentage (E)	Staff Adjustment (F)
	Fuel For Electric Generation:			
6	Coal	$ 45,620	-153%	$ 14,653
7	Natural Gas	$ (75,040)	252%	$ (24,102)
8	Gas Mtm And Futures	$ -		
9	Handling	$ (223)	1%	$ (72)
10	Fuel Oil	$ -		
	Nuclear:			
11	Amortization	$ 12,108	-41%	$ 3,889
12	Spent Fuel	$ -		
13	Total Nuclear Fuel			
14	Total Fuel			
15	Purchased Power	$ (17,452)	59%	$ (5,605)
16	Power Mtm	$ -		
17	Power Supply Adjuster	$ -		
18	Transmission By Others	$ 5,177	-17%	$ 1,663
19	Total Purchased Power & Transmission			
20	Total Fuel And Purchased Power	$ (29,810)	100%	$ (9,575)

Notes and Source:
Col A: APS Pro Forma Adjustment for Cash Working Capital JCL_WP9

Arizona Public Service Company
Cash Working Capital

Docket No. E-01345A-11-0224
Schedule B-7
Page 3 of 3

Test Year Ended December 31, 2010
(Thousands of Dollars)

Line No	Description	Reference	Amount (A)	Amount (B)
	III. Reconciliation of Non-Fuel O&M Expense Adjustments			
1	Total Staff O&M Non-Fuel Expense adjustments	Sch C.1		$ (20,725)
	Specific to Selected Cash Working Capital Components:			
2	Payroll	C-10	$ 4,994	
3	Incentive	C-14	$ (18,930)	
4	Stock Compensation			
5	Severance (Excludes Pension)	C-12	$ (3,128)	
6	Pension and OPEB			
7	Employee Benefits			
8	Payroll Taxes			
9	Materials & Supplies			
10	Vehicle Lease Payments			
11	Prepaid Vehicle Licenses			
12	Rents			
13	Prepaid Rents			
14	Palo Verde Lease			
15	Palo Verde S/L Gain Amort			
16	Insurance	C-13	$ (550)	
17	Subtotal		$ (17,614)	$ (17,614)
18	Other			$ (3,112)

Arizona Public Service Company
Forensic Investigation of Grant-Funded Projects

Docket No. E-01345A-11-0224
Schedule C-1
Page 1 of 1

Test Year Ended December 31, 2010

(Thousands of Dollars)

Line No.	Description	Total Company Amount (A)	ACC Jurisdictional Amount (B)
1	Remove APS Expense for Forensic Investigation of Grant-Funded Projects	$ (2,129)	$ (2,057)

Notes and Source

		Total Company (C)	ACC Jurisdicitonal (D)
	Company Recorded Operating Expense for Forensic Investigation		
2	IES project expenses	$ 2,334	
3	SNG project expenses	$ 503	
4	Lega/Audit expemses	$ 292	
5	APS Pro forma Adjustment	$ (1,000)	
6	Remaining Expense To Be Removed	$ 2,129	$ 2,057

Col C: APS response to STF 9.2
Col D: APS' October 26, 2011 Update Filing, Schedule C-2, page 12, APS Adjustment No 34. "Exclude ARRA Project Expenses"

Arizona Public Service Company
General Advertising Expense

Test Year Ended December 31, 2010

Docket No. E-01345A-11-0224
Schedule C-2
Page 1 of 1

Line No.	Description	Total Company Adjustment (A)	ACC Jurisdictional Factor (B)	ACC Jurisdictional Adjustment (C)
	Adjust General Advertising Expense			
1	Remove Breakfast at the Zoo	$ (40,688)	0.906371	$ (36,878)
2	Normalize General Advertising Expense allowance	$ (590,801)	0.906371	$ (535,485)
3	Adjustment to General Advertising Expense	$ (631,489)		$ (572,363)

Notes and Source

Account 930.1

General Advertising Expense

	Period	Reference	Amount (D)	Adjustment (E)	Adjusted (F)
4	2008	Response to Staff 21.5	$ 3,435,898		$ 3,435,898
5	2009	APS14766, page 8 and Staff 21.4	$ 1,807,823		$ 1,807,823
6	2010	APS14082 and APS14165, p.9 and Staff 21.4	$ 3,548,750	$ (40,688) [A]	$ 3,508,062
7	2011 budget	Staff 21.5 and Staff 27.10			$ 2,059,000
7	Three-Year Average, 2008-2010				$ 2,917,261
8	APS proposed without Breakfast at the Zoo				$ 3,508,062
9	Adjustment to normalize General Advertising Expense allowance				$ (590,801)
10	Four-Year Average, 2008-2011				$ 2,702,696
11	APS proposed without Breakfast at the Zoo				$ 3,508,062
12	Adjustment to normalize General Advertising Expense allowance				$ (805,366)

Other Comparable Information

13	2011 YTD 6/30	APS14165, page 9 of 9	$ 1,028,946		
14		Annualized	$ 2,057,892		
				Allowance Compared with Budget	
				Amount	Percent
15	2011 budget	Staff 21.5	$ 2,059,000	$ 858,261	41.7%
16	Four-Year Average, 2008-2011		$ 2,702,696	$ 214,565	7.9%
			Annual	Monthly	
17	2011 budget	Staff 27.10; APS14964, page 1 of 1	$ 2,059,000	$171,583.33	
18	2011 YTD 9/30	Staff 27.10; APS14964, page 1 of 1	$ 1,406,210		
19		Annualized	$ 1,874,947		

[A] *Pre-filed 1.40, APS14082 and response to Staff 21.1*

Col.B: ACC Jurisdictional Factor

	Adminstrative and General:		
20	ACC Jurisdictional	$ 195,988,517	AP_WP1
21	Electric Total	$ 216,234,381	AP_WP1
22	ACC Jurisdictional Factor	0.906371	

Arizona Public Service Company
Property Tax Expense

Docket No. E-01345A-11-0224
Schedule C-3
Page 1 of 1

Test Year Ended December 31, 2010
(Thousands of Dollars)

Line No.	Description	Per APS Original Filing (A)	Per Staff (B)	Staff Adjustment (C)
	I. Full Cash Value			
1	Plant in Service	$ 7,874,172	$ 7,870,683	
2	Environmental	$ 22,009	$ 22,009	
3	Renewable Energy Equipment	$ 4,632	$ 4,632	
4	Total	$ 7,900,813	$ 7,897,324	
	II. Assessed Value			
5	Assessment Ratio	20%	20%	
6	Plant in Service	1,574,834	1,574,137	
7	Environmental	4,402	4,402	
8	Renewable Energy Equipment	926	926	
9	Total	1,580,163	1,579,465	
	III. Estimated Property Taxes			
10	Property Tax Rate	9.00%	8.96%	
11	Plant in Service	141,735	141,043	
12	Environmental	396	394	
13	Renewable Energy Equipment	83	83	
14	Total Estimated Property Taxes	142,215	141,520	
15	Arizona Property Tax Expense for 2010	124,244	124,244	
16	Total Property Tax Expense Increase	17,971	17,276	$ (695)
	IV. Jurisdictional Expense Adjustment			
17	ACC Jurisdictional Property Tax Expense Adjustment	$ 15,115	$ 14,531	$ (584)

Notes and Source

Col.A: APS workpaper JCL_WP26, page 4 of 5
Line 15&16: APS workpaper JCL_WP26, page 2 of 5
Col.B: APS October 26, 2011 Update, APS14932, page 4 of 5
Line 15&16: APS14935, page 2 of 5; workpaper JCL_WP26 updated, page 2 of 5
Line 17, Col.A: APS' original filing, Schedule C-2, APS adjustment 14
Line 17, Col.B: APS' October 26, 2011 updated filing, Schedule C-2, APS adjustment 14 revised

Arizona Public Service Company
Solar Post Test Year Plant Depreciation and Property Tax Expense

Docket No. E-01345A-11-0224
Schedule C-4
Page 1 of 1

Test Year Ended December 31, 2010
(Thousands of Dollars)

Line No.	Description	Per APS (A)	Per Staff (B)	Staff Adjustment (C)
	I. Depreciation Expense			
1	ACC Jurisdictional Post Test Year Plant Additions	$ 267,979	$ 232,573	$ (35,406)
2	Less: land	$ (5,017)	$ (4,755)	
3	Depreciable Solar Plant	$ 262,962	$ 227,818	
4	Depreciation Rate	3.33%	3.33%	
5	Adjustment to Depreciation Expense	8,757	7,586	(1,170)
	II. Property Taxes			
6	ACC Jurisdictional Post Test Year Plant Additions	267,979	232,573	
7	Less: AFUDC	$ (5,735)	$ (5,735)	
8	Subtotal	262,244	226,838	
9	Assessment Ratio	20%	20%	
10	Subtotal	52,449	45,368	
11	Renewable Benefits	20%	20%	
12	Total Taxable Value	10,490	9,074	
13	Property Tax Rate	9.00%	8.96%	
14	Property Tax Expense Adjustment	944	813	(131)

Notes and Source
Col A: APS Company witness Jeffrey B Guldner Schedule JBG_WP1
Cols A and B, Line 1: See Schedule B-1
Col.B, line 13: APS14932, page 4 of 5
Col. C: Col.B-Col.A

Arizona Public Service Company
Fossil Post Test Year Plant Depreciation and Property Tax Expense

Docket No. E-01345A-11-0224
Schedule C-5
Page 1 of 1

Test Year Ended December 31, 2010
(Thousands of Dollars)

Line No.	Description	Per APS (A)	Per Staff (B)	Staff Adjustment (C)
	I. Depreciation Expense			
1	Jurisdictional Fossil Plant Additions	$ 150,956	$ 127,498	$ (23,458)
2	ACC Jurisdictional Post Test Year Steam Production Plant Additions	$ 66,421	$ 56,099	
2	ACC Jurisdictional Post Test Year Other Production Plant Additions	$ 84,535	$ 71,399	
3	Fossil Plant Additions	$ 150,956	$ 127,498	
4	Depreciation Rate for Steam Production Plant	2.84%	2.84%	
5	Depreciation Rate for Other Production Plant	2.62%	2.62%	-
6	Annual Steam Depreciation	$ 1,886	$ 1,593	
7	Annual Other Production Depreciation	$ 2,215	$ 1,871	
8	Total Fossil Depreciation Expense Adjustment	$ 4,101	$ 3,464	$ (637)
	II. Property Taxes			
9	ACC Jurisdictional Post Test Year Steam ProductionPlant Additions	$ 66,421	$ 56,099	
10	ACC Jurisdictional Post Test Year Other ProductionPlant Additions	$ 84,535	$ 71,399	
11	Total Fossil Plant Additions	$ 150,956	$ 127,498	
12	Full Cash Value Steam	$ 22,583	$ 19,074	
13	Full Cash Value Other Production	$ 28,404	$ 23,990	
14	Total Full Cash Value for Fossil	$ 50,987	$ 43,064	
15	2010 Assessment Ratio	20%	20%	
16	Assessed Value Steam	4,517	3,815	
17	Assessed Value Other Production	$ 5,681	$ 4,798	
18	Total Assessed Value for Fossil	$ 10,197	$ 8,613	
19	Property Tax Rate	9.00%	8.96%	
20	Property Tax Expense Adjustment	$ 918	$ 772	$ (146)

Notes and Source
Col A: APS Company witness Jason La Benz Schedule JCL_WP21
Col.B, lines 1, 3 and 11: Schedule B-2
Col.B, line 19: APS14932, page 4 of 5
Col.C = Col.B-Col.A

Arizona Public Service Company
Nuclear Post Test Year Plant Depreciation and Property Tax Expense

Docket No. E-01345A-11-0224
Schedule C-6
Page 1 of 1

Test Year Ended December 31, 2010
(Thousands of Dollars)

Line No.	Description	Per APS (A)	Per Staff (C)	Staff Adjustment (C)
	I. Depreciation Expense			
1	ACC Jurisdictional Post Test Year Nuclear Plant Additions	$ 116,019	$ 98,483	$ (17,536)
2	Depreciation Rate for Nuclear Plant	1.44%	1.44%	
3	Annual Nuclear Plant Depreciation	$ 1,671	$ 1,418	$ (253)
	II. Property Taxes			
4	ACC Jurisdictional Post Test Year Nuclear Plant Additions	$ 116,019	$ 98,483	
5	Full Cash Value Nuclear	$ 39,446	$ 33,484	
6	2010 Assessment Ratio	20%	20%	
7	Total Assessed Value for Nuclear	$ 7,889	$ 6,697	
8	Property Tax Rate	9.00%	8.96%	
9	Property Tax Expense Adjustment	$ 710	$ 600	$ (110)

Notes and Source
Col A: APS Company witness Jason La Benz Schedule JCL_WP21
Cols A and B, Line 1: See Schedule B-3
Col.B, line 8: APS14932, page 4 of 5

Arizona Public Service Company
Distribution and General and Intangible Post Test Year Plant Depreciation and Property Tax Expense

Docket No. E-01345A-11-0224
Schedule C-7
Page 1 of 1

Test Year Ended December 31, 2010
(Thousands of Dollars)

Line No.	Description	Per APS (A)	Per Staff (C)	Staff Adjustment (C)
	I. Depreciation Expense			
1	ACC Jurisdictional Post Test Year Distribution Plant Additions	$ 326,411	$ 285,450	$ (40,961)
2	ACC Jurisdictional Post Test Year Other General and Intangible Plant Additions	$ 97,499	$ 85,264	$ (12,235)
3	Depreciable Distribution and General and Intangible Plant	$ 423,910	$ 370,714	$ (53,196)
4	Depreciation Rate for Distribution Plant	2.37%	2.37%	
5	Depreciation Rate for General and Intangible Plant	5.90%	5.90%	-
6	Annual Distribution Depreciation	$ 7,736	$ 6,765	
7	Annual General and Intangible Depreciation	$ 5,752	$ 5,031	
8	Total Fossil Depreciation Expense Adjustment	$ 13,488	$ 11,796	$ (1,693)
	II. Property Taxes			
9	ACC Jurisdictional Post Test Year Distribution Plant Additions	$ 326,411	$ 285,450	
10	ACC Jurisdictional Post Test Year Other General and Intangible Plant Additions	$ 97,499	$ 85,264	
11	Total Fossil Plant Additions	$ 423,910	$ 370,714	
12	Full Cash Value Distribution	$ 322,543	$ 282,067	
13	Full Cash Value General and Intangible	$ 94,623	$ 82,749	
14	Total Full Cash Value for Distribution and General and Intangible	$ 417,166	$ 364,816	
15	2010 Assessment Ratio	20%	20%	
16	Assessed Value Distribution	$ 64,509	$ 56,413	
17	Assessed Value General and Intangible	$ 18,925	$ 16,550	
18	Total Assessed Value for Distribution and General and Intangible	$ 83,433	$ 72,963	
19	Property Tax Rate	9.00%	8.96%	
20	Property Tax Expense Adjustment	$ 7,509	$ 6,538	$ (971)

Notes and Source
Col A: APS Company witness Jason La Benz Schedule JCL_WP21
Col B lines 3 and 11: See Schedule B-4
Col.B, line 19: APS14932, page 4 of 5

Arizona Public Service Company
Interest Synchronization

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Schedule C-8
Page 1 of 1

Test Year Ended December 31, 2010
(Thousands of Dollars)

Line No.	Description	ACC Jurisdictional Amount	Reference
1	Adjusted rate base	$ 5,662,998	Schedule B
2	Weighted cost of debt	2.94%	Schedule D
3	Synchronized interest deduction	$ 166,492	Line 1 x Line 2
4	Synchronized interest deduction per APS' filing	$ 168,106	See note below
5	Difference (decreased) increased interest deduction	$ (1,614)	Line 3 - Line 4
6	Combined federal and state income tax rates	39.51%	APS Sch. C-3
7	Increase (decrease) to income tax expense	$ 638	

Notes and Source

Line 4:

8	APS Adjusted Rate Base	$ 5,720,277	Schedule B
9	APS Weighted Cost of Debt	2.94%	Schedule D
10	Synchronized interest deduction per APS	$ 168,106	

Arizona Public Service Company
Base Fuel and Purchased Power

Test Year Ended December 31, 2010

Docket No. E-01345A-11-0224
Schedule C-9
Page 1 of 1

Line No.	Description	Total Company Amount (A)	ACC Jurisdictional Amount (B)	Reference
1	Adjustment to Base Fuel and Purchased Power	$ (9,575)	$ (9,575)	A

Notes and Source

A: Per APS Witness Ewen Attachment PME-4 and APS' supplemental response to Staff 22.9, as shown below:

		Per APS (C)	Per Staff (D)	Adjustment (E)	With Four Corners 4&5 Net Fuel Savings (F)
	Adjusted Test Year Fuel and Purchased Power Costs (cents per kWh)				
2	Normalized Fuel and Purchased Costs	3.2415	3.2071	$ (0.0344)	3.0943
3	Test Year Fuel and Purchased Power Costs	3.3486	3.3486	$ -	3.3486
4	Difference	(0.1071)	(0.1415)	$ (0.0344)	(0.2543)
	Adjusted Test Year Retail Sales (MWh)				
5	Test Year Retail Sales (MWh)	27,709,463	27,709,463		27,709,463
6	Pro Forma Adjustment to Normalize Weather	116,749	116,749		116,749
7	Pro Forma Adjustment to Annualize 12/31/07 Customer Level	7,544	7,544		7,544
8	Adjusted Test Year Retail Sales	27,833,756	27,833,756		27,833,756
9	Pro Forma Adjustment to Fuel and Purchased Power Expense	$ (29,810)	$ (39,385)	$ (9,575)	$ (70,781)
10	Incremental Fuel Cost (savings) APS estimates with Four Corners 4&5 acquisition				$ (31,396)

Col. D, Line 2: APS Supplemental Response to STF 22.9 Updates on APS Attachment PME-3, page 2 of 4.
Col. F, Line 2: APS Supplemental Response to STF 22.9 Updates on APS Attachment PME-3, page 3 of 4. This includes the net fuels savings effects that APS projects if it acquires Southern California Edison's share of Four Corners 4 and 5

Arizona Public Services
Payroll Expense

Test Year Ended December 31, 2010
(Thousands of Dollars)

Line No.	Description	APS Original Filing O&M Expense Change (A)	APS Update Filing O&M Expense Change (B)	Staff Adjustment (C)
1	Payroll Expense for Total Company	$ (519)	$ 4,855	$ 5,374
2	Payroll Expense for ACC Jurisdictional	$ (482)	$ 4,512	$ 4,994

Notes and Source:
Col A, lines 1 and 2: APS original Company Filing Schedule C-2, page 4 of 12
Col B, line 1 and 2: APS Oct 26 2011 Update Company Filing APS14944, page 4 of 12:

	Component	APS Original Filing O&M Expense (A)	APS Update Filing O&M Expense (B)	Total Change (C)	Change From Results of New Union Contract (D)	Change From APS Corrections (E)
3	Wage Change to March 2011	$ 10,173	$ 11,316	$ 1,143		$ 1,143
4	Union 387 Increase (1%) - APS' original filing	$ 783		$ (783)	$ (783)	
5	Union 387 Increase (1.5%) - APS' update		$ 1,107	$ 1,107	$ 1,107	
6	Union 387 Increase (2.5%) - APS' update		$ 1,872	$ 1,872	$ 1,872	
7	Employee Change to March 2011	$ (11,475)	$ (9,440)	$ 2,035		$ 2,035
8	Total	$ (519)	$ 4,855	$ 5,374	$ 2,196	$ 3,178

Col A, lines 3 to 8: APS Company witness Jason C La Benz Workpaper JCL_WP23, page 2 of 10
Col B, lines 3 to 8: APS Oct 26 2011 Update Company Filing APS14945, page 2 of 10
Col.E: APS' response to data request Staff 32.1 describes the error discovered by APS when updating its payroll adjustment for the new union wage contract. APS' original pro forma mistakenly included as base pay the selling of paid time off and paid earned and accrued vacation, which resulted in overstating the actual test year base payroll and understating the net impact of the annualization adjustment.

Arizona Public Service Company
Depreciation Expense - New Depreciation Rates

Test Year Ended December 31, 2010

Line No.	Description	Account (A)	Original Cost as of 12/31/2010 (B)	Depreciation Rate per Decision No. 71448 (C)	Depreciation Expense (D)	Reference
	I. Account 370.01, Electronic Meters					
1	Meters Plant Account	370.01	$ 62,207,543	3.68%	$ 2,289,238	A
2	APS Depreciation Accrual				$ 3,863,088	A
3	Adjustment to Restore Meters to Currently Authorized Depreciation Rate				$ (1,573,850)	
4	ACC Jurisdictional Allocation Factor				0.993900	B
5	ACC Jurisdictional Adjustment to Depreciation Expense				$ (1,564,250)	
	II. Account 370.03, AMI Meters					
6	Meters Plant Account	370.03	$ 117,715,566	3.82%	$ 4,496,735	
7	APS Depreciation Accrual				$ 7,686,826	
8	Adjustment to Restore Meters to Currently Authorized Depreciation Rate				$ (3,190,091)	
9	ACC Jurisdictional Allocation Factor				0.993900	B
10	ACC Jurisdictional Adjustment to Depreciation Expense				$ (3,170,631)	
	III. Summary of ACC Jurisdictional Adjustment for Meters Depreciation Expense					
11	Depreciation Expense for Account 370.01, Electronic Meters				$ (1,564,250)	
12	Depreciation Expense for Account 370.03, AMI Meters				$ (3,170,631)	
13	Total Adjustment for Meters Depreciation Expense				$ (4,734,881)	

Notes and Source

A: APS workpaper JCL_WP17, page 4
B: ACC jurisdictional allocation factor CUST370 from Company Schedule G-7, page 2, line 18

	Description	Original Plant Cost @ 12/31/2010 (E)	Accumulated Depreciation at 12/31/2010 (F)	Net Plant Balance (G)	Currently Authorized Depreciation Rate (H)	Depreciation Expense (I)	Increase Dollars (J)	Increase Percent (K)
	Using Recorded Depreciation Reserve							
14	Electronic Meters - Plant Account 370.01	$ 62,207,543	$ (19,681,616)	$ 42,525,927	3.68%	$ 2,289,238		
15	AMI Meters - Plant Account 370.03	$ 117,715,566	$ (5,454,950)	$ 112,260,616	3.82%	$ 4,496,735		
16	Total Meters	$ 179,923,109	$ (25,136,566)	$ 154,786,543		$ 6,785,973		
					APS Proposed Depreciation Rate			
	Using APS Proposed Redistributed Reserve							
17	Electronic Meters - Plant Account 370.01	$ 62,207,543	$ (16,047,329)	$ 46,160,214	6.21%	$ 3,863,088	$ 1,573,850	68.7%
18	AMI Meters - Plant Account 370.03	$ 117,715,566	$ (9,009,526)	$ 108,706,040	6.53%	$ 7,686,826	$ 3,190,091	70.9%
19	Total Meters	$ 179,923,109	$ (25,056,855)	$ 154,866,254		$ 11,549,914	$ 4,763,941	70.2%

Cols. E and F: Plant and Accumulated Depreciation amounts from Attachment REW-2, Statement D filed in conjunction with Dr. White's Direct Testimony
Statement C, page 36, shows Plant and recorded and redistributed reserves
Statement A, page 18, shows currently authorized and APS-proposed depreciation rates

Arizona Public Service Company
Prospective Amortization of 2010 Severance Costs

Test Year Ended December 31, 2010

Docket No. E-01345A-11-0224
Schedule C-12
Page 1 of 1

Line No.	Description	Total Company (A)	ACC Jurisdictional (B)
1	Severance Costs Adjustment	$ (3,366)	$ (3,128)

Notes and Source

Per APS Company Severance Costs Adjustment:

		Per Company		Per Staff	
		Total Company	ACC Jurisdictional	Total Company	ACC Jurisdictional
2	Net Test Year Expense (Note A)	$ 10,099	$ 9,384	$ 10,099	$ 9,384
3	Amortization (Notes B and C)	$ 3,366	$ 3,128		
4	Adjustment	$ (6,733)	$ (6,256)	$ (10,099)	$ (9,384)

[A] APS recorded the severance cost as expense in the 2010 test year
[B] APS proposes to amortize this projectively for ratemaking purposes, using a three-year amortization
[C] Staff recommends that the amortization of the severance cost commence when the associated savings commenced. Based on that, there should be no amount remaining to be prospectively amortized when new base rates go into effect for APS as a result of this rate case.

Arizona Public Service Company
Directors and Officers Liability Insurance Expense

Docket No. E-01345A-11-0224
Schedule C-13
Page 1 of 1

Test Year Ended December 31, 2010
(Thousands of Dollars)

Line No.	Description	FERC Account	Total Company (A)	ACC Jurisdictional (B)
1	Remove Half of D&O Insurance Expense	925	$ (585)	$ (550)

Notes and Source

Cols A and B: APS response to STF 21.6

2	Directors and Officers Liability Insurance Expense	925	$ 1,170	$ 1,099
3	50% of D&O Expense		$ 585	$ 550

Arizona Public Service Company
Incentive Compensation

Docket No. E-01345A-11-0224
Schedule C-14
Page 1 of 1

Test Year Ended December 31, 2010
(Thousands of Dollars)

Line No.	Description	Staff Jurisdictional Expense Adjustment (A)	Reference
1	Adjustment for Allowance for 50% of a Normalized Amount of Incentive Compensation Expense	$ (18,930)	Line 22, below
2	Allowance for 50% of a Normalized Amount of Incentive Compensation Expense	$ 14,030	Line 19, Col.I

Notes and Source
Cols B through G: APS response to STF 22.2

	Account	Total Company 2008 (B)	Total Company 2009 (C)	Total Company 2010 (D)	ACC Jurisdictional 2008 (E)	ACC Jurisdictional 2009 (F)	ACC Jurisdictional 2010 (G)
		[BEGIN CONFIDENTIAL]					
3	506	[redacted]					
4	519						
5	524						
6	528						
7	546						
8	549						
9	557						
10	266						
11	588						
12	903						
13	916						
14	920						
15	928						
16	930						
17	Total						[END CONFIDENTIAL]

		Total Company (H)	ACC Jurisdictional (I)	
18	3 Year Average	$ 30,194	$ 28,059	
19	Expense Allowance Based on 50% of Normalized Amount	$ 15,097	$ 14,030	
20	Adjustment from 2010 Expense to 3 Year Average	$ (5,273)	$ (4,900)	
21	50% of 3 Year Average Expense	(15,097)	(14,030)	
22	Total Adjustment to Incentive Compensation Expense	$ (20,370)	$ (18,930)	$ (18,930)
23	Expense Allowance Based on 50% of Normalized Amount	Sum of Col.G, lines 16 and 20		$ 14,030

Arizona Public Services
Normalization of Fossil Non-Plant Maintenance Expense
ACC Jurisdictional

Test Year Ended December 31, 2010
(Thousands of Dollars)

Line No.	Description	Test Year at 12/31/2010 (A)	Normalized Per APS (B)	Normalized Per Staff (C)	APS Adjustment (D)	Staff Adjustment (E)	Net Staff Adjustment (F)
1	Maintenance Expense for Total Company	$ 116	$ 882	$ 609	$ 766	$ 493	$ (273)
2	Maintenance Expense for ACC						$ (266)

Notes and Source:
Col A: APS witness Jason C La Benz Workpaper JCL_WP30 Page 5 of 63
Col.B and C: See columns M and N, respectively:

		2005 (G)	2006 (H)	2007 (I)	2008 (J)	2009 (K)	2010 (L)	Normalized Per APS (Avg of 2005 - 2010) (M)	Normalized Per Staff (Avg of 2006-2010) (N)
3	Routine Maintenance	$ 2,246	$ 999	$ 660	$ 495	$ 773	$ 116	$ 882	$ 609
4	Overhaul	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Total Normalized Expense	$ 2,246	$ 999	$ 660	$ 495	$ 773	$ 116	$ 882	$ 609
6	Dollar increase over 2010 recorded							$ 766	$ 493
7	Percentage increase over 2010 recorded							660%	425%

8	APS Fossil Maintenance Adjustment for Total Company	$ (4,397)
9	APS Fossil Maintenance Adjustment for ACC	$ (4,290)
10	ACC Jurisdictional Percentage	97.57%

Lines 3 to 5 for year 2005 to 2010 data are from APS witness Jason C La Benz Workpaper JCL_WP30 Page 5 of 63
Lines 8 and 9 data are from APS witness Jason C La Benz Workpaper JCL_WP30 Page 1 of 63

Arizona Public Service Company
Normalize Fossil Maintenance Expense

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Schedule C-15
Page 2 of 2

Test Year Ended December 31, 2010
(Thousands of Dollars)

APS Fossil Maintenance Expense Adjustment:

Line No.	Operating Unit	OVERHAUL Normal	OVERHAUL Test Year	OVERHAUL Pro-Forma	ROUTINE MAINTENANCE Normal	ROUTINE MAINTENANCE Test Year	ROUTINE MAINTENANCE Pro-Forma	TOTAL MAINTENANCE Normal	TOTAL MAINTENANCE Test Year	TOTAL MAINTENANCE Pro-Forma
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
1	Cholla 1	2,239	38	**2,201**	1,583	**1,763**	**1,763**	3,822	1,801	2,021
2	Cholla 2	3,053	8,041	**(4,988)**	4,327	2,016	**2,016**	7,380	10,057	(2,677)
3	Cholla 3	2,310	0	**2,310**	1,628	2,325	**2,325**	3,938	2,325	1,613
4	Cholla Common	10	0	**10**	4,641	4,084	**4,084**	4,651	4,084	567
5	Four Corners 1	2,324	472	**1,852**	2,761	2,433	**2,433**	**5,085**	2,905	2,180
6	Four Corners 2	2,387	7,092	**(4,705)**	2,756	2,398	**2,398**	**5,143**	9,490	(4,347)
7	Four Corners 3	3,291	0	**3,291**	3,256	3,244	**3,244**	**6,547**	3,244	3,303
8	Four Corners 4	842	3,516	**(2,674)**	1,261	1,352	**1,352**	**2,103**	4,868	(2,765)
9	Four Corners 5	744	6	**738**	1,234	975	**975**	**1,978**	981	997
10	Four Corners Common	0	0	**0**	1,903	1,862	**1,862**	**1,903**	1,862	41
11	Navajo 1, 2, 3	2,853	5,324	**(2,471)**	4,780	3,448	**3,448**	7,633	8,772	(1,139)
12	Ocotillo Steam 1	193	135	**58**	400	151	**151**	593	286	307
13	Ocotillo Steam 2	98	66	**32**	248	129	**129**	346	195	151
14	Ocotillo Steam Common	19	16	**3**	342	428	**428**	361	444	(83)
15	Ocotillo CT 1	58	145	**(87)**	35	48	**48**	93	193	(100)
16	Ocotillo CT 2	7	6	**1**	21	34	**34**	28	40	(12)
17	Ocotillo CT Common	0	0	**0**	0	0	**0**	0	0	0
18	Ocotillo Common	15	9	**6**	197	197	**197**	212	206	6
19	Redhawk CC 1	3,536	12,862	**(9,326)**	2,742	2,320	**2,320**	6,278	15,182	(8,904)
20	Redhawk CC 2	3,118	1,369	**1,750**	2,781	2,291	**2,291**	5,899	3,660	2,240
21	Douglas CT	9	10	**(1)**	41	46	**46**	50	56	(6)
22	Saguaro Steam 1	26	4	**22**	36	28	**28**	62	32	30
23	Saguaro Steam 2	20	1	**19**	71	27	**27**	91	28	63
24	Saguaro Steam Common	0	0	**0**	112	97	**97**	112	97	15
25	Saguaro CT 1	6	15	**(9)**	13	20	**20**	19	35	(16)
26	Saguaro CT 2	6	20	**(14)**	21	22	**22**	27	42	(15)
27	Saguaro CT 3	2	1	**1**	186	166	**166**	188	167	21
28	Saguaro CT Common	0	0	**0**	5	1	**1**	5	1	4
29	Saguaro Common	0	0	**0**	304	308	**308**	304	308	(4)
30	Sundance CT1 - CT10	1,099	1,609	**(510)**	452	831	**831**	1,551	2,440	(889)
31	West Phoenix CC 1	82	0	**82**	802	258	**258**	884	258	626
32	West Phoenix CC 2	376	1	**375**	303	94	**94**	679	95	584
33	West Phoenix CC 3	221	0	**221**	267	133	**133**	488	133	355
34	West Phoenix CC 4	454	157	**297**	661	455	**455**	1,115	612	503
35	West Phoenix CC 5	2,452	2,456	**(4)**	2,146	2,017	**2,017**	4,598	4,473	125
36	West Phoenix CC Commoı	0	0	**0**	143	301	**301**	143	301	(158)
37	West Phoenix CT 1	2	0	**2**	113	58	**58**	115	58	57
38	West Phoenix CT 2	2	12	**(10)**	36	100	**100**	38	112	(74)
39	West Phoenix CT Commoı	0	0	**0**	(29)	3	**3**	(29)	3	(32)
40	West Phoenix Common	0	0	**0**	968	934	**934**	968	934	34
41	Yucca CT 1	31	0	**31**	2	(63)	**(63)**	33	(63)	96
42	Yucca CT 2	31	0	**31**	6	(3)	**(3)**	37	(3)	40
43	Yucca CT 3	23	0	**23**	(4)	(171)	**(171)**	19	(171)	190
44	Yucca CT 4	7	0	**7**	9	(10)	**(10)**	16	(10)	26
45	Yucca CT 5	0	0	**0**	9	29	**29**	9	29	(20)
46	Yucca CT 6	0	0	**0**	8	21	**21**	8	21	(13)
47	Yucca 5-6 Common	0	0	**0**	19	86	**86**	19	86	(67)
48	Yucca CT Common	0	0	**0**	7	10	**10**	7	10	(3)
49	Yucca Common	0	0	**0**	51	84	**84**	51	84	(33)
50	Fossil Non-Plant	0	0	**0**	881	116	**116**	881	116	765
51	**Total Fossil**	31,946	43,382	(11,436)	44,535	37,496	7,039	76,481	80,878	(4,397)
52	ACC Fossil									$ (4,290)

Notes and Source:

Data are from APS Income Statement Pro Forma Adjustment for Normalized Fossil Maintenance Expense JCL_WP30
Amounts in the "normal" columns are based on a six-year average of "time adjusted dollars".
Subtotals for Four Corners Plant maintenance are shown below.

		APS Proposed			APS Proposed			APS Proposed		
53	Four Corners Units 1-3	**8,002**	7,564	438	**8,773**	8,075	8,075	**16,775**	15,639	1,136
54	Four Corners Units 4&5	**1,586**	3,522	(1,936)	**2,495**	2,327	2,327	**4,081**	5,849	(1,768)
55	Four Corners Common	**0**	0	0	**1,903**	1,862	1,862	**1,903**	1,862	41
56	Four Corners Total	**9,588**	11,086	(1,498)	**13,171**	12,264	12,264	**22,759**	23,350	(591)

Arizona Public Services
Edison Electric Institute Dues

Test Year Ended December 31, 2010

Line No.	Description	Total Company Test Year (A)	Company Adjustment (B)	Company Adjusted Amount (C)	Staff Adjustment Total Co. (D)		ACC Jurisdictional Allocation Factor (E)	ACC Jurisdictional Amount (F)
1	Regular Activities of EEI	$ 678,611	$ (108,578)	$ 570,033	$ (230,252)	a	0.939290	$ (216,273)

Notes and Source

Cols A, B and C: Per APS' response to Staff 1.36

a: Staff adjustment for Regular Dues based on a disallowance percentage of 49.93% (see page 2)

		Staff Adjustment	
2	EEI Regular Activities Dues	$ 678,611	
3	Regular Dues disallowance percentage	49.93%	See page 2
4	Staff total adjustment to Regular Dues	$ (338,830)	
5	Less: Company adjustment	$ (108,578)	
6	Staff adjustment to APS' Adjusted Regular Dues	$ (230,252)	

Edison Electric Institute
Schedule of Expenses by NARUC Category
For Core Dues Activities
For the Year Ended December 31, 2005

Line No.	NARUC Operating Expense Category	% of Dues	Recommended Disallowance
1	Legislative Advocacy	20.38%	20.38%
2	Legislative Policy Research	6.02%	
3	Regulatory Advocacy	16.49%	16.49%
4	Regulatory Policy Research	13.99%	
5	Advertising	1.67%	1.67%
6	Marketing	3.68%	3.68%
7	Utility Operations and Engineering	11.31%	
8	Finance, Legal, Planning and Customer Service	18.75%	
9	Public Relations	7.71%	7.71%
10	Total Expenses	100.00%	49.93%

Comments:

* The above percentages represent expenses associated with EEI's core dues activities, based on the operating expense categories established by NARUC. Core expenses are those expenses paid for by shareholder-owned electric utilities' dues.

* Administrative expenses are included in the percentages listed above. Approximately 11% of EEI's core dues expenses are administrative.

Arizona Public Service Company
Docket No. E-01345A-11-0224
Attachment RCS-3
Copies of APS' Responses to Data Requests
and Workpapers Referenced in the Direct Testimony and Schedules of
Ralph C. Smith

Data Request/ Workpaper No.	Subject	Confidential	No. of Pages	Page No.
Staff 6.55 Supplemental	Post test year plant pro forma reflecting actual information through July 31, 2011 (without voluminous and/or confidential attachments)	No	1	2
Staff 27.2	Post test year plant actual amounts will be available 30 days after the close of the respective quarterly accounting period	No	1	3
Staff 27.8	Accumulated Depreciation actual amounts will be available 30 days after the close of the respective quarterly accounting period	No	1	4
Staff 27.9	Post test year ADIT actual amounts will be available 30 days after the close of the respective quarterly accounting period	No	1	5
Staff 25.11	Uncollectibles factor for years 2008-2010	No	3	6 - 8
Staff 27.4	Post test year plant	No	3	9 - 11
Staff 22.7	Post test year CWIP with expected in-service timing	No	2	12 - 13
Staff 27.13	Post test year CWIP with expected in-service timing	No	2	14 - 15
Staff 27.6	Accumulated Depreciation	No	1	16
Staff 15.13	ADIT impact from bonus depreciation relating to post test year plant	No	5	17 - 21
AECC 1.11	Bonus depreciation and its impact on ADIT	No	5	22 - 26
Staff 20.1	Estimated jurisdictional ADIT (Actuals: 7/31/11 - 8/31/11; Forecast: 9/30/11 - 3/31/12)	No	2	27 - 28
Staff 9.2	APS is not including costs related to IES or SNG; Removal of costs related to forensic investigation of DOE grant-funded plant (without voluminous attachments)	No	1	29
Staff 9.3	Removal of expenses related to SNG and DOE reimbursements and liability	No	1	30
Staff 20.2	Explanation of how project expenditures and related government reimbursements in 2010 are accounted	No	1	31
Staff 20.3	Grant funded projects are not included in plant additions or post test year plant	No	1	32
Prefiled 1.40	Itemization of test year advertising expense	No	2	33 - 34
Staff 21.1	APS advertising (without voluminous attachments)	No	2	35 - 36
Staff 21.3	Trial Balance of advertising expense for fiscal year 2011 through September	No	2	37 - 38
Staff 21.4	Explanation of why 2010 general advertising expense was higher than 2009	No	1	39
Staff 21.5	Advertising expense (actual for 2008 and budgeted for 2011)	No	1	40
Staff 27.10	Breakfast at the Zoo expense; Budget for advertising expense (without voluminous attachments)	No	2	41 - 42
Staff 32.1	Explanation of the error corrections made to the original APS payroll annualization adjustment	No	2	43 - 44
	Response to data request 12.27 from Docket No. E-01345A-08-0172 regarding meter addition investments for 2008-2009	No	2	45 - 46
	Response to data request 17.7 from Docket No. E-01345A-08-0172 regarding depreciation rates from 1998 through the present (without attachment)	No	2	47 - 48
TEP Exhibit KAK-1	Tucson Electric Power Company - Docket No. E-01933A-07-0402 - Dr. Kateregga 2007 Depreciation Rate Study for TEP - meter related depreciation rate information	No	3	49 - 51
UNSE Exhibit REW-2	UNS Electric, Inc. - Docket No. E-04204A-06-0783 - Dr. White 2006 Depreciation Rate Review for UNSE - meter related depreciation rate information	No	3	52 - 54
UNSE Attachment REW-2	UNS Electric, Inc. - Docket No. E-04204A-09-0206 - Dr. White 2009 Technical Update for UNSE - meter related depreciation rate information	No	5	58 - 62
APS Attachment REW-1	APS - Docket No. E-01345A-08-0172 - Dr. White 2008 Depreciation Rate Study for APS - meter related depreciation rate information	No	3	55 - 57
Staff 25.8	APS' request for prospective 3-year amortization of 2010 non-voluntary severance program expense	No	1	63
Staff 25.6	APS' request for a portion of the non-voluntary severance program expense to remain in the test year (without attachments)	No	1	64
Staff 25.5	Request for accounting deferrals or to establish a regulatory asset for the non-voluntary severance program expense was not made by APS; Net employee reduction amount as a result of voluntary and non-voluntary terminations; explanation of how the amount of first year savings was attained; the amount of total savings related to O&M and capital savings (without voluminous attachments)	No	3	65 - 67
Staff 21.6	Directors and Officers liability insurance is expensed as incurred with no prepaid asset account	No	2	68 - 69
Staff 19.17	Amount of incentive compensation charged to O&M for years 2005 - 2007 (without voluminous attachments)	No	4	70 - 73
Staff 25.21	Cause of fossil non-plant maintenance cost differential in 2005 compared to other years	No	1	74
Staff 27.11	Summary of APS' proposed ratemaking treatment of Four Corners; remaining net book value of the Four Corners assets	No	2	75 - 76
Staff 25.22	Normal overhaul and maintenance expense will end after a fossil unit is retired; proposed deferral order regarding Four Corners maintenance costs is pending in another docket	No	2	77 - 78
Staff 1.36	Removal of percentage of EEI dues (includes APS14209 excerpt)	No	2	79 - 80
Staff 22.5	APS did not provided requested EEI budget of financial information by NARUC category	No	1	81
Staff 27.7	Jurisdictional ADIT amounts for March 31, 2012	No	1	82
Staff 15.7	Estimated ADIT (actual: 7/31/11 - 8/31/11; Forecast: 9/30/11 - 3/31/12)	No	2	83 - 84
Staff 22.9 supplemental	Revised forecast of base cost of fuel (without voluminous attachments)	No	2	85 - 86
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ARIZONA CORPORATION COMMISSION
STAFF'S SIXTH SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
AUGUST 10, 2011

Staff 6.55: **DIRECT TESTIMONY OF M.A. SCHIAVONI: Re: Attachment MAS-1.** Please update the projected closed cost and estimated in-Service Date for the listed projects and/or work items. Please confirm that the various line items indicating in-Service prior to July 31, 2011 were, in fact, put in-service at the closed costs indicated or edit the listing to indicate that the dates and/or costs were otherwise.

Response: Pursuant to discussions with ACC Commission Staff, the Company will update the capital project information for each of the Post Test Year Plant pro formas (Fossil Generation, Nuclear Generation, Distribution and General and Intangible Plant, and Solar Generation) with actual data through August 31, 2011. This information will be provided to all intervening parties no later than September 20, 2011.

Supplemental Response 9/22/2011: Attached are the following updated Post-Test Year Plant Additions pro forma adjustments using actuals through July 31, 2011:

- Solar Generation – APS14743
- Fossil Generation - APS14744
- Nuclear Generation - APS14745
- Distribution and General and Intangibles - APS14746

Supporting calculations for property taxes and depreciation expense is also attached as APS14747. Please note the information attached to the Solar Generation Post-Test Year Plant Additions is confidential and is being provided pursuant to an executed protective agreement.

Witness: Jeff Guldner/Mark Schiavoni/Randy Edington/Daniel Froetscher/Jay La Benz

ARIZONA CORPORATION COMMISSION
STAFF'S TWENTY SEVENTH SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
OCTOBER 27, 2011

Staff 27.2: Post test year plant.

a) When does APS expect to have actual 12/31/2011 (post test year) plant amounts available for review?

b) When does APS expect to have actual 3/31/2012 (post test year) plant amounts available for review?

c) Please provide the actual 12/31/2011 (post test year) plant amounts, by account, as soon as they are available, and provide the related trial balances. Reconcile the amounts of plant, by account, as of each date with the amounts on the trial balance.

d) Please provide the actual 3/31/2012 (post test year) plant amounts, by account, as soon as they are available, and provide the related trial balances. Reconcile the amounts of plant, by account, as of each date with the amounts on the trial balance.

e) Please identify the amounts of recorded plant at 3/31/2012 that corresponds to the West Phoenix disallowance amount at 12/31/2010 in APS' proposed rate base adjustment for that.

f) Please identify the amounts of recorded plant at 12/31/2011 that corresponds to the West Phoenix disallowance amount at 12/31/2010 in APS' proposed rate base adjustment for that.

Response:

a) APS expects to have actual 12/31/2011 Post Test Year amounts available for review 30 days after the close of the year.

b) APS expects to have actual 3/31/2012 Post Test Year amounts available for review 30 days after the close of the period.

c) - (f) See (a) and (b).

Witness: Jay La Benz

ARIZONA CORPORATION COMMISSION
STAFF'S TWENTY SEVENTH SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
OCTOBER 27, 2011

Staff 27.8: Accumulated Depreciation.

a) When does APS expect to have actual 12/31/2011 accumulated depreciation amounts available for review?

b) When does APS expect to have actual 3/31/2012 accumulated depreciation amounts available for review?

c) Please provide the actual 12/31/2011 accumulated depreciation amounts, by account, as soon as they are available, and provide the related trial balances. Reconcile the amounts of plant, by account, as of each date with the amounts on the trial balance.

d) Please provide the actual 3/31/2012 accumulated depreciation amounts, by account, as soon as they are available, and provide the related trial balances. Reconcile the amounts of plant, by account, as of each date with the amounts on the trial balance.

e) Please identify the amounts of recorded accumulated depreciation at 3/31/2012 that corresponds to the West Phoenix disallowance amount at 12/31/2010 in APS' proposed rate base adjustment for that.

f) Please identify the amounts of recorded accumulated depreciation at 12/31/2011 that corresponds to the West Phoenix disallowance amount at 12/31/2010 in APS' proposed rate base adjustment for that.

Response:

a) APS expects to have actual 12/31/2011 accumulated depreciation available for review 30 days after the close of the year.

b) APS expects to have actual 3/31/2012 accumulated depreciation available for review 30 days after the close of the period.

c) - (f) See (a) and (b).

Witness: Jay La Benz

ARIZONA CORPORATION COMMISSION
STAFF'S TWENTY SEVENTH SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
OCTOBER 27, 2011

Staff 27.9: Accumulated Deferred Income Taxes.

a) When does APS expect to have actual 12/31/2011 Accumulated Deferred Income Tax amounts available for review?

b) When does APS expect to have actual 3/31/2012 Accumulated Deferred Income Tax amounts available for review?

c) Please provide the actual 12/31/2011 Accumulated Deferred Income Tax amounts, by account, as soon as they are available, and provide the related trial balances. Reconcile the amounts of plant, by account, as of each date with the amounts on the trial balance.

d) Please provide the actual 3/31/2012 Accumulated Deferred Income Tax amounts, by account, as soon as they are available, and provide the related trial balances. Reconcile the amounts of plant, by account, as of each date with the amounts on the trial balance.

e) Please identify the amounts of recorded Accumulated Deferred Income Tax at 3/31/2012 that corresponds to the West Phoenix disallowance amount at 12/31/2010 in APS' proposed rate base adjustment for that.

f) Please identify the amounts of recorded Accumulated Deferred Income Tax at 12/31/2011 that corresponds to the West Phoenix disallowance amount at 12/31/2010 in APS' proposed rate base adjustment for that.

Response:

a) APS expects to have actual 12/31/2011 Post Test Year Accumulated Deferred Income Tax (ADIT) amounts available 30 days after the close of the year.

b) APS expects to have actual 03/31/2012 Post Test Year ADIT amounts available for review 30 days after the close of the period.

c)-f) See (a) and (b).

Witness: Jason La Benz

ARIZONA CORPORATION COMMISSION
STAFF'S TWENTY FIFTH SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
OCTOBER 25, 2011

Staff 25.11: Uncollectibles. Refer to APS' response to data request Prefiled 1.21, APS14067.

a. Please identify the annual revenues each year 2008, 2009 and 2010, to which the uncollectibles relate.

b. Please show an uncollectibles factor for each year 2008, 2009 and 2010.

c. Why has the uncollectibles expense in account 904 decreased from 2008 to 2009?

d. Why has the uncollectibles expense in account 904 decreased from 2000 to 2010?

e. Please reconcile the 2009 amounts shown on APS14067 with the 2009 general ledger page showing account 9040000, Uncollectible Accounts (APS14162, page 4791 of 4840). Identify, quantify and explain each reconciling item.

f. Please reconcile the 2010 amounts shown on APS14067 with the 2010 general ledger page showing account 9040000, Uncollectible Accounts (APS14048, page 5007 of 5053). Identify, quantify and explain each reconciling item.

Response:

a. 2008 $2,921,679,877
2009 $2,981,308,172
2010 $2,964,091,853

b. The uncollectible factor applied to revenue for 2008, 2009 and 2010 was:
2008 0.21%
2009 0.21%
2010 0.21%

c. The decrease in uncollectibles expense from 2008 to 2009 is primarily due to an increase in the write-off reserve in 2008. The reserve was increased in September 2008 when the factor was increased from 0.16% to 0.21%. This resulted in an increase to expense of $753k in 2008.

d. APS assumes this question refers to 2009 as opposed to 2000. The decrease in uncollectibles expense from 2009 to 2010 is primarily due to a small decrease in the reserve due to the slight decrease in revenue and a reduction in uncollectible expense.

Witness: Jay La Benz

ARIZONA CORPORATION COMMISSION
STAFF'S TWENTY FIFTH SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
OCTOBER 25, 2011

Response to Staff 25.11 Continued:

e. See APS14973, attached.

f. See APS14973, attached.

Witness: Jay La Benz

STF25.11 e	Charge Number	Account	Budget Item	Sub Budget	Amount			
	1904-002	9040000	GEN OPS-99	BAD DEBT	$6,871,183.71	*	$6,871,183.71	
	1904-004	9040000	GEN OPS-99	BAD DEBT	$85,000.00			Power Trading Writeoff Expense
	1904-999	9040000	GEN OPS-99	UNCOL ACTS	$91,447.87	*	$91,447.87	
	99-904-001	9040000	EXPENSE-99	BAD DEBT	$3,013,989.44			Note receivable reserve
					$10,061,621.02		$6,962,631.58	

* These values summed together total $6,962,631.58 and agrees to the values refelcted on APS14067.

STF25.11 f	Charge Number	Account	Budget Item	Sub Budget	Amount			
	1904-002	9040000	GEN OPS-99	BAD DEBT	$6,777,073.68	**	$6,777,073.68	
	1904-999	9040000	GEN OPS-99	UNCOL ACTS	($24,592.24)	**	($24,592.24)	
	99-904-001	9040000	EXPENSE-99	BAD DEBT	($2,996,079.61)			Note receivable reserve reversal
					$3,756,401.83		$6,752,481.44	

** These values summed together total $6,752,481.44 and agrees to the values refelcted on APS14067.

ARIZONA CORPORATION COMMISSION
STAFF'S TWENTY SEVENTH SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
OCTOBER 27, 2011

Staff 27.4: Post test year plant, APS update in response to STF 6.55, APS14743 through APS146.

a) Please confirm that the Company's proposed post test year plant additions for solar of $260.765 million total company and $251.899 ACC jurisdictional through June 30, 2012 include $20.006 million and $19.326 million of additions projected for April 1, 2012 through June 30, 2012. If this cannot be confirmed, please explain fully and identify the amount of post test year solar plant additions that APS projected for the period April 1, 2012 through June 30, 2012 per the STF 6.55 update.

b) Please confirm that the Company's proposed post test year plant additions for nuclear of $111.397 million total company and $107.609 ACC jurisdictional through June 30, 2012 include $9.447 million and $9.126 million of additions projected for April 1, 2012 through June 30, 2012. If this cannot be confirmed, please explain fully and identify the amount of post test year nuclear plant additions that APS projected for the period April 1, 2012 through June 30, 2012 per the STF 6.55 update.

c) Please confirm that the Company's proposed post test year plant additions for coal and other fossil generation of $154.606 million total company and $149.350 ACC jurisdictional through June 30, 2012 include $22.621 million and $21.852 million of additions projected for April 1, 2012 through June 30, 2012. If this cannot be confirmed, please explain fully and identify the amount of post test year coal and other fossil generation plant additions that APS projected for the period April 1, 2012 through June 30, 2012 per the STF 6.55 update.

d) Please confirm that the Company's proposed post test year plant additions for distribution of $333.398 million total company and $326.411 million ACC jurisdictional through June 30, 2012 include $9.386 million and $9.160 million of additions projected for April 1, 2012 through June 30, 2012. If this cannot be confirmed, please explain fully and identify the amount of post test year distribution plant additions that APS projected for the period April 1, 2012 through June 30, 2012 per the STF 6.55 update.

e) Please confirm that the Company's proposed post test year plant additions for general and intangible of $99.586 million total company and $97.499 million ACC jurisdictional through June 30, 2012 include $2.795 million and $2.736 million of additions projected for April 1, 2012 through June

ARIZONA CORPORATION COMMISSION
STAFF'S TWENTY SEVENTH SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
OCTOBER 27, 2011

Staff 27.4 Continued:

30, 2012. If this cannot be confirmed, please explain fully and identify the amount of post test year general and intangible plant additions that APS projected for the period April 1, 2012 through June 30 2012 per the STF 6.55 update.

f) Please identify the amount included in the Company's proposed post test year plant additions other than transmission for (1) total company and (2) for ACC jurisdictional through June 30, 2012 per the STF 6.55 update materials include for additions projected for April 1, 2012 through June 30, 2012 and provide supporting documentation.

Response:

(a) - (c) APS confirms these amounts.

(d) The amounts listed appear to be from the original filing. For the updated Staff 6.55 amounts please see attached, APS14974.

(e) The amounts listed appear to be from the original filing. For the updated Staff 6.55 amounts please see attached, APS14974.

(f) Please see attached, APS14974.

Staff 27.4 Docket No. E-01345A-11-0224

(000's)

	(a) Updated PTY Total Company	(b) April-June Total Company	(c) April-June ACC Jurisdiction
Solar	260,765	20,006	19,326
Nuclear	111,397	9,447	9,126
Coal and other Fossil	154,606	22,621	21,852
Distribution	330,604	40,038	40,030
G & I	92,155	4,071	3,154
Total	**949,527**	**96,183**	**93,488**

*Column (a) include the total Post Test Year amounts by function.
Colunn (b) amounts for Apr 2012 thru July 2012 are included in column (a).

ARIZONA CORPORATION COMMISSION
STAFF'S TWENTY SECOND SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
OCTOBER 14, 2011

Staff 22.7: Post test year plant based test year CWIP going into service. Refer to APS' 12-31-2010 CWIP balance is $459.316 million (per Sch E-1, line 4).

a) Please provide an itemized listing, by plant account, of the components of the 12-31-2010 CWIP balance that total to the $459.316 million.

b) Please identify each item of 12-31-2010 CWIP that had been placed into service by August 31, 2011 and provide the dollar amounts by plant account.

c) Please identify each item of 12-31-2010 CWIP that APS expects will be placed into service between September 1 and December 31, 2011 and indentify the dollar amounts for each, by plant account.

d) Please identify each item of 12-31-2010 CWIP that APS expects will be placed into service between January 1 and March 31, 2012 and indentify the dollar amounts for each, by plant account.

Response: (a)-(d) Attached as APS14913 is the requested schedule.

Witness: Jay La Benz

ARIZONA PUBLIC SERVICE COMPANY
Staff Question 22.7 (a -d)

Balance per Sch E-1 line 4	459,316,067
Less: Nuclear Fuel (account 1201)	(91,884,172)
CWIP Accruals (1071, 1072 & 1074)	1,981,183
Construction In Progress (account 107)	**369,413,078**

	(a)	(b)		(c)	(d)
Function *	**Dec 2010 CWIP Balance**	**CWIP Jan - Aug 2011 ****	**Actual Additions as of Aug 2011 ****	**Estimated Additions Sept 1 - Dec 31 2011**	**Estimated Additions Jan 1 - Mar 31 2012**
Intangible	27,420,972	14,896,571	17,193,632	4,206,814	425,301
Steam	33,455,051	12,918,827	19,409,029	4,224,674	4,247,363
Nuclear	86,481,939	16,817,625	18,889,236	46,334,932	700,784
Other Production	53,840,615	42,267,371	84,534,634	6,994,826	372,351
Transmission	80,606,203	18,105,616	23,318,013	6,646,014	21,517,132
Distribution	48,204,086	32,205,966	54,585,816	9,470,993	907,305
General Plant	39,404,212	23,978,893	25,531,249	12,718,312	0
	369,413,078	**161,190,870**	**243,461,609**	**90,596,565**	**28,170,236**

* CWIP balances are not classified into specific plant accounts until the project is in-service and unitized
** CWIP Amounts" are totals inlcuded in December balance while Actual Additions are totals of acutal dollars spent and put into service.

ARIZONA CORPORATION COMMISSION
STAFF'S TWENTY SEVENTH SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
OCTOBER 27, 2011

Staff 27.13: December 31, 2010 end-of-test-year CWIP going into service by March 31, 2012. Refer to the response to STF 22.7.

a) Does the information on APS14913 include ONLY costs that were recorded as CWIP on APS' books at December 31, 2010?

b) Does the information on APS14913 include any additional dollars charged to CWIP or Plant accounts after December 31, 2010 that were not contained in the December 31, 2010 end-of-test year CWIP balance?

c) If the answer to either part a or b is affirmative, please provide similar information that includes ONLY costs that were recorded as CWIP on APS' books at December 31, 2010 and does not include any additional dollars charged to CWIP or Plant accounts after December 31, 2010 that were not contained in the December 31, 2010 end-of-test year CWIP balance.

d) Are there any amounts for December 31, 2010 CWIP, i.e., in the $369,413,078 in column a on APS14913, that relate to projects under construction that are NOT expected to be in service by March 31, 2012? If so, please identify those amounts, preferably by function.

Response:

a) In APS14913, columns a, c, d, and b the portion labeled "CWIP Jan-Aug 2011" reflect only costs that were recorded as CWIP as of December 31,2011. The portion of Column b "Actual Additions as of Aug 2011" reflects actual plant additions for work orders that were included in the 12-31-2011 CWIP balance.

b) Yes, see response (a).

c) In APS14913, column (a) only includes costs that were booked to CWIP as of December 31, 2010. It does not include any estimated or actual dollars after December 31, 2010.

d) See column "e" in APS14970, attached.

Witness: Jay La Benz

ARIZONA PUBLIC SERVICE COMPANY
Staff Question 27.13(a -d)

Balance per Sch E-1 line 4	459,316,067
Less: Nuclear Fuel (account 1201)	(91,884,172)
CWIP Accruals (1071, 1072 & 1074)	1,981,183
Construction In Progress (account 107)	**369,413,078**

	(a)	(b)	(c)	(d)	(e)
Function *	**Dec 2010 CWIP Balance**	**Actual CWIP in Service between Jan - Aug 2011**	**Estimated CWIP to go in service between Sept 1 - Dec 31 2011**	**Estimated CWIP to go into service between Jan 1 - Mar 31 2012**	**12-31-2010 CWIP Balance Not Scheduled to go into service between Jan 2011 & Mar 2012**
Intangible	27,420,972	14,896,571	4,206,814	425,301	7,892,287
Steam	33,455,051	12,918,827	4,224,674	4,247,363	12,064,187
Nuclear	86,481,939	16,817,625	46,334,932	700,784	22,628,598
Other Production	53,840,615	42,267,371	6,994,826	372,351	4,206,067
Transmission	80,606,203	18,105,616	6,646,014	21,517,132	34,337,441
Distribution	48,204,086	32,205,966	9,470,993	907,305	5,619,822
General Plant	39,404,212	23,978,893	12,718,312	0	2,707,006
	369,413,078	**161,190,870**	**90,596,565**	**28,170,236**	**89,455,407**

* CWIP balances are <u>not</u> classified into specific plant accounts until the project is in-service and unitized

ARIZONA CORPORATION COMMISSION
STAFF'S TWENTY SEVENTH SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
OCTOBER 27, 2011

Staff 27.6: Accumulated Depreciation. Referring to the originally filed APS adjustments for post test year plant, by type of plant, and to the updated amounts that APS provided in response to STF 6.55, please provide the Total Company and ACC Jurisdictional amounts (1) as of 3/31/2012 and (2) identify the changes APS estimated to occur for the period April 1, 2012 through June 30, 2012.

Response:

(1) Please see APS's response to Staff 15.9 for the 3/31/2012 Total Company Accumulated Depreciation. The corresponding ACC jurisdiction of these amounts are as follows:

- Solar: $3.391 Million
- Fossil: $113.349 Million
- Nuclear: $94.045 Million
- Distribution and General & Intangibles: $219.674 Million

(2) For Fossil Generation, Nuclear Generation, and Distribution and General and Intangible Plant the only change in accumulated depreciation for the referenced period is continued depreciation on plant in service at 12/31/2010. Consistent with the RES treatment Solar Generation, changes for the referenced period includes book depreciation on additions during the post test year period.

Witness: Jay La Benz

ARIZONA CORPORATION COMMISSION
STAFF'S FIFTEENTH SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
SEPTEMBER 21, 2011

Staff 15.13: ADIT on post test year plant additions.

a) Please identify the dollar amount of 2011 bonus tax depreciation related to each of the post test year Plant additions on JCL_wp8;

b) Please identify the dollar amount of 2012 bonus tax depreciation related to each of the post test year Plant additions on JCL_wp8;

c) Please identify the ADIT impacts from all 2011 and 2012 bonus tax depreciation related to each of the post test year Plant additions on JCL_wp8;

d) Please include supporting workpapers and calculations in Excel format for the bonus depreciation and the related ADIT impacts; and

e) Please provide the related ADIT impacts if post test year plant additions were limited to those projected to actually be in service by March 31, 2012.

Response: Inclusion of any such estimated projections of deferred taxes as a rate base offset may be deemed by the IRS as inconsistent with the historical Test Year method generally used for cost of service and ratemaking purposes. Without guidance from the IRS that explicitly allows such inclusions, APS believes using such methodology would not be appropriate and could result in extremely unfavorable tax consequences to the Company and its customers.

a) Please see response to AECC 1.11 (c) for an estimate of 2011 bonus depreciation related to each of the post-Test Year Plant Additions on JCL_WP8.

Based upon the updated pro forma calculations for post test year plant provided in APS's Supplemental response to Staff 6.55, the estimated bonus deprecation tax deduction for 2011 has been modified from the estimate provided in AECC 1.11 (c) to a range of $404M - $450M, as shown at APS14831. It is anticipated that APS will be unable to fully realize this benefit in 2011 due to expected tax loss carryforwards. Only realized benefits are eligible for *normalization*.

b) Please see APS's response to AECC 1.11 (c) for an estimate of 2012 bonus depreciation related to each of the post test year Plant additions on JCL_WP8.

Witness: Jason La Benz

ARIZONA CORPORATION COMMISSION
STAFF'S FIFTEENTH SET OF DATA REQUESTS
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Response to Staff 15.13 Continued:

Based upon the updated pro forma calculations for post test year plant provided in APS's Supplemental response to Staff 6.55, the estimated bonus deprecation tax deduction for 2012 has been modified from the estimate provided in AECC 1.11 c) to a range of $26M - $29M, as shown at APS14831.

c) Please see response to AECC 1.11 (c) for an estimate of the ADIT impacts from all 2011 and 2012 bonus depreciation related to each of the post test year Plant additions on JCL_wp8.

Based upon the updated pro forma calculations for post test year plant provided in APS's Supplemental response to Staff 6.55, the estimated net ADIT impacts from all 2011 and 2012 bonus depreciation has been modified from the estimate provided in AECC 1.11 c) to a range of $79M - $128M, as shown at APS14831.

Additionally, an estimate of the ADIT impacts from all 2011 and 2012 bonus depreciation related to each of the post test year Plant additions has been reflected in the responses to Staff 15.1 and Staff 15.7.

As discussed above, without guidance from the IRS that explicitly allows inclusion of these ADIT impacts in rate base, APS believes using such methodology would not be appropriate and could result in extremely unfavorable tax consequences to the Company and its customers.

d) Attached in APS's response to AECC 1.11 (c) at APS14740 are the detailed schedules. Additionally, attached at APS14831 are detailed schedules used to derive the estimated bonus depreciation deduction and related ADIT impacts based upon the updated pro forma calculations for post test year plant provided in APS's Supplemental response to Staff 6.55.

As discussed above, without guidance from the IRS that explicitly allows inclusion of these ADIT impacts in rate base, APS believes using such methodology would not be appropriate and could result in extremely unfavorable tax consequences to the Company and its customers.

e) Net ADIT impacts if post test year plant additions were limited to those projected to actually be in service by March 31, 2012 would be materially similar with the information

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SEPTEMBER 21, 2011

Response to Staff 15.13 Continued:

computed at APS14831. Net ADIT for 2012 bonus depreciation for plant additions, limited to either March 31, 2012 or June 30, 2012, would result in zero net ADIT for 2012 bonus depreciation benefits.

As discussed above, without guidance from the IRS that explicitly allows inclusion of these ADIT impacts in rate base, APS believes using such methodology would not be appropriate and could result in extremely unfavorable tax consequences to the Company and its customers.

ARIZONA PUBLIC SERVICE COMPANY
RESPONSE TO STAFF 15.13

		2011					2012				
Gross Deferred Tax Liability	[A]	**$**	**(141,541)**	**to**	**$**	**(157,605)**	**$**	**(4,579)**	**to**	**$**	**(5,087)**
Solar Generation Post Test Year Plant Additions		$	(45,976)	to	$	(51,194)	$	(1,531)	to	$	(1,701)
Fossil Generation Post Test Year Plant Additions		$	(10,368)	to	$	(11,545)	$	(39)	to	$	(44)
Nuclear Generation Post Test Year Plant Additions		$	(6,508)	to	$	(7,246)	$	(35)	to	$	(39)
Distribution, G&I Post Test Year Plant Additions		$	(78,689)	to	$	(87,620)	$	(2,973)	to	$	(3,304)
Estimated Deferred Tax Asset - Loss Carryforward	[B]	**$**	**62,848**	**to**	**$**	**29,960**	**$**	**15,298**	**to**	**$**	**11,065**
Net Deferred Tax Liability	[C] = [A] + [B]	**$**	**(78,693)**	**to**	**$**	**(127,645)**	$	-	**to**	$	-
Solar Generation Post Test Year Plant Additions		$	(25,561)	to	$	(41,462)	$	-	to	$	-
Fossil Generation Post Test Year Plant Additions		$	(5,764)	to	$	(9,350)	$	-	to	$	-
Nuclear Generation Post Test Year Plant Additions		$	(3,618)	to	$	(5,869)	$	-	to	$	-
Distribution, G&I Post Test Year Plant Additions		$	(43,749)	to	$	(70,964)	$	-	to	$	-

	2011	2012	Total
Tax Basis Eligible for Bonus Depreciation			
Solar Generation Post Test Year Plant Additions	$ 161,176,646	$ 19,443,704	$ 180,620,350
Fossil Generation Post Test Year Plant Additions	$ 36,347,771	$ 499,297	$ 36,847,069
Nuclear Generation Post Test Year Plant Additions	$ 22,813,593	$ 440,040	$ 23,253,632
Distribution Post Test Year Plant Additions	$ 140,150,733	$ 14,060,607	$ 154,211,340
Smart Grid Post Test Year Plant Additions	$ 26,751,088	$ 4,671,220	$ 31,422,308
AMI Meters Post Test Year Plant Additions	$ 35,444,273	$ 12,738,031	$ 48,182,304
IT and Facilities Post Test Year Plant Additions	$ 73,514,385	$ 6,288,106	$ 79,802,491
Tax Subtotal	**$ 496,198,489**	**$ 58,141,005**	**$ 554,339,494**

	MINIMUM ESTIMATED BENEFIT			MAX ESTIMATED BENEFIT		
50% Bonus Eligible - Estimate (MAX)	37%	90%		18.50%	100%	
100% Bonus Eligible - Estimate (MAX)	63%	-		81.50%	-	
50% Bonus Depreciation						
Solar Generation	$ (29,817,680)	$ (8,749,667)	$ (38,567,346)	$ (14,908,840)	$ (9,721,852)	$ (24,630,692)
Fossil Generation	$ (6,724,338)	$ (224,684)	$ (6,949,022)	$ (3,362,169)	$ (249,649)	$ (3,611,818)
Nuclear Generation	$ (4,220,515)	$ (198,018)	$ (4,418,532)	$ (2,110,257)	$ (220,020)	$ (2,330,277)
Distribution	$ (25,927,886)	$ (6,327,273)	$ (32,255,159)	$ (12,963,943)	$ (7,030,304)	$ (19,994,246)
Smart Grid	$ (4,948,951)	$ (2,102,049)	$ (7,051,000)	$ (2,474,476)	$ (2,335,610)	$ (4,810,086)
AMI Meters	$ (6,557,190)	$ (5,732,114)	$ (12,289,304)	$ (3,278,595)	$ (6,369,016)	$ (9,647,611)
IT and Facilities	$ (13,600,161)	$ (2,829,648)	$ (16,429,809)	$ (6,800,081)	$ (3,144,053)	$ (9,944,134)
100% Bonus Derprecation						
Solar Generation	$ (101,541,287)	$ -	$ (101,541,287)	$ (131,358,967)	$ -	$ (131,358,967)
Fossil Generation	$ (22,899,096)	$ -	$ (22,899,096)	$ (29,623,434)	$ -	$ (29,623,434)
Nuclear Generation	$ (14,372,563)	$ -	$ (14,372,563)	$ (18,593,078)	$ -	$ (18,593,078)
Distribution	$ (88,294,962)	$ -	$ (88,294,962)	$ (114,222,847)	$ -	$ (114,222,847)
Smart Grid	$ (16,853,185)	$ -	$ (16,853,185)	$ (21,802,137)	$ -	$ (21,802,137)
AMI Meters	$ (22,329,892)	$ -	$ (22,329,892)	$ (28,887,082)	$ -	$ (28,887,082)
IT and Facilities	$ (46,314,063)	$ -	$ (46,314,063)	$ (59,914,224)	$ -	$ (59,914,224)
Estimated Allowable Bonus Depreciation	**$ (404,401,768)**	**$ (26,163,452)**	**$ (430,565,221)**	**$ (450,300,129)**	**$ (29,070,503)**	**$ (479,370,631)**
Estimated Federal Tax Benefit @ 35%	**(141,540,619)**	**(9,157,208)**		**(157,605,045)**	**(10,174,676)**	
FAS109 Recognition at July 31, 2012	**(141,540,619)**	**(4,578,604)**		**(157,605,045)**	**(5,087,338)**	

FREEPORT-MCMORAN COPPER & GOLD INC. AND ARIZONANS FOR ELECTRIC CHOICE AND COMPETITION ("AECC") FIRST SET OF DATA REQUESTS REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN DOCKET NO. E-01345A-11-0224 SEPTEMBER 8, 2011

AECC 1.11: **Federal Income Tax** - Computation of Increase in Gross Revenue Requirements for the pro forma 12 month test period ending Dec. 31,2010 as shown in Schedule A-1:

a. The Tax Relief, Unemployment Insurance and Job Creation Act of 2010 (signed into law on December 17, 2010) allows greatly accelerated depreciation on qualifying property placed in service in 2011 and 2012 - 100% bonus tax depreciation in 2011 and 50% bonus tax depreciation in 2012. In the August 25, 2010 technical conference, APS stated that its pro forma adjustments summarized in Schedule B-2 and C-2 did not include the impacts of bonus tax depreciation for all qualified property placed in service after Dec 31, 2010 as provided for in the Tax Relief, Unemployment Insurance and Job Creation Act of 2010 (signed into law on December 17, 2010). Please confirm this statement.

b. Assuming APS did not include this bonus depreciation impact, please provide a detailed explanation of why the impact of bonus tax depreciation for all qualified property was not included in the derivation of the APS's Total Company and ACC Jurisdiction pro forma earned rate of returns in this case. If bonus depreciation for qualified property is included for any portion of the period between December 31, 2010 and July 31, 2012, but not the entire period, please identify the period for which bonus depreciation was included.

c. Assuming APS did not include this bonus depreciation impact, please provide all of the adjustments necessary for each APS adjustment, if applicable, shown in Schedule B-2 and C-2 to produce test year pro forma earned results of operations that incorporate all allowed bonus depreciation for qualified property placed in service by July 31, 2012 as authorized by the statutes in effect on Dec 31, 2010, summarized for all of the rate base and expense categories shown in Schedules B-1 and C-1 for both the Total Company and ACC Jurisdiction. These adjustments should allow for a complete assessment of the impact of including bonus tax depreciation in the pro forma earned rates of return. As part of this response, please include all electronic workpapers with formulas intact used to derive the bonus tax depreciation impact.

FREEPORT-MCMORAN COPPER & GOLD INC. AND
ARIZONANS FOR ELECTRIC CHOICE AND COMPETITION ("AECC")
FIRST SET OF DATA REQUESTS REGARDING THE APPLICATION
TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP
A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
SEPTEMBER 8, 2011

AECC 1.11 Continued:

d. Please prepare a schedule similar to Schedule A-I that identifies the impact on APS's requested revenue increase for the impact of including bonus tax depreciation in APS's pro forma test year data. Please provide this schedule in electronic format with formulas intact.

Response:

a. APS confirms this statement.

b. All bonus depreciation benefits realized by APS as of December 31, 2010 have been included in the Total Company and ACC Jurisdiction pro forma earned rate of returns in this case. Bonus depreciation benefits for future years, which are yet unrealized by the Company, have not been included.

Consistent with the 2007 ACC Settlement, estimated projections of future unrealized deferred taxes related to post-Test Year plant additions (in this instance the period between January 1, 2011 and July 31, 2012) are not reflected in the Total Company and ACC Jurisdiction pro forma earned rate of returns. Inclusions of any such estimated projection of deferred taxes may be deemed by the IRS as inconsistent with the historical Test Year method generally used for cost of service and ratemaking purposes. Without guidance from the IRS that explicitly allows such inclusions, APS believes using such methodology would not be appropriate and could result in extremely unfavorable tax consequences to the Company and its customers.

c. The total estimated net deferred tax liability related to bonus depreciation for the period January 1, 2011 through July 31, 2012 is between $79 million and $124 million. This estimated net deferred tax liability is based upon a gross deferred tax liability for bonus deprecation between $146 million to $163 million, offset by deferred tax assets for expected federal tax loss carryforwards (created by the inclusion of bonus deprecation in taxable income) of between $41 million to $74 million.

Attached at APS14740 is the detailed calculation of the bonus depreciation impact. Due to uncertainty inherent in the computation of taxable income prior to the end of the year, an adjustment range is provided for the rate base pro forma categories shown on Schedule B-2.

Witness: Jason La Benz

FREEPORT-MCMORAN COPPER & GOLD INC. AND
ARIZONANS FOR ELECTRIC CHOICE AND COMPETITION ("AECC")
FIRST SET OF DATA REQUESTS REGARDING THE APPLICATION
TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP
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SEPTEMBER 8, 2011

Response to AECC 1.11 Continued:

As discussed in b., above, the Company believes that without an express ruling from the IRS that explicitly allows inclusion of this deferred tax liability, it would be improper to adjust APS's requested revenue increase.

d. Other than the adjustments outline in c., above, which would adjust rate base, APS does not anticipate any other changes to the information presented on Schedule A-1.

As discussed in b., above, the Company believes that without express guidance from the IRS that explicitly allows inclusion of the deferred tax liability, it would be improper to adjust APS's requested revenue increase.

ARIZONA PUBLIC SERVICE COMPANY
RESPONSE TO AECC 1.11 (c)

		2011			2012		
Gross Deferred Tax Liability	[A]	**$ (137,979)**	**to**	**$ (153,639)**	**$ (8,298)**	**to**	**$ (9,220)**
Solar Generation Post Test Year Plant Additions		$ (46,698)	to	$ (51,998)	$ (2,657)	to	$ (2,952)
Fossil Generation Post Test Year Plant Additions		$ (10,849)	to	$ (12,081)	$ (245)	to	$ (272)
Nuclear Generation Post Test Year Plant Additions		$ (6,345)	to	$ (7,065)	$ (362)	to	$ (402)
Distribution, G&I Post Test Year Plant Additions		$ (74,086)	to	$ (82,495)	$ (5,034)	to	$ (5,594)
Estimated Deferred Tax Asset - Loss Carryforward	[B]	**$ 59,286**	**to**	**$ 29,960**	**14,471**	**to**	**11,065**
Net Deferred Tax Liability	[C] = [A] + [B]	**$ (78,693)**	**to**	**$ (123,679)**	**$ -**	**to**	**$ -**
Solar Generation Post Test Year Plant Additions		$ (26,633)	to	$ (41,858)	$ -	to	$ -
Fossil Generation Post Test Year Plant Additions		$ (6,188)	to	$ (9,725)	$ -	to	$ -
Nuclear Generation Post Test Year Plant Additions		$ (3,619)	to	$ (5,687)	$ -	to	$ -
Distribution, G&I Post Test Year Plant Additions		$ (42,253)	to	$ (66,408)	$ -	to	$ -

	2011	2012	Total
Tax Basis Eligible for Bonus Depreciation			
Solar Generation Post Test Year Plant Additions	$ 163,708,616	$ 33,735,118	$ 197,443,734
Fossil Generation Post Test Year Plant Additions	$ 38,034,664	$ 3,114,099	$ 41,148,763
Nuclear Generation Post Test Year Plant Additions	$ 22,243,815	$ 4,596,347	$ 26,840,162
Distribution Post Test Year Plant Additions	$ 124,080,367	$ 26,762,468	$ 150,842,835
Smart Grid Post Test Year Plant Additions	$ 31,028,366	$ 8,501,066	$ 39,529,432
AMI Meters Post Test Year Plant Additions	$ 32,064,146	$ 13,664,038	$ 45,728,184
IT and Facilities Post Test Year Plant Additions	$ 72,551,391	$ 14,998,238	$ 87,549,629
Tax Subtotal	**$ 483,711,365**	**$ 105,371,374**	**$ 589,082,739**

	MINIMUM ESTIMATED BENEFIT			MAX ESTIMATED BENEFIT		
50% Bonus Eligible - Estimate (MAX)	37%	90%		18.50%	100%	
100% Bonus Eligible - Estimate (MAX)	63%	-		81.50%	-	
50% Bonus Depreciation						
Solar Generation	$ (30,286,094)	$ (15,180,803)	$ (45,466,897)	$ (15,143,047)	$ (16,867,559)	$ (32,010,606)
Fossil Generation	$ (7,036,413)	$ (1,401,345)	$ (8,437,758)	$ (3,518,206)	$ (1,557,050)	$ (5,075,256)
Nuclear Generation	$ (4,115,106)	$ (2,068,356)	$ (6,183,462)	$ (2,057,553)	$ (2,298,174)	$ (4,355,726)
Distribution	$ (22,954,868)	$ (12,043,110)	$ (34,997,978)	$ (11,477,434)	$ (13,381,234)	$ (24,858,668)
Smart Grid	$ (5,740,248)	$ (3,825,480)	$ (9,565,727)	$ (2,870,124)	$ (4,250,533)	$ (7,120,657)
AMI Meters	$ (5,931,867)	$ (6,148,817)	$ (12,080,684)	$ (2,965,934)	$ (6,832,019)	$ (9,797,953)
IT and Facilities	$ (13,422,007)	$ (6,749,207)	$ (20,171,214)	$ (6,711,004)	$ (7,499,119)	$ (14,210,123)
100% Bonus Derprecation						
Solar Generation	$ (103,136,428)	$ -	$ (103,136,428)	$ (133,422,522)	$ -	$ (133,422,522)
Fossil Generation	$ (23,961,838)	$ -	$ (23,961,838)	$ (30,998,251)	$ -	$ (30,998,251)
Nuclear Generation	$ (14,013,603)	$ -	$ (14,013,603)	$ (18,128,709)	$ -	$ (18,128,709)
Distribution	$ (78,170,631)	$ -	$ (78,170,631)	$ (101,125,499)	$ -	$ (101,125,499)
Smart Grid	$ (19,547,870)	$ -	$ (19,547,870)	$ (25,288,118)	$ -	$ (25,288,118)
AMI Meters	$ (20,200,412)	$ -	$ (20,200,412)	$ (26,132,279)	$ -	$ (26,132,279)
IT and Facilities	$ (45,707,376)	$ -	$ (45,707,376)	$ (59,129,383)	$ -	$ (59,129,383)
Estimated Allowable Bonus Depreciation	**$ (394,224,763)**	**$ (47,417,118)**	**$ (441,641,881)**	**$ (438,968,064)**	**$ (52,685,687)**	**$ (491,653,751)**
Estimated Federal Tax Benefit @ 35%	**(137,978,667)**	**(16,595,991)**		**(153,638,822)**	**(18,439,990)**	
FAS109 Recognition at July 31, 2012	**(137,978,667)**	**(8,297,996)**		**(153,638,822)**	**(9,219,995)**	

ARIZONA CORPORATION COMMISSION
STAFF'S TWENTIETH SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
OCTOBER 6, 2011

Staff 20.1: ADIT. Please provide ACC jurisdictional amounts for the monthly ADIT items listed on the response to STF 15.7.

Response: Attached as APS14858, which provides the ACC jurisdictional amount corresponding to the Total Company amounts shown on response Staff 15.7.

Witness: Zachary J. Fryer

ARIZONA PUBLIC SERVICE COMPANY
DEFERRED TAXES - ACC JURISDICTIONAL
SUPPORTING SCHEDULE FOR B-1
(dollars in thousands)

	ACCOUNT DESCRIPTION	Actuals Increase (Decrease) RATE BASE 7/31/11	Actuals Increase (Decrease) RATE BASE 8/31/11	Forecast Increase (Decrease) RATE BASE 9/30/11	Forecast Increase (Decrease) RATE BASE 10/31/11	Forecast Increase (Decrease) RATE BASE 11/30/11	Forecast Increase (Decrease) RATE BASE 12/31/11	Forecast Increase (Decrease) RATE BASE 1/31/12	Forecast Increase (Decrease) RATE BASE 2/29/12	Forecast Increase (Decrease) RATE BASE 3/31/12
1.	Total Deferred Taxes per General Ledger	$ (1,519,663)	$ (1,576,602)	$ (1,577,653)	$ (1,581,501)	$ (1,580,248)	$ (1,581,978)	$ (1,583,556)	$ (1,580,034)	$ (1,572,089)
	Exclude:									
2.	Reg Asset-Power Supply Adjustor Mark to Market	(24,323)	(24,323)	(17,971)	(17,427)	(17,604)	(17,360)	(17,288)	(17,447)	(17,878)
3.	Reg Asset-Transmission Vegetation Management	-	-	-	-	-	-	-	-	-
4.	Reg Asset-Unamortized Loss on Reaquired Debt	(8,062)	(7,909)	(7,844)	(7,822)	(7,829)	(7,819)	(7,814)	(7,825)	(7,854)
5.	Option Ii Benefits (Includes Reg Asset and Def Comp)	3,970	3,604	3,449	3,395	3,413	3,388	3,383	3,395	3,428
6.	Reg Asset-Demand Side Management	(4,203)	(2,711)	(2,078)	(1,857)	(1,929)	(1,830)	(1,812)	(1,851)	(1,956)
7.	Reg Liab-Renewable Energy Standard	19,521	20,338	20,684	20,805	20,766	20,820	20,846	20,788	20,633
8.	Reg Liab-Power Supply Adjustor	8,908	1,015	(2,333)	(3,501)	(3,120)	(3,645)	(3,613)	(3,685)	(3,878)
9.	Renewable Energy Incentives	46,383	52,157	54,606	55,460	55,182	55,566	55,679	55,427	54,744
10.	Mark to Market	73,088	62,905	80,444	79,887	80,069	79,818	79,744	79,910	80,360
11.	OCI-Pension Taxes	20,559	20,559	20,559	20,559	20,559	20,559	20,559	20,559	20,559
12.	Superfund	1,634	1,590	1,571	1,565	1,567	1,564	1,563	1,566	1,574
13.	Other	966	966	966	966	966	966	966	966	966
14.	Subtotal Of Exclusions	138,441	128,191	152,053	152,030	152,040	152,027	152,213	151,803	150,698
15.	Total Deferred Taxes (Line 1 - Line 14)	$ (1,658,104)	$ (1,704,793)	$ (1,729,706)	$ (1,733,531)	$ (1,732,288)	$ (1,734,005)	$ (1,735,769)	$ (1,731,837)	$ (1,722,787)

ARIZONA CORPORATION COMMISSION
STAFF'S NINTH SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
SEPTEMBER 1, 2011

Staff 9.2: How much cost has APS included in rate base and operating expenses related to the project for the Integrated Energy System with Beneficial CO2 Reuse? If any amounts have been included, provide the following information:

a. Identify and provide the work order related to the project.

b. List all rate base and operating expense amounts by account.

c. List all project costs by vendor amount.

d. List all reimbursements from the U.S. Department of Energy (DOE) under Award No. DE-FE0001099.

e. List the amount of reserve or liability against DOE provided funds recorded through December 31, 2010.

f. List all accounting entries related to this project through the present.

Response: The Company Test Year cost of service does not include costs in rate base associated with the Integrated Energy System (IES) project or the Substitute Natural Gas (SNG) project referenced in Staff 9.3. The amount of operating expense recorded to these projects in 2010 were as follows:

IES project expenses	$2,334,478 (see APS14734)
SNG project expenses	502,924 (see APS14735)
Legal/Audit expenses	291,522 (see Staff 9.4)
Proforma Adjustment	(1,000,000)
Total	$2,128,924

The above noted proforma adjustment is discussed in the testimony of Jason La Benz and is reflected on Schedule C-2, column 27, Page 9 of 12 of the Company's filing. The associated workpaper is JCL_39 page 2 of 3 ("remove grant reserve"). This adjustment removed project costs incurred prior to 2010 that were recorded as expense in the Test Year.

The remaining expenses ($2,128,924) were included in the Test Year within above-the-line research and development accounts. However, given on-going discussions with the Department of Energy regarding these projects, APS will remove the expenses recorded during the Test Year that are associated with these projects.

Witness: Jeff Guldner

ARIZONA CORPORATION COMMISSION
STAFF'S NINTH SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
SEPTEMBER 1, 2011

Staff 9.3: How much cost has APS included in rate base and operating expenses related to the project for the Development of a Hydrogasification Process for the Co-Production of Substitute Natural Gas (SNG) and Electric Power from Western Coals?

a. Identify and provide the work order related to the project.

b. List all rate base and operating expense amounts by account.

c. List all project costs by vendor amount.

d. List all reimbursements from the U.S. Department of Energy (DOE) under Award No. DE-FC26-06NT42759.

e. List the amount of reserve or liability against DOE provided funds recorded through December 31, 2010.

f. List all accounting entries related to this project through the present.

Response: Please see APS's response to Staff 9.2.

Witness: Jeff Guldner

ARIZONA CORPORATION COMMISSION
STAFF'S TWENTIETH SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
OCTOBER 6, 2011

Staff 20.2: Grant funded projects.

Refer to the response to STF 15.23, APS14811, page 5 of 18. Please show, by account, how APS accounted for the project expenditures and the related government reimbursements in 2010 for each of the following projects:

a. High Penetration of Photovoltaic Generation Study (HPS).

b. Distributed Energy Leadership Program (DELP).

c. Membrane Technology Research (MTR)

Response: Please see the table below for the requested information:

Grant Name	Account	2010	Reimbursement
a) HPS	1430	$ 319,904.74	See STF 19.21
	5880	$(15,303.76)[1]	
b) DELP	1430	$ 17,824.32	See STF 19.21
	5880	$ 5,962.39	
c) MTR	1430	$ (14,978.95)	$ 326,588.54
	4560		$ 76,601.99
	5140	$ 109.53	
	9302	$ 9,667.46	

Please see APS's response to Staff 19.21 for the government reimbursements for HPS and DELP.

1. Project costs for the HPS award are recorded to FERC 1430. As part of the monthly accounting cycle, APS's portion of the costs or "cost share" is moved from FERC 1430 to FERC 5880 through a system allocation. This allocation inadvertently moved $53,727.14 of DOE reimbursements to FERC 5880 causing a credit in FERC 5880. In July 2011, a reconciling entry was made to correct FERC 1430 and FERC 5880.

Witness: Jeff Guldner

ARIZONA CORPORATION COMMISSION
STAFF'S TWENTIETH SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
OCTOBER 6, 2011

Staff 20.3: Post test year plant for grant funded projects.

Has APS included costs for any grant-funded projects in its request for post test year plant? If not, explain fully why not. If so:

a. Please show the amounts of actual plant additions for grant-funded plant by month, by account, through the most current date for which actual information is available and the Company's best estimates for months after that through March 31, 2012.

b. Please show by account, by month, the related grant funding for each such project.

Response: (a)-(b) No. APS has not included costs for any grant-funded projects in its request for plant additions or post-Test Tear plant.

Witness: Jeff Guldner

ARIZONA PUBLIC SERVICE COMPANY
PRE-FILED SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-XXXX
JUNE 1, 2011

Pre-filed 1.40: Advertising Expense. For each of the advertising expense amounts in the Test Year, please provide an itemization of the amount by advertising campaign/advertisement.

Response: Attached, in Excel, as APS14082 is a summary of Test Year advertising expenses charged to FERC account 930.1 "General Advertising Expenses."

Witness: Jay La Benz

Advertsing Expense

ITEM/DESCRIPTION	TOTAL AMOUNT	
Communications Payroll Expense	$	131,623
Breakfast at the Zoo		40,688
Miscellaneous Admin expense		3,238
SUBTOTAL:	**$**	**175,550**
Energy Conservation/Sustainability		
Sustainability TV Campaign Prod./Talent	$	1,594,012
KNXV-TV		522,851
External Advertising retainer		480,000
Hispanic DSM Rebates		195,923
Green Up Arizona		143,523
General APS advertising		128,106
Sustainability Hispanic TV Advertising		113,975
Energy Star homes expense		33,979
Latino Perspectives Magazine Advertising		33,700
COX Gross Advertising		25,500
Clear Channel Outdoor Refrig recycling		25,000
APS Home Energy expense		22,060
Luke AFB Supplement		11,542
Raising Arizona Kids Refrig recycling		10,927
Latino Future Refrig recycling		7,035
Energy Daily Advertising		6,470
Flagstaff Community Power expense		5,864
Green Choice expense		5,354
Solar Today advertising		4,495
Clear Channel Outdoor bulletins		1,370
Sustaining AZ Production		1,200
Renewables advertising		313
SUBTOTAL:	**$**	**3,373,201**
TOTAL	**$**	**3,548,750**

ARIZONA CORPORATION COMMISSION
STAFF'S TWENTY FIRST SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
OCTOBER 12, 2011

Staff 21.1: General Advertising Expense. Refer to the response to Prefiled 1.40, APS14082. Provide copies of the advertisements related to the following items:

a) Sustainability TV Campaign Prod/Talent - $1.594 million

b) KNVX-TV, $522,851

c) External Advertising Retainer, $480,000

d) Green Up Arizona, $143,523

e) General APS Advertising, $128,106

f) Sustainability Hispanic TV Advertising, $113,975

g) Latino Perspectives Magazine Advertising, $33,700

h) COX Gross Advertising, $25,500

i) Clear Channel Outdoor Refrig recycling, $25,000

j) APS Home Energy Expense, $22,060

k) Luke AFB Supplement, $11,542

l) Raising Arizona Kids Refrig Recycling, $10,927

m) Energy Daily Advertising, $6,470

n) Flagstaff Community Power expense, $5,864

o) Clear Channel Outdoor bulletins, $1,370

p) Breakfast at the Zoo, $40,688

Response:

(a) Please see APS19000, attached.

(b) Please see APS19001, attached.

(c) The external advertising retainer PO can be found in response to Staff 21.2. Their services include general account management for advertising production.

(d) Please see APS19002, attached.

(e) The general advertising amount of $128,006 does not have a specific advertisement to provide, rather this supports multiple ads already contained in this response.

(f) Please see APS19003, attached.

(g) Please see APS19004, attached.

Witness: Jeff Guldner

ARIZONA CORPORATION COMMISSION
STAFF'S TWENTY FIRST SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
OCTOBER 12, 2011

Response to Staff 21.1 Continued:

(h) Please see APS19005, attached.

(i) Please see APS19006, attached.

(j) Please see APS19007, attached.

(k) Please see APS19008, attached.

(l) Please see APS19009, attached.

(m) Please see APS19010, attached.

(n) Please see APS19011, attached.

(o) Please see APS19012, attached.

(p) The Breakfast at the Zoo charges did not encompass advertising and should have been recorded to Account 930.2, instead of 930.1. No advertising copy is available.

ARIZONA CORPORATION COMMISSION
STAFF'S TWENTY FIRST SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
OCTOBER 12, 2011

Staff 21.3: Please provide an update of the Trial Balance (APS14766, 7 pages) for fiscal 2011 through period 9 (September 2011).

Response: The Company is in the process of closing its books for the required SEC quarterly filing. Once the Company has filed its Form 10-Q, it will provide the Trial Balance for fiscal 2011 through period 9 (September 2011).

Supplemental Response: Please see APS14965 for the requested trial balance.

Witness: Jay La Benz

APS®

Report ID: PWGLC006
BU: APSCO
Fiscal Year: 2011 To Period: 9

Trial Balance by Account w/ Beginning Balance

Page 1
Run Date: 11/1/2011
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Account	Description		Beginning Balance	Year To Date	End Balance
Balance Sheet Accounts					
5880000	Dist-Misc Distribution Exp Ops	$0.00	$24,545,211.32	$24,545,211.32	
5890000	Dist-Rents Ops	$0.00	$408,118.02	$408,118.02	
5900000	Dist-Supv and Engnrg Maint	$0.00	$891,333.92	$891,333.92	
5910000	Dist-Maint of Structures	$0.00	$497,653.55	$497,653.55	
5920000	Dist-Maint of Station Equip	$0.00	$1,350,449.06	$1,350,449.06	
5930000	Dist-Maint of OH Lines	$0.00	$10,420,990.11	$10,420,990.11	
5940000	Dist-Maint of UG Lines	$0.00	$6,193,194.81	$6,193,194.81	
5950000	Dist-Maint Line Transformers	$0.00	$2,429,262.78	$2,429,262.78	
5960000	Dist-Maint-StrtLghtg & Signal	$0.00	$287,198.50	$287,198.50	
5970000	Dist-Maint of Meters	$0.00	$(1,811.23)	$(1,811.23)	
5980000	Dist-Maint of Misc Distrib Plt	$0.00	$3,019,015.76	$3,019,015.76	
5990090	Income Summary IU	$0.00	$321,962,201.12	$321,962,201.12	
9010000	Supervision	$0.00	$2,000,384.71	$2,000,384.71	
9020000	Meter Reading	$0.00	$7,090,446.95	$7,090,446.95	
9030000	Cust Records and Collection	$0.00	$28,362,719.69	$28,362,719.69	
9040000	Uncollectible Accts	$0.00	$4,806,169.01	$4,806,169.01	
9050000	Misc Cust Accts	$0.00	$406,569.68	$406,569.68	
9070000	Supervision-Cust Service	$0.00	$1,253,388.47	$1,253,388.47	
9080000	Customer Assistance	$0.00	$53,706,828.80	$53,706,828.80	
9090000	Info-Instructional Advertising	$0.00	$406,277.06	$406,277.06	
9100000	Misc Cust Serv and Info	$0.00	$1,047,346.76	$1,047,346.76	
9120000	Demonstrating and Selling	$0.00	$2,543,155.55	$2,543,155.55	
9130000	Advertising-Sales Expenses	$0.00	$140,612.23	$140,612.23	
9160000	Misc Sales Expenses	$0.00	$3,457,789.89	$3,457,789.89	
9200000	A&G Payroll - Operations	$0.00	$60,012,774.90	$60,012,774.90	
9200003	Supply Chain AG	$0.00	$1,735,914.57	$1,735,914.57	
9210000	Office Supplies & Expenses	$0.00	$13,979,014.61	$13,979,014.61	
9220000	Admin Exp Transferred-Credit	$0.00	$(18,886,856.64)	$(18,886,856.64)	
9230000	Outside Services Employed	$0.00	$9,671,083.45	$9,671,083.45	
9240000	Property Insurance	$0.00	$4,872,394.88	$4,872,394.88	
9250000	Injuries and Damages	$0.00	$4,127,660.66	$4,127,660.66	
9250001	Injuries and Damages-Benefits	$0.00	$959,189.15	$959,189.15	
9250011	BTL Injuries and Damages	$0.00	$12,977.30	$12,977.30	
9260000	Employee Pensions&Benefit	$0.00	$1,309,788.57	$1,309,788.57	
9260001	Emp Pensions&Benefit-Benefits	$0.00	$62,784,312.01	$62,784,312.01	
9280000	Regulatory Commission	$0.00	$14,071,174.05	$14,071,174.05	
9301000	General Advertising Expenses	$0.00	$1,800,728.47	$1,800,728.47	
9302000	Misc General Expenses	$0.00	$(35,528,769.16)	$(35,528,769.16)	
9310000	Rents - O&M	$0.00	$5,655,456.42	$5,655,456.42	
9350000	Maintence of General Plant	$0.00	$3,873,720.64	$3,873,720.64	
Subtotal for Income Statement Accounts		$0.00	($0.00)	$(0.00)	
	Grand Total :	$0.00	$(0.00)	$(0.00)	

ARIZONA CORPORATION COMMISSION
STAFF'S TWENTY FIRST SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
OCTOBER 12, 2011

Staff 21.4: General Advertising Expense. Why is the 2010 General Advertising Expense (Account 9301000) of $3,548,750 (APS14082 and APS14165, page 9) so much higher than the 2009 amount of $1,807,823 (APS14164, page 8)? Identify, quantify and explain the new and/or expanded advertising programs.

Response: The 2010 general advertising expense was greater than 2009 due to expanded energy efficiency campaigns. These campaigns help APS achieve the Energy Efficiency goals established by the ACC which require APS to reduce sales by 22% by 2020.

Witness: Jay La Benz

ARIZONA CORPORATION COMMISSION
STAFF'S TWENTY FIRST SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
OCTOBER 12, 2011

Staff 21.5: General Advertising Expense.

a) What was the General Advertising Expense amount recorded for Account 9301000 for 2008?

b) What is the budgeted General Advertising Expense for 2011?

Response:

(a) In 2008 the amount recorded in Account 930.1 was $3,435,898.

(b) The budget for 2011 is $ 2,059,000 and for 2012 is $4,060,000.

Witness: Jay La Benz

ARIZONA CORPORATION COMMISSION
STAFF'S TWENTY SEVENTH SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
OCTOBER 27, 2011

Staff 27.10: General Advertising Expense. Refer to the response to Pre-filed 1.40, APS14082, and to the responses to STF 21.1 through 21.5.

a) What was the purpose of, and ratepayer benefit resulting from, the $40,688 Breakfast at the Zoo expense?

b) Provide the invoices and support for the $40,688 Breakfast at the Zoo expense.

c) Was the Breakfast at the Zoo for APS employees? If not, who was it for?

d) Provide the invoices for the $480,000 External Advertising Retainer.

e) Provide the invoices for 2010 work that were submitted per paragraph 8.2 of the contract that was provided in response to STF 21.2.

f) Please reconcile the invoices provided in response to part c with the $480,000 amount for External Advertising Retainer.

g) Where specifically in the contract that was provided in response to STF 21.2 is a retainer specified?

h) Why is the General Advertising Expense budget for 2011 of $2.059 million per the response to STF 21.5 so much lower than the $3.549 million amount for 2010 per APS14082/response to Pre-filed 1.40.

i) Provide a comparison of the 2011 budget with the actual expense recorded in Account 930.1, General Advertising Expense, for year-to-date 2011. Include explanations of budget variances.

Response:

a) The event was attended by approximately 2,000 employees and their families. The general purpose of the event was to partner with the Phoenix Zoo in Corporate wide recognition and appreciation of employee efforts to serve APS's over 1 million customers.

b) Attached as APS14975 is the requested invoices. Please note these invoices are confidential and are being provided pursuant to an executed protective agreement.

c) Yes, it was for an employee event.

d) Please see APS14952 through APS14963, attached, for the invoices. Please note these invoices are confidential and are being provided pursuant to an executed protective

ARIZONA CORPORATION COMMISSION
STAFF'S TWENTY SEVENTH SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
OCTOBER 27, 2011

Response to Staff 27.10 Continued:

agreement.

e) Attached as APS14979 are the Test Year invoices. Please note these invoices are confidential and are being provided pursuant to an executed protective agreement.

f) No reconciliation is necessary, the amounts tie.

g) The retainer was not specified in the contract. Rather, the retainer was an amount agreed upon to establish a baseline fund for advertising and account management support for the necessary advertising workload.

h) In 2010, the General Advertising Expense budget included $1.6 million dollars to fund production costs for a new Sustainability TV and radio campaign and these ads continued to run in 2011.

i) Please see APS14964, attached, for the budget to actual comparison.

ARIZONA CORPORATION COMMISSION
STAFF'S THIRTY SECOND SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
NOVEMBER 7, 2011

Staff 32.1: Payroll Expense/Payroll Annualization.

a. Explain fully and in detail how and why the as-recorded 2010 test year payroll amounts changed from APS' original filing, JCL_WP23, page 2 of 10 to APS14945, page 2 of 10, as shown in the following table:

Component	APS Original Filing JCL_WP23 Page 2 of 10 Test Year	APS Oct 25, 2011, Update APS14945 Page 2 of 10 Test Year	Test Year Difference
Base Payroll	$ 553,891,955	$ 548,692,451	$ (5,199,504)
Unemployment	$ 3,107,699	$ 3,107,453	$ (246)
Social Security Tax	$ 32,996,495	$ 32,725,341	$ (271,154)
Medicare Tax	$ 8,031,433	$ 7,956,041	$ (75,393)
Total	$ 598,027,583	$ 592,481,286	$ (5,546,297)

b. Identify all amounts in the "Test Year" column on APS14945, page 2 of 10 that do not represent actual recorded test year amounts.

c. Identify all amounts in the "Test Year" column on JCL_WP23, page 3 of 10 that do not represent actual recorded test year amounts.

d. Identify when APS first discovered an error in its "Test Year" amounts on JCL_WP23, page 2 of 10, and explain in detail the nature of the error.

e. Explain fully and in detail exactly what was not known and certain about the "Wage Change to March 2011" amounts reflected in APS' original filing on JCL_WP23, page 2 of 10.

f. Explain fully and in detail exactly what was not known and certain about the "Employee Change to March 2011" amounts reflected in APS' original filing on JCL_WP23, page 2 of 10.

g. Why have the "Wage Change to March 2011" amounts and the "Employee Change to March 2011" amounts reflected in APS' original filing on JCL_WP23, page 2 of 10 change in APS' October 26, 2011 update per APS14945, page 2 of 10; explain fully and show and explain in detail exactly why such March 2011 amounts should have changed and did change:

Witness: Jay La Benz

ARIZONA CORPORATION COMMISSION
STAFF'S THIRTY SECOND SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
NOVEMBER 7, 2011

Staff 32.1
Continued:

Component	APS Original Filing JCL_WP23 Page 2 of 10 Total	APS Original Filing JCL_WP23 Page 2 of 10 APS O&M	APS Oct 25, 2011, Update APS14945 Page 2 of 10 Total	APS Oct 25, 2011, Update APS14945 Page 2 of 10 APS O&M	Difference Total	Difference APS O&M
Wage Change to March 2011	$ 20,784,713	$ 10,172,941	$ 23,119,516	$ 11,315,694	$ 2,334,803	$ 1,142,753
Employee Change to March 2011	$ (23,446,008)	$ (11,475,494)	$ (19,286,438)	$ (9,439,620)	$ 4,159,570	$ 2,035,874

Response:

a) The selling of paid time off and paid earned & accrued vacation was mistakenly included as base pay in the original calculation of Test Year base pay; therefore, the actual Test Year total base payroll, unemployment, Social Security and Medicare were overstated by $5,546,297. Therefore, when computing the pro forma, the necessary adjustment was correspondingly understated.

b) All amounts in the "Test Year" column on APS14945, page 2 of 10, represent actual recorded Test Year amounts.

c) The amounts in the "Test Year" column on APS14945, page 3 of 10, represent actual recorded Test Year amounts and should be used to replace those originally filed as JCL_WP23 page 3 of 10.

d) The error was found when updating the Payroll Annualization Pro Forma to reflect the new Union wage contract for the October 25, 2011 Update. See Staff 32.1 (a) for the explanation of the error.

e) At the time the Payroll Annualization Pro Forma was developed March 2011 actual employee wages were known and were used in the pro forma adjustment.

f) At the time the Payroll Annualization Pro Forma was developed March 2011 actual employee head counts wages were known and were used in the pro forma adjustment.

g) The changes to both the Wage Change and Employee Change from the original filing on JCL_WP23, page 2 of 10 to the APS's October 26, 2011 update APS14945, page 2 of 10 are all related to the correction to test year base payroll as explained in Staff 32.1 (a).

Witness: Jay La Benz

ARIZONA CORPORATION COMMISSION
STAFF'S TWELFTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY,
REGARDING THE AMENDED APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
E-01345A-08-0172
OCTOBER 9, 2008

Staff 12.27 Meters. Refer to the Company's response to Staff 6.43e, Staff 6.15 and APS12960. (a) Please confirm that on APS12960 a "vintage" and an "activity year" of 2007 would indicate a transaction occurring in 2007. If not, explain fully why not. (b) Also, explain what the "vintage" and "activity year" mean in APS12960 if anything different than the definitions listed in APS12959. (c) Please confirm that "adjusting year code" of "10" on APS12960 indicates a normal addition and "20" indicates a normal retirement. If not, explain fully why not. (d) Please confirm that in 2007 APS added $12,186,852 as a normal addition in Account 37001 and in 2005 added $11,535,469. If this is not the case, explain fully why not. (e) Please show in detail the amounts that APS added to plant in Account 37001 in each year 2005, 2006 and 2007 for normal additions. (f) Please confirm that in 2006 APS added $591,859 in Account 37002 as a normal addition. If this is not the case, explain fully why not and show in detail the amounts that APS added to plant in Account 37002 in 2006 for normal additions. (g) Please provide all work orders and cost-benefit analysis APS has for making normal additions of plant into Accounts 37001 and 37002 in each year 2005, 2006, 2007 and 2008. (h) Does APS project making any normal additions (Code 10 per APS12959) of plant into either account, 37001 or 37002, in 2008, 2009 or 2010? If not, explain fully why not. If so, please show the Code 10 "normal" additions to each of these accounts projected for each year.

Response:

(a) Yes. Please see response (d).

(b) APS's transaction definition is the same as in APS12959 on page 2.

(c) Transaction code 10 is a normal addition and transaction code 20 is a normal retirement.

(d) The 37001 additions of $12,186,852 and $11,535,469 for 2007 and 2005 respectively are NOT the total additions for the specified vintages. The total additions for 2007 were $11,935,595 and for 2005 were 11,953,122. See schedule attached hereto at APS08997.

ARIZONA CORPORATION COMMISSION
STAFF'S TWELFTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY,
REGARDING THE AMENDED APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
E-01345A-08-0172
OCTOBER 9, 2008

Staff 12.27

Response Continued:

(e) Attached as APS08997 is the requested schedule.

(f) Yes, however the 2006 addition was transferred in 2008 to 37001.

(g) The work orders used for capitalizing meter in utility accounts 37001 and 37002 are 63-1000, 63-2000 and 63-1020. In response to the cost-benefit analysis question, please see Staff Interim 2.10.

(h) The estimated meter additions for 37001 are $12.5M in 2008, $8.9M in 2009 and $4.2M in 2010. For utility account 37002, APS does not plan on any additions. 37002 are the older meter types that will no longer be purchased. APS is expecting a full AMI rollout.

Supplemental Response:

(g) The work orders used for capitalizing meter in utility accounts 37001 and 37002 are 63-1000, 63-2000 and 63-1020. These charge numbers were established in the late 90's. They are fixed in our inventory system in order to facilitate the pre-capitalization process. The approval for meter purchases is done at the Purchase Order (PO) level. The projected installs are measured with what is in stock in order to determine what needs to be purchased.

In response to the cost-benefit analysis question, please see Staff Interim 2.10.

Witness: Jason La Benz

ARIZONA CORPORATION COMMISSION
STAFF'S SEVENTEENTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY,
REGARDING THE AMENDED APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
E-01345A-08-0172
OCTOBER 24, 2008

Staff 17.7 Depreciation. Account 370.01. Refer to APS09011, 2008 Depreciation Study workpapers. (a) Show in detail how each of the "derived additions" in column c on page 194 of 374 was derived. Include complete supporting calculations. (b) Provide the accounting entries and all journal entry support for the $65,427,927 "sales, transfer and adjustment" amount for 2004 in column E on page 195 and page 196. (c) On page 194, please explain what the amounts in column E, "amount surviving" based on experience to 12/31/2007 represent. (d) Are the "amounts surviving" for 1998 through 2003 plant in account 370.01 as of 12/31/2007 consistent with a five-year amortization? If not, explain fully why not. If so, explain in detail how. (e) What depreciation or amortization rate did APS use for Account 370.01 in each year, 1998 through 2007?

Response:

(a) All transactions used to derive Column C were provided in response to Staff 6.15. Open the database, filter on the desired account, filter all transactions excluding Code 20s and sum the resulting transactions for each vintage year to produce results shown in the schedule attached as APS13179.

(b) The $65,427,927 was a system transfer for meters. APS had one depreciation group for meters excluding AMI meters. In 2004 these meters were split into two distinct depreciation groups, electronic meters and the electromechanical meters. 37001 are the newer electronic meters and 37002 are the old electromechanical meters. The $65.4M was the transfer from the 37002 depreciation group to 37001.

Please see APS09011 pages 195, 202 and 203. Page 202 and 203 show the transfer from (credit) 37002 (electromechanical meters) to 37001 electronic meters which is shown as a debit on page 195.

(c) Column C is the age distribution of surviving plant at December 31, 2007 as also reported in the Generation Arrangement shown in Column C, page 193. An age distribution is plant surviving (*i.e.*, in service) by vintage year of placement.

ARIZONA CORPORATION COMMISSION
STAFF'S SEVENTEENTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY,
REGARDING THE AMENDED APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
E-01345A-08-0172
OCTOBER 24, 2008

Staff 17.7

Response Continued:

(d) Yes. These vintages will be retired upon implementation of amortization accounting. Vintages 2003–2007 and any subsequent additions will be retired as each vintage achieves an age equal to the amortization period. Amortization over five years is consistent with APS's commitment to a program of replacing electronic and electromechanical meters with AMI meters by 2012. See also White direct testimony, page 12, lines 1 ff.; White Attachment REW–1, page 3–4; response to Staff 6.43; response to Staff 6.51; response to Staff 12.25; and response to Staff 12.27.

(e) The depreciation rates from 1998 to 2007 were as follows:

<u>37001: Electronic Meters</u>	
1998 to March 2005:	4.54%
April 2005 to June 2007:	3.61%
July 2007 to present:	3.68%
<u>37002: Electromechanical Meters</u>	
1998 to March 2005:	4.54%
April 2005 to June 2007:	2.84%
July 2007 to present:	3.02%

Witness: Ronald White

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
MIKE GLEASON - CHAIRMAN
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
KRISTIN K. MAYES
GARY PIERCE

IN THE MATTER OF THE FILING BY TUCSON ELECTRIC POWER COMPANY TO AMEND DECISION NO. 62103.	DOCKET NO. E-01933A-05-0650
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. E-01933A-07-____

Direct Testimony of

Dr. Kimbugwe A. Kateregga

on Behalf of

Tucson Electric Power Company

July 2, 2007

Exhibit KAK–1

2007 Depreciation Rate Study

Tucson Electric Power Company

–Local Generation
–Non–Local Generation
–Distribution and General

Prepared by
Foster Associates, Inc.

TUCSON ELECTRIC POWER COMPANY Statement A

Comparison of Present and Proposed Accrual Rates
Present: BG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	Present Rem. Life	Present Fut. Net Salvage	Present Accrual Rate	Proposed Avg. Life	Proposed Rem. Life	Proposed Net Salvage	Proposed Reserve Ratio	Proposed Accrual Rate
A	B	C	D	E	F	G	H	I
DISTRIBUTION PLANT								
360.00 Rights-of-Way			2.22%		43.78		37.61%	1.43%
361.00 Structures and Improvements		-10.0%	2.44%		44.83		26.99%	1.63%
362.00 Station Equipment		-19.0%	4.25%		46.02		33.01%	1.46%
364.00 Poles, Towers and Fixtures		-59.0%	5.48%		39.16		35.98%	1.63%
365.00 Overhead Conductors and Devices		-17.0%	3.66%		41.83		38.71%	1.47%
366.00 Underground Conduit		-40.0%	2.33%		43.44		38.11%	1.42%
367.00 Underground Conductors and Devices		33.0%	1.63%		32.32		38.89%	1.89%
368.OH Line Transformers - Overhead		-15.0%	3.38%		26.12		51.83%	1.84%
368.UG Line Transformers - Underground		-15.0%	3.38%		23.28		41.39%	2.52%
369.OH Services - Overhead		-34.0%	3.83%		28.70		53.55%	1.62%
369.UG Services - Underground		-34.0%	3.83%		47.81		28.30%	1.50%
370.00 Meters		-25.0%	3.79%		19.73		40.91%	2.99%
373.00 Street Lighting and Signal Systems		-25.0%	4.46%		36.67		36.24%	1.74%
374.00 Asset Retirement Costs		-7.0%	3.22%		31.53		6.20%	2.97%
Total Distribution Plant			3.35%		33.61		38.52%	1.82%
GENERAL PLANT								
Depreciable								
390.00 Structures and Improvements			2.22%		21.45		54.04%	2.14%
391.CM Office Furn. and Equip. - Computer			20.00%		2.95		57.04%	14.56%
392.C0 Transportation Equipment - Class 0		16.0%	8.87%		14.63	15.0%	25.99%	4.03%
392.C1 Transportation Equipment - Class 1		16.0%	14.00%		5.10	15.0%	41.06%	8.62%
392.C2 Transportation Equipment - Class 2		21.0%	11.29%		4.99	25.0%	36.55%	7.71%
392.C3 Transportation Equipment - Class 3		18.0%	10.25%		7.07	15.0%	41.05%	6.22%
392.C4 Transportation Equipment - Class 4		9.0%	7.00%		9.80	10.0%	43.96%	4.70%
392.C5 Transportation Equipment - Class 5		1.0%	7.07%		10.67	5.0%	38.28%	5.32%
396.00 Power Operated Equipment			3.33%		11.46	5.0%	46.95%	4.19%
397.00 Communication Equipment			6.67%		18.13		32.72%	3.71%
Total Depreciable			7.57%		9.53	4.0%	44.54%	5.31%
Amortizable								
391.FE Office Furn. and Equip. - Furniture	← 24 Year Amortization →				← 24 Year Amortization →			
393.00 Stores Equipment	← 15 Year Amortization →				← 15 Year Amortization →			
394.00 Tools, Shop and Garage Equipment	← 17 Year Amortization →				← 17 Year Amortization →			
395.00 Laboratory Equipment	← 17 Year Amortization →				← 17 Year Amortization →			
398.00 Miscellaneous Equipment	← 20 Year Amortization →				← 20 Year Amortization →			
Total Amortizable			8.00%		11.16		43.56%	5.06%
Total General Plant			7.65%		9.75	3.3%	44.37%	5.26%
TOTAL INVESTMENT			3.96%		25.53	0.5%	39.34%	2.30%
NET SALVAGE								
108.02 Distribution	43.08	-50.0%			33.61	-15.0%	5.68%	0.28%
Total Net Salvage					33.61		5.68%	0.28%
TOTAL UTILITY			3.96%		25.53	-6.7%	44.22%	2.54%

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 UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND REQUEST FOR APPROVAL OF RELATED FINANCING.	)	DOCKET NO. G-04204A-06-____

Direct Testimony of

Dr. Ronald E. White

on Behalf of

UNS Gas, Inc.

December 15, 2006

Exhibit REW–2

2006 Depreciation Rate Review

UNS Electric, Inc.

Prepared by
Foster Associates, Inc.

UNS ELECTRIC, INC. Statement A

Comparison of Present and Proposed Accrual Rates
Present: BG Procedure / RL Technique
Proposed: BG Procedure / RL Technique

Account Description	Present Rem. Life	Present Net Salvage	Present Accrual Rate	Proposed Rem. Life	Proposed Net Salvage	Proposed Reserve Ratio	Proposed Accrual Rate
A	B	C	D	E	F	G	H
INTANGIBLE PLANT							
Depreciable							
303.WP Misc. Intangible - WAPA Switchboard	38.00		2.92%	30.16		5.64%	3.13%
Total Depreciable			2.92%	30.16		5.64%	3.13%
Amortizable							
302.00 Franchises and Consents	38.00			← 25 Year Amortization →			
303.00 Miscellaneous Intangible Plant	38.20			← 15 Year Amortization →			
303.WC Misc. Intangible - WAPA Fiber Optic	38.20		4.13%	← 23 Year Amortization →			
303.PC Misc.Intangible Plant - PC Software	31.00		20.00%	← 5 Year Amortization →			
Total Amortizable			4.23%	7.21		61.05%	3.06%
Total Intangible Plant			3.79%	10.88		42.48%	3.09%
OTHER PRODUCTION PLANT							
341.00 Structures and Improvements	38.00		1.38%	29.50		39.01%	2.07%
342.00 Fuel Holders, Producers and Accessories	38.20		2.42%	32.63		18.06%	2.51%
343.00 Prime Movers	37.00		2.34%	26.17		33.89%	2.53%
344.00 Generators	22.60		0.67%	36.15		15.62%	2.33%
345.00 Accessory Electric Equipment	39.50		2.20%	29.39		31.02%	2.35%
346.00 Miscellaneous Power Plant Equipment	31.00		1.87%	33.34		12.02%	2.64%
Total Other Production Plant			2.00%	28.73		29.41%	2.46%
TRANSMISSION PLANT							
350.RW Rights of Way				31.35		36.56%	2.02%
352.00 Structures and Improvements	19.70		3.77%	12.75		60.15%	3.13%
353.00 Station Equipment	23.00		2.92%	21.72		31.49%	3.15%
354.00 Towers and Fixtures	12.40		4.08%	15.92		20.00%	5.03%
355.00 Poles and Fixtures	15.90	-10.0%	5.77%	12.68	-10.0%	53.19%	4.48%
356.00 Overhead Conductors and Devices	30.10		2.71%	23.85		36.50%	2.66%
359.00 Roads and Trails	44.90		2.01%	35.18		29.05%	2.02%
Total Transmission Plant			3.68%	18.90	-2.9%	39.12%	3.41%
DISTRIBUTION PLANT							
360.RW Rights of Way				27.71		43.70%	2.03%
361.00 Structures and Improvements	23.60		3.20%	25.54		24.39%	2.96%
362.00 Station Equipment	15.30		4.82%	11.54		52.77%	4.09%
364.00 Poles, Towers and Fixtures	18.90	-10.0%	4.23%	14.83	-10.0%	48.65%	4.14%
365.00 Overhead Conductors and Devices	18.40	-10.0%	4.36%	15.16	-10.0%	47.39%	4.13%
366.00 Underground Conduit	21.50		4.28%	18.66	-5.0%	34.33%	3.79%
367.00 Underground Conductors and Devices	14.30		5.36%	14.20		37.50%	4.40%
368.00 Line Transformers	14.20	-5.0%	4.93%	13.46	-5.0%	42.69%	4.63%
369.OH Services - Overhead	18.30		4.23%	14.43		45.63%	3.77%
369.UG Services - Underground	18.30		4.23%	16.26		38.99%	3.75%
370.00 Meters	26.20	-5.0%	3.25%	24.14	-5.0%	29.99%	3.11%
373.00 Street Lighting and Signal Systems	17.40		4.55%	16.64		32.78%	4.04%
Total Distribution Plant			4.50%	14.75	-6.0%	44.74%	4.16%
GENERAL PLANT							
Depreciable							
390.00 Structures and Improvements	27.80		2.89%	29.03		23.14%	2.65%
392.C1 Transportation Equipment - Class 1			25.00%	4.00		49.01%	12.75%
392.C2 Transportation Equipment - Class 2			25.00%	3.02		48.68%	16.99%
392.C3 Transportation Equipment - Class 3			25.00%	3.28		33.72%	20.21%
392.C4 Transportation Equipment - Class 4			12.50%	1.63		78.05%	13.47%
392.C5 Transportation Equipment - Class 5			12.50%	6.58		17.40%	12.55%
396.00 Power Operated Equipment	6.80		3.33%	5.16		64.30%	6.92%
Total Depreciable			12.12%	4.13		54.16%	11.33%

DIRECT TESTIMONY
OF
DR. RONALD E. WHITE

ARIZONA PUBLIC SERVICE COMPANY
DOCKET NO. E-01345A-08-0172

June 2008

Attachment REW–1

2008 Depreciation Rate Study

Arizona Public Service Company

Prepared by
Foster Associates, Inc.

tion period. Reserve imbalances created by the recommended amortization periods were eliminated by a systematic redistribution of recorded reserves. Reserve imbalances for the proposed amortization accounts were distributed to the remaining depreciable accounts in the General plant function. Net salvage realized in the future will be netted against current–year vintage additions.

Amortization accounting is also recommended for Account 370.01 (Meters – Electronic) and Account 370.02 (Meters – Electromechanical). APS has committed to a program of replacing electronic and electromechanical meters with AMI (Advanced Metering Infrastructure) meters by 2012. Accordingly, a 5–year amortization period is recommended for Accounts 370.01 and 370.02. The current projection life of 26 years for electronic meters is recommended for AMI meters pending sufficient retirement experience to estimate service lives for AMI metering technology. Reserve imbalances associated with the proposed meter amortization accounts were distributed to the remaining depreciable accounts in the Distribution plant function.

PROPOSED DEPRECIATION RATES

Table 2 below provides a summary of the changes in annual rates and accruals resulting from an application of the parameters and depreciation system recommended in the 2008 study for APS.

Function	Accrual Rate			2008 Annualized Accrual		
	Present	Proposed	Diff.	Present	Proposed	Difference
A	B	C	D=C-B	E	F	G=F-E
Steam Production	3.86%	3.51%	-0.35%	$57,991,639	$52,743,069	($5,248,570)
Nuclear Production	2.80%	2.78%	-0.02%	68,608,141	68,160,962	(447,179)
Other Production	2.59%	3.02%	0.43%	34,229,815	39,880,095	5,650,280
Transmission	1.38%	2.26%	0.88%	1,139,490	1,865,917	726,427
Distribution	2.50%	2.37%	-0.13%	103,532,446	97,969,879	(5,562,567)
General Plant	5.99%	4.99%	-1.00%	25,358,257	21,114,220	(4,244,037)
Total	2.93%	2.84%	-0.09%	$290,859,788	$281,734,142	($9,125,646)

Table 2. Present and Proposed Rates and Accruals

Foster Associates is recommending primary account depreciation rates equivalent to a composite rate of 2.84 percent. Depreciation expense is currently accrued at rates that composite to 2.93 percent. The recommended change in the composite depreciation rate is, therefore, a decrease of 0.09 percentage points.

A continued application of current rates would provide annualized depreciation expense of $290,859,788 compared with an annualized expense of $281,734,142 using the rates developed in this study. The proposed 2008 expense decrease is $9,125,646. The computed change in annualized accruals includes a

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
KRISTIN K. MAYES - CHAIRMAN
GARY PIERCE
PAUL NEWMAN
SANDRA D. KENNEDY
BOB STUMP

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. E-04204A-09-____

Direct Testimony of

Dr. Ronald E. White

on Behalf of

UNS Electric, Inc.

April 30, 2009

Attachment REW–2

2009 Technical Update

UNS Electric, Inc.

Prepared by
Foster Associates, Inc.

Statement E

UNS ELECTRIC, INC. (Excluding Black Mountain)
Current and Proposed Parameters
Broad Group Procedure

	Current Parameters						Proposed Parameters					
Account Description	P-Life/ AYFR	Curve Shape	BG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	BG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
362.00 Station Equipment	25.00	S4	25.00	11.54			25.00	S4	25.00	13.57		
364.00 Poles, Towers and Fixtures	27.00	S4	27.00	14.83	-9.9	-10.0	27.00	S4	27.00	13.80	-9.7	-10.0
365.00 Overhead Conductors and Devices	27.00	S3	27.00	15.16	-9.8	-10.0	27.00	S3	27.00	15.12	-9.9	-10.0
366.00 Underground Conduit	28.00	S2	26.00	18.66	-5.0	-5.0	28.00	S2	28.00	18.66	-5.0	-5.0
367.00 Underground Conductors and Devices	23.00	S3	23.00	14.20			23.00	S3	23.00	15.52	-0.5	
368.00 Line Transformers	23.00	S4	23.00	13.46	-5.0	-5.0	23.00	S4	23.00	13.82	-5.6	-5.0
369.OH Services - Overhead	27.00	R5	27.00	14.43			27.00	R5	27.00	13.82		
369.UG Services - Underground	27.00	R5	27.00	16.26			27.00	R5	27.00	17.43		
370.00 Meters	34.00	R3	34.00	24.14	-4.8	-5.0	34.00	R3	34.00	25.56	-3.9	-5.0
373.00 Street Lighting and Signal Systems	25.00	S4	25.00	16.64			25.00	S4	25.00	14.77		
Total Distribution Plant									25.67	14.91	-5.7	-5.7
GENERAL PLANT												
Depreciable												
390.00 Structures and Improvements	38.00	R2	38.00	29.03			38.00	R2	38.00	27.19		
392.C1 Transportation Equipment - Class 1	8.00	L1.5	8.00	4.00			8.00	L1.5	8.00	5.76	4.0	10.0
392.C2 Transportation Equipment - Class 2	6.00	L2	6.00	3.02			6.00	L2	6.00	3.65	7.7	10.0
392.C3 Transportation Equipment - Class 3	5.00	S5	5.00	3.28			5.00	S5	5.00	2.41	5.2	10.0
392.C4 Transportation Equipment - Class 4	8.00	S4	8.00	1.63			8.00	S4	8.00	3.11	3.3	10.0
392.C5 Transportation Equipment - Class 5	8.00	S4	8.00	6.58			8.00	S4	8.00	5.62	10.0	10.0
396.00 Power Operated Equipment	15.00	S5	15.00	5.16			15.00	S5	15.00	9.00		
Total Depreciable									9.25	5.78	4.9	6.8
Amortizable												
391.10 Office Furniture and Equipment	21.00	SQ	21.00				21.00	SQ	21.00	8.70		
391.20 Computer Equipment - PCs	5.00	SQ	5.00				5.00	SQ	5.00	2.89		
393.00 Stores Equipment	33.00	SQ	33.00				33.00	SQ	33.00	12.68		
394.00 Tools, Shop and Garage Equipment	29.00	SQ	29.00				29.00	SQ	29.00	15.69		
395.00 Laboratory Equipment	40.00	SQ	40.00				40.00	SQ	40.00	28.70		
397.CE Communication Equipment	23.00	SQ	23.00				23.00	SQ	23.00	16.10		
398.00 Miscellaneous Equipment	18.00	SQ	18.00				18.00	SQ	18.00	6.22		
Total Amortizable									19.83	11.59		
Total General Plant									11.65	7.10	-4.3	-4.5
TOTAL UTILITY									25.01	15.09	-4.3	-4.5

UNS ELECTRIC, INC. (including Black Mountain) Statement A

Comparison of Current and Proposed Accrual Rates
Current: BG Procedure / RL Technique
Proposed: BG Procedure / RL Technique

Account Description	Current Rates (at 12/31/2008)			Proposed Rates (at 12/31/2008)		
	Investment	Net Salvage	Total	Investment	Net Salvage	Total
A	B	C	D=B+C	E	F	G=E+F
INTANGIBLE PLANT						
Depreciable						
303.WP Misc. Intangible - WAPA Switchboard	3.13%		3.13%	2.82%		2.82%
Total Depreciable	3.13%		3.13%	2.82%		2.82%
Amortizable						
302.00 Franchises and Consents	← 25 Year Amortization →					
303.00 Miscellaneous Intangible Plant	← 15 Year Amortization →			← 15 Year Amortization →		
303.WC Misc. Intangible - WAPA Fiber Optic	← 23 Year Amortization →			← 23 Year Amortization →		
303.PC Misc.Intangible Plant - PC Software	← 5 Year Amortization →			← 5 Year Amortization →		
Total Amortizable	7.00%		7.00%	7.00%		7.00%
Total Intangible Plant	5.25%		5.25%	5.11%		5.11%
OTHER PRODUCTION PLANT						
341.00 Structures and Improvements	2.35%		2.35%	2.36%		2.36%
342.00 *Fuel Holders, Producers and Accessories*	2.53%		2.53%	2.55%		2.55%
343.00 Prime Movers	2.53%		2.53%	2.53%		2.53%
344.00 Generators	2.54%		2.54%	2.58%		2.58%
345.00 Accessory Electric Equipment	2.52%		2.52%	2.55%		2.55%
346.00 Miscellaneous Power Plant Equipment	2.58%		2.58%	2.62%		2.62%
353.00 Station Equipment	3.13%		3.13%	2.62%		2.62%
Total Other Production Plant	2.55%		2.55%	2.56%		2.56%
TRANSMISSION PLANT						
350.RW Rights of Way	2.02%		2.02%	1.91%		1.91%
352.00 *Structures and Improvements*	3.13%		3.13%	2.93%		2.93%
353.00 Station Equipment	3.15%		3.15%	3.02%		3.02%
354.00 Towers and Fixtures	5.03%		5.03%	4.89%		4.89%
355.00 Poles and Fixtures	4.08%	0.40%	4.48%	3.86%	0.38%	4.24%
356.00 Overhead Conductors and Devices	2.66%		2.66%	2.55%		2.55%
358.00 Underground Conductors and Devices	4.36%		4.36%	1.99%	0.10%	2.09%
359.00 Roads and Trails	2.02%		2.02%	1.93%		1.93%
Total Transmission Plant	3.38%	0.15%	3.52%	3.22%	0.14%	3.36%
DISTRIBUTION PLANT						
360.RW Rights of Way	2.03%		2.03%	1.95%		1.95%
361.00 Structures and Improvements	2.96%		2.96%	2.90%		2.90%
362.00 Station Equipment	4.09%		4.09%	3.84%		3.84%
364.00 Poles, Towers and Fixtures	3.76%	0.38%	4.14%	3.54%	0.34%	3.88%
365.00 Overhead Conductors and Devices	3.76%	0.37%	4.13%	3.57%	0.35%	3.92%
366.00 Underground Conduit	3.61%	0.18%	3.79%	3.49%	0.17%	3.66%
367.00 Underground Conductors and Devices	4.40%		4.40%	4.25%	0.02%	4.27%
368.00 Line Transformers	4.41%	0.22%	4.63%	4.21%	0.24%	4.45%
369.OH Services - Overhead	3.77%		3.77%	3.54%		3.54%
369.UG Services - Underground	3.75%		3.75%	3.61%		3.61%
370.00 Meters	2.96%	0.15%	3.11%	2.90%	0.11%	3.01%
373.00 Street Lighting and Signal Systems	4.04%		4.04%	3.87%		3.87%
Total Distribution Plant	3.95%	0.22%	4.17%	3.76%	0.21%	3.97%
GENERAL PLANT						
Depreciable						
390.00 Structures and Improvements	2.65%		2.65%	2.60%		2.60%
392.C1 Transportation Equipment - Class 1	12.75%		12.75%	12.35%	-0.46%	11.89%
392.C2 Transportation Equipment - Class 2	16.99%		16.99%	16.33%	-1.24%	15.09%
392.C3 Transportation Equipment - Class 3	20.21%		20.21%	19.32%	-0.94%	18.38%
392.C4 Transportation Equipment - Class 4	13.47%		13.47%	11.88%	-0.32%	11.56%
392.C5 Transportation Equipment - Class 5	12.55%		12.55%	12.33%	-1.23%	11.10%
398.00 Power Operated Equipment	6.92%		6.92%	6.53%		6.53%
Total Depreciable	11.04%		11.04%	10.56%	-0.68%	9.87%

UNS ELECTRIC, INC. (Including Black Mountain)

Current and Proposed Parameters

Broad Group Procedure

Statement E

Account Description	Current Parameters						Proposed Parameters					
	P-Life/ AYFR	Curve Shape	BG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	BG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
Amortizable												
391.10 Office Furniture and Equipment	21.00	SQ	21.00				21.00	SQ	21.00	8.70		
391.20 Computer Equipment - PCs	5.00	SQ	5.00				5.00	SQ	5.00	2.89		
393.00 Stores Equipment	33.00	SQ	33.00				33.00	SQ	33.00	12.68		
394.00 Tools, Shop and Garage Equipment	29.00	SQ	29.00				29.00	SQ	29.00	15.69		
395.00 Laboratory Equipment	40.00	SQ	40.00				40.00	SQ	40.00	28.70		
397.CE Communication Equipment	23.00	SQ	23.00				23.00	SQ	23.00	16.10		
398.00 Miscellaneous Equipment	18.00	SQ	18.00				18.00	SQ	18.00	6.22		
Total Amortizable									19.83	11.59		
Total General Plant									11.65	7.10	-3.8	-3.9
TOTAL UTILITY									26.10	16.98	-3.8	-3.9
OTHER PRODUCTION PLANT												
Nogales												
341.00 Structures and Improvements	49.00	S6	49.00	29.50			49.00	S6	49.00	40.31		
342.00 Fuel Holders, Producers and Accessories	40.00	S4	40.00	32.63			40.00	S4	40.00	31.64		
343.00 Prime Movers	40.00	R3	40.00	26.17			40.00	R3	40.00	28.50	0.1	
344.00 Generators	43.00	S0	43.00	36.15			43.00	S0	43.00	38.26		
345.00 Accessory Electric Equipment	43.00	S6	43.00	29.39			43.00	S6	43.00	31.86		
346.00 Miscellaneous Power Plant Equipment	38.00	R1	38.00	33.34			38.00	R1	38.00	34.33		
353.00 Station Equipment												
Total Nogales									41.42	32.23		
Black Mountain												
341.00 Structures and Improvements							2048	200-SC	38.00	37.55		
342.00 Fuel Holders, Producers and Accessories							2048	200-SC	38.00	37.55		
343.00 Prime Movers												
344.00 Generators							2048	200-SC	38.00	37.55		
345.00 Accessory Electric Equipment							2048	200-SC	38.00	37.55		
346.00 Miscellaneous Power Plant Equipment							2048	200-SC	38.00	37.55		
353.00 Station Equipment							2048	200-SC	38.00	37.55		
Total Black Mountain									38.00	37.55		

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OCTOBER 25, 2011

Staff 25.8: Refer to the cost of the January 2010 through March 2011 non-voluntary severance program:

a. Please confirm that APS is requesting an amount of O&M expense of $3.366 million in the current case for the January 2010 through March 2011 non-voluntary severance program. If that amount cannot be confirmed, please identify the amount of O&M expense that APS is requesting, show how it was derived and reconcile it to the information shown on JCL_WP27, page 2 of 12.

b. What is the ACC jurisdictional amount that corresponds with the $3.366 million on JCL_WP27, page 2 of 12?

Response:

a. Yes, APS is requesting that $3.366 million of the $10.099 million associated with the 2010 non-voluntary severance program remain in the Test Year.

b. The ACC jurisdictional amount that corresponds with the $3.366 million is $3.128 million.

Witness: Jay La Benz

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Staff 25.6: Refer to JCL_WP27, page 2 of 12.

a. Please explain what the APSCCO and Grand Total amounts for each prior year, 2003 through 2010 represent.

b. Show in detail how the APS share of the Four Corner and Cholla amounts for 2010 were determined.

c. Provide the basis and support for the "41% participant recovery" factor.

d. Does APS' proposed cost amortization period start when the savings started? If not, explain fully why not.

e. Please identify when the savings started.

Response:

a. APSCO is the regulated utility Arizona Public Service Company. Grand Total is the sum of Pinnacle West and all of its subsidiaries.

b. See attachment APS14950. The percentage of ownership for Cholla and Four Corners was used to calculate APS's share of the costs. APS's ownership share is as follows:

- Four Corners Units 1-3: 100%
- Four Corners Units 4-5: 15%
- Four Corners Common: 38.44%
- Cholla Units 1-3: 100%
- Cholla Common: 63.34%

c. APS receives recovery of a portion of its A&G expenses from the other owners of the power plants that APS operates but does not own 100% of the asset. The supporting calculation is included as attachment APS14951.

d. Yes, APS is requesting that $3.366 million of the $10.099 million associated with the 2010 non-voluntary severance program remain in the test year, which represents the first year of a 3 year amortization of the severance costs.

e. The savings started during the 2010 Test Year, as described in Staff 25.5, the savings from the headcount reductions have been reflected by reducing payroll costs as if those severed employees had been gone for all 12 months of the Test Year.

Witness: Jay La Benz

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Staff 25.5: Severance. Refer to Mr. La Benz' direct testimony at page 25-26 concerning the non-voluntary severance program.

a. Please identify the number of positions severed by month related to the January 2010 through March 2011 non-voluntary severance program.

b. Please show in detail how the first year savings of $22.446 million was derived.

c. Please provide a breakout of the first year savings of $22.446 million by month.

d. Please identify the period covered by the "first year" referenced on page 25, lines 17-18.

e. Please show in detail how the $10.099 million of costs were recorded in each year.

f. Please explain in detail and provide supporting calculations showing exactly how the $10.099 million cost associated with severing positions through a non-voluntary severance program that was recorded charged to O&M expense in 2010 relates to the first year savings of $22.446 million.

g. How much of the first year savings of $22.446 million occurred in 2010? Please show the 2010 savings in total and provide a breakout of such savings between (1) APS O&M expense and (2) capitalized construction costs and other.

h. How much of the first year savings of $22.446 million has occurred in 2011 through September 30, 2011?

i. Is there a second and third year savings related to the January 2010 through March 2011 non-voluntary severance program? If not, explain fully why not. If so, please identify, quantify and explain the periods and annual amounts covered by the second and third year savings.

j. How much total savings from the January 2010 through March 2011 non-voluntary severance program does APS anticipate that it will have realized in the period January 1, 2010 through June 30, 2012? Please show the amount by year.

k. Did APS file a request for accounting deferrals and/or to establish a regulatory asset related to the $10.099 million cost of severing positions? If not, explain fully why not. If so, please identify and provide a copy of that request.

Witness: Jay La Benz

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Response: a. During the period January 2010 through March 2011 the total number of APS/PNW regular employees was reduced by a net 259 employees. This was a combination of voluntary employee terminations and non-voluntary employee terminations, offset by employee new hires.

The month to month net change in regular APS/PNWCC employees levels is as follows:

- Jan 2010 to Feb 2010 - (37)
- Feb 2010 to Mar 2010 - (42)
- Mar 2010 to Apr 2010 - (42)
- Apr 2010 to May 2010 - (12)
- May 2010 to Jun 2010 - (4)
- Jun 2010 to Jul 2010 - (30)
- Jul 2010 to Aug 2010 - (12)
- Aug 2010 to Sep 2010 - (20)
- Sep 2010 to Oct 2010 - (14)
- Oct 2010 to Nov 2010 - +28
- Nov 2010 to Dec 2010 - (16)
- Dec 2010 to Jan 2011 - (18)
- Jan 2011 to Feb 2011 - (15)
- Feb 2011 to Mar 2011 - (25)

b. To clarify, the first year savings was $23,446,000, not $22,446,000. To the extent that an employee left the Company prior to the end of the test year, those wage savings are already reflected in the test year by virtue of them not being employed. The $23,446,000 savings portion of the Annualize Payroll Pro Forma related to the change in employee headcount levels and removes the expense that was in the test year for the months prior to departure so that the adjusted test year cost excludes the full 12 months of wages. Please see attachment APS14949 for the calculation of the savings.

c. The calculation of the pro forma adjustment to payroll expense was made on an employee by employee basis and was not tabulated on a monthly basis.

d. Since the Annualize Payroll Pro Forma annualizes the test year to March 2011 levels of employee head count, the first full year of savings would therefore be the 12 month period April 2011 through March 2012.

Witness: Jay La Benz

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Response to Staff 25.5 Continued:

e. Please see the work papers JCL_WP27 pages 1 through 12 and APS's response to Staff 25.6 (b).

f. The $23,446,000 pro forma adjustment, which represents the payroll cost savings not already reflected in the test year, is based on the net reduction of 259 employees. Non-voluntary employee reductions were each paid a severance. The cost to APS of these severance costs totaled $10,099,000. The concept is that 2010 severance costs reduce future annual payroll costs. New customer rates will reflect lower payroll, but that benefit should be partially offset by the cost of obtaining that benefit.

g. None of the $23,446,000 savings actually occurred in the 2010 Test Year, which is why it is reflected as a savings adjustment to the 2010 Test Year as part of the "Annualize Payroll" Pro Forma. The Annualize Payroll Pro Forma adjusts the Test Year to reflect March 2011 employees and wage levels. The Annualize Payroll Pro Forma removes the expense that still remains in the test year for the employees prior to termination. Of the $23,446,000 savings, approximately $11,500,000 relate to APS O&M and $3,900,000 relate to APS Capital, with the remainder relating to amounts billed to participants in jointly owned facilities.

h. See APS's responses to 25.5(c) & 25.5(d)

i. See APS's responses to 25.5(c) & 25.5(d)

j. See APS's responses to 25.5(c) & 25.5(d)

k. APS did not file a request for accounting deferrals or establish a regulatory asset related to the $10,099,000. It did request, however, that the expense be amortized over a 3 year period to match the cost against the benefit.

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OCTOBER 12, 2011

Staff 21.6: Directors and Officers liability insurance.

a) Has the Company included any amounts in rate base for Directors and Officers liability insurance? If so, please identify the total and ACC jurisdictional amounts by account.

b) Has the Company included any amounts in operating expense for Directors and Officers liability insurance? If so, please identify the total and ACC jurisdictional amounts by account.

c) Please identify the cost and coverage for each Directors and Officers liability insurance policy that was in effect during each year 2009, 2010 and 2011.

d) Does the Company record any amounts for Directors and Officers liability insurance as prepaids? If not, explain fully why not. If so, please show the amounts for January 1, 2010 through the present.

Response:

a) No, premiums for Directors and Officers liability insurance are expensed during the period in which the policy is in effect (see response b), not capitalized.

b) Yes, in 2010 the Company included $1,170,354 Total Company and $1,099,366 ACC Jurisdiction in operating expenses which was recorded to FERC account 9250000.

c) The Company maintained a deductible of $2,500,000 for each of the years referenced. The following is a breakdown of coverage and premiums for each policy carried in these years:

2009

Insurance Carrier	Coverage Amount	Annual Premium
AEGIS	$35,000,000	$514,475
EIM	$10,000,000	$151,200
Zurich	$15,000,000	$155,925
RLI	$15,000,000	$93,555
Twin City Fire	$15,000,000	$80,100

Witness: Jim Hatfield

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Response to Staff 21.6 continued:

2010

Insurance Carrier	Coverage Amount	Annual Premium
AEGIS	$35,000,000	$657,354
Chubb (Federal Insurance)	$15,000,000	$135,000
Zurich	$15,000,000	$103,500
AXIS	$15,000,000	$76,500
EIM	$10,000,000	$54,000
ACE	$15,000,000 (Side A Only)	$81,000
Arch	$15,000,000 (Side A Only)	$63,000

2011

Insurance Carrier	Coverage Amount	Annual Premium
AEGIS	$35,000,000	$617,947
Chubb (Federal Insurance)	$15,000,000	$141,000
Zurich	$15,000,000	$108,100
AXIS	$15,000,000	$79,900
EIM	$10,000,000	$56,400
ACE	$15,000,000 (Side A Only)	$82,500
Arch	$15,000,000 (Side A Only)	$65,800

d) The Company records premiums as an expense for the year in which coverage applies. Accordingly, all premiums incurred for the 2010 policy year were expensed in that calendar year.

Witness: Jim Hatfield

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OCTOBER 6, 2011

Staff 19.17: Refer to the response to STF 15.20.

a) Identify which lower priority projects were cancelled.

b) Please identify the "certain employee groups" for which base compensation was maintained in 2009 versus 2008.

c) What exactly was done to produce the vegetation management savings of $400k?

d) What exactly was done to produce the $1.3 million savings for pole line hardware and related equipment?

e) What exactly was standardized for fossil plant operations to produce the claimed $3.5 million savings?

f) What fossil plant staffing was reduced and how many full time equivalent (FTE) positions were cut related to the $3.1 million claimed savings?

g) Explain exactly what is meant by wage escalation being "absorbed" into a department and how that produces the claimed savings.

h) What exactly were the Energy Delivery O&M improvements that resulted in the $1.2 million of claimed savings?

i) What exactly were the Energy Delivery Tech and GIS mapping department improvements that resulted in the claimed savings of $1.0 million?

j) What were the IT department staff and contractor reductions (in FTEs) that resulted in the claimed savings?

k) Which IT lesser priority work was eliminated?

Response:

a) Interest savings were calculated from capital project cash flow savings from either lower costs or cancelled projects. While the majority of cash flow savings were the result of projects being completed at a lower cost than anticipated, the specific projects that were cancelled consisted of:

a. Various facilities projects cancelled at CHQ, totaling $4.5M in 2010. This represented projects on several floors that were planned for upgrading to current standards for furniture, flooring, remodeling, re-wiring, electrical, patching, painting, and technology wiring.

b. Various facilities projects cancelled at Energy Delivery Division locations, totaling $1.5M in 2010. This

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Response to Staff 19.17 Continued:

represented projects at a variety of locations across the state of the same type and nature as described in the response to a) above.

b) As detailed in the letter dated March 18, 2009 on our compliance filing regarding 2009 cost management efforts, the employee groups for which base compensation was impacted included all officers, senior managers and all other management personnel. It also included reduced merit increases for non-union frontline employees. Attached is the March 18, 2009 letter as APS14884.

c) Within the supply chain area, standardized procurement practices were established and implemented to improve planning, procuring, warehousing and delivery of materials and services. Specific activities included:

a. For the vegetation management area savings, a contract renegotiation process was undertaken based on a detailed analysis and breakdown of the contract rate structure. As a result of discussions with the incumbent supplier, contract concessions were attained in several areas including general liability insurance costs and worker compensation costs, which totaled to $400K for 2010.

b. For the Energy Delivery pole line hardware and related equipment area savings, a comprehensive strategic sourcing analysis was conducted on some 280 items within our warehouses procured from a variety of suppliers. As a result of this sourcing process, reduced costs were achieved from suppliers in a variety of ways, including by establishing set margins based on spend volume, reducing freight costs by using alternative means, reducing the quantity of suppliers to concentrate the spend volume, dealing directly with manufacturers instead of using distributors and using national pricing agreements and index pricing with set margins, all of which totaled to $1.3M in 2010.

d) See c) above.

e) As presented in Mark Schiavoni's testimony on pages 24-26, the standardization was of the many and varied processes at each of the fossil plants. This standardization of processes

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Response to Staff 19.17 Continued:

enabled the plants to become more cost effective and efficient. Historically, the plants had been run as individual entities rather than as an integrated fleet. A fossil operations model was established to move to a one-fleet mind-set. This model consists of a comprehensive playbook of how Fossil Generation will operate and conduct business. It represents a proven way of managing and doing business that will allow Fossil Generation to align priorities, standardize on best practices, sustain results, and continuously improve operations. During 2010, over 100 Policy, Process and Procedure documents were developed and implemented. These processes and documents are categorized under five main groups:

a. Safety effectiveness
b. Workforce effectiveness
c. Environmental commitment
d. Operational excellence
e. Asset management

f) As indicated in our response to Staff 15.20, these reduced fossil staffing costs occurred at Cholla, Four Corners, and our other fossil areas. While full time equivalent positions are not specifically tracked within the company, employee counts by regular, temporary and contract employee groups are tracked. The savings identified in Staff 15.20 for the Fossil area was the result of over 100 regular employee positions being reduced in 2010, with the majority of those occurring at the Four Corners power plant, the savings of which totaled $3.1M in 2010.

g) Wage escalation costs being absorbed by a department means that the particular department is not receiving additional budgeted funds to cover the additional costs associated with the wage escalation. Therefore, the department must find savings across its other activities to offset the wage escalation cost increase.

h) As presented in Daniel Froetscher's testimony on pages 18-20, Energy Delivery has had a concerted focus on cost improvement over the last several years. This improvement effort has included attention on work prioritization, work scheduling, work load, overtime costs, third party contractors, and process improvements such as the SOAR initiative. While these changes have lowered costs associated with capital projects, they have also improved the efficiencies

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Response to Staff 19.17 Continued:

of several operations and maintenance departments. Two of the primary departments that focus on operational activities, the ED Operations and Maintenance Department and the ED Technology and GIS (Geographical Information System) Department, were able to gain cost reductions through these many process and efficiency improvements during 2010. More specifically, the ED Operations and Maintenance Department was able to gain efficiencies of $1.2M in 2010 by reducing overtime, reducing contractor work and stretching out the filling of vacancies. The ED Technology and GIS Department was able to gain efficiencies of $1.0M in 2010 by re-evaluating its processes and workload and reducing its workforce.

i) See h) above.

j) As indicated in response to f) above, while full time equivalent positions are not specifically tracked within the company, employee counts by regular, temporary and contract employee groups are tracked. The savings identified in Staff 15.20 for the IT area was the result of over 100 contractor and regular employee positions being reduced in 2010, with the majority of those occurring from reduced contractor positions.

k) As indicated in the response to Staff 15.20, most work processes and work activities performed by the IT Department were re-evaluated in 2010 and many work activities were reduced. Work requests that were reduced primarily included (but not exclusively) requests for development of new applications and enhancements to existing applications of a less critical nature to the supply and distribution of electricity to our customers, as well as requests for replacements of existing equipment that were beyond manufacturers' specifications in terms of technology support but still functional.

Witness: Don Robinson

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Staff 25.21: Refer to JCL_WP30, page 5 of 63. What specific non-plant maintenance was done in 2005 that caused the amounts in that year to be so much higher than in each and every other year?

Response: Year 2005 was $900,000 higher than other years because of $657,000 in incentive charged in that year plus a higher than average payroll accrual charged that year to department 9960 of $235,000 compared to the six year average of $55,000.

Witness: Jay La Benz

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OCTOBER 27, 2011

Staff 27.11: Four Corners Units 4&5 acquisition – impacts on APS' filing.

a) Please identify, quantify and explain each component of APS' filing that is impacted by, or reflects an assumption that the proposed acquisition by APS of Southern California Edison's ownership in those units would be consummated.

b) For each component or aspect of APS' filing that is based on, or effectively reflects that the proposed acquisition by APS of Southern California Edison's ownership in those units would be consummated, please show the impact on APS' filing if that proposed transaction were not to be consummated.

c) Please explain and quantify the impacts of the proposed acquisition of Four Corners Units 4 and 5 on each of the following components of APS' filing, as well as any others that have been affected by that proposed acquisition:

1. Rate base – show by component
2. Mine reclamation cost recovery
3. Dismantlement cost recovery
4. Depreciation rates
5. Base cost of fuel and purchased power

Response: (a) – (c) The attached file APS14988 shows the remaining net book value of the Four Corners assets as of December 31, 2010. See Direct Testimony of Ronald E White, page 10 for a description of how depreciation and dismantlement costs were addressed in consideration of the proposed acquisition by APS of Southern California Edison's ownership in those units. In addition, the coal mine reclamation pro forma takes into consideration the remaining lives of the Four Corners units. If this transaction is not consummated these costs would still need to be recovered, although the pattern of recovery may be different. They could be recovered over the years 2012-2016, which represents the likely remaining life of Four Corners absent the APS acquisition of SCE's interest, or some other reasonable period of time as determined by the Commission. See Staff 22.9 for a discussion related to fuel impacts.

Witness: Jay La Benz

ARIZONA PUBLIC SERVICE
Depreciation Reserve Summary
Steam Production
As of December 31, 2010

Four Corners Units 1-3		Recorded Reserve	
Account Description	Original Cost	Total Reserve	Net Book Value
311.00 Structures & Improvements	40,683,091	22,130,773	18,552,319
312.00 Boiler Plant Equipment	242,101,914	166,321,891	75,780,023
314.00 Turbogenerators	50,183,693	34,950,798	15,232,896
315.00 Accessory Equip	24,333,485	14,311,157	10,022,328
316.00 Misc Power Plant Equip	11,655,314	5,718,804	5,936,510
	368,957,497	**243,433,422**	**125,524,075**

Four Corners Units 4-5			
Account Description	Original Cost	Total Reserve	Net Book Value
311.00 Structures & Improvements	11,882,266	7,361,654	4,520,612
312.00 Boiler Plant Equipment	118,062,055	75,799,402	42,262,653
314.00 Turbogenerators	21,183,385	10,435,941	10,747,444
315.00 Accessory Equip	11,137,088	7,001,791	4,135,297
316.00 Misc Power Plant Equip	3,614,952	2,053,080	1,561,872
	165,879,746	**102,651,868**	**63,227,878**

Four Corners Common			
Account Description	Original Cost	Total Reserve	Net Book Value
311.00 Structures & Improvements	4,983,659	2,342,778	2,640,881
312.00 Boiler Plant Equipment	15,238,147	7,855,190	7,382,958
314.00 Turbogenerators	1,987,500	1,288,114	699,386
315.00 Accessory Equip	4,593,380	1,839,483	2,753,897
316.00 Misc Power Plant Equip	10,452,621	4,142,487	6,310,134
	37,255,307	**17,468,052**	**19,787,256**
Total Four Corners	**572,092,550**	**363,553,342**	**208,539,209**

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OCTOBER 25, 2011

Staff 25.22: Four Corners Units 1-3 maintenance.

a. Refer to JCL_WP30, pages 2 and 3 of 63. Please provide APS' specific plans and budgets for overhauls on Four Corners Units 1, 2 and 3, in each year, 2011 and 2012.

b. Please provide APS' actual expense for overhauls on Four Corners Units 1, 2 and 3 in 2011 through September.

c. Refer to JCL_WP30, pages 2 and 3 of 63. Please provide APS' specific plans and budgets for Routine Maintenance on Four Corners Units 1, 2 and 3, in each year, 2011 and 2012.

d. Please provide APS' actual expense for Routine Maintenance on Four Corners Units 1, 2 and 3 in 2011 through September.

e. Given the expectation that APS will retire Four Corners Units 1, 2 and 3 in 2012, please explain how the planned retirement will affect the $5.085 million, $5.142 million and $6.547 million maintenance expense for Four Corners Units 1, 2 and 3 that APS is requesting.

f. Does the overhaul and routine maintenance cycle typically cease with a fossil unit after it has been retired? If not, explain fully why not.

g. What amounts of Overhaul and Routine Maintenance does APS project for each unit of Four Corners Units 1, 2 and 3 beyond 2012? Explain and provide the projections.

   1. If APS has different projections for Units 1-3 post-2012 maintenance depending upon whether those units are retired in 2012 or not, please identify, explain and provide the alternative versions.

Response:

(a) Please see APS14967, attached.

(b) Please see APS14967, attached.

(c) Routine Maintenance costs are related to the continuing preventative and corrective maintenance, inspections and emergent repairs at the plants. Thus, unlike outages, there is no specific and/or pre-defined work scope for all of the activities that are performed under Routine Maintenance. Please see attachment to STF25.18 for 2011 Budget and 2012 Forecast of Routine Maintenance.

(d) APS's actual routine maintenance on Four Corners Units 1, 2 and 3 in 2011 through September are $3,227K, $2,328K, and $2,642K, respectively.

Witness: Jay La Benz/Mark Schiavoni

ARIZONA CORPORATION COMMISSION
STAFF'S TWENTY FIFTH SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
OCTOBER 25, 2011

Response to Staff 25.22 Continued:

(e) APS's deferral order proposed in Docket No. E-01345A-10-0474, would net any reduced costs of Units 1-3 with the acquisition of SCE's share of Units 4-5, thus providing customers the benefit of any cost offsets. Also, as stated in that Docket, Units 1-3 could continue running past the acquisition date to (1) allow for a transition period and (2) if favorable market conditions exist, APS could sell the output as off-system sales, crediting margins to customers through the PSA.

(f) The normal overhaul and ongoing maintenance cycles would cease after a fossil unit has been retired. However, costs will be incurred after a plant ceases operation in order to perform activities to secure the unit in a safe condition until dismantlement and decommissioning.

(g) Please see response to 25.22(e) and (f).

(g)(1) In the event Units 1-3 remain in-service beyond 2012, maintenance costs for those units would increase and would likely reflect amounts similar to those submitted in the Fossil Maintenance Normalization proforma. If a deferral order is granted maintenance costs for Units 1-3 would influence the amount of such deferral, see response to 25.22 (e).

Witness: Jay La Benz/Mark Schiavoni

ARIZONA CORPORATION COMMISSION
STAFF'S FIRST SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
JULY 14, 2011

Staff 1.36: Edison Electric Institute dues.

a. What amount of dues for EEI has the Company requested? Show the amounts, by account.
b. Provide copies of the Edison Electric Institute dues invoices for the years 2009, 2010 and 2011.
c. Include invoices for each EEI committee any subgroup.
d. Identify the portion for EEI dues and for each EEI group for lobbying activities that has been recorded into below-the-line accounts.

Response:

a. The company has requested $619,143 of EEI membership dues recorded in account 930.2. Also included in the request are subcommitte dues attched in part c below. UARG membership dues of $157,896 recorded in account 930.2. USWAG membership dues of $34,763 recorded in account 930.2. APLIC membership dues of $2,500 recorded in account 593.

b. Attached as APS14207, APS14208, and APS14209 are the requested invoices.

c. Attached as APS14210, APS14211, and APS14218 are the requested invoices.

d. Lobbying expenses for EEI of $132,329 were recorded into below-the-line accounts during the Test Year. Also included in the EEI dues are donations of $30,000 that were recorded into below-the-line accounts during the Test Year.

Witness: Jay La Benz

2011 Allocation

	Total	O&M 00-9302-00 620	Lobbying 00-4264-00 430	Charitable 00-4261-00 895	2011 Split O&M	2011 Split Lobbying
Regular Activities	705,660	557,471	148,189		79.00%	21.00%
Industry Issues	70,566	45,868	24,698		65.00%	35.00%
Mutual Assistance Prog	5,000	5,000				
2011 Contribution	30,000			30,000		
	811,226	608,339	172,887	30,000		

2010 Allocation

	Total	O&M 00-9302-00 620	Lobbying 00-4264-00 430	Charitable 00-4261-00 895	2010 Split O&M	2010 Split Lobbying
Regular Activities	678,611	570,033	108,578		84.00%	16.00%
Industry Issues	67,861	44,110	23,751		65.00%	35.00%
Mutual Assistance Prog	5,000	5,000				
2010 Contribution	30,000			30,000		
	781,472	619,143	132,329	30,000		

ARIZONA CORPORATION COMMISSION
STAFF'S TWENTY SECOND SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
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OCTOBER 14, 2011

Staff 22.5: Edison Electric Institute.

a) Please provide the EEI budget for each year 2008, 2009, 2010 and 2011.

b) Please provide the EEI financial statements for each year 2008, 2009, 2010 and 2011.

c) Does APS have any information breaking out EEI core dues activities by NARUC operating expense category, i.e., legislative advocacy; legislative policy research; regulatory advocacy; regulatory policy research; advertising; marketing; utility operations and engineering; finance, legal planning and customer service; public relations; and other? If not, explain fully why not. If so, please provide the most current information APS has.

Response:

a) APS does not receive copies of EEI's budget.

b) APS does not receive copies of EEI's financial statements.

c) EEI does not prepare a schedule of expenses by NARUC Category. Instead EEI provides a copy of a letter that identifies the percent of dues spent on legislative advocacy, which APS previously provided in response to Staff 1.36 as APS14209.

Witness: Jay La Benz

ARIZONA CORPORATION COMMISSION
STAFF'S TWENTY SEVENTH SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
OCTOBER 27, 2011

Staff 27.7: Accumulated Deferred Income Taxes. Referring to the originally filed APS adjustments for post test year plant, by type of plant, and to the updated amounts that APS provided in response to STF 6.55, please provide the Total Company and ACC Jurisdictional amounts (1) as of 3/31/2012 and (2) identify the changes APS estimated to occur for the period April 1, 2012 through June 30, 2012.

Response:

(1) Please see the APS response to Staff 15.9 for 3/31/2012 Total Company Accumulated Deferred Income Taxes (ADIT). The corresponding ACC jurisdiction of these amounts are as follows:

- Solar: $2.476 Million
- Fossil: $12.344 Million
- Nuclear: $30.226 Million
- Distribution and General & Intangibles: $1.878 Million

(2) For Fossil Generation, Nuclear Generation, and Distribution and General and Intangible Plant, the only change in ADIT for the referenced period is continued book and tax depreciation differences on plant in service at 12/31/2010. Consistent with the RES treatment, permitted by Decision No. 71448, Solar Generation ADIT change for the referenced period includes book and tax depreciation on additions during the post test year period.

Witness: Jay La Benz

ARIZONA CORPORATION COMMISSION
STAFF'S FIFTEENTH SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
SEPTEMBER 21, 2011

Staff 15.7: Accumulated Deferred Income Taxes (ADIT).
For ADIT, show the month-end balances by component and in total based on current monthly actual (if available) or projected (if actual is not yet available) information showing all monthly balances for each month, July 2011 through March 2012, and the resultant estimated ADIT balance at March 31, 2012.

Response: Inclusion of any such estimated projections of deferred taxes as a rate base offset may be deemed by the IRS as inconsistent with the historical Test Year method generally used for cost of service and ratemaking purposes. Without guidance from the IRS that explicitly allows such inclusions, APS believes using such methodology would not be appropriate and could result in extremely unfavorable tax consequences to the Company and its customers. That said, please see schedule attached as APS14830.

Witness: Jason La Benz

ARIZONA PUBLIC SERVICE COMPANY
DEFERRED TAXES
SUPPORTING SCHEDULE FOR B-1
(dollars in thousands)

ACCOUNT DESCRIPTION	Actuals Increase (Decrease) RATE BASE 7/31/11	Actuals Increase (Decrease) RATE BASE 8/31/11	Forecast Increase (Decrease) RATE BASE 9/30/11	Forecast Increase (Decrease) RATE BASE 10/31/11	Forecast Increase (Decrease) RATE BASE 11/30/11	Forecast Increase (Decrease) RATE BASE 12/31/11	Forecast Increase (Decrease) RATE BASE 1/31/12	Forecast Increase (Decrease) RATE BASE 2/29/12	Forecast Increase (Decrease) RATE BASE 3/31/12
Total Deferred Taxes per General Ledger	$ (1,819,235)	$ (1,887,398)	$ (1,888,657)	$ (1,893,263)	$ (1,891,763)	$ (1,893,834)	$ (1,895,722)	$ (1,891,506)	$ (1,881,995)
Exclude									
Reg Asset-Power Supply Adjustor Mark to Market	(24,929)	(24,929)	(18,418)	(17,861)	(18,042)	(17,792)	(17,719)	(17,882)	(18,323)
Reg Asset-Transmission Vegetation Management	(17,857)	(17,747)	(17,701)	(17,685)	(17,690)	(17,683)	(17,680)	(17,687)	(17,708)
Reg Asset-Unamortized Loss on Reaquired Debt	(8,346)	(8,187)	(8,120)	(8,097)	(8,105)	(8,094)	(8,089)	(8,100)	(8,130)
Option II Benefits (Includes Reg Asset and Def Comp)	4,272	3,879	3,712	3,653	3,672	3,646	3,640	3,653	3,689
Reg Asset-Demand Side Management	(4,351)	(2,806)	(2,151)	(1,922)	(1,997)	(1,894)	(1,876)	(1,916)	(2,025)
Reg Liab-Renewable Energy Standard	20,208	21,054	21,412	21,538	21,497	21,553	21,580	21,520	21,359
Reg Liab-Power Supply Adjustor	9,129	1,041	(2,391)	(3,588)	(3,198)	(3,736)	(3,703)	(3,776)	(3,974)
Renewable Energy Incentives	47,539	53,456	55,966	56,841	56,556	56,950	57,066	56,807	56,107
Mark to Market	74,908	64,472	82,448	81,877	82,063	81,806	81,730	81,900	82,362
OCI-Pension Taxes	22,123	22,123	22,123	22,123	22,123	22,123	22,123	22,123	22,123
Superfund	1,758	1,711	1,691	1,684	1,686	1,683	1,682	1,685	1,694
Other	1,039	1,039	1,039	1,039	1,039	1,039	1,039	1,039	1,039
Total Deferred Taxes	$ (1,944,729)	$ (2,002,501)	$ (2,028,266)	$ (2,032,865)	$ (2,031,367)	$ (2,033,434)	$ (2,035,202)	$ (2,031,256)	$ (2,022,162)

ARIZONA CORPORATION COMMISSION
STAFF'S TWENTY SECOND SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
OCTOBER 14, 2011

Staff 22.9: Base cost of fuel.

a) Please update Attachment PME-3 and PME-4 using current information on fuel costs projected for 2012. Please provide the updated results in Excel.

b) Please provide quantifications and workpapers for the items in footnotes 1 through 7 on Attachment PME-3:

1) ISFSI expense

2) Coal reclamation costs

3) Fuel costs associated with long-term tolling arrangements

4) Native load head liquidation costs

5) Fixed capacity contract costs

6) Above market purchases of renewable that are recovered through RES

7) Generation associated with Company owned facilities

Response:

a) APS is in the process of updating the base fuel and purchased power pro forma adjustment and will provide it upon its completion. We anticipate having this update available at the Rate Case Technical Conference on October 27, 2011.

b)

1) Please see PME_WP2, page 1 of 3, for the test year amounts of nuclear ISFSI amortization excluded from the base fuel rate.

2) Please see PME_WP2, page 1 of 3, for the test year amounts of coal reclamation costs excluded from the base fuel rate.

3) Please see PME_WP5, page 2 of 7, for the amount of gas fuel expense associated with long-term tolling arrangements included in the base fuel rate.

4) Please see PME_WP5, page 2 of 7, for the current contract cost vs. market value of the native load power hedges (labeled "SE06 Hedge MTM") included in the base fuel rate.

Witness: Pete Ewen

ARIZONA CORPORATION COMMISSION
STAFF'S TWENTY SECOND SET OF DATA REQUESTS
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Response to Staff 22.9 continued:

5) Please see PME_WP5, page 2 of 7, for the amount of fixed capacity contract costs (labeled "Demand Cost" or "Demand") included in the base fuel rate.

6) Please see PME_WP5, page 2 of 7, for the amount of above market purchases of renewable energy that are recovered through RES (labeled "Above-Market Premiums") included in the base fuel rate.

7) Please see APS14923, attached.

Supplemental Response to Staff 22.9:

a) Attached are the supplemental base fuel updated and associated workpapers:

- Attachment PME-3 as APS14926
- Attachment PME-4 as APS14927
- Workpaper PME_WP1 as APS14928
- Workpaper PME_WP2 as APS14937
- Workpaper PME_WP5 as APS14929
- Workpaper PME_WP6 as APS14930
- Workpaper PME_WP9 as APS14931

Witness: Pete Ewen

Arizona Public Service Company
Docket No. E-01345A-11-0224
Attachment RCS-4
Copies of Confidential APS' Responses to Data Requests and Workpapers Referenced in the Direct Testimony and Schedules of Ralph C. Smith

****APS Confidential Pages Have Been Redacted****

Data Request/ Workpaper No.	Subject	Confidential	No. of Pages	Page No.
Staff 19.14	ADIT on post test year plant	Yes	4	2 - 5
Staff 19.15	APS will have a **[*BEGIN CONFIDENTIAL*]** **[*END CONFIDENTIAL*]**; tax loss carryforwards and income tax expense	Yes	3	6 - 8
Staff 27.1	Actuarial valuation of pension and OPEB costs presented on May 20, 2011 by Towers Watson	Yes	4	9 - 12
Staff 9.4	Expense in test year related to APS' forensic investigation of Department of Energy funded projects	Yes	1	13
Staff 9.7	Expense in test year related to investigation of of DOE grant-funded projects	Yes	1	14
Staff 9.8	Investigation of DOE grant-funded projects is complete	Yes	1	15
Staff 9.9	Documentation referenced in Deloitte & Touche audit workpapers not provided	Yes	1	16
Staff 19.21	Expenses for investigation into grants and government awards removed from test year	Yes	2	17 - 18
Staff 20.4	Expenditures for grant-funded projects	Yes	3	19 - 21
Staff 21.2	External advertising retainer contract (response without copy of contract)	Yes	1	22
Staff 22.2	Incentive compensation for years 2008 - 2010	Yes	2	23 - 24
Staff 20.8	Incentive compensation allocations for officers, front line and non-senior management	Yes	5	25 - 29
Staff 1.16	Description of retirement and incentive compensation programs	Yes	28	30 - 57
	Total Pages Including this Page		57	

ARIZONA CORPORATION COMMISSION
STAFF'S NINETEENTH SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
OCTOBER 6, 2011

Staff 19.14: ADIT on post test year plant. Refer to the response to STF 15.13.

a) Explain fully and in detail and cite all provision of the tax law, treasury regulations, IRS revenue rulings etc. relied upon for APS' opinion that reflecting ADIT that is directly related to post test year plant might in any way be inappropriate.

b) Please provide a draft of the guidance that APS would need to seek from the IRS to explicitly allow post test year ADIT to match post test year plant amounts being reflected in rate base.

c) Please describe fully how APS would propose to reflect for ratemaking purposes the post test year ADIT that is directly related to post test year plant being included in rate base.

d) Identify, quantify and explain in detail all tax loss carry forwards that exist for APS at December 31, 2010, and their estimated use and impact on 2011 bonus tax depreciation.

e) Provide all APS calculations of projected or estimated use of tax loss carry forwards that exist at December 31, 2010.

f) Provide all APS calculations of projected or estimated use of tax loss carry forwards that APS expects would exist at December 31, 2011 with APS taking 2011 bonus federal tax depreciation in 2011.

g) How were the 37%, 63%, 90%, 18.5%, and 81.5% on APS14831 page 2 of 2 derived? Provide explanations and supporting calculations.

Response:

a) Accelerated depreciation was enacted by Congress with the general intention of encouraging economic growth and investment by providing a capital subsidy to those businesses investing in certain machinery and equipment. The immediate provision of the benefits of accelerated depreciation to utility customers (via lower current rates) was generally seen as contrary to the intended purpose of the incentive. To prevent this outcome, normalization of accelerated depreciation is required for ratemaking purposes by IRC Section 168(f)(2) and (i)(9) and former IRC Section 167(l).

The service continues to rely on the IRC §167(l) regulations in resolving issues arising under the MACRS normalization requirements.

Witness: Jay La Benz

ARIZONA CORPORATION COMMISSION
STAFF'S NINETEENTH SET OF DATA REQUESTS
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Response to Staff 19.14 Continued:

For depreciation, a utility is generally considered in compliance with the normalization rules if it meets three requirements: First, it must account for the variation between straight-line cost of service depreciation and accelerated tax deprecation in the ratemaking process by making an adjustment to a reserve account - that is, it must include a deferred tax expense component in cost of service. Second, while the deferred tax liability associated with accelerated tax depreciation (the reserve account) can be used as a rate base reduction, the amount of the rate base reduction is limited. Finally, the reserve account must only be reversed for certain, specified events.

The proposal regarding ADIT associated with post-test year plant implicates the second of the above-mentioned requirements - the rate base reduction limitation.

Treasury Regulation §1.167(l)-1(h)(6)(i) provides that "...a taxpayer does not use a normalization method of accounting if, for ratemaking purposes, the amount of the reserve for deferred taxes under section 167(l) which is excluded from the base to which the taxpayer's return is applied, or which is treated as a no-cost capital in those rate cases in which the rate of return is base on cost of capital, exceeds the amount of such reserve for deferred taxes for the period used in determining the taxpayer's tax expense in computing cost of service in such ratemaking."

This regulation section provides that a taxpayer may not exclude from rate base a reserve for deferred taxes in excess of the amount of reserve determined in computing tax expense in accordance with the normalization requirements. Thus, it requires that the reduction in rate base be synchronized with the quantity of deferred taxes reflected in cost of service. The Company is concerned that the incremental ADIT associated with post-test period plant fails to satisfy this requirement insofar as it was never included in cost of service.

This regulation was drafted as a response to the ratemaking practice of computing tax expense for cost of service purposes utilizing historical information (e.g., 2010 historic test year), while computing the reserve for deferred income taxes allowable as a reduction from rate base based on projected data (e.g., deferred taxes for post test year).

Witness: Jay La Benz

ARIZONA CORPORATION COMMISSION
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Response to Staff 19.14 Continued:

In the view of the IRS, this created two problems. First, assuming a financially healthy utility, the amount excluded from rate base was greater than the reserve for deferred tax at the end of the historical period. Failure to allow an investment return on this excess of the excluded amount over the amount of the reserve for the historical period resulted in flow-through of the benefits of the projected reserve accrual. Second, even though any projected increase in the reserve for deferred taxes would accrue over time, the entire amount expected to be in the reserve at the end of the future period was excluded from rate base. Excluding the full projected amount, even if ratemaking tax expense was computed using the same projections, resulted in denying a return on a greater amount that the utility was projected to have on hand at any particular time over this future period. Section 1.167(l)-1(h)(6)(i) deals with the first problem, that of *consistency,* while 1.167(l)-1(h)(6)(ii) addresses the second problem, that of *timing"* (PLR 9029040).

The amount of the reserve excluded from rate base must be computed on the same period used to determine ratemaking tax expense. If a historical period is used to determine depreciation for federal income tax expense for ratemaking purposes, the maximum amount of the reserve that can be excluded from rate base is the amount of such reserve at the end of the historical period.

Failure to comply with the normalization rules can subject a utility to significant penalties, including the forfeiture of accelerated depreciation deductions for the utility's public utility property. Taxpayers are obligated by regulation to report a normalization violation to the IRS within 90 days.

b) A draft of the guidance (a Private Letter Ruling) that APS would need to seek from the IRS has not yet been prepared, and could take several months to draft. Additionally, outside tax counsel would be needed to properly draft and file such a request for guidance. APS believes that the associated expenditures should not be made until it becomes readily apparent that no other options are available.

c) With regard to the reflection of ADIT associated with post-test year plant, APS proposes one of two options:

ARIZONA CORPORATION COMMISSION
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Response to Staff 19.14 Continued:

1) Allow post test year additions in a manner consistent with the 2009 rate settlement. That is, do not reduce the post test year plant additions for estimated post test year ADIT. Aside from being consistent with prior practice, this will clearly not violate the normalization rate base reduction limitation.

2) Permit APS to use a complete future test period ending June 30, 2012 for all rate case items. Not only would the information upon which rates are established be more representative of the conditions during the period in which rates would be in effect, because all components of the rate case would then employ the same basis of reporting, there would be no concern regarding the application of the normalization rules.

d) No federal tax loss carry forwards existed for APS at December 31, 2010.

e) As stated above, no federal tax loss carry forwards existed for APS at December 31, 2010.

f) **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

g) The percentages on APS14831 page 2 of 2, provided in response to Staff 15.13, represent estimated ranges of post test year plant additions eligible for either 100-percent or 50-percent bonus tax depreciation. These amounts were estimated based upon prior experience with bonus depreciation from 2001 to present.

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Staff 19.15: Tax loss carry forwards and income tax expense. Refer to the response to STF 15.13, which mentions that APS expects tax loss carry forwards.

a) Did APS pay any federal income tax for 2010? If not, explain fully why not. If so, please identify the amount paid.

b) Did APS' parent company pay any federal income tax for 2010? If not, explain fully why not. If so, please identify the amount paid.

c) Does APS anticipate having to pay any federal income tax for 2011? If not, explain fully why not. If so, please identify the amount APS expects to pay and include supporting calculations.

d) Does APS anticipate having to pay any federal income tax for 2012? If not, explain fully why not. If so, please identify the amount APS expects to pay and include supporting calculations.

e) Does APS' rate filing reflect any claim for current federal income tax expense? If not, explain fully why not. If so, please identify the amount and show in detail how it was calculated.

f) Does APS' rate filing reflect any claim for deferred federal income tax expense? If not, explain fully why not. If so, please identify the amount and show in detail how it was calculated.

g) Does APS' rate filing reflect any claim for current Arizona state income tax expense? If not, explain fully why not. If so, please identify the amount and show in detail how it was calculated.

h) Does APS' rate filing reflect any claim for deferred Arizona state income tax expense? If not, explain fully why not. If so, please identify the amount and show in detail how it was calculated.

i) Can APS have a positive current federal income tax expense if no federal income taxes are being paid for the year and APS has a net operating loss carry forward? If not, explain fully why not. If so, explain exactly how that can occur.

Response: a) **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

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Response to Staff 19.15 Continued:

b) **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

c) No. As a result of 100-percent bonus depreciation, APS will have a tax net operating loss in 2011.

d) **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

e) Yes, APS's rate filing reflects a claim for current federal income tax expense. APS rate filing is based upon the 2010 historical test year. Line 15 of JCL_WP25 shows the actual test year tax expense of $175.4 million.

f) Yes, APS's rate filing reflects a claim for deferred federal income tax expense. APS rate filing is based upon the 2010 historical test year. Line 15 of JCL_WP25 shows the actual test year tax expense of $175.4 million. This actual test year tax expense contains federal deferred tax expense of $208.4 million.

g) Yes, APS's rate filing reflects a claim for current state income tax expense. APS rate filing is based upon the 2010 historical test year. Line 15 of JCL_WP25 shows the actual test year tax expense of $175.4 million. The actual test year tax expense contains a current state tax expense of $17.9 million.

h) Yes, APS's rate filing reflects a claim for deferred state income tax expense. APS rate filing is based upon the 2010 historical test year. Line 15 of JCL_WP25 shows the actual test year tax expense of $175.4 million. The actual test year tax expense contains a deferred state tax expense of $16.9 million.

i) Yes. Income tax expense for financial accounting and ratemaking purposes is generally based upon accrual accounting principles. Income tax liability reported on a federal income tax return is based upon actual cash taxes paid. As such, material differences will arise.

Witness: Jay La Benz

ARIZONA CORPORATION COMMISSION
STAFF'S NINETEENTH SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
OCTOBER 6, 2011

Response to Staff 19.15 Continued:

The Internal Revenue Code provides certain specific rules for the determination of taxable income. The use of these rules means that a utility's income tax expense for financial accounting and ratemaking purposes generally will not be the same as the income tax liability shown on its tax return. Moreover, the ACC has required the full tax normalization of these and other items since at least 1983. See Decision No. 53761.

If a public utility commission uses the utility's Federal income tax liability as shown on the utility's income tax return for income tax expense for ratemaking purposes, the commission is using a "flow-through" method of accounting for taxes. Section 168(f) of the Internal Revenue Code requires that a regulated public utility use a "normalization" method of accounting in order to qualify for certain accelerated tax benefits. "Flow-through" is explicitly not allowed.

ARIZONA CORPORATION COMMISSION
STAFF'S TWENTY SEVENTH SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
OCTOBER 27, 2011

Staff 27.1: Pension/OPEB deferral.

a) Are any of the amounts for pensions and OPEBs in JCL_WP35 supported by the actuarial reports that were provided in response to Pre-filed 1.23? If so, please reconcile the amounts for pensions and OPEBs in JCL_WP35 to such actuarial reports.
b) Please provide the actuarial reports supporting the 2011 and 2012 pension and OPEB amounts in JCL_WP35.
c) What is the "SEBRP" in JCL_WP35?
d) Does the SEBRP in JCL_WP35 have any relation to the Supplemental Executive Retirement Benefits Plan mentioned in APS witness Guldner's direct testimony at page 6, lines 25-27? If not, explain fully why not. If so, please identify the relationship.
e) Identify, quantify and explain exactly how much of the pension/OPEB deferral amount of $26,219,162 on JCL_WP35 relates to the Supplemental Executive Retirement Benefits Plan, and provide supporting calculations.
f) Does APS believe that Section IX of the Settlement Agreement in Docket No. E-01345A-08-0172 or Order No. 71448 authorized APS to defer costs for the Supplemental Executive Retirement Benefits Plan? If not, explain fully why not. If so, explain fully and provide the supporting documentation.
g) Referring to JCL_WP35, page 4 of 9 and Settlement Agreement page 17, Section IX, Pensions and OPEB Deferrals. Does APS agree that the $23.949 million in Settlement Agreement paragraph 9.3 is the same as the $23,948,768 on JCL_WP35, page 4 of 9 and only includes the $17,228,847 for pension and $6,719,921 for OPEB, and does include cost for the Supplemental Executive Retirement Benefits Plan or for the "Misc. Expense" line items? If not, explain fully why not.
h) Does the $29,464,689 pension amount or $20,703,241 OPEB amount on JCL_WP35, page 3 of 9 include any amounts that would correspond to the "Misc. Expense" line item on JCL_WP35, page 4 of 9? If so, please identify the "Misc. Expense" amounts included in those figures. If not, explain fully why not.
i) Refer to JCL_WP35, page 3 of 9. Provide the most current Towers Perrin information on Pension and OPEB that corresponds to the Pension and OPEB amounts on JCL_WP35, page 3 of 9. This includes the "final 2011 calc" mentioned on that workpaper as well as any subsequent corrections, revisions or adjustments.

Witness: Jay La Benz

ARIZONA CORPORATION COMMISSION
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DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
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OCTOBER 27, 2011

Staff 27.1 Continued:

j) Does APS have any estimates or projections of its 2012 pension or OPEB cost? If not, explain fully why not. If so, please provide the most current projections and estimates.
k) On JCL_WP35, page 2 of 9, why did APS assume that the 2012 pension and OPEB amounts were identical to the 2011 estimates?
l) Please identify the amount and date of pension funding payments for each year, 2008 through 2011 to date.
m) Please identify the amount and date of OPEB funding payments for each year, 2008 through 2011 to date.
n) Please identify the amount and estimated date of pension funding payments for the remainder of 2011 and for 2012.
o) Please identify the amount and estimated date of OPEB funding payments for the remainder of 2011 and for 2012.

Response:

a) No. The information provided in Pre-Filed 1.23 covered actual valuations for 2008, 2009 and 2010. The information contained in JCL_WP35 was based upon projected 2011 valuation, provided in (b).

b) The 2011 and 2012 pension and OPEB costs were developed using the modeling tool provided by Towers Watson and actual inputs for trust fund balances, returns, etc. See attachment, APS14989, which contains the model inputs and outputs.

c) The "SEBRP" is the Supplemental Executive Benefit Retirement Plan (i.e. unqualified pension plan).

d) Yes, they are the same.

e) None of the $26,219,162 on JCL_WP35 relates to the Supplemental Executive Benefits Retirement Plan.

f) No. Costs associated with Supplemental Executive Benefits Retirement Plan have not been deferred by the Company.

g) The $23,948,768 on JCL_WP35 ties to the $23.949 million in Section 9.3 of the Settlement Agreement. This amount only includes $17,228,847 for pension and $6,719,921 for OPEB. It does not include SERBP or "Misc Items."

h) No. It does not include any "Misc Items" as Section 9.3 of the Settlement Agreement only allows APS to defer costs associated with Pension and OPEB.

Witness: Jay La Benz

ARIZONA CORPORATION COMMISSION
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OCTOBER 27, 2011

Response to Staff 27.1 Continued:

i) See attachment APS14990, which contains the latest (2011) valuation, presented to the Company on May 20, 2011 by Towers Watson. Please note these are total plan expenses and include not only those amounts related to APS O&M, but APS capital, and those billed to other participant owners of joint facilities that the Company operates but does not own 100% the assets. Please note this attachment is confidential and is being provided pursuant to an executed protective agreement.

j) Yes. See attachment APS14991, which contains the 2012 Budget, which is based on APS's most recent Pension and OPEB assumptions. Please note this attachment is confidential and is being provided pursuant to an executed protective agreement.

k) The numbers for 2011 and 2012 are identical because an estimate for 2012 costs was not available and the Company had no additional information at the time of filing that would warrant assuming a difference. Please see response to part (j) for the most recent 2012 assumptions.

l) Pension – 2011 – $0 to date
Pension - 2010 - $194,880,000 (January - $48,365,000, March - $48,365,000, December - $98,150,000).
Pension 2009 - $0
Pension 2008 - $33,705,000 September

m) OPEB – 2011 - $0 to date
OPEB – 2010 - $16,391,050 December
OPEB – 2009 - $14,998,778 December
OPEB – 2008 - $10,569,301 (September - $9,702,601, December - $866,700)

n) 2011 - $0
2012 - $67,041,000

o) 2011 - $19,718,000
2012 - $19,718,000

PAGES 12-16 ARE CONFIDENTIAL AND HAVE BEEN REDACTED

ARIZONA CORPORATION COMMISSION
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DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
OCTOBER 6, 2011

Staff 19.21: Grants and government awards. Refer to the response to STF 15.23. Refer to APS14788, pages 2 and 6 of 12.

a) Have grant monies related to any of the three items listed on APS14788, pages 2 and 6 of 12, been received by APS (1) as of December 31, 2010, or (2) currently? If not, explain fully why not. If so, please identify the amounts of grant money received for each listed item at each date, and show in detail how APS has accounted for those funds.

b) Please identify the amount of test year expense, by account, for Lewis & Fowler consultants.

c) Please identify the amount of test year expense, by account, for each of the following (per APS14788, page 8 of 12):

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

Response:

a) The Grants referred to in the table below are: Integrated Energy System with Beneficial CO2 Use (IES); the High Penetration of Photovoltaic Generation Study – Flagstaff Community Power (HPS), and the Distributed Energy Leadership (Utilities) Program (DELP).

Grant Name	Account	As of December 31, 2010	Year-to-date September 30, 2011
IES	1430	$ 380,162.82	$ 0.00
HPS	1430	$ 314,387.95	$ 281,632.83
DELP	1430	$ 62,113.51	$1,953,065.90

For information related to IES, please see APS response to Staff 9.2.

b) Please see below table:

Vendor	Account	2010
Lewis & Fowler	9200	$ 339,925.48

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OCTOBER 6, 2011

Response to Staff 19.21 Continued:

Lewis & Fowler provided government grant compliance and oversight work associated with all of APS' government-funded grants and certain types of third party contracts funded with government monies.

Lewis & Fowler had a separate work scope supporting IES that cost for which is not reflected in the table above and for which APS has proposed to remove from the Test Year. Please see APS's response to Staff 9.2.

(c) [redacted] Please note this portion of the response is confidential and is being provided pursuant to an executed protective agreement.

PAGES 19-21 ARE CONFIDENTIAL AND HAVE BEEN REDACTED

ARIZONA CORPORATION COMMISSION
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DOCKET NO. E-01345A-11-0224
OCTOBER 12, 2011

Staff 21.2: General Advertising Expense. Refer to the response to Prefiled 1.40, APS14082. Please provide the contract for the External Advertising Retainer, $480,000.

Response: Attached as APS14914 is the requested contract. Please note the attachment is confidential and is being provided pursuant to an executed protective agreement.

ARIZONA CORPORATION COMMISSION
STAFF'S TWENTY SECOND SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
OCTOBER 14, 2011

Staff 22.2: Annual Incentive Compensation. Refer to the response to STF 1.34, APS14222.

a) Please provide similar information showing the annual incentive compensation expense, by account, for each year 2008 and 2009.

b) Please identify how much of the annual incentive compensation in each year, 2008, 2009 and 2010 relates to officers and senior management.

c) Please identify how much of the annual incentive compensation in each year, 2008, 2009 and 2010 relates to union employees.

d) Please identify how much of the annual incentive compensation in each year, 2008, 2009 and 2010 relates to front line and non-senior management.

e) Please provide the ACC jurisdictional amounts, by account, for the annual incentive compensation expense for each year 2008, 2009 and 2010.

Response: (a)-(e) See attachment APS14921 for 2008, 2009 and 2010 requested information. Please note this attachment is confidential and is being provided pursuant to an executed protective agreement.

Witness: Jay La Benz

PAGE 24 IS CONFIDENTIAL AND HAS BEEN REDACTED

ARIZONA CORPORATION COMMISSION
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OCTOBER 6, 2011

Staff 20.8: Annual incentive plan (AIP).

a. Please identify the amount of AIP cost, by account, APS has requested be included in the Company's proposed pro forma adjusted operating expenses.

b. Please identify the amount of AIP cost, by account, APS recorded in 2010.

c. Please reconcile the amount identified in response to part b) with the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** mentioned on APS14820, page 3 of 9.

d. Please provide the high-level documentation for the annual incentive plan calculation process, mentioned on APS14820, page 4 of 9, in item 3.

e. Please provide the documentation related to the 2010 incentive calculation process, mentioned on APS14820, page 4 of 9, in item 2.

f. Please identify the earnings requirement and threshold earnings that must be achieved prior to any payout under the AIP (referenced on APS14820, page 6 of 9) and provide the documentation related to measuring it and evaluating whether it was achieved. Provide this information for the 2010 AIP payout, and also, provide the earnings requirement and threshold earnings that must be achieved prior to any payout under the AIP for 2011.

g. Provide the documentation for the Individual Performance component that was added in 2010, per APS14820, page 6 of 9.

h. How did APS account for the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** mentioned on APS14820, page 7 of 9. Show the amounts by account recorded for this in each year, 2010 and 2011.

i. Has APS included any amount in its expense request related to the $220,000 mentioned on APS14820, page 7 of 9? If so, please identify the amount by account.

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j. APS14820, page 8 of 9 mentions **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

1. Please provide a copy of the corrected spreadsheet in Excel. If a corrected Excel spreadsheet does not exist, provide in Excel the original spreadsheet that was used for the calculations of AIP noted on APS14820, page 8 of 9.

2. Please identify the Officer amounts of AIP incentive compensation for 2010 by account.

k. Please reconcile the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

l. Refer to APS14820, page 9 of 9. Please provide the formalized documentation of the incentive calculation, including the documentation of the Company and Business Unit incentive metrics for each of the business unit areas. Please provide this information for 2010 and 2011. Please identify any related Excel files showing AIP calculations for each year, and provide such Excel files electronically in Excel.

Response:

a) See attachment APS14893 for the cost by account that APS has requested in this case.

b) See same attachment as provided in a).

c) [redacted]

d) The high-level management action plan documentation is scheduled to be completed by October 31, 2011.

e) See response to d).

Witness: Jim Hatfield/Jay La Benz

ARIZONA CORPORATION COMMISSION
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OCTOBER 6, 2011

Response to Staff 20.8 Continued:

f) For the 2010 AIP, the plan documents were previously provided in response to Staff 1.16 and pre-filed 1.24. The actual APS earnings achievement of $336M is as shown on SFR E-9 and as provided in response to Staff 1.16. For the 2011 AIP, the plan documents were provided in Staff 1.16.

g) The Individual Performance component documentation is as described in the 2010 plan document, which was previously provided in Staff 1.16.

h) [redacted]

i) Yes, the $220,000 costs have been included as described in the response to h) and the attachment to a) above.

j) [redacted]

1) This was an error contained in a draft document, which was fixed before it was sent to the HR Committee. This corrected error was unrelated to the incentive cost accrual that was recorded in 2010 and included in the test year filing.

2) [redacted]

k) [redacted]

ARIZONA CORPORATION COMMISSION
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OCTOBER 6, 2011

Response to Staff 20.8 Continued:

l) See response to d) above.

Please note some portions of this response are confidential and are being provided pursuant to an executed protective agreement.

STF 20.8 a), b), c), h), j2) & k)
Annual Incentive Plan Costs for 2010

	Total APS Annual Incentive Plan Costs for 2010		Officer Portion
	FERC Acct	Amount ($000)	Amount ($000)
Capital	107	9,188	
	Payroll Taxes	643	
		9,831	0
O&M	506	4,779	330
	519	784	
	524	7,052	352
	546	1,198	82
	549	566	
	557	963	69
	566	1,470	441
	588	6,662	
	903	3,242	146
	916	703	41
	920	2,814	1,211
	928	285	75
	930	1,008	798
	O&M Incetive Total	31,525	3,545
	Payroll Taxes	2,890	314
		34,415	3,859

	Total Incentive Plan Costs	Officer Portion
	Amount ($000)	Amount ($000)
Participants	30,964	3,021
PNW/BTL	1,377	319
APS Capital	9,188	
APS O&M	31,525	3,545
Total	73,054	6,885

ARIZONA CORPORATION COMMISSION
STAFF'S FIRST SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
JULY 14, 2011

Staff 1.16: Incentive Programs. List and describe all retirement and incentive programs available to Company officers and employees. Provide a complete copy of each incentive compensation program and all related materials. Identify the goals and targets in each year 2009-2011, and all evaluations of whether such goals were exceeded.

Response: As shown in response to Staff 1.15, the retirement programs consist of the SERP program, the 401-K program and the pension plan program. Please see that response for details of the retirement programs. The incentive program for APS is the APS Annual Incentive Award program. APS provided the plans for 2009 and 2010 in response to Pre-Filed 1.24. The 2011 APS Annual Incentive Plan is attached as APS14212. The performance and metric results for the 2008, 2009 and 2010 Annual Incentive Plans, as communicated to our employees, is attached as APS14213, APS14214 and APS14215. Please note that this information is confidential and is being provided pursuant to an executed protective agreement.

Witness: Jim Hatfield

PAGES 31-57 ARE CONFIDENTIAL AND HAVE BEEN REDACTED

Arizona Public Service Company
Docket No. E-01345A-11-0224
Attachment RCS-5
Copies of Regulatory Commission Order Excerpts Addressing Sharing of Directors & Officers Liability Insurance Cost Between Shareholders and Ratepayers

Jurisdiction	Docket No.	Order Date	Utility	No. of Pages	Page No.
Florida	090079-EI; 090144-EI; 090145-EI	March 5, 2010	Progress Energy Florida, Inc.	4	2 - 5
Connecticut	08-07-04	February 4, 2009	United Illuminating Company	3	6 - 8
Connecticut	07-07-01	January 28, 2008	Connecticut Light and Power Company	3	9 - 11
Connecticut	05-06-04	January 27, 2006	United Illuminating Company	3	12 - 14
Connecticut	03-07-02	December 17, 2003	Connecticut Light and Power Company	3	15 - 17
Connecticut	98-1-02	February 5, 1999	Connecticut Light and Power Company	2	18 - 19
Connecticut	99-09-03	May 25, 2000	Connecticut Natural Gas Corporation	3	20 - 22
Arkansas	06-101-U	June 15, 2007	Entergy Arkansas, Inc.	3	23 - 25
Arkansas	04-121-U	September 19, 2005	Centerpoint Energy Resources Corp	3	26 - 28
Arkansas	04-176-U	October 31, 2005	Arkansas Western Gas Company	3	29 - 31
			Total Pages Including this Page	31	

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for increase in rates by Progress Energy Florida, Inc.	DOCKET NO. 090079-EI
In re: Petition for limited proceeding to include Bartow repowering project in base rates, by Progress Energy Florida, Inc.	DOCKET NO. 090144-EI
In re: Petition for expedited approval of the deferral of pension expenses, authorization to charge storm hardening expenses to the storm damage reserve, and variance from or waiver of Rule 25-6.0143(1)(c), (d), and (f), F.A.C., by Progress Energy Florida, Inc.	DOCKET NO. 090145-EI ORDER NO. PSC-10-0131-FOF-EI ISSUED: March 5, 2010

The following Commissioners participated in the disposition of this matter:

NANCY ARGENZIANO, Chairman
LISA POLAK EDGAR
NATHAN A. SKOP
DAVID E. KLEMENT
BEN A. "STEVE" STEVENS III

APPEARANCES:

R. ALEXANDER GLENN, JOHN T. BURNETT, ESQUIRES, Progress Energy Service Company, LLC, P.O. Box 14042, St. Petersburg, Florida 33733-4042; JAMES MICHAEL WALLS, DIANNE M. TRIPLETT, and MATTHEW BERNIER, ESQUIRES, Carlton Fields, P.A., Post Office Box 3239, Tampa, Florida 33601-3239; RICHARD D. MELSON, ESQUIRE, 705 Piedmont Drive, Tallahassee, Florida 32312
On behalf of Progress Energy Florida, Inc. (PEF).

CHARLES REHWINKEL, Associate Public Counsel, CHARLIE BECK, Deputy Public Counsel, and PATRICIA A. CHRISTENSEN, Associate Public Counsel, ESQUIRES, Office of the Public Counsel, c/o the Florida Legislature, 111 West Madison Street, Room 812, Tallahassee, Florida 32399-1400
On behalf of the Citizens of the State of Florida (OPC).

STEPHANIE ALEXANDER, ESQUIRE, 200 West 200 West College Avenue, Suite 216, Tallahassee, Florida 32301
On behalf of the Florida Association for Fairness in Rate Making (AFFIRM).

costs have been removed. Accordingly, we find that PEF has made the appropriate adjustments to remove aviation cost for the test year.

H. Advertising Expenses

PEF removed promotional advertising costs in the amount of $3,388,000, as reflected in MFR Schedule C-2. The jurisdictional amount, net of tax, is $2,081,000. The explanation given by PEF is to exclude the cost of promotional advertising in order to comply with our guidelines.

We note an excerpt from the procedures followed by our auditors for the 2008 base year:

> We reviewed additional samples of utility advertising expenses, industry dues, economic development expenses, outside services, sales expenses, customer service expenses and administrative and general service expenses to ensure that amounts supporting non-utility operations were removed.

The Company's advertising expense is one of the areas specifically examined by our auditors. There were no findings with respect to this issue. Therefore, we find that PEF has made the appropriate adjustments to remove advertising expenses for the test year.

I. Directors and Officers (D&O) Liability Insurance

PEF argued that OPC witness Schultz is incorrect in his assertion that D&O liability insurance does not benefit ratepayers, and thus should be disallowed. PEF cited to the most recent TECO case in which this Commission decided that D&O liability insurance is a necessary and reasonable business expense and is appropriately included in customers' rates.[40] PEF asserted that we have already rejected the argument that Mr. Schultz raises in other cases and there is no valid reason for us to depart from its previous findings in this case.

OPC witness Schultz questioned whether the cost of D&O liability insurance is a necessary and appropriate expense to pass on to ratepayers. He stated that the expense protects shareholders from the decisions they made when they hired the Company's Board of Directors and the Board of Directors in turn hired the officers of the Company. He noted that the Company included $2.2 million in Account 925 for D&O liability insurance, but he believes the correct amount to be $2,750,650 for $300,000,000 in coverage. He disagreed with our recent Peoples Gas case in which the expense was allowed as a legitimate business expense.[41] The witness testified that the pertinent issue is whether the cost is beneficial to ratepayers, not whether it is a legitimate business expense. He stated that we have disallowed the cost in the past.

OPC witness Schultz testified that other jurisdictions have disallowed the expense. He stated, for example, that a Connecticut decision limited recovery by Connecticut Light and

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[40] Order No. PSC-09-0283-FOF-EI, issued April 30, 2009, in Docket No. 080317-EI, In re: Petition for rate increase by Tampa Electric Company, p. 64.

[41] Order No. PSC-09-0411-FOF-GU, issued June 9, 2009, in Docket No. 080318-GU, In re: Petition for rate increase by Peoples Gas System, p. 37-38.

Power to thirty percent, because ratepayers should not be required to protect shareholders from the decisions they make in electing the Board of Directors. He added that Consolidated Edison was not allowed to recover the full amount in a New York case. He explained that the disallowance was due to excessive coverage in part, and that a portion of the amount found to be reasonable was also disallowed. He stated the reason for the additional disallowance was that D&O Liability insurance provides protection to shareholders from matters in which the customers have no influence.

OPC witness Schultz recommended disallowance of the total cost of D&O liability insurance of $2,750,650 ($2,412,100 jurisdictional) because the purpose of the insurance is to protect shareholders, not ratepayers. He stated that he does not take the position that the Company should not have the insurance, but that it should be paid for by those who benefit from the insurance; that is, the shareholders.

OPC argued that PEF did not offer any testimony in rebuttal to OPC witness Schultz that the D&O liability insurance should be disallowed. OPC stated that, in each of the cases cited by witness Schultz in his testimony, the Company argued that D&O liability insurance is a necessary and prudent cost required to attract and retain competent directors and officers, yet a disallowance was made. OPC challenged the cost for $300,000,000 of coverage as being excessive, and questioned whether the cost for that level of coverage is appropriate to pass on to ratepayers.

OPC noted in particular a Consolidated Edison Company Case. OPC stated that in the final decision, the New York Commission (NYC) ruled that $300,000,000 of coverage was excessive based on the comparisons to similar companies and disallowed the premium associated with $100,000,000 excess, and then disallowed 50 percent of the premium associated with the $200,000,000 that was determined to be reasonable. OPC stated that, in the discussion, the NYC noted that D&O insurance provides substantial protection to shareholders who elect directors and have influence over whether competent directors and officers are in place, while customers have no influence. OPC noted that the NYC further stated at page 91 of its order that:

> We find no particularly good way to distinguish and quantify the benefits of D&O insurance to ratepayers from the benefits to shareholders, especially taking into account the advantage that shareholders have in control over directors and officers. We believe the fairest and most reasonable way to apportion the cost of D&O insurance therefore is to share it equally between ratepayers and shareholders.

FIPUG argued that the amount should be disallowed, because the expense directly benefits only PEF's shareholders.

We agree with OPC witness Schultz that this Commission has disallowed D&O insurance in water and wastewater cases in the past.[42] We do not agree with OPC that the ratepayers do not

[42] See Order Nos. PSC-09-0385-FOF-WS, issued May 29, 2009, in Docket No. 080121-WS, In re: Application for increase in water and wastewater rates in Alachua, Brevard, DeSoto, Highlands, Lake, Lee, Marion, Orange, Palm

benefit from D&O liability insurance. We believe that D&O liability insurance has become a necessary part of conducting business for any company or organization and it would be difficult for companies to attract and retain competent directors and officers with out it. We also believe that ratepayers receive benefits from being part of a large public company, such as easier access to capital which may result in lower rates. As stated in the TECO order:

> We find that [D&O liability] insurance is a part of doing business for a publicly-owned Company. It is necessary to attract and retain competent directors and officers. Corporate surveys indicate that virtually all public entities maintain [D&O liability] insurance, including investor-owned electric utilities. . . . We do not agree with OPC that the ratepayers do not benefit from [D&O liability] insurance. It is not realistic to expect a large public company to operate effectively without [D&O liability] insurance.[43]

We agree with PEF that the amount of the D&O liability insurance provided in discovery responses is $2.2 million, not $2.75 million as adjusted by OPC witness Schultz. However, we note that the amount of the premium for the test year is projected to be higher than the premium for 2008-2009, but lower than the previous three years, even though the amount of coverage was increased from $280 million to $300 million.

In summary, we believe that D&O liability insurance has become a necessary part of conducting business for any publicly owned company and it would be difficult for companies to attract and retain competent directors and officers without it. We also believe that ratepayers receive benefits from being part of a large public company including, among other things, easier access to capital. Because D&O liability insurance benefits both the ratepayer and the shareholder, it should be a shared cost. Thus, we find that O&M expense shall be reduced by $964,913 jurisdictional to reflect the sharing of costs between the ratepayers and the shareholders.

J. Injuries and Damages Expense

PEF stated that FERC Account 925 on MFR Schedule C-4, p. 44 of 48, reflects an expense of $8,882,000 for injuries and expenses. PEF stated that the numbers were audited by our auditors who reconciled the amounts on the MFRs for 2008 expenses to the Company's actual book and records. PEF stated that it based its 2010 budget for injuries and damages expense on the Company's actual historical 2008 expenses. PEF argued that it is, therefore, entitled to recover this expense.

Beach, Pasco, Polk, Putnam, Seminole, Sumter, Volusia, and Washington Counties by Aqua Utilities Florida, Inc., p. 81; PSC-07-0505-SC-WS, issued June 13, 2007, in Docket No. 060253-WS, In re: Application for increase in water and wastewater rates in Marion, Orange, Pasco, Pinellas, and Seminole Counties by Utilities, Inc. of Florida, p.44; PSC-03-1440-FOF-WS, issued December 22, 2003, in Docket No. 020071-WS, In re: Application for rate increase in Marion, Orange, Pasco, Pinellas, and Seminole Counties by Utilities, Inc. of Florida, p. 84; and PSC-99-1912-FOF-SU, issued September 27, 1999, in Docket No. 971065-SU, In re: Application for rate increase in Pinellas County by Mid-County Services, Inc., p. 20-22.

[43] Order No. PSC-09-0283-FOF-EI, issued April 30, 2009, in Docket No. 080317-EI, In re: Petition for rate increase by Tampa Electric Company, p. 64.

STATE OF CONNECTICUT

DEPARTMENT OF PUBLIC UTILITY CONTROL
TEN FRANKLIN SQUARE
NEW BRITAIN, CT 06051

DOCKET NO. 08-07-04 APPLICATION OF THE UNITED ILLUMINATING COMPANY TO INCREASE ITS RATES AND CHARGES

February 4, 2009

By the following Commissioners:

John W. Betkoski, III
Donald W. Downes
Anthony J. Palermino

DECISION

TABLE P/R - 5

CORRECTED TABLE

(in $000s)

Compensation Expense	2009	2010
Proposed Base Payroll	$56,627	$59,115
Department Adjustment	($3,880)	($4,565)
Allowed Base Payroll	$52,747	$54,550
Overtime and Premium Pay	$6,754	$7,024
Department Adjustment	($1,672)	($1,942)
Allowed O/T and Premium Pay	$5,082	$5,082
Capitalized Overhead Pay	($4,083)	($4,207)
Department Adjustment	$80	$63
Allowed Cap. O/H	($4,003)	($4,144)
Incentive Compensation	$7,665	$7,791
Department Adjustment	($3,671)	($3,797)
Allowed Incent. Comp.	$3,994	$3,994
Total Compensation Proposed	**$66,963**	**$69,723**
Total Dept. Adjustments	**($9,143)**	**($10,241)**
Total Allowed Compensation	**$57,820**	**$59,482**
Allocated Incentive Comp.	**$1,154**	**$1,146**
Total Department Adjustments	**($553)**	**($559)**
Allowed Alloc. Inc. Comp.	**$601**	**$587**
Total Compensation Adjustments	**($9,696)**	**($10,800)**

To address the public's concern that customers are paying 100% of the compensation paid to the top officers of the Company, the Department offers that, for example, the adjustments made in this Decision reduce the amount of compensation paid to the Company President and Chief Operating Officer, that are actually included in rates and paid by customers, by approximately 33% and 31%, respectively.

2. Directors and Officers Liability Insurance

In its Application UI requested the Department authorize $844 thousand for 2009 and 2010 Directors and Officers Liability Insurance (DOL) ($852 thousand less $8 thousand allocated to non-regulated entities). Schedule WP C-3.31 A&B. The Company's position is that DOL is a business expense of having a public corporation, and the customers pay for all of the ordinary business expenses that a company would incur. Tr. 10/14/08, pp 62 and 63.

The OCC stated that in the past two rate decisions involving UI, the Department has determined that a portion of UI's DOL insurance costs should be funded by ratepayers. Despite this fact, UI is proposing to recover 100% of its DOL insurance

costs in this proceeding. The OCC cited its previous arguments that corporate scandals have increased costs dramatically, that ratepayers do not elect the Board of Directors (BOD) and officers of the Company, and that shareholders, who are protected by the insurance, should not be subsidized by ratepayers for DOL insurance costs that are designed to protect shareholders from their own decisions. The facts and circumstances regarding the DOL insurance have not changed since UI's last rate case. The OCC recommends that the DOL insurance be reduced by 75% with only 25% being passed on to customers, but stated that its absolute preference would be to disallow the cost completely. OCC Brief, pp. 79 and 80.

The AG indicates that the amount requested is roughly six times the amount that the Department approved in the 2006 Decision. In the 2006 Decision, the Department specifically agreed with both the AG and OCC that "DOL insurance protects only shareholders from the actions of management that they selected." Although the Department allowed UI to collect one-quarter of its requested amount in the 2006 Decision, the Company requested the entire amount be funded by ratepayers. The AG stated that this bold act of indifference to the Department's clear precedent and to the financial stresses facing its customers should be firmly rejected. At the very most, the Department should authorize only the levels for DOL insurance that it approved in the 2006 Decision. AG Brief, p. 18.

In the 2006 Decision, the Department noted the OCC's and AG's positions, as well as the position of the Company who stated that if there was no insurance and there was a huge claim, it could put the Company in financial peril, which would potentially impair its ability to serve. Therefore, the Department allocated 75% of DOL costs to the shareholders, with the residual 25% to be funded by ratepayers. 2006 Decision, pp. 46 and 47. The Department rejects the Company's current proposal that ratepayers fund 100% of DOL insurance costs, and reconfirms the precedent afforded by the 2006 Decision. Accordingly, the Department allows $211 thousand of DOL insurance costs to be funded by ratepayers in years 2009 and 2010 ($844 thousand times 25%). This results in DOL insurance expense decreases of $633 thousand in each of years 2009 and 2010.

3. Fringe Benefits

a. Compensation Adjustment to Fringe Benefits

In Section III.1.f., the Department made adjustments to compensation of $12.033 million and $13.655 million in 2009 and 2010, respectively. This also results in an adjustment to fringe benefits that accompany compensation. The Company indicates that its composite fringe benefit rate for 2009 and 2010 is 45%. Responses to Interrogatories EL-30-2; EL-31-2; and EL 33-1.

In its Written Exceptions, the Company argues, against its own filed and sworn record evidence of a 45% fringe benefit expense related to compensation, that the "correct compensation-driven benefits loader from an expense standpoint" is 20.6% and attempts to justify that amount by listing greatly reduced expense amounts for certain "Compensation Driven Employee-Related Benefits Loader." UI Exceptions, pp. 29 and 30. The Department notes that the Company's Response to Interrogatory EL-33 that

STATE OF CONNECTICUT

DEPARTMENT OF PUBLIC UTILITY CONTROL
TEN FRANKLIN SQUARE
NEW BRITAIN, CT 06051

DOCKET NO. 07-07-01 APPLICATION OF THE CONNECTICUT LIGHT AND POWER COMPANY TO AMEND RATE SCHEDULES

January 28, 2008

By the following Commissioners:

Anthony J. Palermino
Anne C. George
John W. Betkoski, III

DECISION

expenses by $2.232 million to remove the non payroll projected costs in excess of the original budget.

2. Insurance Expense

The test year expense for insurance expense was $6.817 million. The Company proposed a rate year increase of $.65 million or a rate year expense of $7.467 million. Application, Schedule C-3.10. CL&P revised the request and reduced the insurance expense by $17,000. The revision was a result of recent premium information. The change is a combination of increases and decreases in different types of insurance. Response to Interrogatory EL-80-SP01.

The Department accepts the Company's revisions except for the Directors and Officers insurance expense and capital allocation as discussed in detail below.

a. Director and Officer Insurance Expense

The test year expense for Director and Officer (D&O) insurance expense was $1.423 million. The Company proposed a rate year increase of $0.164 million or a rate year expense of $1.587 million. Application, WP C-3.10. As indicated above, CL&P revised its rate year insurance expense and decreased the rate year D&O insurance expense amount by $.270 million to $1.317 million. Response to Interrogatory EL-80-SP01 and Late Filed Exhibit No. 112SP-01.

CL&P claims that D&O insurance is a legitimate and customary operating expense and that no director or officer with the necessary knowledge and experience would take the risks associated with serving CL&P without this type of protection. CL&P states that the Sarbanes-Oxley Act requires that certain skill-sets be reflected in the Board of Directors (BOD), and in order to attract and retain individuals that meet these requirements CL&P must offer D&O coverage to its BOD. CL&P indicated that the Department has already confirmed that D&O is a necessary operating expense that is recoverable. CL&P Brief, p. 39.

The AG argues for the removal of the entire $1.587 million. The AG states that it is inappropriate to force customers to fund a plan that benefits only shareholders. D&O insurance protects shareholders from their own decisions and is intended to protect directors and officers from lawsuits brought by shareholders. AG Brief, p. 20.

The OCC states that premiums for insurance excluding D&O insurance decreased from $9.4 million to $8.41 million while D&O insurance is estimated to increase 11.5% from $1.423 million to $1.587 million. Further, the OCC believes that the D&O insurance requested amount is excessive, ignores the Department's prior rulings, and ratepayers should not be required to protect shareholders from the decisions they make in electing the BOD. The OCC argues that Sarbanes-Oxley merely requires officers & directors who have a fiduciary duty to acknowledge responsibility by signing their names. It was not the implementation of Sarbanes-Oxley that caused an increase in premiums, it's the claims filed that caused the increase. The OCC adds that D&O insurance has drastically increased from 5.67% of the aggregate insurance amount in 2002 to 13.15% in 2006 and projected to cost 15.87% in the rate

year. The OCC recommends a D&O insurance reduction of $1.202 million to $0.385 million. The OCC calculated this amount by using the 2002 test year amount increased by inflation. OCC Brief, p. 44.

In Docket No. 03-07-02, CL&P requested a rate year amount of $1.043 million and was allowed the test year amount of $.330 million. 03-07-02 Decision, pp. 48-49. This allowed 33% of the requested amount. In that decision, the Department indicated that it does allow some level of D&O insurance expense in rates to assure some level of ratepayer protection from lawsuits. In the UI Decision, the Department allowed 25% of the D&O insurance expense to be allocated to customers. In the Decision dated February 5, 1999, n Docket No. 98-01-02, DPUC Review of the Connecticut Light and Power Company's Rates and Charges – Phase II, the Department took the OCC approach and calculated the 1999 expense by inflating the 1996 level. This allowed 46.7% of the requested amount. In the Decision dated May 25, 2000, in Docket No. 99-09-03, Application of Connecticut Natural Gas Corporation for a Rate Increase, the Department allowed 20% of the premium amount.

The Department agrees in part with the OCC that ratepayers should not be required to protect shareholders from the decisions they make in electing the BOD. However, the Department historically has allocated a percentage to ratepayers to protect from catastrophic lawsuits. Accordingly, the Department finds it appropriate to allocate 30% to ratepayers and 70% to shareholders. This allocation is fair and consistent with the level allowed in Docket No. 03-07-02. Therefore, the Department allows $.395 million ($1.317 million x 30%) and disallows $.922 million to be collected in rates.

b. Insurance Expense - Capital Allocation

CL&P originally proposed a rate year capitalization factor of 25.3%. Application, Schedule WPC-3.10. The Company revised this amount to 26.6% in order to reflect updates based on recent invoices. Response to EL-80-SP01 and Late Filed Exhibit No. 112. The test year before pro forma adjustment was 35.6%. Application, Schedule WPC-3.10. A majority of the pro forma adjustment was to remove a non-recurring charge for the public liability reserve. This adjustment was based on an independent study performed by Mercer, Inc. The remaining pro forma adjustment included the addition of $284,000 that was for a non-recurring credit or refund received from USICO, a mutual property insurance company. Response to Interrogatory EL-43.

The OCC claims that CL&P has included a significant increase in the percent of costs being charged to expense as opposed to capital. Specifically, the Company's proposed reduction of more than 10% to the capital allocation is significant considering CL&P's focus on system improvements. The OCC argues that the Company did not present any evidence to justify an allocation change. OCC Brief, p. 41. The OCC recommends using the test year capitalization factor of 35.6%. That capitalized amount reduces the aggregate insurance expense to $5.802 million for a total disallowance of $1.665 million. OCC Brief, pp. 43-44.

As indicated below, the Company's insurance capitalization percents have ranged from a low of 25.6% to a high of 40.5% in the years 2002 through 2006.

STATE OF CONNECTICUT

DEPARTMENT OF PUBLIC UTILITY CONTROL
TEN FRANKLIN SQUARE
NEW BRITAIN, CT 06051

DOCKET NO. 05-06-04 APPLICATION OF THE UNITED ILLUMINATING COMPANY TO INCREASE ITS RATES AND CHARGES

January 27, 2006

By the following Commissioners:

John W. Betkoski, III
Donald W. Downes
Jack R. Goldberg
Anne C. George
Anthony J. Palermino

DECISION

Description	2006	2007	2008	2009
Benchmarking studies	$ 72,000	$ 72,000	$ 73,000	$ 74,000
BPL	$ 98,000	$ 98,000	$ 98,000	$ 98,000
Regulatory consulting	$ 131,000	$ 138,000	$ 145,000	$ 152,000
Client services support	$ 275,000	$ 296,000	$ 311,000	$ 329,000
Total professional services expense disallowed	$ 576,000	$ 604,000	$ 627,000	$ 653,000

8. Outside Services - Audit and Accounting Expense

UI originally projected $533,000, $552,000, $573,000 and $594,000 for audit and accounting expense for rate years 2006 through 2009, respectively. Schedule C-3.16 A–D. UI later increased the projected expenses by $149,000, $164,000, $177,000 and $194,000 for rate years 2006 through 2009, respectively, citing the Company's response to Interrogatory EL-159. Late Filed Exhibit No. 1, Revised.

However, the response to Interrogatory EL-159 only identified a potential increase of $100,000 for 2006. The Company's response to Interrogatory EL-159 and the testimony on 10/14/05 state that the original projection was strictly an estimate and that UI is in negotiations with Pricewaterhouse Coopers for a new contract. UI is seeking to enter into a long term fixed price contract for SEC reporting audit services to mitigate the potential increase. UI testified that the Company is still negotiating and trying to get the price increase down, but, the increase could be greater than the original estimate. Response to Interrogatory EL-159; Tr. 10/14/05, pp. 174 and 175. UI later testified that they negotiated a new contract and the increases in Late Filed Exhibit No. 1 are based on the cost of the new contract. Tr. 11/9/05, p. 2394.

The OCC believes that the response to Interrogatory EL-159 does not support the amount of increase apparently requested by UI in Late Filed Exhibit No. 1 and leaves unanswered questions regarding the certainty of the projected increases. Therefore, the OCC has removed the increases identified in Late Filed Exhibit No. 1. OCC Brief, pp. 63 and 64, Exhibit 5.

The Department takes into account the entire record evidence on a given expense in determining if it is proper for the rate year. Therefore, based on the testimony given during the late filed exhibit hearing, the Department approves the increase to accounting and audit expense as shown in Late Filed Exhibit No. 1, Revised.

9. Directors and Officers Liability Insurance

The Company proposes expenses for Directors and Officers Liability Insurance (DOL) of $533,879 for 2006, and $559,612 for each of the years 2007 through 2009. Response to Interrogatory OCC-104. UI contends that it could not attract a director if it didn't have DOL. It is a cost of doing business. Tr. 10/12/05, p. 868. Further, the Company asserts that, taken to the extreme, "if there was no insurance and there was a huge claim, it could put the company in financial peril, which would potentially impair its ability to serve." Tr. 10/11/05, p. 801.

The OCC indicates that "the numerous corporate scandals since 2001 has caused the cost of the DOL insurance to skyrocket." Schultz and DeRonne PFT, p. 48. Further, "DOL insurance provides shareholders protection from their decision. Ratepayers in general do not elect the Board of Directors and do not appoint officers to run the Company. Shareholders are protected by this insurance against their own decision in the selection of management. Ratepayers should not pay for the cost of insurance designed to protect shareholders from their own decisions." OCC Brief, p. 93; Tr. 10/12/05, pp. 867 and 868. Therefore, the OCC recommends that all of the DOL amounts during the rate period be excluded from rates and be covered completely by shareholders, not ratepayers.

The AG agrees with the OCC's reasoning that DOL insurance protects only shareholders from the actions of management that they selected. Thus, DOL insurance expense should be eliminated from UI's rates entirely. AG Brief, pp. 24 and 25.

The Department partially agrees with the OCC, the AG and the Company. In the 03-07-02 Decision, the Department allowed a portion of that company's proposed expense and stated that "the Department has historically allowed some level of expense for D&O Insurance in rates to assure some level of ratepayer protection from catastrophic lawsuits." 03-07-02 Decision, p. 49. The Department also notes that the annual gross DOL premium (before credits and allocations) was $134, 430 in years 2001 and 2002, increasing to $1,029,516 in years 2007 through 2009, lending credence to the OCC's assertion regarding corporate scandals, above. The Department agrees with the OCC that the shareholders should bear the weight of their decisions in appointing directors (who appoint the officers of the Company). Accordingly, the Department allows $140,000 of DOL expense, or approximately ¼ of the total company expense, to be collected in rates as the customers' responsibility.

The Department, therefore, disallows DOL expenses of $393,879 in 2006, and $419,612 in each of 2007, 2008 and 2009.

10. Postage Expense

UI projected postage expense in the amounts of $1,475,000, $1,479,000, $1,485,000, and $1,491,000 for rate years 2006 though 2009, respectively. UI increased the test year expense of $1,361,000 by $74,000 for an anticipated 5.4% increase from the USPS and $31,000 for volume and usage increase. Schedule C-3.20 A – D.

The Governors of the U.S. Postal Service have accepted the recommendation to increase most postal rates and fees by 5.4% effective January 8, 2006, including an increase in the rate for first-class mail from 37 cents to 39 cents. See http://www.usps.com/ratecase/welcome.htm.

UI states that the volume and usage increase is due to items such as increase in collection letters due to higher disconnect for nonpayment activity, new program mailings and increased economic development activity. Response to Interrogatory EL-220.

STATE OF CONNECTICUT

DEPARTMENT OF PUBLIC UTILITY CONTROL
TEN FRANKLIN SQUARE
NEW BRITAIN, CT 06051

DOCKET NO. 03-07-02 APPLICATION OF THE CONNECTICUT LIGHT AND POWER COMPANY TO AMEND ITS RATE SCHEDULES

December 17, 2003

By the following Commissioners:

Donald W. Downes
Jack R. Goldberg
John W. Betkoski, III
Linda J. Kelly
Anne C. George

DECISION

The Department, therefore, accepts the Company's revision to computer and other expenses as indicated in the Response to Interrogatory OCC-93. Accordingly, the Department reduces computer expenses by $.348 million ($10.119 million less $9.771 million) and other O&M expenses related to the test year processing and storage balance of $.596 million, for a total O&M adjustment for these items of $.944 million ($.348 million plus $.596 million).

2. Insurance Expense

a. Directors and Officers Liability Insurance

The Company requested Directors & Officers Liability Insurance Expense (D&O Insurance) of $1.043 million in the rate year. This included a test year pro forma adjustment of $.029 million and a rate year adjustment of $.684 million above the test year actual amount of $.330 million based on the actual renewal premiums for the policy period 4/23/03 to 4/23/04. Schedule WP C-3.12; Response to Interrogatory OCC-101.

The OCC argues for the removal of the entire $1.043 million of D&O Insurance expense. The OCC states:

> Ratepayers should not be forced to pay a cost that protects shareholders from the shareholders' own decisions. Shareholders determine who the Board of Directors are and the Board of Directors are responsible for appointing officers of the Company. The officers are highly compensated to provide quality leadership with the utmost integrity. Ratepayers are responsible for paying for the directors and officers services. The shareholders, not ratepayers, determine who the directors and officers are. Therefore, the shareholder should assume the risk associated with their decision regarding the management of the Company. The cost to obtain insurance to protect the shareholders investment from their choice of management should be the responsibility of the shareholders.

OCC Brief, p. 64

The OCC also cites that the escalation in D&O Insurance rates stem from the insurers' need to continue to reserve for litigation and settlement expenses in connection with an influx of claims arising from such entities as Worldcom, Enron, Kmart, etc. Response to Interrogatory OCC-101. The increases in D&O Insurance and the related costs are due to the failures of directors and officers to ensure the Company operated prudently and reasonably. An alternative to total disallowance of cost would be to allow the test year cost of $.330 million. OCC Brief, p. 65.

The Department is sympathetic with OCC's arguments and generally agrees that the increased premiums are, at least in part, caused by Officer/Director mismanagement or misconduct in major corporations. Further, the Department notes that CL&P's recent claims experience includes settlement of eight federal and state shareholder class action lawsuits that stemmed from the Nuclear Regulatory Commission's Watch List of problems at its Millstone Nuclear Plant in 1996 that resulted

in a $20.050 million settlement by its insurer. Further, a $33 million settlement was reached with the non-NU joint owners of Millstone 3 related to the Company's operation of that plant. Late Filed Exhibit 73 and 73-SP01. However, the Department has historically allowed some level of expense for D&O Insurance in rates to assure some level of ratepayer protection from catastrophic lawsuits. Therefore, the Department will allow the test year cost of $.330 million and reduce the Company's D&O Insurance expense by $.713 million ($1.043 million less $.330 million).

b. Public Liability Expense

The Company requested Public Liability Expense of $2.591 million in the rate year in Account 925.02. This Account includes the cost of the reserve accrual to protect the utility against injuries and damages claims of employees or others, losses of such character not covered by insurance, and expenses incurred in settlement of injuries and damages claims. It also includes the cost of labor and related supplies and expenses incurred in injuries and damages activities. Uniform System of Accounts prescribed for Electric Utilities, Public Utilities Control Authority State of Connecticut, 1/1/63, p. 177 (USOC). In its calculation of this expense, CL&P removed $1.497 million of test year expense that was capitalized, thus reducing the overall test year expense of $2.591 million to $1.094 million. Schedule WP C-3.12.

In response to an OCC data request, the OCC questioned why CL&P should no longer treat the public liability expense as an overhead cost, subject to capitalization. In the Company's response it indicated "[u]pon further review it was determined that public liability insurance is an appropriate cost to be capitalized under the FERC Electric Plant instructions." CL&P determined that the payroll overhead rate is the best vehicle for capitalizing these costs and changed the overhead rate for the remainder of 2003 to include these costs. Response to Interrogatory OCC-99. Accordingly, the OCC recommends that $1.497 million of public liability expense be capitalized, thereby reducing CL&P's proposed expense.

The Department agrees with the OCC and the Company that a portion of public liability expense, particularly as it relates to construction projects, is properly capitalizable. The USOC provides, for example, that the cost of injuries and damages or reserve accruals capitalized shall be charged to construction directly or by transfer to construction work orders from this account. USOC, p. 177. The Department also notes that it has been CL&P's consistent practice to capitalize a portion of public liability expense. Response to Interrogatory OCC-100. The Company provided a revised schedule that calculated the capitalized portion of Public Liability Expense using a capitalization rate of 38.5% that resulted in a capitalization amount of $.998 million. Schedule WP C-3.12 Revised. The Department notes that the capitalization percentage is consistent with other payroll-related capitalizations. Schedule WP C-3.28a. The Department, therefore, reduces public liability expense by $.998 million to reflect such capitalization.

STATE OF CONNECTICUT

DEPARTMENT OF PUBLIC UTILITY CONTROL
TEN FRANKLIN SQUARE
NEW BRITAIN, CT 06051

DOCKET NO. 98-01-02 DPUC REVIEW OF THE CONNECTICUT LIGHT AND POWER COMPANY'S RATES AND CHARGES - PHASE II

February 5, 1999

By the following Commissioners:

Glenn Arthur
Jack R. Goldberg
Linda Kelly Arnold
Donald W. Downes
John W. Betkoski, III

DECISION

amount. OCC analyzed the storm expense data and found that there is no relationship between total storm expense and inflation. For example, storm expenses were higher in 1992 and 1993 compared to 1994 and expenses in 1995 and 1996 were higher compared to 1997. Therefore, OCC also believes that there is no justification for an escalation factor in the storm budget. PRO Brief, pp. 9 and 10; OCC Brief, pp. IV-52 and 53.

The Department often uses a historical average, excluding the highest and lowest years' costs, to calculate a rate year expense and believes that is the appropriate method for storm expense. The Department agrees with OCC's analysis on the escalation factor. The Department calculates 1999 storm expense to be $8.483 million by averaging storm costs for 1992 - 1997, excluding the lowest and highest costs in 1994 and 1996. Therefore, the Department reduces expenses by $3.169 million ($11.652 million - $8.483 million).

27. Directors' and Officers' Insurance

CL&P has requested $1.391 million in directors' and officers' (D&O) liability insurance premiums for the rate year. Response to Interrogatory OCC-70. D&O insurance expenses for the years 1994 - 1997 were $497,000, $456,000, $630,000 and $1,022,000, respectively. Expenses increased due to claims paid and higher liability limits. CL&P projects 1999 expenses will be higher for the same reasons. Responses to Interrogatories OCC-312 and PRO-6; Late Filed Exhibit No. 5, AR-DPUC-14. The Company indicated that the two reasons were actually one and the same. As claims are paid, the insurance available in the future is reduced by that amount. Because of the claims already paid and potential claims, the Company purchased higher limits to restore its liability coverage to previous amounts. This would give the Company enough coverage for potential future claims. Tr. 10/20/98, pp. 4005 and 4006; Late Filed Exhibit No. 162. A Company witness testified that all of the shareholder lawsuits are well known to CL&P and the Department and any damage claims would be borne by shareholders. Tr. 9/10/98, pp. 430-432.

PRO, AG and OCC argue that D&O costs have increased from 1995 to 1997 as a direct result of management imprudence and the nuclear outages. The claims paid and pending relate to the nuclear outages. OCC and PRO believe the expense should be reduced to the 1996 level. Even though the outages occurred during 1996, PRO believes this would allow for some increase due to inflation. OCC Brief, p. IV-39; PRO Brief, p. 12; AG Brief, p. 15.

Ratepayers should not have to fund higher liability limits for directors and officers when it is those directors and officers who failed to ensure that the Company operated prudently and reasonably. The Department reduces D&O liability insurance premiums to a level that does not reflect the nuclear outages. The Department agrees that the 1999 expense should be based on the 1996 level. However, the Department also believes that this is an expense that is typically influenced by inflation and sets the 1999 allowed expense at $.65 million, which is the 1996 actual expense adjusted for inflation. Therefore, 1999 expenses are reduced by $.741 million ($1.391 million - $.65 million).

STATE OF CONNECTICUT

DEPARTMENT OF PUBLIC UTILITY CONTROL
TEN FRANKLIN SQUARE
NEW BRITAIN, CT 06051

DOCKET NO. 99-09-03 APPLICATION OF CONNECTICUT NATURAL GAS CORPORATION FOR A RATE INCREASE

May 25, 2000

By the following Commissioners:

Glenn Arthur
Jack R. Goldberg
Linda Kelly Arnold

DECISION

tax rate of 8.3% in the rate year. Tr. 2/16/00, p. 1775. Accordingly, the Department will reduce payroll taxes by an additional $42,746 ($515,017 x 8.3%).

In Version B, CNG made a vacancy adjustment of $160,493. However, the Company failed to make a corresponding adjustment for payroll taxes and the O&M allocation factor of 83.6%. Schedule WPC-3.28. Accordingly, the Department will further reduce this expense by $13,321 ($160,493 x 8.3%). The Department's total reduction to payroll taxes is $255,260 ($199,193 + $42,746 + $13,321).

c. Gross Receipts Tax

Gas distribution companies are subject to the Connecticut gross receipts tax (GRT). GRT rates of 4% and 5% apply to residential customers and commercial/industrial customers, respectively. CNG's initial application projected a pro forma GRT expense of $10,599,786 for pro forma taxes at present rates. Schedule WPC-3.41. The Company's request for a $15,738,284 increase in its revenue requirement added $675,684 for a total pro forma GRT of $11,275,470. Schedule C1/C2. Subsequently, the Company increased its pro forma revenues by $8,010,815. Late Filed Exhibit No. 4, Version B. This increased pro forma GRT by $343,924. Together, the changes increased pro forma GRT by $709,958 to $11,619,394.

The Company calculated a 4.29% blended GRT rate by combining the calculated taxes on residential revenues and commercial revenues. Schedule WPC-3.41. CNG's calculation of its blended GRT rate properly excluded taxes on non-taxable interruptible service revenues. Tr. 1/11/00, p. 137.

In Section II.C, above, the Department adjusted CNG's revenues for firm transportation by $58,700, and for an additional customer by $109,000. The Department will make an adjustment to GRT at the rate of 4.29%. Therefore, the Department will increase CNG's GRT by $7,194 ([$58,700 + $109,000] x 4.29%).

d. Summary of Other Tax Adjustments

The Department's total adjustment for other taxes is $(1,055,804), $(255,260) for payroll tax, $(807,738) for property tax, and $7,194 for gross receipts tax.

9. Insurance

a. Directors and Officers Liability

CNG has included the cost of D&O liability policies in pro forma insurance expense. The D&O insurance provides the Company with coverage for certain types of wrongful acts by directors or officers of the corporation. Its intent is to safeguard the assets of the corporation so that the Company can continue to provide service to its customers and earn a fair return for its shareholders. The Company has two such policies. The first provides regular coverage and has a $84,100 annual premium. The Company included $70,308 of that premium (83.6%) in its pro forma expense. The second policy provides excess coverage and has a $87,900 annual premium. The

Company included $73,397 of that premium in its pro forma expense for a total pro forma D&O insurance cost of $143,705 ($70,308 + $73,397). Schedule WPC-3.32.

OCC recommends that CNG's adjusted expenses be reduced by $81,807 to reflect the allocation of 20% of regular D&O liability insurance and 100% of the excess D&O liability insurance to shareholders. OCC would prefer that the cost be split equally between ratepayers and shareholders. Not withstanding that action, the OCC believes it appropriate to remain consistent with the Previous Rate Decision where 20% of the regulated premium was disallowed. OCC Brief, pp. 11, 37. Based on CNG testimony, PRO recommends a $7,031 reduction to this expense. PRO Brief, p. 11.

In the Previous Rate Decision, the Department found that the Company needed D&O insurance to attract and keep qualified directors and officers. However, because shareholders could also initiate suits against the directors and officers, the Department disallowed 20% of the premium of regular coverage. Additionally, the Department found that the Company had not justified allowance of premiums of excess D&O coverage in rates. Decision, p. 33.

The Company has not presented any evidence in the instant docket to warrant dissimilar treatment. Accordingly, the Department again disallows the cost of the excess coverage policy premium in its entirety and 20% of the regular policy. Accordingly, the Department will reduce this expense by $14,062 (20% x $70,308) to eliminate costs attributable to shareholders. The resultant allowed premium of $56,246 requires an adjustment of $14,062. Adding that to the disallowed excess coverage premium of $73,397 produces a total reduction to D&O insurance expense of $87,459.

b. Weather Stabilization Insurance

CNG seeks to recover $993,063 in premiums for a weather stabilization insurance (WSI) policy covering the 2000/2001 heating season. Schedule C-3.32. This approximates the cost of the policy for the 1999/2000 season but is more than the cost of the policy in the 1998/1999 season. The witness stated that the Company obtained this insurance coverage to mitigate large swings in the Company's earnings in periods of extremely warm weather. CNG also proposed to set up a deferred account to allow true-ups of insurance premium costs in future rate proceedings. Bolduc PFT, pp. 7, 10.

AG proposes that the Department reject CNG's proposal to recover any costs associated with WSI because it is not a cost that ratepayers should bear. Additionally, AG points out that shareholders have already been compensated for weather in the allowed ROE. Furthermore, the Company has failed to show that the WSI provides any real benefits to ratepayers. Brief, p. 6.

OCC opposes the inclusion of WSI premiums above the line. Brief, p. 44. OCC agrees with AG that weather related risks are reflected in a company's ROE, and further states that eliminating that risk would require a fundamental reassessment of the cost of doing business. Cotton PFT, p. 12.

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ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF) ENTERGY ARKANSAS, INC. FOR APPROVAL) OF CHANGES IN RATES FOR RETAIL) ELECTRIC SERVICE)	DOCKET NO. 06-101-U ORDER NO. 10

ORDER

Summary

On August 15, 2006, Entergy Arkansas, Inc. ("EAI") filed in this Docket its Application seeking an increase in the rates it charges its Arkansas retail electric customers. As later amended, EAI seeks a retail revenue requirement increase of $106,534,000 or approximately 11.79% above its current authorized retail revenue requirement. However, based upon the evidence presented in this Docket, the Commission finds that EAI's retail revenue requirement is excessive and should be reduced by approximately $5.67 million effective as of June 15, 2007. Among other adjustments the Commission denied EAI's request for an 11.25% return on equity. Instead, the Commission set EAI's return on equity at 9.9%.

The Commission also denied EAI's request to recover a number of expenses from its ratepayers, including reducing the level of incentive pay and stock options requested by EAI by over $21 million, and by rejecting EAI's request for its ratepayers to pay for entertainment expenses which included tickets to sporting events and concerts, golf balls and golf tournament expenses, and dinners and alcohol to entertain political figures.

Further, the Commission approved EAI's request to recover costs relating to projects and organizations that promote new technologies and research and

Having found no direct or measurable benefit to ratepayers of these types of incentives, the Commission directs that these costs not be included in rates.

As to Mr. Marcus' recommendation to disallow certain perquisites provided EAI's Chief Executive Officer and the five top executives at Entergy Corp. which include club dues, financial counseling, the corporate airplane, and a tax "gross-up", the Commission finds no substantial evidence to support the recovery of such expenditures from EAI's ratepayers. The Commission finds that, as noted by Mr. Marcus, these types of expenditures are unreasonable in light of the salaries paid Entergy's top executives. The Commission therefore disallows these perquisites.

Director and Officer Liability Insurance

EAI's application included $191,580[38] in expenses for Director and Officer Liability ("D&O") Insurance. Staff witness Plunkett recommends a 50% sharing of these costs, pursuant to past Commission practice and based on the benefits that D&O insurance provides for both stockholders and ratepayers. (T. 1472) Ms. Plunkett further testifies that her recommendation does not presuppose that this expenditure is unreasonable nor does it imply it is not useful in shielding officers and directors from shareholder litigation. Rather, she continues, her recommendation recognizes that the protection afforded officers and directors is primarily a benefit to shareholders, with EAI providing little evidence of benefits to ratepayers. (T. 1505)

AG witness Marcus, noting similar Commission findings in other dockets, also recommends that these costs be shared equally between shareholders and ratepayers,

[38]Ms. Plunkett removed $95,790 in D&O Insurance from EAI per book, representing 50% of actual expenses. Actual per book expenses would be twice that amount or $191,580.

testifying that the shareholders are the beneficiaries of such policies when mismanagement is the subject of litigation by shareholders. (T. 702, 767)

Mr. McDonald recommends that the Commission reject the Staff's and the AG's proposed adjustment, arguing that the cost is "a reasonable and legitimate cost...to encourage qualified individuals to serve as a member of the board of directors." Mr. McDonald also testifies that the positions taken by Staff and the AG, on this and other similar recommendations would, if carried to every EAI cost, result in leaving EAI without "its legal right to recover the reasonable costs it incurs to provide electric service to its customers." (T. 155)

The Commission agrees that ratepayers, as well as shareholders, benefit from good utility management, which D&O Insurance helps secure. However, as found in prior dockets, the direct monetary benefits of D&O Insurance flow to shareholders as recipients of any payment made under these policies. That monetary protection is not enjoyed by ratepayers. The Commission therefore finds that, because shareholders materially benefit from this insurance, the costs of D&O Insurance should be equally shared between shareholder and ratepayer.[39]

Civic Dues, Donations, and Club Memberships

Both Staff witness Plunkett and AG witness Marcus recommend disallowance of all costs related to civic club dues, club memberships, donations, and other costs such as "institutional advertising, lobbying, and donations, including support and sponsorship of local community organizations and local events." (T. 695.697, 1471) Ms. Plunkett notes that both FERC, which requires these items be listed as non-utility expenses, and

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ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF AN APPLICATION FOR A GENERAL CHANGE OR MODIFICATION IN CENTERPOINT ENERGY ARKLA, A DIVISION OF CENTERPOINT ENERGY RESOURCES CORP'S RATES, CHARGES, AND TARIFFS	)	DOCKET NO. 04-121-U ORDER NO. 16

ORDER

On November 24, 2004, CenterPoint Energy Arkla ("Arkla" or the "Company") filed an Application for approval of a general change or modification in its rates and tariffs.[1] Arkla's initial Application reflects that it was seeking a non-gas rate increase of $33,996,382 based on an overall non-gas revenue requirement of $182,525,265. Order No. 4, entered on December 16, 2004, suspended Arkla's proposed rates, charges, and tariffs pending further investigation by the Commission.

The parties to this proceeding are Arkla, the General Staff of the Arkansas Public Service Commission ("Staff"), the Attorney General of Arkansas ("AG"), Arkansas Gas Consumers ("AGC"), and the Commercial Energy Users Group ("CEUG").

Arkla filed the written testimonies of Jeffrey A. Bish, Charles J. Harder, F. Jay Cummings, Samuel C. Hadaway, Alan D. Henry, Michael TheBerge, Gerald W. Tucker, Steve Malkey, Michael J. Adams, Walter L. Fitzgerald, Michael Hamilton, and John J. Spanos. The Staff filed the written testimonies of Robert Booth, Alice D. Wright, Alisa Williams[2], Don E. Martin, Gail P. Fritchman, Don Malone, L.A. Richmond, Gayle Frier, Johnny Brown, Robert H. Swaim, and Adrienne R.W. Bradley. The AG filed the written testimony of William B. Marcus.

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[1] Arkla filed additional revisions to its Application on December 27, 2004, January 10, 2005, and January 13, 2005.
[2] On August 3, 2005, the Staff filed Notice that Jeff Hilton, Manager of Staff's Audit Section, was adopting the pre-filed testimony of Staff witness Alisa Williams.

adjustments were calculated by applying the contribution rate to each party's respective payroll adjustments.

The Commission finds that the employee savings plan contribution rate should be applied to the amount determined for regular salaries and wages, overtime, and incentive pay consistent with the Commission's decision on these issues. The Commission accepted Arkla's position on regular salaries and wages, and overtime, and the Staff's position on incentive pay. (Adjustment No. IS-20).

Director's and Officer's Insurance ("D&O")

The purpose of D&O insurance is to protect officers and directors of a corporation from liability in the event of a claim or lawsuit against them asserting wrongdoing in connection with the Company's business. AG witness Marcus has two concerns with Arkla's treatment of this expense: (1) Arkla's revised allocation methodology from an asset-based to an O&M-based allocation has doubled Arkla's costs; and (2) the costs should be split on a 50-50 basis to recognize that shareholders are the major beneficiaries of policy payouts when something goes wrong. (T. 1376-1377) Arkla Witness Harder testified that the use of an O&M allocation factor is appropriate for an expense that bears no relation to the level of plant. He contended that this is a necessary business expense which enables the Company to attract and retain qualified management. (T. 152-153) Mr. Marcus disagreed, stating that the expense is not related to O&M expense either, the allocation shifts the cost to Arkla away from Arkla's electric affiliate, and utility profits are asset-based. Also, since shareholders receive the benefit of insurance payouts, they should bear a portion of the cost of buying the insurance. (T. 1465-1466) Mr.

Harder responded, contending that: (1) the AG cites no evidence to show shareholders are the primary beneficiaries of these insurance proceeds; (2) litigation often involves past stockholders, in which instance they are no different than other individuals filing tort claims; and (3) when current shareholders are involved, payments are made to the corporation in which case customers are the ultimate beneficiaries. (T. 1227-1229)

The Commission finds that Arkla has not justified its change in allocation factors nor has it justified why this expense should not be split equally between stockholders and ratepayers. Arkla did not adequately explain why, at this time, it changed from a asset-based to an O&M expense-based allocation factor. Arkla's explanation that it is an expense to attract qualified management does not establish a justifiable relationship between the cost and the cost expense allocation factor the Company used. Mr. Marcus testified that D&O insurance costs are part of general corporate overhead to protect Company profits which are largely asset-based for a utility. (T. 167-169) Mr. Marcus' testimony that this insurance protects corporate profits also lends support for sharing the insurance costs between shareholders and ratepayers. The news (T. 1040) is replete with stories about companies experiencing lawsuits by shareholders. The Commission agrees with the AG that more often than not it is the current shareholders who sue management and who receive a large portion of the proceeds from the D&O insurance payouts. Accordingly, the Commission finds that Arkla's existing asset-based allocation for D&O insurance should be maintained and that the expense for D&O insurance should be shared on a 50-50 basis between shareholders and ratepayes.

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ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF ARKANSAS WESTERN GAS COMPANY FOR APPROVAL OF A GENERAL CHANGE IN RATES AND TARIFFS	))))	DOCKET NO. 04-176-U ORDER NO. 6

ORDER

PROCEDURAL HISTORY

On December 29, 2004, Arkansas Western Gas Company ("AWG" or the "Company") filed an application for approval of a general change or modification in its rates and tariffs. AWG requested that its rates be increased by $9,739,459 annually. Order No. 2, entered January 10, 2005, suspended AWG's proposed rates, charges, and tariffs pending further investigation by the Commission. Order No. 2 also established a procedural schedule for the purposes of investigating AWG's application.

The parties to this proceeding are AWG, the General Staff of the Arkansas Public Service Commission ("Staff"), the Attorney General of Arkansas ("AG"), Northwest Arkansas Gas Consumers ("NWAGC"), and the Commercial Energy Users Group ("CEUG").

On December 29, 2004, AWG filed the Direct Testimony and Exhibits of Alan N. Stewart, Executive Vice-President of AWG, Donna R. Campbell, Manager, Rates and Regulation Department of AWG, Ricky A. Gunter, Vice President of Rates and Regulation for AWG, Glenn M. Morgan, Controller and Treasurer for AWG, and Dr. Roger A. Morin,[1] Principal, Utility Research International, in support of its application.

[1]Professor of Finance, Georgia State University and Professor of Finance for Regulated Industry at the Center for the Study of Regulated Industry at Georgia State University, Atlanta, Georgia.

3. **Payroll Taxes**:

Differences between Staff's and the Company's calculation of payroll taxes and that of the AG relate entirely to the differences between the parties regarding the appropriate level of payroll to include in revenue requirement.

In view of the foregoing findings on payroll, the Commission finds that Staff's adjustments for FICA and other payroll taxes is appropriate and should be adopted.

C. Fringe Benefits

As with payroll taxes, any differences among the parties for fringe benefits, including worker's compensation, medical insurance, pension expense, and employee savings plan/life insurance relate to the level of proposed payroll. Therefore, as with payroll taxes, in view of the foregoing findings on payroll, the Commission finds that Staff's adjustments for any fringe benefits should be adopted.

D. Directors and Officers Insurance ("D & O")

The AG and AWG also disagree about inclusion in revenue requirement of 100% of the liability insurance provided by AWG and SWN for its directors and officers. Mr. Marcus argues that the major beneficiaries of this type of insurance will be the stockholders and its issuance provides no assurances of better management or decision making by officers and directors for the benefit of ratepayers. He also testifies that, in AWG's last rate case, Docket No. 02-227-U, the Commission approved a sharing of the cost between ratepayers and stockholders and he recommends that the Commission require equal sharing here. (Tr. at 72-73) Mr. Morgan disputes the AG's view of the benefits provided by this expense, noting that this type of insurance is essential

to the operation of AWG, without which it could not attract the necessary management personnel to operate the Company. (Tr. at 350)

As it has held in previous rate cases, most notably in AWG's last rate case in Docket No. 02-227-U, the Commission finds that D&O insurance benefits both stockholders and ratepayers. Therefore, as recommended by AG witness Marcus this expense should be split 50/50 between stockholders and ratepayers.

E. Uncollectible Accounts Expense

Uncollectible accounts expense has been calculated by the parties, each using a percent of uncollectible accounts to revenues applied to pro forma operating revenues as explained by Staff witness Williams. (Tr. at 1442) As discussed in the following section on the revenue conversion factor, the calculation of that percent remains in dispute. The Commission has found in its discussion of the revenue conversion factor that Staff's calculated factor for uncollectible accounts expense is appropriate. In view of that finding, the Commission, therefore, also approves Staff's calculated level of uncollectible accounts expense.

F. Revenue Conversion Factor

Revenue conversion factor issues still in contention among the parties include: the term over which uncollectible accounts as a percent of revenues are averaged in order to estimate a normal level; a proposal to incorporate late payment charge revenues in the conversion factor as a percent of revenues; and a proposal to calculate and apply separate conversion factors by class to recognize each class's distinctive level of uncollectible accounts.

BEFORE THE ARIZONA CORPORATION COMMISSION

GARY PIERCE
Chairman
BOB STUMP
Commissioner
BRENDA BURNS
Commissioner
PAUL NEWMAN
Commissioner
SANDRA D. KENNEDY
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, AND TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN.	DOCKET NO. E-01345A-11-0224

DIRECT

TESTIMONY

OF

DAVID C. PARCELL

ON BEHALF OF

UTILITIES DIVISION STAFF

ARIZONA CORPORATION COMMISSION

NOVEMBER 18, 2011

DAVID C. PARCELL
EXECUTIVE SUMMARY
ARIZONA PUBLIC SERVICE COMPANY
DOCKET NO. E-01345A-11-0224

My Direct Testimony provides my estimate of the cost of capital for Arizona Public Service Company ("APS" or "Company"). My cost of capital recommendation is as follows:

	Percent	Cost	Return
Long-term Debt	46.06%	6.38%	2.94%
Common Equity	53.94%	9.90%	5.34%
Total Capital	100.00%		8.28%

The only difference between my 8.28 percent recommendation and the 8.87 percent cost of capital request of APS is the cost of common equity – **I propose a cost of equity of 9.9 percent** and APS requests a cost of equity of 11.0 percent.

My 9.9 percent cost of common equity is derived from my consideration of three costs of equity models:

Discounted Flow	9.3-10.5%
Capital Asset Pricing Model	7.0-7.2%
Comparable Earnings	9.5-10.0%

However, my recommendation for APS focuses on the results of the Discounted Flow and Comparable Earnings Analyses.

In addition, my Direct Testimony addresses the Fair Value Rate of Return ("FVROR") which should be applied to the Fair Value Rate Base of APS. I recommend two alternative FVROR values for APS – a 5.74 percent value using a zero percent return on the Fair Value Increment (differential between Fair Value Rate Base and Original Cost Rate Base) and 6.05 percent value using a 1.00 percent inflation-adjusted risk-free return.

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I. INTRODUCTION

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

A. My name is David C. Parcell. I am President and Senior Economist of Technical Associates, Inc. My business address is Suite 580, 9030 Stony Point Parkway, Richmond, Virginia 23235.

Q. Please briefly 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. In connection with this, I have previously filed cost of capital testimony in about 470 public utility ratemaking proceedings before some 50 regulatory agencies in the United States and Canada. I have previously testified in approximately 20 public utility rate proceedings before this Commission, including the two prior rate cases of Arizona Public Service Company ("APS" or "Company"). Attachment 1 provides a more complete description of my education and relevant work experience.

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

A. I have been retained by the Utilities Division Staff ("Staff") to evaluate the cost of capital aspects of the current filing of APS. I have performed independent studies and am making recommendations on the current cost of capital for APS. In addition, since APS is a subsidiary of Pinnacle West Capital Corporation ("PWC" or "Parent"), I have also evaluated PWC in my analyses.

Q. Have you prepared schedules in support of your testimony?

A. Yes, I have prepared one exhibit, labeled Schedule 1 through Schedule 13, attached to my testimony. These schedules were 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 shown on Schedule 1 and can be summarized as follows:

	Percent	Cost	Return
Long-Term Debt	46.06%	6.38%	2.94%
Common Equity	53.94%	9.3-10.5%	5.02-5.66%
Total	100.00%		7.95-8.60%
			8.28% with 9.9% ROE

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 the Company's total cost of capital. The first step in performing these analyses is the development of the appropriate capital structure. I have used the December 31, 2010 capital structure of APS, as proposed in the Company's filing, in my 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 cost rate for 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. Each of these methodologies is applied to a group of proxy utilities similar to APS/PWC and the group of electric utilities used by APS witness William E. Avera. These three methodologies and my findings are:

Methodology	Range
Discounted Cash Flow (DCF)	9.3-10.5% (9.90% mid-point)
Capital Asset Pricing Model (CAPM)	7.0-7.2% (7.10% mid-point)
Comparable Earnings (CE)	9.5-10.0% (9.75% mid-point)

My recommendation for APS focuses on the results of the DCF and CE analyses. I have focused on both the broad range (i.e., 9.3 percent to 10.5 percent) and the mid-points of these analyses (i.e., 9.90 percent for DCF and 9.75 percent for CE). My recommendation is a range of 9.3 percent to 10.5 percent, or a **9.90 percent mid-point estimate**. This 9.90 percent recommendation also properly reflects the tough economic times that both the U.S. and APS's service areas have and are enduring.

Combining these three steps into weighted cost of capital results in an overall rate of return of 7.95 percent to 8.60 percent, with a mid-point estimate of 8.28 percent (which incorporates a cost of common equity of 9.90 percent).

III. ECONOMIC/LEGAL PRINCIPLES AND METHODOLOGIES

Q. What are the primary economic principles that establish the standards for determining a fair rate of return for a regulated utility?

A. Public utility rates are normally established in a manner designed to allow the recovery of their costs, including capital costs. This is frequently referred to as "cost of service" ratemaking. Rates for regulated public utilities traditionally have 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. Thus, the revenue impact of the cost of capital is derived by multiplying the rate base by the rate of return, including income taxes.

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 values by their cost rates. This is also known as the weighted cost of capital.

Technically, "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. I have equated the two concepts in my testimony.

From an economic standpoint, a fair rate of return is normally interpreted to mean that an efficient and economically managed utility will be able to maintain its financial integrity, attract capital, and establish 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.

Two United States Supreme Court decisions provide guidance for determining a fair rate of return. The first decision 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 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.]**

Thus, the Bluefield decision, in my opinion as a non-lawyer, 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 three economic and financial parameters 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. The opportunity cost principle provides 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. In Simms v. Round Valley Light & Power Company,[1] the Arizona Supreme Court took exception to application of the following principle in Arizona since the Constitution mandates consideration of fair value:

> *"In the Hope case the court, in testing the reasonableness of rates fixed by the Federal Power Commission under the Natural Gas Act, 15 U.S.C.A. Section 717 et seq., after holding that Congress had provided no formula by which just and reasonable rates were to be determined, ruled that it was the final result reached and not the method used in reaching the result that was controlling and that it was unimportant to 'determine the various permissible ways in which any rate base on which the return is computed might be arrived at."*

[1] 294 P.2d 378 (1956).

My testimony does not advocate that the Commission ignore the *Simms* holding in this regard, or the fair value of APS property, which it is required to consider under Article 15, Section 14 of the Arizona Constitution. Rather, I find the Hope and Bluefield decisions to be helpful in their discussion of comparable earnings, financial integrity and capital attraction. I note that APS witness Avera also cites the Hope and Bluefield cases as "guidelines" for evaluating the cost of capital for the Company. *See* Avera Direct at page 8.

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. Many state regulatory commissions rely upon the DCF and CAPM models to develop the cost of common equity for utilities.

Q. What methods did you use to determine APS' cost of common equity?

A. I utilized three methodologies to determine APS's cost of common equity: the DCF, CAPM, and CE methods. I have not employed a RP model in my analyses although, as

discussed later, my CAPM analysis is a form of the RP methodology. Each of these methodologies will be described in more detail in my testimony that follows.

IV. GENERAL ECONOMIC CONDITIONS

Q. Are economic and financial conditions important in determining the cost of capital for APS?

A. Yes. The costs of capital, for both fixed-cost (debt and preferred stock) components and common equity, are determined in part by current and prospective economic and financial conditions. At any given time, each of the following factors has an influence on the costs of capital:

- the level of economic activity (*i.e.,* growth rate of the economy);
- the stage of the business cycle *(i.e.,* recession, expansion, or transition);
- the level of inflation; and
- expected economic conditions.

My understanding is that this position is consistent with the Bluefield decision that noted "[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." Bluefield, 262 U.S. at 679.

Q. What indicators of economic and financial activity did you evaluate in your analyses?

A. I examine several sets of economic statistics from 1975 to the present. I chose this time period because it permits the evaluation of economic conditions over four full business cycles, allowing for an assessment of changes in long-term trends. This period also

approximates the beginning and continuation of active rate case activities by public utilities.

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 timeframe of the four prior business cycles and the most recent cycle.

A. The four prior complete cycles and most recent cycle cover the following periods:

Business Cycle	Expansion Cycle	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
2001-2009	Dec. 2001-Nov. 2007	Dec. 2007-June 2009
Current	July 2009-	

Source: National Bureau of Economic, Research, "Business Cycle Expansions and Contractions."

Q. Do you have any general observations concerning the recent trends in economic conditions and their impact on capital costs over this broad period?

A. Yes, I do. As I will describe below, until the end of 2007, the United States economy had enjoyed general prosperity and stability since the early 1980s. This period had been characterized by longer economic expansions, relatively tame contractions, relatively low and declining inflation, and declining interest rates and other capital costs.

However, in 2008 and 2009, the economy declined significantly, initially as a result of the 2007 collapse of the "sub-prime" mortgage market and the related liquidity crisis in the financial sector of the economy. Subsequently, this financial crisis intensified with a more broad-based decline, initially based on a substantial increase in petroleum prices and a dramatic decline in the U.S. financial sector, culminating with the collapse and/or bailouts of a significant number of venerable institutions such as Bear Stearns, Lehman Brothers, Merrill Lynch, Freddie Mac, Fannie Mae, AIG and Wachovia. The recession also witnessed the demise of national entities such as Circuit City, and the bankruptcies of automotive manufacturers such as Chrysler and General Motors.

This decline has been described as the worst financial crisis since the Great Depression and has been referred to as the "Great Recession." The U.S. and other governments have implemented and continue to implement unprecedented actions to attempt to correct or minimize its scope and effects.

It appears that the recession reached its low point in mid-2009 and that the economy has since begun to expand again, although at a slow and sporadic rate. However, the length and severity of the recession, as well as a relatively slow and uneven recovery, indicate that the impacts of the recession have been and will be felt for an extended period of time. As an example of this, the U.S. and Arizona unemployment rates still stand at about 9 percent – near the highest rates in decades.

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 relevant economic data for the cited time period. Pages 1 and 2 contain general macroeconomic statistics; pages 3 and 4 show interest rates; and pages 5 and 6 contain equity market statistics.

Pages 1 and 2 show that 2007 was the sixth year of an economic expansion but, as I previously noted, the economy subsequently entered a significant decline, as indicated by the growth in real (*i.e.,* adjusted for inflation) Gross Domestic Product ("GDP"), industrial production, and an increase in the unemployment rate. This recession was significant for both its depth and length of time it lasted.

Pages 1 and 2 also show the rate of inflation. As reflected in the Consumer Price Index ("CPI"), for example, inflation rose significantly during the 1975-1982 business cycle and reached double-digit levels in 1979-1980. The rate of inflation declined substantially beginning in 1981, and remained at or below 6.1 percent during the 1983-1991 business cycle. Since 1991, the CPI has been 4.1 percent or lower. The 0.1 percent rate of inflation in 2008, the 2.7 percent level in 2009 and the 1.5 percent rate in 2010 were among the lowest levels of the past 30 years. This is indicative of virtually no inflation, which is reflective of lower capital costs.

Q. What have been the trends in interest rates over the four prior business cycles and the current time?

A. Pages 3 and 4 of Schedule 2 show several series of interest rates. Rates rose sharply to record levels in 1975-1981 when the inflation rate was high and generally rising. Interest rates declined substantially in conjunction with inflation rates during the remainder of the

1980s and throughout the 1990s. Interest rates declined even further from 2000-2005 and generally recorded their then-lowest levels since the 1960s.

Since the recession began, the Federal Reserve has lowered the Federal Funds rate (i.e., short-term rate) on several occasions; currently it is 0.25 percent, an all-time low. In 2008, there was a pronounced decline in short-term rates and long-term U.S. Treasury Securities yields, accompanied by an increase in corporate bond yields and a decrease in stock prices, reflecting the "flight to safety," wherein there was a reluctance of investors to purchase common stocks and corporate bonds while concomitantly moving their money into very safe government bonds. Since then, as seen on page 4, bond yields (both U.S. and utility) have declined to their lowest levels in the past four business cycles and in more than 35 years, with lending rates remaining at historically low levels.

Q. What trends does Schedule 2 show for common share prices?

A. Pages 5 and 6 show several series of common stock prices and ratios. These indicate that share prices were essentially stagnant during the high inflation/high interest rate environment of the late 1970s and early 1980s. The 1983-1991 business cycle and the more recent cycles witnessed a significant upward trend in stock prices. The beginning of the recent financial crisis saw stock prices decline precipitously. Stock prices in 2008 and early 2009 were down significantly from 2007 levels, reflecting the financial/economic crises. Beginning in the second quarter of 2009, prices have recovered substantially but remain below the levels prevailing prior to the current recession. Through the third quarter of 2011, it is evident that stock prices maintain much of the volatility that was present during the recent financial crisis. I also note that events of the past four years have

made public utility stocks, with their consistent and rising dividend rates, relatively more attractive to investors.[2]

Q. What conclusions do you draw from your discussion of economic and financial conditions?

A. It is apparent that recent economic and financial circumstances have been radically different from any that have prevailed since at least the 1930s. The late 2008-early 2009 deterioration in stock prices, the decline in U.S. Treasury bond yields, and the increase in corporate bond yields are evidenced in the recent "flight to safety." On the other side of this "flight to safety" is the negative perception of the recent decline, which has significantly reduced the value of most retirement accounts, investment portfolios and other assets. One significant aspect of this has been a decline in investor expectations of returns, including stock returns. Finally, as noted above, interest rates currently are at levels below those prevailing prior to the financial crisis of late 2008-early 2009 and are near the lowest level in the past 35 years. This "flight to safety" does not represent an increase in the cost of capital; rather, it more properly reflects an "availability of capital" since investors were unwilling to invest in many assets other than U.S. Treasury bonds. Further reflecting a decreased cost of capital, utility bond rates are at their lowest levels in the past four business cycles.

V. APS' OPERATIONS AND BUSINESS RISKS

Q. Please summarize APS and its operations.

A. APS is a public utility that generates, transmits, and distributes electric energy in Arizona. Its service area includes about 1.1 million customers in 11 of Arizona's 15 counties. APS

[2] See, for example, Investment Insights, On Wall Street, "S&P Looks to Utilities ETFs in the Downtrodden Equities Market," August 22, 2011, http://www.onwall street.com/news/utility-stocks-etfs-investments-products-2679728-1.html.

also provides wholesale power to certain municipalities and other utilities. It is the largest utility in Arizona. APS is a subsidiary of Pinnacle West Capital Corporation ("PWC").

Q. Please describe PWC.

A. PWC is a holding company. Its principal subsidiary is APS.

Q. What has been the trend in APS's bond ratings in recent years?

A. This is shown on Schedule 3. APS's debt is currently rated Baa2 by Moody's and BBB by Standard & Poor's. As is indicated in Schedule 3, APS has higher Moody's ratings than its parent PWC. APS's debt has been rated in the Baa category (per Moody's) and BBB category (per Standard & Poor's) since at least 2000. It was downgraded by S&P to BBB- from BBB in 2005 and remained there until 2011, when it again obtained a BBB rating. It has had a Baa2 rating by Moody's since 2006.

Q. How do the bond ratings of APS compare to other electric and combination gas/electric utilities?

A. As I indicated in the previous answer, APS has Triple B bond ratings on its long-term debt. Below is a table depicting the bond rating data of the 59 electric utilities and combination gas/electric utilities covered by AUS Utility Reports:

Moody's Rating	Number of Companies	S&P Rating	Number of Companies
Aa3	2	AA-	2
A1	5	A+	1
A2	9	A	9
A3	14	A-	14
Baa1	11	BBB+	12
Baa2*	12	BBB*	7
Baa3	--	BBB-	6
Ba or less	--	BB	--
NR	4	NR	7

* APS ratings.

As this indicates, APS's ratings are generally lower than many utilities. However, the Company's ratings are higher than was the case prior to 2011, when APS's S&P ratings were at the bottom of investment grade.

Q. How does the current financial status of APS compare to that in existence at the time of the Company's last general rate proceeding in 2008?

A. As I indicated previously, APS had Baa2 security ratings by Moody's and BBB- by S&P in 2008, the time-frame of the Company's last general rate proceeding (Docket No. E-01345A-08-0172). The latter is the lowest investment grade category. This was emphasized by APS in its testimony in that proceeding. For example, APS President Brandt made the following points in his direct testimony in that proceeding:

> APS (was) *in serious financial jeopardy* (page 23, line 21);
>
> APS' declining ROE had caused Pinnacle West's stock to perform significantly worse than that of other electric utilities (page 27, lines 1-2);
>
> APS' credit ratings on its outstanding debt were currently on the lowest rungs of the investment grade credit ladder (page 31, lines 22-23);
>
> Each of the nationally recognized statistical rating organizations that rated APS' debt – S&P, Moody's, and Fitch – as well as various financial analysts had

recently noted the significant danger to downgrade presently threatening APS (page 32, lines 24-26 and page 33, line 1);

APS faced a "challenging regulatory environment" (page 33, line 2); and,

Growth was contributing to APS' financial pressure (page 42).

The BBB- credit rating by S&P, in fact, served as a focal point of APS' filing. Mr. Brandt devoted considerable testimony to the "adverse consequences of APS having its credit rating downgraded to junk." He cited the following "problems that come with non-investment grade credit ratings":

APS' access to the debt and equity markets would become limited to those lenders and investors (if any) willing to take the risk on a junk grade company (page 35, lines 23-25);

Investors will demand a higher yield for an investment in a company with low credit ratings to compensate for increased risk (page 36, lines 1-11);

APS would lose much of cost savings associated with outstanding tax-exempt debt (page 36, lines 12-20);

APS' access to commercial paper would be eliminated (page 36, lines 21-26 and page 37, lines 1-15);

APS may also lose many of its important existing bank credit agreements (page 37, lines 16-21); and,

Complications of APS' purchased power contracts (page 37, lines 22-26 and page 38, lines 1-9).

The potential of downgrades to below-investment grade status also was the focal point of APS' presentation in its interim rate case (Docket No. E-01345A-08-0172). This was demonstrated by the Opening Statement of APS' counsel in the 2008 interim rate hearing (September 15, 2008 Tr., page 9):

> Thus, what is really at issue in this proceeding is the objective evidence that APS once again faces a financial crisis because current rates, particularly after the expiration of the PSA surcharge in July of this year, do not provide APS with sufficient cash flow to fund its substantial capital expenditure obligations to meet system growth. And at the same time those existing rates undermine the ability of the company to earn the reasonable return on equity to which it is entitled.
>
> This twofold shortfall in earnings and available cash flow once again put the company's credit standing in jeopardy, a credit standing, by the way, as I am sure you all know and remember, that is already on the brink of junk status due to previous cash flow problems. And these problems that I have just described, as you will hear in this proceeding, have at the same time reduced the stock of Pinnacle West, APS's parent company, to essentially the lowest performing stock of all investor owned electric utilities in this country.

Since 2008, the financial condition of APS has improved substantially. As indicated above, S&P upgraded APS' debt to BBB in 2011. In addition, S&P assigns an outlook of "positive" to APS, indicating a further upgrade is more likely than a downgrade.

The stock rankings of PWC have also improved since 2008. For example, Value Line recently (mid-2011) raised PWC's "safety" from 3 to 2 and its "technical" rank from 3 to 2.

In addition, the regulatory climate of APS as viewed by the rating agencies has improved. The settlement among the parties in the 2008 general rate proceeding was viewed as constructive and positive. This also reflects a significant improvement in comparison to 2008 from the perspective of APS.

Finally, the stock price of PWC has performed favorably to that of the Dow Jones Utilities and the S&P 500 index from the beginning of 2010 (approximate implementation of rates from 2008 case) to the current time:

Pinnacle West Capital	24%
Dow Jones Utilities	16%
S&P 500 Index	14%

Q. Was the market-to-book ratio of APS an issue in the 2008 proceeding?

A. Yes, it was. In the 2008 interim rate hearing, APS witness Brandt stated (September 15, 2008 Tr. 66 and 68):

> . . . we are selling below book value in an extremely depressed market. We are one of the poorest performing electric utility stocks, virtually at the bottom of the universe of electric utility stocks.
>
> . . .
>
> Below book value you are basically confiscating the existing value of your shareholders. And you can get away with that maybe once, but these are the people . . . these are the long-term investors in the utility industry, long-term holders of our stock with obviously major positions, the top things, they don't forget things like this. And when you need it in the future, they will remember if you did do it in this environment.

Since that time, PWC's stock price has recovered to well above book-value. In fact, PWC sold common stock in 2010 at a price of $38.00 per share (net proceeds of $36.67 per share), well above the 2009 book-value of $32.69 (per Value Line).

Q. How do the rating agency descriptions of APS differ now in comparison to those in 2008?

A. There has been a substantial improvement in the rating agency descriptions of APS. This can be demonstrated by reviewing the language of S&P (the rating agency focused on by APS in the last general rate proceeding). For example, in a June 25, 2008 (i.e., at about the time of the 2008 rate filing) RatingsDirect on APS (Attachment 2), S&P cited the following "weaknesses:"

> Heavy construction program, coupled with a lagged regulatory process in Arizona;
>
> Continued tension in the relationship between APS and ACC, which is particularly unfavorable for credit quality due to the company's ongoing need for rate relief;
>
> Consolidated free operating cash flows are expected to be negative through at least 2010; and,
>
> SunCor's near-term prospects to make distributions to its parent are limited.

In contrast, in the June 24, 2011 RatingsDirect (Attachment 3) wherein it raised APS' ratings, S&P noted the following:

> The ratings reflect our view of improved consolidated financial performance, evidenced by stronger credit metrics, and progress in advancing the regulatory strategy of APS in Arizona. A reduction in debt leverage from equity issuances and debt reductions, coupled with stronger cash flows from higher earnings and tax benefits, increased FFO to debt. Prudent financial management during the current rate case stay-out period and the use of cost riders resulted in improved financial stability. A shift in company focus toward improving regulatory relationships in the past few years continues to benefit credit quality because the company has transitioned to slower customer growth. We could raise the ratings further if regulatory dealings remain constructive and the company continues to manage the balance sheet with equity issuances to offset high capital spending.
>
> . . .

> The company has undergone a significant transition in recent years. High customer growth had necessitated that the company file regular general rate cases with the Arizona Corporation Commission (ACC) to recover its investments and operating costs, prior to the collapse of the housing market. The use of a historical test year in Arizona, coupled with an 18- to 24-month completion time for fully litigated rate cases, made it very difficult for APS to earn authorized returns. In recent years, regulatory lag has decreased and financial performance has improved because of interim rates, recovery of certain post-test-year costs, and an improved 11% authorized equity return in the previous general rate case. Slower growth and the addition of several rate case riders that allow the company to true up certain costs outside of the general rate case process have mitigated the need to file large cases frequently. However, capital spending remains due to replacements and renewable spending, necessitating a continued reliance on rate increases.

Q. Why are you describing APS' financial circumstances in 2008?

A. I am doing so to demonstrate that the 11.0 percent cost of common equity in the settlement in Docket No. E-01345A-08-0172 was a stipulated number that took into account, for example, the 9.0 percent low-end of the 9.0 percent to 11.0 percent range recommended in Staff's testimony, as well as all other aspects of settlement.

Q. Are you aware that APS is requesting the approval of several regulatory mechanisms in this proceeding?

A. Yes, I am. APS is requesting approval of the following new regulatory mechanisms in this case:

> Efficiency and Infrastructure Account (EIA) – revenue decoupling mechanism, which is annually adjusted based on a revenue per customer calculation; and,
>
> Environmental and Reliability Account (ERA) – allows APS to recover costs for environmental and generation capacity additions.

Q. In addition to these, has APS had access to any other regulatory mechanisms since its last general rate proceeding?

A. Yes, it has. APS has had the following regulatory mechanisms:[3]

- Power Supply Adjustor ("PSA") – recovers 90 percent of variance between actual fuel and purchased power costs and base fuel rate; and, includes forward-looking, historical and transition components.

- Renewable Energy Surcharge ("RES") – recovers costs related to renewable initiatives; collects projected dollars to meet RES targets; and, provides incentives to customers to install distributed renewable energy.

- Demand-Side Management Adjustment Clause ("DSMAC") – recovers costs related to energy efficiency and DSM programs above $10 million in base rates; provides performance incentive to APS for net benefits achieved; and, provides rebates and other incentives to participating customers.

- Environmental Improvement Surcharge ("EIS") – recovers retroactively costs related to environmental upgrades not fully recovered through base rates; and, allows for cost recovery of ACC-approved projects.

- Retail Line Extension Fees – "pay as you go" mechanism collects dollars spent for new distribution construction at beginning of project; and, better protects existing customers by allocating cost of expansion to developers.

[3] Pinnacle West Capital Corporation, "Delivering Superior Shareholder Value" Investor Meetings, August 10-12, 2011.

- Transmission Cost Adjustor ("TCA") – recovers FERC-approved transmission costs related to retail customers; and, resets annually as result of FERC Formula Rate process.

- FERC Formula Rates – recovers transmission costs based on historical costs per FERC Form 1 and certain projected data; and, resets annually.

Q. Have the rating agencies commented favorably on these mechanisms?

A. Yes. Moody's, for example, stated the following in its February 25, 2011 Global Credit Opinion on APS (Attachment 4):

> Improved Cost Recovery;
>
> Although regulatory lag continues, APS utilizes several mechanisms that allow its rates to be adjusted outside of a general rate case. Moody's generally views these mechanisms as being supportive of credit quality as they tend to result in a more timely recovery of costs. APS' rates are adjusted annually to recover 90% of the difference between its costs for fuel and purchased power and the amounts included in base rates, limiting APS' exposure to volatile power and gas prices. The fuel recovery factor includes a forward estimate of power costs, which further helps to limit cost deferrals; and,
>
> APS also has adjustment mechanisms that allow the utility to recover its costs for renewable energy, efficiency and demand side management programs. Transmission costs are recovered through a transmission cost adjustor which resets annually based on charges in APS' Federal Energy Regulatory Commission approved formula-based tariffs. APS is also currently able to recover its costs for new customer hookups via line extension payments from customers.
>
> In December 2010, the ACC issued a policy statement supporting decoupling rate structures implemented through rate cases over a three year evaluation period. We generally view decoupling mechanisms as supportive to credit quality as they are intended to improve a utility's fixed cost recovery. No Arizona utilities currently have a decoupling mechanism: implementation is intended to occur during the next rate case process.

VI. CAPITAL STRUCTURE AND COST OF DEBT

Q. What is the importance of determining a proper capital structure in a regulatory framework?

A. A utility's capital structure is important because 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 its capital costs. The rate-base/rate-of-return concept recognizes the assets employed in providing utility services and provides for a return on these assets by identifying the liabilities and common equity (and their cost rates) 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 because 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 have you evaluated the capital structure of APS?

A. I have first examined the five year historic (2006-2010) capital structure ratios of APS. These are shown on Page 1 of Schedule 4. I have summarized below the common equity ratios for APS:

	Including S-T Debt	Excluding S-T Debt
2006	52.7%	52.7%
2007	52.0%	53.8%
2008	49.7%	53.9%
2009	50.5%	52.0%
2010	53.1%	56.5%

Page 2 of Schedule 4 shows the capital structure ratios of PWC (Consolidated). The yearly common equity ratios are:

	Including S-T Debt	Excluding S-T Debt
2006	49.7%	50.1%
2007	48.0%	51.7%
2008	46.0%	52.0%
2009	45.6%	48.7%
2010	49.9%	54.7%

These common equity ratios are generally lower than those of APS over the past five years.

Q. How do these capital structures compare to those of investor-owned combination gas/electric utilities?

A. Schedule 5 shows the common equity ratios (including short-term debt in capitalization) for the two groups of electric utilities covered by AUS Utility Reports. These are:

Year	Electric	Combination Gas And Electric
2006	45%	44%
2007	47%	46%
2008	45%	43%
2009	46%	45%
2010	46%	46%

These common equity ratios are lower than those of APS and PWC.

Q. What capital structure ratios has APS requested in this proceeding?

A. APS is requesting the following capital structure:

Capital Item	Percent
Long-Term Debt	46.06%
Common Equity	53.94%
Total Capital	100.00%

This is the December 31, 2010 capital structure of the Company.

Q. Do you use this capital structure in your cost of capital analyses?

A. Yes, I do.

Q. What is the cost of debt in the company's application?

A. The cost of long-term debt is 6.38 percent. I use this cost rate in my analyses.

VII. SELECTION OF PROXY GROUPS

Q. How have you estimated the cost of common equity for APS?

A. APS is not a publicly-traded company. Consequently, it is not possible to directly apply cost of equity models to this entity. Its parent, PWC, is publicly-traded, so it is possible to directly apply cost of equity models to this entity. However, it is generally preferred to analyze groups of comparison or "proxy" companies as a substitute for APS to determine its cost of common equity.

I have examined two such groups for comparison of APS. I selected one group of electric and combination electric/gas utilities similar to APS and PWC using the criteria listed on Schedule 6. These criteria are as follows:

(1) Market cap of $1 billion to $10 billion;

(2) Electric revenues 50 percent or greater;

(3) Common equity ratio 40 percent or greater;

(4) Value Line Safety Rank of 1, 2 or 3;

(5) S&P stock ranking of A or B;

(6) S&P and Moody's bond ratings of BBB and Baa; and

(7) Currently pays dividends.

Second, I have conducted studies of the cost of equity for the "proxy companies" selected by APS witness 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.

The most common variant of the DCF model assumes that dividends are expected to grow at a constant rate. This variant of the dividend discount model is known as the constant growth or Gordon DCF model. In this framework, cost of capital is derived by the following formula:

$$K = \frac{D}{P} + g$$

where:
K = discount rate (cost of capital)
P = current price
D = current dividend rate
g = constant rate of expected growth

This formula essentially recognizes that the return expected or required by investors is comprised of two factors: the dividend yield (current income) and expected growth in dividends (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 the groups of proxy utility stocks described in the previous section with several indicators of expected dividend growth.

Q. How did you derive the dividend yield component of the DCF equation?

A. There are several methods that can be used for calculating the dividend 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 dividend yield component is the version listed below:

$$Yield = \frac{D_0(1+0.5g)}{P_0}$$

This dividend 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 proxy company for the most recent three month period (August-October 2011). The D_0 is the current annualized dividend rate for each proxy company.

Q. How have you estimated the dividend growth component of the DCF equation?

A. The dividend 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 dividend growth component is to reflect the growth expected by investors that 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. This is evidenced by the fact that every investment decision resulting in the purchase of a particular stock is matched by another investment decision to

sell that stock. Obviously, since two investors reach different decisions at the same market price, their expectations differ.

A wide array of indicators exists 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 dividend growth in deriving the growth component of the DCF model.

I have considered five indicators of growth in my DCF analyses. These are:

1. 2006-2010 (5-year average) earnings retention, or fundamental growth (per Value Line);

2. 5-year average of historic growth in earnings per share ("EPS"), dividends per share ("DPS"), and book value per share ("BVPS") (per Value Line);

3. 2011, 2012 and 2014-2016 projections of earnings retention growth (per Value Line);

4. 2008-2010 to 2014-2016 projections of EPS, DPS, and BVPS (per Value Line); and

5. 5-year projections of EPS growth as reported in First Call (per Yahoo! Finance).

I believe this combination of growth indicators is a representative and appropriate set with which to begin the process of estimating investor expectations of dividend growth for the

groups of proxy companies. I also believe that these growth indicators reflect the types of information that investors consider in making their investment decisions. As I indicated previously, investors have an array of information available to them, all of which should be expected to have some impact on their decision-making process.

Q. Please describe your DCF calculations.

A. Schedule 7 presents my DCF analysis. Page 1 shows the calculation of the "raw" (i.e., prior to adjustment for growth) dividend yield for each proxy company. Pages 2 and 3 show the growth rate for the groups of proxy companies. Page 4 shows the "raw" DCF calculations, which are presented on several bases: mean, median, and high values. These results can be summarized as follows:

	Mean	Median	Mean Low[4]	Mean High[5]	Median Low[4]	Median High[5]
Proxy Group	8.8%	8.9%	7.4%	9.9%	7.5%	10.6%
Avera Group	9.3%	9.2%	8.5%	10.2%	8.7%	10.0%

I note that the individual DCF calculations shown on Schedule 7 should not be interpreted to reflect the expected cost of capital for the proxy groups; rather, the individual values shown should be interpreted as alternative information considered by investors. The individual DCF calculations also demonstrate how the focus on a single growth rate, such as EPS projections, can produce a DCF conclusion that is not reflective of a broader perspective of available information.

The results in Schedule 7 indicate average (mean and median) DCF cost rates of 8.8 percent to 9.3 percent. The "low" and "high" DCF rates (i.e., using the lowest and highest

[4] Using only the lowest growth rates.
[5] Using only the highest growth rates.

growth rates only) range from 7.4 percent to 10.6 percent on an average basis and median basis.

Q. What do you conclude from your DCF analysis?

A. This analysis reflects a broad DCF range of 7.4 percent to 10.6 percent for the proxy groups. I give less weight to the extreme lower and upper ends of the DCF results. I believe that a range of 9.3 percent to 10.5 percent (9.9 percent mid-point) reflects the proper DCF cost for APS. This range contains the top mean/median DCF results and contains most of the high DCF results.

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 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
Rm = return on market
β = 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 (*i.e.*, beta), whereas the simple risk premium method assumes the same risk premium for all companies in an industry, such as electric utilities.

Q. What groups of companies have you utilized to perform your CAPM analyses?

A. I have performed CAPM analyses for the same groups of proxy utilities evaluated in my DCF analyses.

Q. Please explain the risk-free rate as used in your CAPM and indicate what rate you employed.

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 CAPM applications, the risk-free rate is generally recognized by use of U.S. Treasury securities. Two general types of U.S. 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 (August-October 2011) for 20-year U.S. Treasury bonds. Over this three-month period, these bonds had an average yield of 2.98 percent.

Q. What is beta and what betas did you employ in your CAPM?

A. Beta is a measure of the relative volatility (and thus risk) of a particular stock in relation to the overall market. Betas of less than 1.0 are considered less risky than the market, whereas betas greater than 1.0 are more risky. Utility stocks traditionally have had betas below 1.0. I utilized the most recent Value Line betas for each company in the groups of proxy utilities.

Q. How did you estimate the market risk premium component in your CAPM analysis?

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 alternative measures of returns of the S&P 500 (a broad-based group of large U.S. companies) and 20-year U.S. Treasury bonds.

First, I have compared the actual annual returns on equity of the S&P 500 with the actual annual yields of U.S. Treasury bonds. Schedule 8 shows the return on equity for the S&P 500 group for the period 1978-2010 (all available years reported by S&P). 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 this version of the risk premium is about 6.34 percent.

I have also considered the total returns (i.e., dividends/interest plus capital gains/losses) for the S&P 500 group as well as for the long-term (20-year) government bonds, as tabulated by Morningstar (formerly Ibbotson Associates), using both arithmetic and geometric means. I have considered the total returns for the entire 1926-2010 period, which are as follows:

	S&P 500	L-T Gov't Bonds	Risk Premium
Arithmetic	11.9%	5.9%	6.0%
Geometric	9.9%	5.5%	4.4%

I conclude from this that the expected risk premium is about 5.58 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.

Q. Please summarize your CAPM calculations.

A. Schedule 9 shows my CAPM calculations. The results are:

	Mean	Median
Proxy Group	7.1%	7.0%
Avera Group	7.1%	7.2%

Q. What is your conclusion concerning the CAPM cost of equity?

A. The result of my CAPM analyses collectively indicates a cost of 7.0 percent to 7.2 percent for the groups of comparison utilities. I conclude that the CAPM cost of equity for APS is 7.0 percent to 7.2 percent (7.1 percent mid-point).

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 thus 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, because the CE method translates into practice the competitive principle upon which regulation is based.

The CE method normally examines the experienced and/or projected returns on book common equity. The logic for examining 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 that utilities that have market-to-book ratios of greater than one (*i.e.,* 100 percent) 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 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 analysis uses prospective returns and thus is not confined to historical data.

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 utilities for the period 1992-2010 (*i.e.,* the last nineteen years). 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 from 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 periods: 2002-2010 (the recent business cycle) and 1992-2001 (the prior business cycle).

Q. Please describe your CE analysis.

A. Schedules 10 and 11 contain summaries of experienced returns on equity for several groups of companies, while Schedule 12 presents a risk comparison of utilities versus unregulated firms.

Schedule 10 shows the earned returns on average common equity and market-to-book ratios for the groups of proxy utilities. These can be summarized as follows:

	Proxy Group	Avera Proxy Group
Historic ROE		
Mean	9.6-11.7%	10.4-11.4%
Median	9.5-12.0%	10.2-11.9%
Historic M/B		
Mean	143-164%	164-165%
Median	144-161%	144-159%
Prospective ROE		
Mean	9.0-9.7%	9.4-10.1%
Median	8.3-9.3%	9.0-9.5%

These results indicate that historic returns of 9.5 percent to 12.0 percent have been adequate to produce market-to-book ratios of 143 percent to 165 percent for the groups of proxy utilities. Furthermore, projected returns on equity for 2011, 2012, 2014-2016 are within a range of 8.3 percent to 10.1 percent for the utility groups. These relate to 2010 market-to-book ratios of 118 percent or 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 11 presents the earned returns on equity and market-to-book ratios for the S&P 500 group over the past nineteen years. As this Schedule indicates, over the two periods this group's average earned returns ranged from 12.4 percent to 14.7 percent with market-to-book ratios ranging between 258 percent and 341 percent.

Q. How can the above information be used to estimate the cost of equity for APS?

A. The recent earnings of the proxy 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 proxy utilities, however, it is necessary to compare the risk levels of the utility industry with those of the competitive sector. I have done this in Schedule 12, which compares several risk indicators for the S&P 500 group and the utility 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 the proxy utilities is no more than 9.5 percent to 10.0 percent. Recent returns of 9.5 percent to 12.0 percent have resulted in market-to-book ratios of 143 and greater. Prospective returns of 8.3 percent to 10.1 percent result in anticipated market-to-book ratios of over 118 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 9.5 percent to 10.0 percent should thus result in a market-to-book ratio of over 100 percent. As I indicated earlier, the fact that market-to-book ratios substantially exceed 100 percent indicates that historic and prospective returns of over 10 percent reflect earnings levels that exceed the cost of equity for those regulated companies.

Please also note that my CE analysis is not based on a mathematical formula approach, as are the DCF and CAPM methodologies. Rather, it is based on recent trends and current conditions in equity markets. Further, it is based on the direct relationship between returns on common stock and market-to-book ratios of common stock. In utility rate

setting, a fair rate of return is based on the utility's assets (*i.e.*, rate base) and the book value of the utility's capital structure. As stated earlier, maintenance of a financially stable utility's market-to-book ratio at 100 percent, or a bit higher, is fully adequate to maintain the utility's financial stability. On the other hand, a market price of a utility's common stock that is 150 percent or more above the stock's book value is indicative of earnings that exceed the utility's reasonable cost of capital. Thus, actual or projected earnings do not directly translate into a utility's reasonable cost of equity. Rather, they must be viewed in relation to the market-to-book ratios of the utility's common stock.

My 9.5 percent to 10.0 percent CE recommendation is not designed to result in market-to-book ratios as low as 1.0 for APS/PWC. Rather, it is based on current market conditions and the proposition that ratepayers should not be required to pay rates based on earnings levels that result in excessive market-to-book ratios.

XI. RETURN ON EQUITY RECOMMENDATION

Q. Please summarize the results of your three cost of equity analyses.

A. My three methodologies produce the following:

	Range	Mid-Point
Discounted Cash Flow	9.3-10.5%	9.90%
Capital Asset Pricing Model	7.0-7.2%	7.10%
Comparable Earnings	9.5-10.0%	9.75%

Q. What is your cost of equity recommendation for APS?

A. My analyses suggest a broad cost of equity range of 7.0 percent to 10.5 percent range for APS. The respective mid-points of my DCF and CE analyses are 9.90 percent and 9.75 percent. I recommend a cost of equity range of 9.3 percent to 10.5 percent (9.90 percent

mid-point) for APS. This range is supported by my DCF and CE analyses, and exceeds my CAPM findings. I believe a 9.90 cost of equity is adequate at this time in order to give some consideration to APS's ratepayers for the economic distress they are incurring due to the recent recession and at same time assist APS maintain, if not improve, its debt rating.

Q. It appears that your CAPM results are somewhat lower than your DCF results. Does this indicate that the CAPM results should not be used at this time?

A. No, this is not the case. Although my recommended range is above the CAPM results, I have not disregarded the CAPM results. It is apparent that the CAPM results are lower than the DCF results, as well as being lower than CAPM results in recent years. The two reasons for this are the current relatively low yields on U.S. Treasury bonds (i.e., risk-free rate) and a lower risk premium that reflects the decline in stock prices of the past few years. However, these currently lower CAPM results are only one-half of the impact of recent economic conditions. The other impact is on the DCF results, which are somewhat higher currently due to the higher yields attributable to the decline in stock prices, as well as the use of EPS projections from a depressed base (beginning) point. It would not be proper to disregard the lower CAPM results while not discounting the higher DCF results.

Q. How does your cost of equity recommendation in this proceeding compare to your cost of equity recommendation in the last APS general rate proceeding?

A. As I indicated above, my cost of capital range in the current proceeding is 9.3 percent to 10.5 percent, with a mid-point of 9.90 percent. In addition, the mid-points of my DCF and CE analyses are 9.90 percent and 9.75 percent, respectively. I am recommending a point estimate of 9.90 percent for APS in this proceeding.

In the last general rate proceeding of APS (Docket No. E-01345A-08-0172), my corresponding cost of equity range was 9.0 percent to 11.0 percent, with a mid-point of 10.0 percent. In that proceeding, I recommended the top of the range, or 11.0 percent. As I indicated (pages 32-33)

> Even though a lower cost of equity (e.g., the mid-point of my 9.0 percent to 11.0 percent range) could be justified, my 11.0 percent recommendation reflects Staffs desire to aid APS in its efforts to attract capital investment, as cited in the testimony of Staff witness Johnson.

I have also demonstrated, in prior sections of my prior testimony, that the financial circumstances of APS are improved currently in comparison to those in existence in the prior general rate proceeding. As I indicated, APS' debt ratings and outlooks have improved and that PWC has successfully raised common equity in the capital markets. As a result, I do not propose any similar adjustment to the top end of the cost of capital range, nor is Staff proposing such an adjustment, in the current proceeding.

XII. TOTAL COST OF CAPITAL

Q. What is the total cost of capital for APS?

A. Schedule 1 reflects the total cost of capital for the Company using APS's test period capital structure along with the cost of debt and common equity costs my analyses support. The resulting total cost of capital is 7.95 percent to 8.60 percent (8.28 percent with 9.90 percent return on equity). I recommend that this 8.28 percent total cost of capital be established for APS.

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 13 shows the pre-tax coverage that would result if APS earned my cost of capital recommendation. As the results indicate, my recommended range would exceed a coverage level above the benchmark range for a BBB rated utility. In addition, the debt ratio (which reflects the Company's proposed capital structure) exceeds the benchmark for a BBB rated utility.

XIII. CRITIQUE OF COMPANY TESTIMONY

Q. Have you reviewed the testimony of APS witness William Avera?

A. Yes, I have.

Q. What is your understanding of Dr. Avera's cost of equity recommendation for APS?

A. Dr. Avera proposes an equity return for APS of 11.25 percent.

Q. Please summarize your understanding of Dr. Avera's cost of equity analyses.

A. Dr. Avera's cost of equity findings can be summarized as follows:

	Utility Proxy Group	Non-Utility Proxy Group
DCF		
Earnings		
Value Line	11.2%	11.9%
IBES	11.0%	12.4%
Zacks	10.9%	12.5%
br + sv	9.5%	12.1%
CAPM	11.4%	10.0%

Based upon these results, Dr. Avera concluded that the "bare bones" cost of equity is a range of 10.6 percent to 11.6 percent. He adds 0.15 percent to this range for flotation costs and concludes the cost of equity is 10.75 percent to 11.75 percent. He further concludes that the cost of equity for APS is the mid-point of this range, or 11.25 percent.

Q. Do you have any comments concerning Dr. Avera's DCF analyses and conclusions?

A. Yes, I do. Dr. Avera's DCF analyses for his utility proxy group contains an 11.0 percent conclusion. This 11.0 percent conclusion is based on his four sets of DCF analyses shown on his page 48. All but one of these sets of DCF analyses are based exclusively on analysts' forecasts of EPS growth and the remaining DCF result is 9.5 percent for his utility proxy group. It is thus obvious that Dr. Avera's 11.25 percent DCF conclusion is based almost exclusively on analysts' forecasts of EPS growth.

Q. Is it proper to focus on analysts' forecasts of EPS growth in a DCF analysis?

A. No. As I indicated in my DCF analysis, it is customary and proper to use alternative measures of growth, not just EPS projections.

Dr. Avera's DCF analyses implicitly assume that investors rely almost exclusively on EPS projections when making investment decisions. This is a very dubious assumption, and Dr. Avera has offered no evidence that it is correct. I note, for example, the Value Line publication – one of the sources of his growth rate estimates – contains many statistics, of both a historic and projected nature, for the benefit of Value Line subscribers, who presumably make investment decisions based at least in part from the information contained in Value Line. For example, Value Line publishes both historic and projected growth rates in numerous financial indicators such as EPS, DPS, BVPS, and retention

growth. Yet, Dr. Avera would have us believe that Value Line subscribers and investors focus exclusively on one single number from this publication.

I note in this regard that the DCF model is a "cash flow" model. The cash flow to investors in a DCF framework is dividends. Dr. Avera's DCF results, in contrast, does not even consider dividend growth rates.

Q. Dr. Avera also conducts DCF analyses to a group of non-regulated companies. Is this a proper standard for establishing APS' cost of equity?

A. No, it is not. This group of non-regulated companies is clearly more risky than his proxy group of electric utilities. As evidence of this, consider the respective sets of DCF analyses for the two groups, as referenced above.

The DCF costs for the non-utility group are much higher than those for the electric group. This clearly indicates that the non-utility group is more risky than the utility group and, thus, serves as no reliable standard for APS.

Q. What are your comments regarding Dr. Avera's CAPM analysis?

A. Dr. Avera's CAPM uses the following inputs for his utility proxy group:

Market risk premium	8.3%
Risk free rate	4.5%
Beta	0.74%
Size Adjustment	0.74%

My first concern with Dr. Avera's CAPM analysis is the use of the 8.3 percent market risk premium. His 8.3 percent market risk premium was derived by combining his estimate of DCF results for the S&P 500 (12.8 percent) and a 4.5 percent yield on 30-year U.S. Treasury bonds. This 12.8 percent expected return for the S&P 500 is excessive. The historic (1926-2010) total returns for the S&P 500 have been much less than 12.8 percent (i.e., 9.9 percent on a geometric growth basis and 11.9 percent on an arithmetic basis). Dr. Avera offers no explanation as to why his DCF results for the S&P 500 group are so much higher than his group's historic returns.

XIV. FAIR VALUE RATE OF RETURN

Q. What is your understanding of APS's position on the issue of fair value rate base and related rate of return implications?

A. It is my understanding that APS is requesting that the fair value of its rate base be used in developing its rates. The Company is requesting that the Commission use the same methodology for determining its fair value rate of return ("FVROR") as was used by the Staff in the last APS case. The Company is requesting a 1.0 percent return on its fair value increment of capital (i.e., the difference between the Reconstructed Cost New ("RCN") rate base and Original Cost ("OC") rate base).

Q. What is your understanding of the Commission's procedure for utilizing the fair value of rate base in setting utility rates?

A. My "non-legal understanding" is that the Commission must consider the fair value of a utility's assets in setting rates. My understanding is based in part on the 2007 Arizona Court of Appeals decision in the Chaparral City case that indicates that the court agreed with the Commission that "the cost of capital analysis 'is geared to concepts of original

cost measures of rate base, not fair value measures of rate base . . . ."[6] The decision goes on to make the following statement: "If the Commission determines that the cost of capital analysis is not the appropriate methodology to determine the rate of return to be applied to the FVRB, the Commission has the discretion to determine the appropriate methodology."[7] It is correspondingly the purpose of this section of my testimony to recommend an "appropriate methodology" for use in conjunction with a FVRB.

Q. Do you have any observations based upon your own experience in cost of capital determination, as to whether a cost of capital developed for application to an original cost rate base is consistent with a fair value rate base?

A. Yes, I do. It is my personal experience, based upon nearly 40 years of providing cost of capital testimony, that the concept of cost of capital is designed to apply to an original cost rate base. This is the case since the cost of capital is derived from the liabilities/owners' equity side of a utility's balance sheet using the book values of the capital structure components. The cost of capital, once determined, is then applied to (i.e., multiplied by) the rate base, which is derived from the asset side of the balance sheet (i.e., OCRB). From a financial perspective, the rationale for this relationship is that the rate base is financed by the capitalization. Under this relationship, a provision is provided for investors (both lenders and owners) to receive a return on their invested capital. Such a relationship is meaningful as long as the cost of capital is applied to the original cost (i.e., book value) rate base, because there is a matching of rate base and capitalization.

When the concept of fair value rate base is incorporated, however, this link between rate base and capital structure is broken. The amount of fair value rate base that exceeds

[6] Chaparral City Water Company v. ACC, 1 CA-0005-0002, at p. 13, #17 (Ariz. App. Feb 13, 2007)(memo decision)
[7] Id.

original cost rate base is not financed with investor-supplied funds and, indeed, is not financed at all. As a result, a customary cost of capital analysis cannot be automatically applied to the fair value rate base since there is no financial link between the two concepts. In my "non-legal" opinion, both the Commission and the Arizona Court of Appeals have also recognized this lack of compatibility between a customary weighted cost of capital ("WCOC") analysis and FVRB.

Q. Why is it important that there be a link between the concepts of rate base and cost of capital?

A. This link is important since financial theory indicates that investors should be provided an opportunity to earn a return on the capital they provided to the utility. Since the capital finances the rate base (in an original cost world), the link between cost of capital and rate base satisfies this financial objective.

Q. Based on your experience as a cost of capital witness over the past 40 years, do you have a suggestion as to how to account for the use of a FVRB in setting rates for APS?

A. Yes, I do. Since the increment between fair value rate base and original cost rate base is not financed with investor-supplied funds, it is logical and appropriate, from a financial standpoint, to assume that this increment has no financing cost. As a result, the cost of capital, through the capital structure, can be modified to account for a level of cost-free capital in an equal dollar amount to the increment of FVRB over the OCRB. Such a procedure would still provide for a return being earned on all investor-supplied funds and would thus be consistent with financial standards.

Q. Have you made such a proposal in this proceeding?

A. Yes, I have. As is shown below, I have developed a capital structure and FVROR that applies to APS's FVRB.

Item	Percent[8]	Cost	Fair Value Return
Long-term Debt	31.94%	6.38%	2.04%
Common Equity	37.40%	9.90%	3.70%
FVRB Increment[9]	30.66%	0.00%	0.00%
Total FVRB Capital	100.00%		5.74%

Applying this 5.74 percent to the FVRB provides for a return on all investor-supplied capital and is therefore an appropriate rate to apply to the FVRB from a financial and economic standpoint. As such, it provides for an appropriate fair value rate of return to be applied to a FVRB. Staff also refers to this as Method 1.

Q. Have you developed an alternative method with which to apply a FVROR to a FVRB?

A. Yes, I have. Should the Commission determine that there should be a specific return (greater than zero) applied to the FVRB Increment, I have provided such a procedure.

Q. Why is it necessary to add a return on only the portion of FVRB that exceeds the OCRB?

A. The WCOC authorized by the Commission has already provided for a full cost of equity return and cost of debt on the portions of equity and debt capital that are supporting the

[8] As shown in Testimony of Utilities Division Staff witness Ralph Smith.
[9] FVRB minus OCRB.

OCRB portion of the FVRB. As a result, there is no need to provide any additional return on the portions of FVRB supported by common equity and debt.

Stated differently, both the cost of debt and the return on common equity (i.e., capital stock, paid-in capital, and retained earnings - the investment of common shareholders) are already provided for in a traditional WCOC. Only the portion of the FVRB that exceeds OCRB ("Fair Value Increment") needs to have a specific return identified in order to reflect a return component on that Fair Value Increment.

Q. What is the proper cost rate to apply to the Fair Value Increment?

A. As I indicated previously, from a financial perspective, it should not be necessary to provide for <u>any</u> return on the Fair Value Increment since this is not investor-supplied capital. However, the Commission may choose to evaluate this issue from both a financial and a public policy perspective. I am aware that APS may claim that the concept of fair value carries with it the notion that investors should receive some benefit when fair value is greater than original cost and should suffer some detriment when fair value is less than original cost. It is possible that the Commission may determine that Arizona's fair value provision, which is somewhat unique, is not inconsistent with these concepts. Nonetheless, the idea that the Company should receive some benefit from the Fair Value Increment does not mean that one should automatically apply to the FVRB a WCOC developed by reference to original cost rate base. If it is determined that it is desirable to provide an additional (non-zero) return on the Fair Value Increment, the proper return should be no larger than the real (i.e., after inflation is removed) risk-free rate of return.

Q. What is the risk-free return?

A. The risk-free return is, in financial terms, the return on an investment that carries little or no risk. Risk-free investments are universally defined as U.S. Treasury Securities, with short-term maturities usually being used as the risk-free rate. Over the past several months, various maturities of U.S. Treasury securities have yielded from about 0.1 percent (short-term) to 4.0 percent (long-term) in nominal terms. I also note that 2011 and 2012 forecasts of long-term U.S. Treasury securities are about 3.5 percent to 5.0 percent. As a result, I use 4.0 percent as the nominal risk-free rate.

Q. What is the "real" risk-free rate?

A. The concept of real rates involves the removal of the rate of inflation from the nominal risk-free rate. In 2010, the rate of inflation, as measured by the Consumer Price Index ("CPI"), was 1.5 percent. Forecasts of the CPI for 2011-2012 are about 2 percent or less. As a result, I propose to use a 2 percent inflation rate for computing the real risk-free rate, which is computed as follows:

Nominal Risk-Free Rate	4.0%
Less: Inflation Rate	2.0%
Equals: Real Risk-Free Rate	2.0%

Q. Please explain why APS's FVROR should consider the real risk-free rate, as opposed to the nominal risk-free rate.

A. The investors of APS are already receiving an inflation factor due to the inclusion of inflation in the Fair Value Increment. Specifically, the Fair Value Increment incorporates inflation by considering the current value of assets, which reflect, in part, past inflation. It

would be double-counting to also include the inflation components in the return to be applied to the Fair Value Increment.

Q. What return on the Fair Value Increment do you recommend in your alternative FVROR proposal?

A. My alternative FVROR proposal ("Method 2") incorporates a return on the Fair Value Increment with a maximum value of 2.0 percent, as developed above. However, I wish to emphasize that this 2.0 percent value is the maximum value that could be applied to the FVRB Increment. In reality, any value between zero percent and 2.0 percent could be used as the cost rate on the FVRB Increment. As I stated above, this Fair Value Increment return is in addition to the return that the Company's investors already earn on their investment in the Company. In this sense, an above-zero cost rate for the fair value increment represents a bonus to the Company that would have to find its justification in policy considerations instead of in pure economic or financial principles; for that reason, the selection of an appropriate cost rate within this range should fall to the Commission's discretion. I would propose the mid-point of this range, or 1.00 percent.

Q. What is the resulting impact of your alternative proposal in this proceeding?

A. I am proposing the following modified FVROR for APS:

Capital Item	Percent	Cost	Return
Long-term Debt	31.94%	6.38%	2.04%
Common Equity	37.40%	9.90%	3.70%
FVRB Increment	30.66%	1.00%	0.31%
Total	100.00%		6.05%

As shown in the above table, this alternative proposal provides for a non-zero return on the Fair Value Increment of APS, and provides for an overall fair value rate of return of 6.05 percent on the FVRB.

Q. Of the two alternative proposals for determining the fair value rate of return that should be applied to the FVRB, which one do you believe is more appropriate and why?

A. From a financial perspective, I believe the first proposal (i.e., zero-cost for FVRB Increment) is most appropriate. This proposal is consistent with financial principles and would fully compensate the Company's investors for their investment. In addition, this proposal utilizes the FVRB of the Company. On the other hand, if the Commission were to determine that a non-zero return on the Fair Value Increment is desirable, the alternative (i.e., a 1.00 percent cost-rate for the FVRB increment) is not inappropriate. It is my understanding that this second alternative was utilized by the Commission in APS's last rate proceeding.

Q. Do these proposals provide for a return on the FVRB of APS?

A. Yes, they do.

Q. Will Staff continue to evaluate appropriate methods for determining the fair value rate of return on fair value rate base?

A. It is my understanding that the Commission Staff will continue to consider these issues in the context of future rate cases. Individual rate cases present different issues and varying sets of circumstances. For example, if one were to assign a non-zero cost rate to the fair value increment, it may be appropriate to determine the cost of equity to reflect a reduction in risk. I have not proposed such an adjustment in this case, but these issues may appear as Staff continues to consider appropriate methods for determining and evaluating the concept of fair value rate of return on fair value rate base.

Q. Does this conclude your Direct Testimony?

A. Yes.

BACKGROUND AND EXPERIENCE PROFILE
DAVID C. PARCELL, MBA, CRRA
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

2007-Present	President, Technical Associates, Inc.
1995-2007	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 DESIGNATION

Certified Rate of Return Analyst - Founding Member

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.

Utility Economics -- 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, Arkansas, California, Connecticut, Delaware, District of Columbia, Florida, Georgia, Hawaii, Illinois, Indiana, Kansas, Kentucky, Maine, Maryland, Missouri, Nebraska, Nevada, New Hampshire, New Jersey, 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.

Exhibit___(DCP-1)
Schedule 1

ARIZONA PUBLIC SERVICE COMPANY
TOTAL COST OF CAPITAL
FOR THE TEST YEAR ENDED DECEMBER 31, 2010

Capital Item	Amount 1/ ($000)	Percent	Cost Rate			Weighted Cost		
Long-Term Debt	$3,382,856	46.06%		6.38%	1/		2.94%	
Short-Term Debt	$0	0.00%		--	1/		--	
Common Equity	$3,961,248	53.94%	9.30%	9.90%	10.50%	5.02%	5.34%	5.66%
Total Capital	$7,344,104	100.00%				**7.95%**	**8.28%**	**8.60%**

1/ As contained in Schedule D-1 of Company Filing.

ECONOMIC INDICATORS

Year	Real GDP* Growth	Industrial Production Growth	Unemploy-ment Rate	Consumer Price Index	Producer Price Index
		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%	3.4%	6.9%	2.7%	0.2%
1994	4.0%	5.5%	6.1%	2.7%	1.7%
1995	3.7%	4.8%	5.6%	2.5%	2.3%
1996	4.5%	4.3%	5.4%	3.3%	2.8%
1997	4.5%	7.3%	4.9%	1.7%	-1.2%
1998	4.2%	5.8%	4.5%	1.6%	0.0%
1999	3.7%	4.5%	4.2%	2.7%	2.9%
2000	4.1%	4.0%	4.0%	3.4%	3.6%
2001	1.1%	-3.3%	4.7%	1.6%	-1.6%
		2002 - 2009 Cycle			
2002	1.8%	0.2%	5.8%	2.4%	1.2%
2003	2.5%	1.3%	6.0%	1.9%	4.0%
2004	3.5%	2.3%	5.5%	3.3%	4.2%
2005	3.1%	3.2%	5.1%	3.4%	5.4%
2006	2.7%	2.2%	4.6%	2.5%	1.1%
2007	1.9%	2.7%	4.6%	4.1%	6.2%
2008	-0.3%	-3.7%	5.8%	0.1%	-0.9%
2009	-3.5%	-11.2%	9.3%	2.7%	4.3%
		Current Cycle			
2010	3.0%	5.3%	9.6%	1.5%	3.8%

*GDP=Gross Domestic Product

Source: Council of Economic Advisors, Economic Indicators, various issues.

ECONOMIC INDICATORS

Year	Real GDP* Growth	Industrial Production Growth	Unemploy-ment Rate	Consumer Price Index	Producer Price Index
2004					
1st Qtr.	3.0%	2.8%	5.6%	5.2%	5.2%
2nd Qtr.	3.5%	4.9%	5.6%	4.4%	4.4%
3rd Qtr.	3.6%	4.6%	5.4%	0.8%	0.8%
4th Qtr.	2.5%	4.3%	5.4%	3.6%	7.2%
2005					
1st Qtr.	4.1%	3.8%	5.3%	4.4%	5.6%
2nd Qtr.	1.7%	3.0%	5.1%	1.6%	-0.4%
3rd Qtr.	3.1%	2.7%	5.0%	8.8%	14.0%
4th Qtr.	2.1%	2.9%	4.9%	-2.0%	4.0%
2006					
1st Qtr.	5.4%	3.4%	4.7%	4.8%	-0.2%
2nd Qtr.	1.4%	4.5%	4.6%	4.8%	5.6%
3rd Qtr.	0.1%	5.2%	4.7%	0.4%	-4.4%
4th Qtr.	3.0%	3.5%	4.5%	0.0%	3.6%
2007					
1st Qtr.	0.9%	2.5%	4.5%	4.8%	6.4%
2nd Qtr.	3.2%	1.6%	4.5%	5.2%	6.8%
3rd Qtr.	2.3%	1.8%	4.6%	1.2%	1.2%
4th Qtr.	2.9%	1.7%	4.8%	6.4%	10.8%
2008					
1st Qtr.	-1.8%	1.9%	4.9%	2.8%	9.6%
2nd Qtr.	1.3%	0.2%	5.3%	7.6%	14.0%
3rd Qtr.	-3.7%	-3.0%	6.0%	2.8%	-0.4%
4th Qtr.	-8.9%	6.0%	6.9%	-13.2%	-28.4%
2009					
1st Qtr.	-6.7%	-11.6%	8.1%	2.4%	-0.4%
2nd Qtr.	-0.7%	-12.9%	9.3%	3.2%	9.2%
3rd Qtr.	1.7%	-9.3%	9.6%	2.0%	-0.8%
4th Qtr.	3.8%	-4.5%	10.0%	2.5%	8.8%
2010					
1st Qtr.	3.9%	2.7%	9.7%	0.9%	6.5%
2nd Qtr.	3.8%	7.4%	9.7%	-1.5%	-3.5%
3rd Qtr.	2.5%	6.9%	9.6%	2.8%	4.3%
4th Qtr.	2.3%	6.3%	9.6%	2.8%	8.0%
2011					
1st Qtr.	0.4%	5.4%	8.9%	5.6%	13.2%
2nd Qtr.	1.3%	3.8%	9.1%	1.6%	2.4%
3rd Qtr.			9.1%		

*GDP=Gross Domestic Product

Source: Council of Economic Advisors, Economic Indicators, various issues.

INTEREST RATES

Year	Prime Rate	US Treasury T Bills 3 Month	US Treasury 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%
			2002 - 2009 Cycle				
2002	4.67%	1.62%	4.61%	[1]	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%
2006	7.96%	4.73%	4.80%		5.84%	6.07%	6.32%
2007	8.05%	4.41%	4.63%		5.94%	6.07%	6.33%
2008	5.09%	1.48%	3.66%		6.18%	6.53%	7.25%
2009	3.25%	0.16%	3.26%		5.75%	6.04%	7.06%
			Current Cycle				
2010	3.25%	0.14%	3.22%		5.24%	5.46%	5.96%

[1] Note: Moody's has not published Aaa utility bond yields since 2001.

Sources: Council of Economic Advisors, Economic Indicators; Moody's Bond Record; Federal Reserve Bulletin; various issues.

INTEREST RATES

	Prime Rate	US Treasury T Bills 3 Month	US Treasury T Bonds 10 Year	Utility Bonds Aaa [1]	Utility Bonds Aa	Utility Bonds A	Utility Bonds Baa
2007							
Jan	8.25%	4.96%	4.76%		5.78%	5.96%	6.16%
Feb	8.25%	5.02%	4.72%		5.73%	5.90%	6.10%
Mar	8.25%	4.97%	4.56%		5.66%	5.85%	6.10%
Apr	8.25%	4.88%	4.69%		5.83%	5.97%	6.24%
May	8.25%	4.77%	4.75%		5.86%	5.99%	6.23%
June	8.25%	4.63%	5.10%		6.18%	6.30%	6.54%
July	8.25%	4.84%	5.00%		6.11%	6.25%	6.49%
Aug	8.25%	4.34%	4.67%		6.11%	6.24%	6.51%
Sept	7.75%	4.01%	4.52%		6.10%	6.18%	6.45%
Oct	7.50%	3.97%	4.53%		6.04%	6.11%	6.36%
Nov	7.50%	3.49%	4.15%		5.87%	5.97%	6.27%
Dec	7.25%	3.08%	4.10%		6.03%	6.16%	6.51%
2008							
Jan	6.00%	2.86%	3.74%		5.87%	6.02%	6.35%
Feb	6.00%	2.21%	3.74%		6.04%	6.21%	6.60%
Mar	5.25%	1.38%	3.51%		5.99%	6.21%	6.68%
Apr	5.00%	1.32%	3.68%		5.99%	6.29%	6.82%
May	5.00%	1.71%	3.88%		6.07%	6.27%	6.79%
June	5.00%	1.90%	4.10%		6.19%	6.38%	6.93%
July	5.00%	1.72%	4.01%		6.13%	6.40%	6.97%
Aug	5.00%	1.79%	3.89%		6.09%	6.37%	6.98%
Sept	5.00%	1.46%	3.69%		6.13%	6.49%	7.15%
Oct	4.00%	0.84%	3.81%		6.95%	7.56%	8.58%
Nov	4.00%	0.30%	3.53%		6.83%	7.60%	8.98%
Dec	3.25%	0.04%	2.42%		5.93%	6.54%	8.13%
2009							
Jan	3.25%	0.12%	2.52%		6.01%	6.39%	7.90%
Feb	3.25%	0.31%	2.87%		6.11%	6.30%	7.74%
Mar	3.25%	0.25%	2.82%		6.14%	6.42%	8.00%
Apr	3.25%	0.17%	2.93%		6.20%	6.48%	8.03%
May	3.25%	0.15%	3.29%		6.23%	6.49%	7.76%
June	3.25%	0.17%	3.72%		6.13%	6.20%	7.30%
July	3.25%	0.19%	3.56%		5.63%	5.97%	6.87%
Aug	3.25%	0.18%	3.59%		5.33%	5.71%	6.36%
Sept	3.25%	0.13%	3.40%		5.15%	5.53%	6.12%
Oct	3.25%	0.08%	3.39%		5.23%	5.55%	6.14%
Nov	3.25%	0.05%	3.40%		5.33%	5.64%	6.18%
Dec	3.25%	0.07%	3.59%		5.52%	5.79%	6.26%
2010							
Jan	3.25%	0.06%	3.73%		5.55%	5.77%	6.16%
Feb	3.25%	0.10%	3.69%		5.69%	5.87%	6.25%
Mar	3.25%	0.15%	3.73%		5.64%	5.84%	6.22%
Apr	3.25%	0.15%	3.85%		5.62%	5.81%	6.19%
May	3.25%	0.16%	3.42%		5.29%	5.50%	5.97%
June	3.25%	0.12%	3.20%		5.22%	5.46%	6.18%
July	3.25%	0.16%	3.01%		4.99%	5.26%	5.98%
Aug	3.25%	0.15%	2.70%		4.75%	5.01%	5.55%
Sept	3.25%	0.15%	2.65%		4.74%	5.01%	5.53%
Oct	3.25%	0.13%	2.54%		4.89%	5.10%	5.62%
Nov	3.25%	0.13%	2.76%		5.12%	5.37%	5.85%
Dec	3.25%	0.14%	3.29%		5.32%	5.56%	6.04%
2011							
Jan	3.25%	0.15%	3.39%		5.29%	5.57%	6.06%
Feb	3.25%	0.14%	3.58%		5.42%	5.68%	6.10%
Mar	3.25%	0.11%	3.41%		5.33%	5.56%	5.97%
Apr	3.25%	0.06%	3.46%		5.32%	5.55%	5.98%
May	3.25%	0.04%	3.17%		5.08%	5.32%	5.74%
June	3.25%	0.04%	3.00%		5.04%	5.26%	5.67%
July	3.25%	0.03%	3.00%		5.05%	5.27%	5.70%
Aug	3.25%	0.05%	2.30%		4.44%	4.69%	5.22%
Sept	3.25%	0.02%	1.98%		4.24%	4.48%	5.11%

[1] Note: Moody's has not published Aaa utility bond yields since 2001.

Sources: Council of Economic Advisors, Economic Indicators; Moody's Bond Record; Federal Reserve Bulletin; various issues.

STOCK PRICE INDICATORS

	S&P Composite [1]	NASDAQ Composite [1]	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	[1]	[1]	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		10,734.90	1.15%	3.63%
2001	1,194.18	2,035.00	10,189.13	1.32%	2.95%
		2002 - 2009 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%	5.36%
2006	1,310.46	2,263.41	11,408.67	1.87%	5.78%
2007	1,477.19	2,578.47	13,169.98	1.86%	5.29%
2008	1,220.04	2,161.65	11,252.62	2.37%	3.54%
2009	948.05	1,845.38	8,876.15	2.40%	1.86%
		Current Cycle			
2010	1,139.97	2,349.89	10,662.80	1.98%	6.04%

[1] Note: this source did not publish the S&P Composite prior to 1988 and the NASDAQ Composite prior to 1991.

Source: Council of Economic Advisors, Economic Indicators, various issues.

STOCK PRICE INDICATORS

	S&P Composite	NASDAQ Composite	DJIA	S&P D/P	S&P E/P
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.	1,225.91	2,144.61	10,532.24	1.83%	5.42%
4th Qtr.	1,262.07	2,246.09	10,827.79	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%	5.86%
3rd Qtr.	1,288.40	2,141.97	11,274.49	1.91%	5.88%
4th Qtr.	1,389.48	2,390.26	12,175.30	1.81%	5.75%
2007					
1st Qtr.	1,425.30	2,444.85	12,470.97	1.84%	5.85%
2nd Qtr.	1,496.43	2,552.37	13,214.26	1.82%	5.65%
3rd Qtr.	1,490.81	2,609.68	13,488.43	1.86%	5.15%
4th Qtr.	1,494.09	2,701.59	13,502.95	1.91%	4.51%
2008					
1st Qtr.	1,350.19	2,332.91	12,383.86	2.11%	4.55%
2nd Qtr.	1,371.65	2,426.26	12,508.59	2.10%	4.05%
3rd Qtr.	1,251.94	2,290.87	11,322.40	2.29%	3.94%
4th Qtr.	909.80	1,599.64	8,795.61	2.98%	1.65%
2009					
1st Qtr.	809.31	1,485.14	7,774.06	3.00%	0.86%
2nd Qtr.	892.23	1,731.41	8,327.83	2.45%	0.82%
3rd Qtr.	996.68	1,985.25	9,229.93	2.16%	1.19%
4th Qtr.	1,088.70	2,162.33	10,172.78	1.99%	4.57%
2010					
1st Qtr.	1,121.60	2,274.88	10,454.42	1.94%	5.21%
2nd Qtr.	1,135.25	2,343.40	10,570.54	1.97%	6.51%
3rd Qtr.	1,096.39	2,237.97	10,390.24	2.09%	6.30%
4th Qtr.	1,204.00	2,534.62	11,236.02	1.95%	6.15%
2011					
1st Qtr.	1,302.74	2,741.01	12,024.62	1.85%	6.13%
2nd Qtr.	1,319.04	2,766.64	12,370.73	1.97%	6.35%
3rd Qtr.	1,228.12	2,613.11	11,671.47	2.15%	

Source: Council of Economic Advisors, Economic Indicators, various issues.

Exhibit___(DCP-1)
Schedule 3

ARIZONA PUBLIC SERVICE AND PINNACLE WEST CAPITAL SECURITY RATINGS

	Moody's		Standard & Poor's	
Date	APS	PWC	APS	PWC
2000	Baa2		BBB	
2001	Baa2/Baa1		BBB	
2002	Baa1		BBB	
2003	Baa1		BBB	
2004	Baa1		BBB	
2005	Baa1		BBB/BBB-	
2006	Baa1/Baa2		BBB-	BBB-
2007	Baa2	Baa3	BBB-	BBB-
2008	Baa2	Baa3	BBB-	BBB-
2009	Baa2	Baa3	BBB-	BBB-
2010	Baa2	Baa3	BBB-	BBB-
2011	Baa2	Baa3	BBB-/BBB	BBB-/BBB

Source: Response to Staff 2.5.

ARIZONA PUBLIC SERVICE COMPANY
CAPITAL STRUCTURE RATIOS
2006 - 2010
($ 000)

YEAR	COMMON EQUITY	LONG-TERM DEBT	SHORT-TERM DEBT
2006	$3,207,473	$2,877,502	$968
	52.7%	47.3%	0.0%
	52.7%	47.3%	
2007	$3,351,441	$2,876,881	$218,978
	52.0%	44.6%	3.4%
	53.8%	46.2%	
2008	$3,339,150	$2,850,242	$522,558
	49.7%	42.5%	7.8%
	53.9%	46.1%	
2009	$3,445,355	$3,180,406	$197,176
	50.5%	46.6%	2.9%
	52.0%	48.0%	
2010	$3,824,953	$2,948,991	$427,682
	53.1%	40.9%	5.9%
	56.5%	43.5%	

Note: Percentages may not total 100.0% due to rounding.

Source: Response to Staff 2.4.

PINNACLE WEST CAPITAL CORP.
CAPITAL STRUCTURE RATIOS
2006 - 2010
($000)

YEAR	COMMON EQUITY	LONG-TERM DEBT	SHORT-TERM DEBT
2006	$3,446,116	$3,426,914	$57,505
	49.7%	49.4%	0.8%
	50.1%	49.9%	
2007	$3,531,611	$3,300,663	$525,177
	48.0%	44.9%	7.1%
	51.7%	48.3%	
2008	$3,445,979	$3,183,386	$869,870
	46.0%	42.4%	11.6%
	52.0%	48.0%	
2009	$3,316,109	$3,496,254	$457,191
	45.6%	48.1%	6.3%
	48.7%	51.3%	
2010	$3,683,327	$3,045,794	$648,479
	49.9%	41.3%	8.8%
	54.7%	45.3%	

Note: Percentages may not total 100.0% due to rounding.

Source: Response to Staff 2.4.

Exhibit___(DCP-1)
Schedule 5

AUS UTILITY REPORTS
ELECTRIC UTILITY GROUPS
CAPITAL STRUCTURE RATIOS
INCLUDING SHORT-TERM DEBT

Year	Electric	Combination Gas & Electric
2006	45%	44%
2007	47%	46%
2008	45%	43%
2009	46%	45%
2010	46%	46%

Source: AUS Utility Reports.

COMPARISON COMPANIES
BASIS FOR SELECTION

Company	Market Cap ($000) (1)	Percent Revenues Electric (2)	Common Equity Ratio (3)	Value Line Safety Rank (4)	S&P Stock Ranking (5)	Moody's/ S&P Bond Rating (6)
Pinnacle West Capital	$4,700,000	97%	55%	2	B	Baa2/BBB-
Arizona Public Service Co.			56%			Baa2/BBB
Proxy Group						
Ameren	$6,900,000	85%	51%	3	B	Baa2/BBB-
Avista Corp.	$1,400,000	63%	48%	2	A-	Baa1/BBB+
Cleco Corp.	$2,100,000	98%	49%	2	B	Baa2/BBB
Great Plains Energy	$2,800,000	100%	49%	3	B	Baa2/BBB
Hawaiian Electric Industries	$2,400,000	89%	54%	3	B	Baa2/BBB-
OGE Energy	$4,800,000	57%	49%	2	A-	Baa1/BBB+
TECO Energy	$4,100,000	84%	41%	3	B	Baa1/BBB
UIL Holdings	$1,700,000	86%	42%	2	B	Baa2/nr
Westar Energy	$3,000,000	100%	46%	2	B	Baa1/BBB+

Criteria For Selection:
Market Cap of $1 billion to $10 billion.
Percent electric revenues of 50% or greater
Common equity ratio of 40% or greater
Value Line Safety Rank of 1, 2, or 3
S&P Stock Ranking of A or B
Moody's and S&P Bond Rating of Baa and BBB.
Currently pays common stock dividends.

Sources:
(1) Value Line - May 27, 2011, June 24, 2011 and May 6, 2011 editions.
(2) AUS Utility Reports, April, 2011 edition, year-end 2010 data.
(3) Value Line - May 27, 2011, June 24, 2011 and May 6, 2011 editions, excludes short-term debt.
(4) Value Line - May 27, 2011, June 24, 2011 and May 6, 2011 editions.
(5) Value Line - May 27, 2011, June 24, 2011 and May 6, 2011 editions.
(6) AUS Utility Reports, August, 2011 edition.

COMPARISON COMPANIES
DIVIDEND YIELD

COMPANY	Quarterly DPS	DPS	August - October, 2011 HIGH	LOW	AVERAGE	YIELD
Proxy Group						
Ameren	$0.385	$1.540	$32.53	$25.55	$29.04	5.3%
Avista Corp.	$0.275	$1.100	$26.35	$21.13	$23.74	4.6%
Cleco Corp.	$0.280	$1.120	$37.74	$30.06	$33.90	3.3%
Great Plains Energy	$0.208	$0.832	$21.33	$16.34	$18.84	4.4%
Hawaiian Electric Industries	$0.310	$1.240	$25.91	$20.59	$23.25	5.3%
OGE Energy	$0.375	$1.500	$53.62	$40.56	$47.09	3.2%
Pinnacle West Capital	$0.525	$2.100	$47.36	$37.28	$42.32	5.0%
TECO Energy	$0.215	$0.860	$18.97	$15.82	$17.40	4.9%
UIL Holdings	$0.432	$1.728	$34.90	$29.00	$31.95	5.4%
Westar Energy	$0.320	$1.280	$27.73	$22.63	$25.18	5.1%
Average						**4.7%**
Avera Proxy Group						
Ameren	$0.385	$1.540	$32.53	$25.55	$29.04	5.3%
American Electric Power	$0.460	$1.840	$40.00	$33.09	$36.55	5.0%
CenterPoint Energy	$0.198	$0.792	$21.39	$17.11	$19.25	4.1%
Cleco	$0.280	$1.120	$37.74	$30.06	$33.90	3.3%
CMS Energy	$0.210	$0.840	$21.58	$16.96	$19.27	4.4%
Constellation Energy	$0.240	$0.960	$40.20	$33.84	$37.02	2.6%
DTE Energy	$0.588	$2.352	$52.82	$43.22	$48.02	4.9%
Edison International	$0.320	$1.280	$41.57	$32.64	$37.11	3.4%
Great Plains Energy	$0.208	$0.832	$21.33	$16.34	$18.84	4.4%
Hawaiian Electric Industries	$0.310	$1.240	$25.91	$20.59	$23.25	5.3%
IDACORP	$0.300	$1.200	$41.97	$33.88	$37.93	3.2%
Integrys Energy Group	$0.680	$2.720	$54.00	$42.76	$48.38	5.6%
ITC Holdings	$0.353	$1.412	$78.89	$64.88	$71.89	2.0%
Pepco Holdings	$0.270	$1.080	$20.33	$16.57	$18.45	5.9%
PG&E Corp	$0.455	$1.820	$43.82	$37.57	$40.70	4.5%
Pinnacle West Capital	$0.525	$2.100	$47.36	$37.28	$42.32	5.0%
Portland General	$0.265	$1.060	$25.18	$21.29	$23.24	4.6%
PPL Corp	$0.350	$1.400	$29.78	$25.00	$27.39	5.1%
TECO Energy	$0.215	$0.860	$18.97	$15.82	$17.40	4.9%
Westar Energy	$0.320	$1.280	$27.73	$22.63	$25.18	5.1%
Wisconsin Energy	$0.260	$1.040	$33.63	$27.00	$30.32	3.4%
Average						**4.4%**

Source: Yahoo! Finance.

COMPARISON COMPANIES
RETENTION GROWTH RATES

COMPANY	2006	2007	2008	2009	2010	Average	2011	2012	2014-'16	Average
Proxy Group										
Ameren	0.2%	1.3%	1.0%	3.5%	3.8%	2.0%	2.5%	2.5%	2.5%	2.5%
Avista Corp.	4.9%	0.8%	3.7%	4.1%	3.3%	3.4%	3.5%	3.0%	2.5%	3.0%
Cleco Corp.	3.0%	2.6%	4.5%	4.7%	6.1%	4.2%	5.5%	5.0%	4.0%	4.8%
Great Plains Energy	0.0%	0.9%	0.0%	0.9%	3.4%	1.0%	2.0%	2.5%	3.0%	2.5%
Hawaiian Electric Industries	0.7%	0.8%	0.5%	0.0%	1.4%	0.7%	0.5%	1.5%	3.5%	1.8%
OGE Energy	6.6%	7.1%	5.4%	6.0%	6.7%	6.4%	8.0%	6.5%	6.5%	7.0%
Pinnacle West Capital	3.4%	2.5%	0.3%	0.7%	3.1%	2.0%	2.0%	3.5%	3.0%	2.8%
TECO Energy	5.0%	5.1%	0.0%	2.1%	3.1%	3.1%	4.5%	5.5%	5.5%	5.2%
UIL Holdings	0.0%	3.1%	1.0%	1.2%	1.7%	1.4%	1.0%	1.0%	2.5%	1.5%
Westar Energy	5.5%	4.3%	1.2%	0.8%	2.8%	2.9%	2.0%	2.5%	4.0%	2.8%
Average						**2.7%**				**3.4%**
Avera Proxy Group										
Ameren	0.2%	1.3%	1.0%	3.5%	3.8%	2.0%	2.5%	2.5%	2.5%	2.5%
American Electric Power	5.7%	5.1%	5.1%	4.6%	3.1%	4.7%	4.5%	4.5%	5.0%	4.7%
CenterPoint Energy	15.7%	10.0%	9.9%	3.6%	3.8%	8.6%	4.0%	4.0%	4.0%	4.0%
Cleco	3.0%	2.6%	4.5%	4.7%	6.1%	4.2%	5.5%	5.0%	4.0%	4.8%
CMS Energy	6.4%	5.1%	8.4%	4.1%	6.9%	6.2%	5.5%	5.5%	5.0%	5.3%
Constellation Energy	9.1%	8.9%	0.0%	1.5%	1.8%	4.3%	3.5%	3.5%	5.5%	4.2%
DTE Energy	1.2%	1.5%	1.7%	2.9%	4.0%	2.3%	3.0%	3.0%	3.5%	3.2%
Edison International	10.1%	9.2%	8.6%	6.7%	6.5%	8.2%	4.5%	4.5%	4.5%	4.5%
Great Plains Energy	0.0%	0.9%	0.0%	0.9%	3.4%	1.0%	2.0%	2.5%	3.0%	2.5%
Hawaiian Electric Industries	0.7%	0.8%	0.5%	0.0%	1.4%	0.7%	0.5%	1.5%	3.5%	1.8%
IDACORP	4.3%	2.4%	3.4%	4.8%	5.5%	4.1%	6.0%	5.5%	4.5%	5.3%
Integrys Energy Group	3.4%	0.0%	0.0%	0.0%	2.3%	1.1%	1.5%	2.0%	3.0%	2.2%
ITC Holdings	0.0%	4.5%	5.4%	6.8%	7.1%	4.8%	8.0%	9.5%	11.0%	9.5%
Pepco Holdings	1.5%	2.3%	4.2%	0.0%	0.8%	1.8%	1.0%	1.0%	2.5%	1.5%
PG&E Corp	6.8%	6.0%	6.8%	5.5%	3.9%	5.8%	3.0%	5.5%	5.5%	4.7%
Pinnacle West Capital	3.4%	2.5%	0.3%	0.7%	3.1%	2.0%	2.0%	3.5%	3.0%	2.8%
Portland General	3.5%	6.6%	2.0%	1.5%	3.0%	3.3%	4.5%	4.5%	4.0%	4.3%
PPL Corp	9.3%	10.0%	8.5%	0.0%	5.2%	6.6%	5.5%	5.5%	5.0%	5.3%
TECO Energy	5.0%	5.1%	0.0%	2.1%	3.1%	3.1%	4.5%	5.5%	5.5%	5.2%
Westar Energy	5.5%	4.3%	1.2%	0.8%	2.8%	2.9%	2.0%	2.5%	4.0%	2.8%
Wisconsin Energy	7.1%	7.1%	7.0%	6.2%	7.0%	6.9%	6.5%	6.5%	6.0%	6.3%
Average						**4.0%**				**4.2%**

Source: Value Line Investment Survey.

COMPARISON COMPANIES
PER SHARE GROWTH RATES

COMPANY	5-Year Historic Growth Rates				Est'd '08-'10 to '14-'16 Growth Rates			
	EPS	DPS	BVPS	Average	EPS	DPS	BVPS	Average
Proxy Group								
Ameren	-1.5%	-6.0%	2.5%	-1.7%	-2.0%	-3.0%	1.5%	-1.2%
Avista Corp.	11.5%	10.0%	4.0%	8.5%	4.5%	9.0%	3.0%	5.5%
Cleco Corp.	7.5%	0.5%	11.0%	6.3%	6.0%	9.5%	6.5%	7.3%
Great Plains Energy	-11.5%	-8.0%	7.0%	-4.2%	6.0%	0.0%	2.0%	2.7%
Hawaiian Electric Industries	-6.0%	0.0%	1.0%	-1.7%	11.0%	1.0%	2.5%	4.8%
OGE Energy	9.0%	1.5%	8.5%	6.3%	6.5%	4.0%	7.5%	6.0%
Pinnacle West Capital	0.5%	3.0%	0.5%	1.3%	6.0%	1.5%	2.5%	3.3%
TECO Energy	12.0%	-0.5%	5.0%	5.5%	10.5%	4.5%	5.0%	6.7%
UIL Holdings	7.5%	0.0%	-2.0%	1.8%	3.0%	0.0%	5.5%	2.8%
Westar Energy	1.0%	7.0%	6.0%	4.7%	8.5%	3.0%	2.0%	4.5%
Average				**2.7%**				**4.3%**
Avera Proxy Group								
Ameren	-1.5%	-6.0%	2.5%	-1.7%	-2.0%	-3.0%	1.5%	-1.2%
American Electric Power	2.0%	2.0%	5.0%	3.0%	4.5%	4.0%	4.5%	4.3%
CenterPoint Energy	5.0%	13.5%	8.5%	9.0%	3.0%	3.0%	10.0%	5.3%
Cleco	7.5%	0.5%	11.0%	6.3%	6.0%	9.5%	6.5%	7.3%
CMS Energy	17.5%		1.5%	9.5%	7.0%	14.0%	5.0%	8.7%
Constellation Energy	-16.0%	1.5%	4.5%	-3.3%	18.0%	-4.0%	6.5%	6.8%
DTE Energy	2.5%	1.0%	3.5%	2.3%	4.5%	4.0%	3.5%	4.0%
Edison International	10.0%	15.5%	10.5%	12.0%	-1.0%	2.0%	4.5%	1.8%
Great Plains Energy	-11.5%	-8.0%	7.0%	-4.2%	6.0%	0.0%	2.0%	2.7%
Hawaiian Electric Industries	-6.0%	0.0%	1.0%	-1.7%	11.0%	1.0%	2.5%	4.8%
IDACORP	11.0%	-2.5%	4.5%	4.3%	4.0%	4.0%	5.0%	4.3%
Integrys Energy Group	-8.0%	4.0%	5.5%	0.5%	9.0%	0.0%	1.5%	3.5%
ITC Holdings					14.0%	5.5%	10.5%	10.0%
Pepco Holdings	-0.5%	1.5%	1.0%	0.7%	2.5%	1.0%	2.0%	1.8%
PG&E Corp	7.0%		10.5%	8.8%	6.0%	4.5%	5.5%	5.3%
Pinnacle West Capital	0.5%	3.0%	0.5%	1.3%	6.0%	1.5%	2.5%	3.3%
Portland General	7.5%		2.0%	4.8%	7.5%	3.0%	3.5%	4.7%
PPL Corp	1.0%	10.0%	7.0%	6.0%	7.0%	3.5%	9.0%	6.5%
TECO Energy	12.0%	-0.5%	5.0%	5.5%	10.5%	4.5%	5.0%	6.7%
Westar Energy	1.0%	7.0%	6.0%	4.7%	8.5%	3.0%	2.0%	4.5%
Wisconsin Energy	8.5%	10.0%	7.5%	8.7%	8.5%	16.0%	4.5%	9.7%
Average				**3.8%**				**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
Proxy Group								
Ameren	5.4%	2.0%	2.5%			1.0%	1.8%	7.2%
Avista Corp.	4.7%	3.4%	3.0%	8.5%	5.5%	4.7%	5.0%	9.8%
Cleco Corp.	3.4%	4.2%	4.8%	6.3%	7.3%	3.0%	5.1%	8.5%
Great Plains Energy	4.5%	1.0%	2.5%		2.7%	5.8%	3.0%	7.5%
Hawaiian Electric Industries	5.4%	0.7%	1.8%		4.8%	8.6%	4.0%	9.4%
OGE Energy	3.3%	6.4%	7.0%	6.3%	6.0%	7.4%	6.6%	9.9%
Pinnacle West Capital	5.0%	2.0%	2.8%	1.3%	3.3%	6.3%	3.2%	8.2%
TECO Energy	5.1%	3.1%	5.2%	5.5%	6.7%	5.7%	5.2%	10.3%
UIL Holdings	5.5%	1.4%	1.5%	1.8%	2.8%	4.1%	2.3%	7.8%
Westar Energy	5.2%	2.9%	2.8%	4.7%	4.5%	5.2%	4.0%	9.2%
Mean	4.7%	2.7%	3.4%	4.9%	4.9%	5.2%	4.0%	**8.8%**
Median	5.1%	2.5%	2.8%	5.5%	4.8%	5.4%	4.0%	**8.9%**
Composite - Mean		**7.4%**	8.1%	9.7%	9.6%	**9.9%**	8.8%	
Composite - Median		**7.5%**	7.9%	**10.6%**	9.9%	10.5%	9.1%	
Avera Proxy Group								
Ameren	5.4%	2.0%	2.5%			1.0%	1.8%	7.2%
American Electric Power	5.1%	4.7%	4.7%	3.0%	4.3%	4.3%	4.2%	9.3%
CenterPoint Energy	4.3%	8.6%	4.0%	9.0%	5.3%	6.4%	6.7%	10.9%
Cleco	3.4%	4.2%	4.8%	6.3%	7.3%	3.0%	5.1%	8.5%
CMS Energy	4.5%	6.2%	5.3%	9.5%	8.7%	6.0%	7.1%	11.7%
Constellation Energy	2.7%	4.3%	4.2%		6.8%	4.5%	4.9%	7.6%
DTE Energy	5.0%	2.3%	3.2%	2.3%	4.0%	3.4%	3.0%	8.0%
Edison International	3.6%	8.2%	4.5%	12.0%	1.8%	2.9%	5.9%	9.4%
Great Plains Energy	4.5%	1.0%	2.5%		2.7%	5.8%	3.0%	7.5%
Hawaiian Electric Industries	5.4%	0.7%	1.8%		4.8%	8.6%	4.0%	9.4%
IDACORP	3.2%	4.1%	5.3%	4.3%	4.3%	4.7%	4.6%	7.8%
Integrys Energy Group	5.7%	1.1%	2.2%	0.5%	3.5%	9.4%	3.3%	9.1%
ITC Holdings	2.1%	4.8%	9.5%		10.0%	18.0%	10.6%	12.6%
Pepco Holdings	5.9%	1.8%	1.5%	0.7%	1.8%	7.5%	2.7%	8.6%
PG&E Corp	4.6%	5.8%	4.7%	8.8%	5.3%	3.8%	5.7%	10.3%
Pinnacle West Capital	5.0%	2.0%	2.8%	1.3%	3.3%	6.3%	3.2%	8.2%
Portland General	4.7%	3.3%	4.3%	4.8%	4.7%	5.3%	4.5%	9.1%
PPL Corp	5.2%	6.6%	5.3%	6.0%	6.5%	0.0%	4.9%	10.1%
TECO Energy	5.1%	3.1%	5.2%	5.5%	6.7%	5.7%	5.2%	10.3%
Westar Energy	5.2%	2.9%	2.8%	4.7%	4.5%	5.2%	4.0%	9.2%
Wisconsin Energy	3.6%	6.9%	6.3%	8.7%	9.7%	7.3%	7.8%	11.3%
Mean	4.5%	4.0%	4.2%	5.5%	5.3%	5.7%	4.9%	**9.3%**
Median	4.7%	4.1%	4.3%	5.1%	4.8%	5.3%	4.6%	**9.2%**
Composite - Mean		**8.5%**	8.6%	9.9%	9.8%	**10.2%**	9.3%	
Composite - Median		**8.7%**	9.0%	9.8%	9.4%	**10.0%**	9.2%	

Note: Negative growth rates excluded from analyses

Sources: Prior pages of this schedule.

STANDARD & POOR'S 500 COMPOSITE
20-YEAR U.S. TREASURY BOND YIELDS
RISK PREMIUMS

Year	EPS	BVPS	ROE	20-YEAR T-BOND YIELD	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%
2005	$69.93	$453.06	16.12%	4.69%	11.43%
2006	$81.51	$504.39	17.03%	4.68%	12.35%
2007	$66.17	$529.59	12.80%	4.86%	7.94%
2008	$14.88	$451.37	3.03%	4.45%	-1.42%
2009	$50.97	$513.58	10.56%	3.47%	7.09%
2010	$77.35	$579.14	14.16%	4.25%	9.91%
Average					**6.34%**

Source: Standard & Poor's Analysts' Handbook, Ibbotson Associates Handbook.

COMPARISON COMPANIES
CAPM COST RATES

COMPANY	RISK-FREE RATE 1/	BETA	RISK PREMIUM	CAPM RATES
Proxy Group				
Ameren	2.98%	0.80	5.58%	7.4%
Avista Corp.	2.98%	0.70	5.58%	6.9%
Cleco Corp.	2.98%	0.65	5.58%	6.6%
Great Plains Energy	2.98%	0.75	5.58%	7.2%
Hawaiian Electric Industries	2.98%	0.70	5.58%	6.9%
OGE Energy	2.98%	0.75	5.58%	7.2%
Pinnacle West Capital	2.98%	0.70	5.58%	6.9%
TECO Energy	2.98%	0.85	5.58%	7.7%
UIL Holdings	2.98%	0.70	5.58%	6.9%
Westar Energy	2.98%	0.75	5.58%	7.2%
Mean				**7.1%**
Median				**7.0%**
Avera Proxy Group				
Ameren	2.98%	0.80	5.58%	7.4%
American Electric Power	2.98%	0.70	5.58%	6.9%
CenterPoint Energy	2.98%	0.80	5.58%	7.4%
Cleco	2.98%	0.65	5.58%	6.6%
CMS Energy	2.98%	0.75	5.58%	7.2%
Constellation Energy	2.98%	0.80	5.58%	7.4%
DTE Energy	2.98%	0.75	5.58%	7.2%
Edison International	2.98%	0.80	5.58%	7.4%
Great Plains Energy	2.98%	0.75	5.58%	7.2%
Hawaiian Electric Industries	2.98%	0.70	5.58%	6.9%
IDACORP	2.98%	0.70	5.58%	6.9%
Integrys Energy Group	2.98%	0.90	5.58%	8.0%
ITC Holdings	2.98%	0.80	5.58%	7.4%
Pepco Holdings	2.98%	0.80	5.58%	7.4%
PG&E Corp	2.98%	0.55	5.58%	6.0%
Pinnacle West Capital	2.98%	0.70	5.58%	6.9%
Portland General	2.98%	0.75	5.58%	7.2%
PPL Corp	2.98%	0.65	5.58%	6.6%
TECO Energy	2.98%	0.85	5.58%	7.7%
Westar Energy	2.98%	0.75	5.58%	7.2%
Wisconsin Energy	2.98%	0.65	5.58%	6.6%
Mean				**7.1%**
Median				**7.2%**

Sources: Value Line Investment Survey, Standard & Poor's Analysts' Handbook, Federal Reserve.

1/ Average yield on 20-Year U.S. Treasury Bonds:

Aug., 2011	3.24%
Sept., 2011	2.83%
Oct., 2011	2.87%
Average	2.98%

COMPARISON COMPANIES
RATES OF RETURN ON AVERAGE COMMON EQUITY

COMPANY	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	1992-2001 Average	2002-2010 Average	2011	2012	2014-16
Proxy Group																								
Ameren	12.7%	12.9%	13.7%	13.1%	12.5%	10.8%	12.7%	12.5%	14.5%	14.3%	10.8%	12.2%	10.0%	10.3%	8.5%	9.3%	8.8%	8.4%	8.5%	13.0%	9.6%	7.0%	7.0%	7.0%
Avista Corp.	11.7%	12.2%	10.5%	11.2%	10.6%	15.0%	10.2%	1.1%	13.4%	7.9%	4.5%	6.7%	4.6%	5.8%	8.8%	4.1%	7.6%	8.4%	8.5%	10.4%	6.6%	9.0%	8.5%	9.0%
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%	9.4%	8.2%	9.9%	9.7%	11.4%	13.4%	10.9%	10.0%	10.0%	9.5%
Great Plains Energy	9.8%	12.0%	11.7%	13.4%	11.6%	11.7%	13.2%	8.9%	14.2%	11.6%	15.6%	16.6%	16.9%	13.7%	9.8%	10.6%	5.9%	4.9%	7.3%	11.8%	11.3%	5.5%	6.5%	7.5%
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%	9.3%	7.7%	7.0%	5.9%	7.7%	11.0%	8.8%	8.0%	9.0%	10.5%
OGE Energy	10.8%	12.4%	13.3%	13.2%	13.8%	13.4%	16.3%	14.9%	14.1%	9.6%	11.1%	13.2%	12.7%	12.4%	14.9%	14.7%	12.9%	12.9%	13.4%	13.2%	13.1%	14.0%	12.5%	12.0%
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%	6.7%	9.2%	8.5%	6.1%	6.8%	9.3%	11.5%	8.0%	8.0%	9.0%	9.0%
TECO Energy	16.1%	15.1%	14.5%	16.6%	16.5%	14.8%	13.5%	13.8%	17.4%	17.2%	13.5%	-0.7%	9.2%	14.2%	14.7%	14.3%	8.1%	10.4%	11.4%	15.6%	10.6%	12.5%	13.5%	13.0%
UIL Holdings	9.2%	10.4%	10.5%	11.8%	10.1%	10.4%	9.5%	11.6%	12.8%	12.1%	8.9%	6.1%	7.1%	5.7%	9.1%	10.1%	10.1%	10.2%	9.8%	10.8%	8.6%	8.5%	8.5%	9.0%
Westar Energy	11.0%	12.4%	10.7%	11.1%	10.4%	-1.6%	7.1%	5.2%	3.2%	-2.2%	5.0%	10.6%	7.7%	9.6%	11.1%	10.0%	6.7%	6.3%	8.6%	6.7%	8.4%	7.5%	8.5%	10.0%
Average	11.7%	12.1%	11.9%	12.5%	12.1%	11.0%	11.8%	10.4%	12.7%	11.0%	10.3%	9.6%	9.8%	10.0%	10.5%	9.8%	8.3%	8.4%	9.6%	11.7%	9.6%	9.0%	9.3%	9.7%
Median	11.0%	12.3%	11.4%	12.5%	11.4%	11.8%	12.1%	12.0%	13.8%	12.3%	11.0%	10.9%	9.3%	10.0%	9.4%	9.7%	7.9%	8.4%	9.0%	12.0%	9.5%	8.3%	8.8%	9.3%
Avera Proxy Group																								
Ameren	12.7%	12.9%	13.7%	13.1%	12.5%	10.8%	12.7%	12.5%	14.5%	14.3%	10.8%	12.2%	10.0%	10.3%	8.5%	9.3%	8.8%	8.4%	8.5%	13.0%	9.6%	7.0%	7.0%	7.0%
American Electric Power	11.1%	11.9%	12.0%	12.4%	13.2%	13.5%	11.3%	10.5%	4.1%	12.9%	12.3%	12.4%	12.7%	11.9%	12.2%	11.7%	11.6%	11.0%	9.3%	11.3%	11.7%	10.5%	10.5%	10.5%
CenterPoint Energy	11.8%	12.7%	12.7%	10.6%	11.6%	10.2%	11.0%	10.3%	15.4%	7.5%	9.6%	26.1%	13.1%	17.2%	29.1%	22.1%	22.6%	16.0%	15.0%	11.4%	19.0%	12.0%	12.0%	11.5%
Cleco	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%	9.4%	8.2%	9.9%	9.7%	11.4%	13.4%	10.9%	10.0%	10.0%	9.5%
CMS Energy	8.9%	18.6%	17.3%	15.7%	14.4%	13.9%	11.1%	13.6%	12.4%	7.5%	-27.1%	-3.3%	7.2%	10.4%	6.2%	6.6%	12.1%	8.3%	11.8%	13.3%	3.6%	12.5%	12.5%	12.5%
Constellation Energy	9.4%	10.4%	10.6%	10.8%	9.6%	10.2%	10.5%	10.9%	11.2%	9.9%	9.8%	11.5%	12.4%	12.4%	14.2%	15.5%	2.1%	6.0%	3.9%	10.4%	9.8%	6.0%	5.5%	7.5%
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%	7.5%	7.7%	7.5%	8.7%	9.6%	12.7%	9.2%	9.0%	9.0%	9.0%
Edison International	13.4%	11.8%	11.5%	11.8%	11.2%	11.8%	12.7%	13.7%	-52.0%	14.9%	15.4%	15.8%	3.9%	17.4%	14.9%	13.4%	13.4%	10.9%	10.7%	6.1%	12.9%	8.0%	8.5%	8.0%
Great Plains Energy	9.8%	12.0%	11.7%	13.4%	11.6%	11.7%	13.2%	8.9%	14.2%	11.6%	15.6%	16.6%	16.9%	13.7%	9.8%	10.6%	5.9%	4.9%	7.3%	11.8%	11.3%	5.5%	6.5%	7.5%
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%	9.3%	7.7%	7.0%	5.9%	7.7%	11.0%	8.8%	8.0%	9.0%	10.5%
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%	9.4%	7.1%	8.0%	9.3%	9.8%	12.3%	7.8%	9.5%	9.0%	8.5%
Integrys Energy Group							18.1%	11.4%	12.1%	12.7%	11.8%	10.7%	14.4%	13.2%	10.3%	6.3%	3.8%	5.8%	8.6%	13.6%	9.4%	9.0%	9.0%	9.5%
ITC Holdings														14.8%	9.0%	13.1%	13.8%	13.3%	13.5%		12.9%	13.5%	14.5%	15.5%
Pepco Holdings	10.6%	12.0%	10.8%	10.5%	11.7%	10.5%	11.3%	11.7%	8.9%	11.9%	9.8%	7.6%	8.3%	8.1%	7.1%	7.9%	9.9%	5.5%	6.5%	11.0%	7.9%	6.5%	6.0%	7.5%
PG&E Corp	13.6%	11.9%	13.9%	14.4%	10.4%	7.5%	8.9%	11.2%	-67.5%	30.1%	-22.1%	20.9%	13.8%	11.7%	13.2%	11.9%	12.8%	11.3%	10.0%	5.4%	9.3%	9.0%	11.0%	11.5%
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%	6.7%	9.2%	8.5%	6.1%	6.8%	9.3%	11.5%	8.0%	8.0%	9.0%	9.0%
Portland General	12.9%	12.0%	11.3%	13.4%	13.9%										5.9%	11.5%	6.5%	6.2%	8.0%	12.7%	7.6%	9.0%	9.0%	9.0%
PPL Corp	13.1%	13.2%	10.6%	12.1%	12.4%	11.7%	15.8%	17.9%	26.1%	27.0%	23.6%	23.1%	18.3%	16.8%	18.4%	18.7%	17.2%	8.5%	14.5%	16.0%	17.7%	12.0%	12.5%	11.5%
TECO Energy	16.1%	15.1%	14.5%	16.6%	16.5%	14.8%	13.5%	13.8%	17.4%	17.2%	13.5%	-0.7%	9.2%	14.2%	14.7%	14.3%	8.1%	10.4%	11.4%	15.6%	10.6%	12.5%	13.5%	13.0%
Westar Energy	11.0%	12.4%	10.7%	11.1%	10.4%	-1.6%	7.1%	5.2%	3.2%	-2.2%	5.0%	10.6%	7.7%	9.6%	11.1%	10.0%	6.7%	6.3%	8.6%	6.7%	8.4%	7.5%	8.5%	10.0%
Wisconsin Energy	11.4%	11.8%	10.5%	13.0%	11.5%	3.2%	10.1%	11.3%	6.4%	10.6%	12.8%	11.8%	9.0%	11.6%	11.1%	11.1%	11.0%	10.8%	12.2%	10.0%	11.3%	13.0%	13.0%	14.0%
Average	12.1%	12.6%	12.0%	12.6%	12.1%	10.5%	12.0%	11.8%	4.9%	13.1%	8.2%	11.6%	10.7%	11.9%	11.5%	11.1%	9.8%	8.8%	9.9%	11.4%	10.4%	9.4%	9.8%	10.1%
Median	11.4%	12.0%	11.5%	12.4%	11.7%	11.7%	11.5%	11.7%	12.1%	12.7%	11.6%	11.5%	9.3%	11.7%	9.8%	10.6%	8.8%	8.5%	9.6%	11.9%	10.2%	9.0%	9.0%	9.5%

COMPARISON COMPANIES
MARKET TO BOOK RATIOS

COMPANY	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	1992-2001 Average	2002-2010 Average
Proxy Group																					
Ameren	169%	188%	160%	170%	175%	174%	180%	167%	163%	173%	163%	162%	161%	172%	164%	159%	122%	83%	81%	172%	141%
Avista Corp.	151%	163%	133%	125%	145%	162%	163%	152%	317%	114%	85%	94%	111%	115%	135%	127%	110%	94%	106%	163%	109%
Cleco Corp.	177%	175%	156%	162%	168%	171%	183%	172%	223%	224%	154%	134%	177%	177%	162%	162%	132%	129%	139%	181%	152%
Great Plains Energy	160%	173%	151%	168%	181%	198%	209%	178%	173%	185%	163%	198%	218%	189%	181%	173%	113%	73%	87%	178%	155%
Hawaiian Electric Industries	171%	154%	141%	149%	147%	147%	154%	132%	127%	145%	153%	151%	179%	181%	192%	166%	166%	113%	140%	147%	160%
OGE Energy	165%	159%	147%	166%	171%	198%	222%	183%	154%	166%	147%	153%	178%	189%	204%	196%	145%	139%	180%	173%	170%
Pinnacle West Capital	116%	125%	99%	116%	133%	152%	180%	143%	145%	154%	116%	114%	130%	130%	129%	127%	100%	90%	113%	136%	117%
TECO Energy	243%	268%	224%	238%	241%	234%	247%	210%	223%	222%	135%	111%	174%	243%	202%	188%	171%	131%	164%	235%	169%
UIL Holdings	123%	157%	127%	123%	114%	111%	151%	144%	141%	139%	126%	113%	133%	135%	174%	189%	168%	127%	136%	133%	145%
Westar Energy	144%	152%	130%	129%	126%	131%	128%	89%	74%	78%	67%	109%	132%	142%	139%	140%	107%	91%	111%	118%	115%
Average	162%	171%	147%	155%	160%	168%	182%	157%	174%	160%	131%	134%	159%	167%	168%	163%	133%	107%	126%	**164%**	**143%**
Median	163%	161%	144%	156%	158%	167%	180%	160%	159%	160%	141%	124%	168%	175%	169%	164%	127%	104%	125%	**161%**	**144%**
Avera Proxy Group																					
Ameren	169%	188%	160%	170%	175%	174%	180%	167%	163%	173%	163%	162%	161%	172%	164%	159%	122%	83%	81%	172%	141%
American Electric Power	143%	159%	143%	156%	176%	187%	191%	154%	147%	179%	138%	124%	155%	165%	161%	190%	145%	112%	118%	164%	145%
CenterPoint Energy	167%	183%	148%	140%	140%	129%	168%	163%	182%	179%	116%	142%	236%	329%	312%	330%	224%	187%	158%	160%	226%
Cleco	177%	175%	156%	162%	168%	171%	183%	172%	223%	224%	154%	134%	177%	177%	162%	162%	132%	129%	139%	181%	152%
CMS Energy	168%	223%	185%	182%	181%	200%	221%	189%	119%	152%	137%	80%	90%	125%	142%	177%	127%	117%	148%	182%	127%
Constellation Energy	128%	140%	127%	136%	142%	152%	164%	141%	193%	160%	110%	135%	157%	194%	227%	312%	264%	87%	80%	148%	174%
DTE Energy	162%	154%	120%	130%	137%	126%	165%	145%	126%	142%	145%	142%	132%	140%	134%	143%	101%	91%	116%	141%	127%
Edison International	167%	172%	122%	116%	120%	158%	192%	173%	197%	128%	117%	108%	153%	205%	194%	208%	149%	101%	111%	155%	150%
Great Plains Energy	160%	173%	151%	168%	181%	198%	209%	178%	173%	185%	163%	198%	218%	189%	181%	173%	113%	73%	87%	178%	155%
Hawaiian Electric Industries	171%	154%	141%	149%	147%	147%	154%	132%	127%	145%	153%	151%	179%	181%	192%	166%	166%	113%	140%	147%	160%
IDACORP	155%	172%	146%	148%	168%	177%	177%	158%	189%	185%	134%	112%	125%	122%	139%	132%	104%	94%	113%	168%	119%
Integrys Energy Group							346%	153%	153%	157%	154%	162%	166%	174%	155%	139%	109%	82%	126%	202%	141%
ITC Holdings														394%	321%	376%	290%	219%	210%		302%
Pepco Holdings	160%	162%	135%	138%	161%	151%	161%	166%	139%	124%	110%	103%	109%	122%	129%	141%	115%	75%	92%	150%	111%
PG&E Corp	168%	175%	142%	134%	115%	123%	152%	135%	179%	136%	149%	203%	196%	179%	201%	203%	144%	149%	148%	146%	175%
Pinnacle West Capital	116%	125%	99%	116%	133%	152%	180%	143%	145%	154%	116%	114%	130%	130%	129%	127%	100%	90%	113%	136%	117%
Portland General	115%	125%	112%	140%	199%										153%	140%	101%	83%	97%	138%	115%
PPL Corp	170%	181%	144%	138%	143%	128%	176%	232%	257%	352%	253%	239%	230%	259%	261%	316%	288%	209%	180%	192%	248%
TECO Energy	243%	268%	224%	238%	241%	234%	247%	210%	223%	222%	135%	111%	174%	243%	202%	188%	171%	131%	164%	235%	169%
Westar Energy	144%	152%	130%	129%	126%	131%	128%	89%	74%	78%	67%	109%	132%	142%	139%	140%	107%	91%	111%	118%	115%
Wisconsin Energy	178%	177%	160%	172%	169%	154%	185%	152%	119%	126%	129%	147%	156%	168%	182%	179%	153%	147%	171%	159%	159%
Average	161%	171%	144%	151%	159%	161%	188%	161%	165%	168%	139%	141%	162%	191%	185%	195%	154%	117%	129%	**164%**	**165%**
Median	167%	172%	143%	140%	161%	153%	180%	158%	163%	157%	137%	135%	157%	176%	164%	173%	132%	101%	118%	**159%**	**144%**

STANDARD & POOR'S 500 COMPOSITE RETURNS AND MARKET-TO-BOOK RATIOS 1992 - 2010

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%
2005	16.1%	278%
2006	17.0%	277%
2007	12.8%	284%
2008	3.0%	224%
2009	10.6%	188%
2010	14.2%	208%
Averages:		
1992-2001	**14.7%**	**341%**
2002-2010	**12.4%**	**258%**

Source: Standard & Poor's Analyst's Handbook, 2011 edition, page 1.

RISK INDICATORS

COMPANY	VALUE LINE SAFETY	VALUE LINE BETA	VALUE LINE FINANCIAL STRENGTH		S& P STOCK RANKING	
Proxy Group						
Ameren	3	0.80	B++	3.67	B	3.00
Avista Corp.	2	0.70	B++	3.67	A-	3.67
Cleco Corp.	2	0.65	B++	3.67	B	3.00
Great Plains Energy	3	0.75	B+	3.33	B	3.00
Hawaiian Electric Industries	3	0.70	B+	3.33	B	3.00
OGE Energy	2	0.75	A	4.00	A-	3.67
Pinnacle West Capital	2	0.70	B++	3.67	B	3.00
TECO Energy	3	0.85	B+	3.33	B	3.00
UIL Holdings	2	0.70	B++	3.67	B	3.00
Westar Energy	2	0.75	B++	3.67	B	3.00
Average	2.4	0.74	B+/B++	3.60	B/B+	3.13
Avera Proxy Group						
Ameren	3	0.80	B++	3.67	B	3.00
American Electric Power	3	0.70	B++	3.67	B	3.00
CenterPoint Energy	3	0.80	B	3.00	B	3.00
Cleco	2	0.65	B++	3.67	B	3.00
CMS Energy	3	0.75	B+	3.33	B	3.00
Constellation Energy	3	0.80	B+	3.33	B	3.00
DTE Energy	3	0.75	B+	3.33	B+	3.33
Edison International	3	0.80	B++	3.67	B	3.00
Great Plains Energy	3	0.75	B+	3.33	B	3.00
Hawaiian Electric Industries	3	0.70	B+	3.33	B	3.00
IDACORP	3	0.70	B+	3.33	B	3.00
Integrys Energy Group	2	0.90	B++	3.67	B	3.00
ITC Holdings	2	0.80	B++	3.67	NR	
Pepco Holdings	3	0.80	B	3.00	B	3.00
PG&E Corp	2	0.55	B++	3.67	B	3.00
Pinnacle West Capital	2	0.70	B++	3.67	B	3.00
Portland General	3	0.75	B+	3.33	NR	
PPL Corp	3	0.65	B++	3.67	A-	3.67
TECO Energy	3	0.85	B+	3.33	B	3.00
Westar Energy	2	0.75	B++	3.67	B	3.00
Wisconsin Energy	2	0.65	B++	3.67	A	4.00
Average	2.7	0.74	B+/B++	3.48	B+	3.11

SUMMARY OF 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+
Proxy Group	2.4	0.74	B+/B++	B/B+
Avera Proxy Group	2.7	0.74	B+/B++	B+
Pinnacle West Capital	2.0	0.70	B++	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 later representing the highest level.

ARIZONA PUBLIC SERVICE COMPANY
RATING AGENCY RATIOS

ITEM	PERCENT	COST RATE	WEIGHTED COST	PRE-TAX COST	
Long-Term Debt	46.06%	6.38%	2.94%	2.94%	
Common Equity	53.94%	9.90%	5.34%	8.22%	(1)
TOTAL CAPITAL	100.00%		8.28%	11.15%	

(1) Post-tax weighted cost divided by .65 (composite tax factor)

Pre-tax coverage = 11.15%/(2.94%)
3.80 X

Standard & Poor's Utility Benchmark Ratios:

	BBB
Pre-tax coverage (X)	
Business Position:	
5	2.4 - 3.5 x
Total Debt to Total Capital (%)	
Business Position	
5	50 - 60 %

Note: Standard & Poor's no longer employs the pre-tax coverage ratios as one of its qualitative ratings criteria. The above-cited S&P benchmark ratios reflect the 1999 criteria reported by S&P.

ATTACHMENT 2

STANDARD
&POOR'S

Global Credit Portal®
RatingsDirect®

June 25, 2008

Arizona Public Service Co.

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Arizona Public Service Co.

Major Rating Factors

Corporate Credit Rating
BBB-/Stable/A-3

Strengths:

- A favorable power supply adjuster (PSA) that while capped at 4 mils per kilowatt-hour (kWh) is benched to projected power prices, which should minimize fuel and purchased power deferral balances going forward;
- Declining legacy deferral balances, reflecting the recovery through surcharges of past fuel and purchased power costs from retail ratepayers;
- An attractive service territory, which while currently weakened by a real estate cycle that is depressing new customer connections, nevertheless is expected to experience above-average growth over the long run;
- A balance power supply portfolio that is a mixture of coal, nuclear, and gas generation and purchases; due to a self-build moratorium in place until 2015, Arizona Public Service (APS) is expected to increasingly rely on gas-fired purchases, which underlines the importance of a strong PSA;
- Stabilized operations at Palo Verde, although the nuclear units remain under heightened Nuclear Regulatory Commission (NRC) scrutiny; APS operates the plant and owns a 29.1% share of the plant; and
- A manageable maturity schedule for both the parent and the utility until 2011 when about $578 million is due on a consolidated basis.

Weaknesses:

- The consolidated financial profile of the company is unlikely to meaningfully improve for the foreseeable future due to APS' heavy capital investment, coupled with a lagged regulatory process in Arizona;
- Continued tension in the relationship between APS and the Arizona Corporation Commission (ACC), which is particularly unfavorable for credit quality due to the company's ongoing need for rate relief;
- APS' re-filing of its 2008 general rate case based on a revised test year is expected to delay rate relief past the summer of 2009, which will, all else equal, weaken cash flow measures;
- Consolidated free operating cash flows are expected to be negative through at least 2010, based on the company's capital spending program; and
- SunCor's near-term prospects to make distributions to its parent are limited, due a depressed real estate cycle, which has hit the southwest especially hard.

Rationale

Standard & Poor's Ratings Services today affirmed the 'BBB-' corporate credit rating assigned to Pinnacle West Capital Corporation (PWCC) and its utility, Arizona Public Service. The outlook is stable. The consolidated credit ratings of PWCC primarily reflect the operations of its largest subsidiary, APS, a regulated, electric utility serving about 1.1 million customers within its service territory, which spans roughly two-thirds of Arizona and includes about half of the Phoenix MSA. We view the business profile of PWCC and APS to be 'strong'. While the company continues to benefit from a number of favorable attributes including a good service territory, a reasonably balanced

power supply portfolio and a good PSA. However, APS' continues to face significant regulatory challenges.

APS provided the company with about 92% of its consolidated net income in 2007. SunCor, PWCC's real estate development company, provided about 4%, but due to the significant real estate slowdown in the southwest, it is unlikely it will be a meaningful contributor of cash flows or income over the next several years. (Prior to the real estate downturn, our forecasts have conservatively limited earnings from this subsidiary due to the cyclic nature of its cash flows.) Other subsidiary operations include Pinnacle West Trading and Marketing, which contributed about 4% of consolidated net income in 2007. This subsidiary has since last year been minimizing trading operations. Its largest contract was serving all-requirements load for UNS Electric Inc., which ended in May 2008.

We view the financial profile of PWCC and APS to be 'aggressive', which reflects: year-end debt to total capitalization of 57% (adjusted for items such as power purchases and operating leases); heavy capital spending that is expected to drive negative free operating cash flow for the foreseeable future; cash flow weakness as a function of protracted rate cases; and, while modest, the presence of unregulated activities, which can be unpredictable in their earnings contributions.

Because the preponderance of cash flows for consolidated operations stems from APS, we expect financial performance will continue to be heavily dependent on regulatory outcomes. The conclusion of APS' last general rate case in June 2007 (filed in November 2005 and revised in early 2006) provided the company with mechanisms to recover legacy deferrals and speed the recovery of fuel costs going forward. This rate relief, in place for the last half of 2007, assisted the company in maintaining credit metrics roughly in line with past performance. Funds from operations (FFO) to total debt was about 16% at year-end, with FFO interest coverage around 4x. On a trailing 12-month basis the company's performance has been slightly above these levels, due in part to the federal tax stimulus package approved by the U.S. Congress earlier this year, which is expected to increase deferred taxes (which are added back to FFO and thus increase this total).

We expect APS to be in more or less continuous rate case mode for the next few years. Given APS' capital spending program, forecasted to be about $1.1 billion annually through 2010, the utility will need to file regular general rate cases to manage recovery of its investment. The use of a historical test year in Arizona, coupled with the fact that fully litigated rate cases take between 18 to 24 months to complete, is expected to result in no meaningful improvement in financial performance through 2009 and possibly beyond, depending on the timing and the outcome of the company's current case.

APS filed its current rate case in March 2008. ACC staff requested that the company revise its filing to reflect a test year ending Dec. 31, 2007 (as opposed to the originally filed version based on a Sept. 30, 2007, test year). The revised case has not been officially certified by the ACC, but certification is expected by July 2. Unlike the company's last rate case, in which $315 million of the $322 million of rate relief granted was for fuel and power-related costs, the majority of the current case is for nonfuel expenditures.

While the revised case increased the company's request to $278 million (about an 8.5% increase, excluding the company's request that customers be assessed about $53 million in impact fees), the re-filing means that is unlikely the ACC will reach an outcome in the case before October 2009, and because the majority of APS' sales occur in the summer months, the company's financial performance could weaken in 2009.

This month, the company requested that the ACC allow it to continue to collect a $0.004/kWh charge that it has been collecting in 2007 to recover legacy purchased power and fuel deferrals. Given that the portion of deferred

costs associated with this surcharge is due to be paid by July or August, APS has asked that the ACC continue the charge, but authorize collection as an interim base rate increase, subject to refund as part of the resolution of its rate case, expected in fall 2009. (Last year, the ACC approved similar relief for Tucson Electric Power in its pending rate case settlement when it granted the southern Arizona utility the opportunity to continue to collect charges related to a competitive transition charge, or CTC, while its rate case is pending.) While retail customers would essentially see no rate increase because APS is asking to continue the surcharge as an interim increase, it is unclear what action the ACC will take. A vote could occur as early as late summer.

In 2008, we expect a procedural schedule to be established for the APS rate case, and greater clarity around the timing of an outcome will be available once this is issued. Of note is that three of the five commissioners are facing term limits and will no longer be on the ACC beginning in 2009. Commissioners are popularly elected and about a dozen candidates have announced they will run for the November election. As a result, a majority of the commissioners presiding now will not be on the commission when an APS rate case ruling is rendered. What this means for credit quality is unclear.

APS was successful earlier this year in receiving approval for a change in its line extension policies, which eliminates the free footage allowance that used to be available for customers. As a result, the portion of the company's capital expenditures associated with new line extensions will be offset with contributions in aid of construction (CIAC). This is favorable and year to date ended March 31, 2008, had added about $10 million in incremental cash flows to the company. Because it is booked under investing activities, cash flow metrics are not improved, but we recognize the significant benefit of APS receiving upfront cash from customers to meet a portion of its distribution capital investment plans. Future cash flows from customers in the form of CIAC will depend on the number of new meter sets, which are significantly off year to date due to the poor real estate market in Arizona and a slowing economy generally.

APS has a well-diversified power supply portfolio that in 2007 consisted of about 22% nuclear generation, 37% coal generation, approximately 18% owned gas generation, and the balance, about 23%, of purchases. We would expect the company's purchased power obligations to steadily climb due to the fact that APS is under a self build moratorium until 2015. APS will also need to meet relatively stringent renewable portfolio standards (RPS). It has in place a surcharge to pass through to customers the costs of RPS compliance.

Palo Verde performance has stabilized, and it has a plan in place to address NRC concerns. As of the first quarter of 2008, the combined capacity factors for all three Palo Verde units was 93%, as compared with 79% for 2007 (which reflects in part an extended planned outage to replace steam generators at unit 3) and 71% in 2006, which largely reflects unplanned outages at unit 1 related to excessive vibration that occurred when that unit exited its extended outage for refueling and replacement of steam generators. Palo Verde Unit 3 remains in the NRC's "multiple/repetitive degraded cornerstone" column of the NRC's Action matrix, which subjects all three Palo Verde units to enhanced NRC inspection regime. Preliminary work in support of this took place throughout the summer of 2007. In February, the NRC issued its inspection report, which determined the plant was operating safely but which also outlined an improvement plan for APS. In late March, APS in turn submitted to the NRC a final improvement plant addressing issues raised in the NRC inspection report. While the nuclear units appear to be on a path to improve operational performance and restore NRC confidence in the operational and safety standards at the plant, this will remain an area of concern until the NRC removes it degraded designation.

Short-term credit factors

APS and PWCC's short-term rating is 'A-3'. Liquidity is adequate. Pinnacle West has $18 million of cash and cash equivalents, and total credit facilities of nearly $1.4 billion, with approximately $943 million available as of March 31, 2008. In October 2007, APS received approval from ACC to increase its authorized short-term debt borrowing capacity by $500 million, and long-term debt borrowing capacity by $1 billion. This will help address the needs of its growing customer base, and the increasing requirement for natural gas and purchased power.

Pinnacle West had close to $185 million available under its $300 million unsecured revolving credit facility that expires in December 2010. APS had $682 million available under its two unsecured revolving credit facilities, $400 million of which expires in December 2010, and $500 million in September 2011. SunCor has two credit facilities expiring in October and December 2008 that total $170 million and approximately $76 million, respectively, available as of September 2007.

Discretionary cash flow is expected to be negative for 2008 due to APS' capital expenditure plans. Excluding the remarketing of APS' pollution control debt, neither PWCC nor APS has any significant debt obligations maturing until 2011.

Outlook

The stable outlook reflects our expectation that consolidated cash flow volatility has been tamped down by the ACC's approval of a stronger PSA that speeds the recovery of fuel costs, but consolidated financial performance will continue to be challenged by regulatory lag at APS, which could be moderated by APS' pending interim rate request. The stable outlook is premised on no meaningful adverse changes in the company's business risks and continued financial performance that is not significantly weaker than 2007 results. Equity issuances will be expected to balance the capital structure of the company as APS continues to invest heavily in infrastructure. Ratings could be lowered to speculative grade if the company is not able to overcome the challenge of ensuring timely recovery of its prudently incurred costs through rate increases approved by the ACC. Given these challenges, and that presented by NRC scrutiny of Palo Verde, we see little potential for positive movement in the ratings or outlook.

Rating Methodology

The ratings on PWCC and its subsidiaries are determined based on Standard & Poor's consolidated ratings methodology. The application of this approach reflects significant financial and operational inter-relationships among the rated entities and captures the relative contribution to business risk and cash flow of the operating segments. In the absence of meaningful regulatory measures that can restrict the flow of funds within the company, Standard & Poor's considers PWCC's consolidated financial profile, while still analyzing the financial profiles of the standalone entities, to be the best indicator of credit quality of the parent and its subsidiaries, including APS.

Accounting

PWCC reports its financial statements in accordance with U.S. GAAP. These statements received an unqualified opinion by PWCC's independent auditor, Deloitte and Touche LLC, in the most recent annual audited period.

The company benefits from the use of regulatory accounting SFAS 71 (accounting for the effects of certain types of

regulation), under which some incurred costs or benefits that will probably be recovered or refunded in customer rates are deferred and recorded as regulatory assets or liabilities. As of Dec. 31, 2007, PWCC's consolidated balance sheet contained total regulatory assets and total regulatory liabilities of $625 million and $643 million respectively, reflecting assets expected to be recovered and liabilities expected to be settled in future rates.

We make several adjustments to PWCC's financial statements. In 1986, APS sold about 42% of Palo Verde Unit 2 as part of a sale-leaseback transaction. We treat these obligations as operating leases and in 2007 imputed an off-balance-sheet obligation of $432.18 million. We also impute $293 million for power purchase obligations in 2007, a number we expect to increase given APS' increasing power purchases. Reported ratios also reflect adjustments to impute debt for unfunded pension and postretirement benefit obligations of $329.72 million as of the end of 2007.

Table 1

Pinnacle West Capital Corp. — Peer Comparison*

Industry Sector: Electric

	Pinnacle West Capital Corp.	Puget Energy Inc.	Avista Corp.	Unisource Energy Corp.	PNM Resources Inc.
Rating as of June 24, 2008	BBB-/Stable/A-3	BBB-/Watch Neg/--	BBB-/Stable/A-3	-/-/-	BB-/Stable/B-2
	--Average of past three fiscal years--				
(Mil. $)					
Revenues	3,304.4	2,899.7	1,427.9	1,309.3	2,154.2
Net income from cont. oper.	264.1	166.1	52.3	57.9	82.8
Funds from operations (FFO)	683.7	442.5	186.2	283.6	281.5
Capital expenditures	778.6	726.5	194.5	225.1	339.1
Cash and short-term investments	99.2	30.1	20.6	113.1	70.4
Debt	4,419.9	3,343.9	1,368.8	1,838.8	2,684.7
Preferred stock	0.0	89.5	0.0	0.0	9.6
Equity	3,366.1	2,298.5	854.7	640.2	1,564.5
Debt and equity	7,786.0	5,642.4	2,223.5	2,479.0	4,249.3
Adjusted ratios					
EBIT interest coverage (x)	2.8	2.0	1.8	1.7	1.7
FFO int. cov. (X)	3.6	2.9	2.7	2.8	2.7
FFO/debt (%)	15.5	13.2	13.6	15.4	10.5
Discretionary cash flow/debt (%)	(8.2)	(13.4)	(1.7)	2.1	(5.7)
Net cash flow / capex (%)	62.2	46.9	81.0	113.0	65.2
Total debt/debt plus equity (%)	56.8	59.3	61.6	74.2	63.2
Return on common equity (%)	6.8	7.2	5.7	8.3	5.4
Common dividend payout ratio (un-adj.) (%)	75.5	60.4	54.7	50.4	72.9

*Fully adjusted (including postretirement obligations)

Table 2

Pinnacle West Capital Corp. -- Financial Summary*

Industry Sector: Electric

	--Fiscal year ended Dec. 31--				
	2007	2006	2005	2004	2003
Rating history	BBB-/Stable/A-3	BBB-/Stable/A-3	BBB-/Stable/A-3	BBB/Negative/A-2	BBB/Stable/A-2
(Mil. $)					
Revenues	3,523.6	3,401.7	2,988.0	2,899.7	2,759.5
Net income from continuing operations	298.8	317.1	176.3	243.2	240.6
Funds from operations (FFO)	735.3	736.3	579.6	567.6	932.3
Capital expenditures	933.9	743.2	658.7	591.7	713.3
Cash and short-term investments	56.3	87.2	154.0	163.4	131.1
Debt	4,686.5	4,358.6	4,214.6	4,272.8	4,129.9
Preferred stock	0.0	0.0	0.0	0.0	0.0
Equity	3,531.6	3,446.1	3,120.5	2,653.7	2,510.0
Debt and equity	8,218.1	7,804.7	7,335.1	6,926.5	6,639.8
Adjusted ratios					
EBIT interest coverage (x)	2.7	3.0	2.6	2.6	2.2
FFO int. cov. (x)	3.7	3.8	3.3	3.2	4.2
FFO/debt (%)	15.7	16.9	13.8	13.3	22.6
Discretionary cash flow/debt (%)	(10.1)	(12.5)	(1.7)	2.6	1.0
Net cash flow / capex (%)	56.2	72.0	59.7	67.7	108.6
Debt/debt and equity (%)	57.0	55.8	57.5	61.7	62.1
Return on common equity (%)	7.3	8.2	4.8	7.7	7.1
Common dividend payout ratio (un-adj.) (%)	70.4	63.4	105.9	68.6	65.4

*Fully adjusted (including postretirement obligations)

Table 3

Reconciliation Of Pinnacle West Capital Corp. Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. $)*

	--Fiscal year ended Dec. 31, 2007--							
Pinnacle West Capital Corp. reported amounts								
	Debt	Operating income (before D&A)	Operating income (before D&A)	Operating income (after D&A)	Interest expense	Cash flow from operations	Cash flow from operations	Capital expenditures
Reported	3,631.6	992.7	992.7	619.3	189.6	649.6	649.6	941.6
Standard & Poor's adjustments								
Operating leases	432.2	79.0	27.7	27.7	27.7	51.3	51.3	15.4
Postretirement benefit obligations	329.7	12.8	12.8	12.8	--	8.7	8.7	--
Capitalized interest	--	--	--	--	23.1	(23.1)	(23.1)	(23.1)
Share-based compensation expense	--	--	6.0	--	--	--	--	--
Power purchase agreements	293.0	21.1	21.1	18.1	18.1	3.0	3.0	--

Table 3

Reconciliation Of Pinnacle West Capital Corp. Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. $)*(cont.)

Reclassification of nonoperating income (expenses)	--	--	--	20.0	--	--	--	-
Reclassification of working-capital cash flow changes	--	--	--	--	--	--	66.6	--
US decommissioning fund contributions	--	--	--	--	--	(20.7)	(20.7)	--
Total adjustments	1,054.9	117.8	67.6	78.6	68.9	19.2	85.8	(7.7)

Standard & Poor's adjusted amounts

	Debt	Operating income (before D&A)	EBITDA	EBIT	Interest expense	Cash flow from operations	Funds from operations	Capital expenditures
Adjusted	4,686.5	1,105.5	1,060.2	697.9	258.4	668.8	735.3	933.9

*Pinnacle West Capital Corp. reported amounts shown are taken from the company's financial statements but might include adjustments made by data providers or reclassifications made by Standard & Poor's analysts. Please note that two reported amounts (operating income before D&A and cash flow from operations) are used to derive more than one Standard & Poor's-adjusted amount (operating income before D&A and EBITDA, and cash flow from operations and funds from operations, respectively). Consequently, the first section in some tables may feature duplicate descriptions and amounts.

Ratings Detail (As Of June 25, 2008)*

Arizona Public Service Co.	
Corporate Credit Rating	BBB-/Stable/A-3
Commercial Paper	
Local Currency	A-3
Senior Unsecured	
Local Currency	BBB-
Corporate Credit Ratings History	
21-Dec-2005	BBB-/Stable/A-3
01-Apr-2005	BBB/Stable/A-2
19-Mar-2004	BBB/Negative/A-2
Related Entities	
Pinnacle West Capital Corp.	
Issuer Credit Rating	BBB-/Stable/A-3
Commercial Paper	
Local Currency	A-3
Senior Unsecured	
Local Currency	BB+
PVNGS II Funding Corp. Inc.	
Issuer Credit Rating	BBB-/Stable/--
Senior Unsecured	
Local Currency	BBB-

*Unless otherwise noted, all ratings in this report are global scale ratings. Standard & Poor's credit ratings on the global scale are comparable across countries. Standard & Poor's credit ratings on a national scale are relative to obligors or obligations within that specific country.

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ATTACHMENT 3

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June 24, 2011

Research Update:

Pinnacle West Capital Corp. And Arizona Public Service Co. Ratings Raised To 'BBB'

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Research Update:

Pinnacle West Capital Corp. And Arizona Public Service Co. Ratings Raised To 'BBB'

Overview

- We are raising our corporate credit rating to 'BBB' from 'BBB-' on holding company Pinnacle West Capital Corp. and electric utility subsidiary Arizona Public Service Co. At the same time, we are raising our unsecured issue rating on APS to 'BBB' from 'BBB-' and the short-term ratings on both entities to 'A-2' from 'A-3'.
- We are raising the ratings based on stronger credit metrics, bolstered by a reduction in debt, higher earnings, and periodic equity issuances; improved regulatory strategy; and prudent financial management during the rate freeze.
- Our outlook remains positive and reflects that we could raise the long-term credit rating another notch if regulatory dealings remain constructive and if the company continues to manage the balance sheet with equity issuances to support high capital spending.

Rating Action

On June 24, 2011, Standard & Poor's Ratings Services raised its corporate credit rating to 'BBB' from 'BBB-' on holding company Pinnacle West Capital Corp. (PWCC) and its electric utility subsidiary Arizona Public Service Co. (APS). At the same time, we raised the senior unsecured debt issue rating at APS to 'BBB' from 'BBB-' and the short-term ratings on both entities to 'A-2' from 'A-3'. The outlook is positive.

Rationale

The ratings reflect our view of improved consolidated financial performance, evidenced by stronger credit metrics, and progress in advancing the regulatory strategy of APS in Arizona. A reduction in debt leverage from equity issuances and debt reductions, coupled with stronger cash flows from higher earnings and tax benefits, increased FFO to debt. Prudent financial management during the current rate case stay-out period and the use of cost riders resulted in improved financial stability. A shift in company focus toward improving regulatory relationships in the past few years continues to benefit credit quality because the company has transitioned to slower customer growth. We could raise the ratings further if regulatory dealings remain constructive and the company continues to manage the balance sheet with equity issuances to offset high capital spending.

The 'BBB' corporate credit ratings on PWCC and APS reflect our view of regulated operations that provide almost all of the consolidated income and

cash flow.

We view the business risk profile of PWCC and APS as excellent under our corporate risk profile matrix. The company benefits from a number of favorable business attributes, including the absence of competition in APS' regulated operations, a service territory with above-normal average growth rates and below-average unemployment prior to the current recession, a balanced power supply portfolio of coal, nuclear, and natural gas generation, and contract purchases backed by a power supply cost adjustment mechanism and a prudent hedging strategy that serve to ensure full recovery and dampen volatility. The business profile also reflects APS' success in managing regulatory risks in Arizona. The lack of material non-regulated operations, which typically increase business risk, adds further support to the profile.

The company has undergone a significant transition in recent years. High customer growth had necessitated that the company file regular general rate cases with the Arizona Corporation Commission (ACC) to recover its investments and operating costs, prior to the collapse of the housing market. The use of a historical test year in Arizona, coupled with an 18- to 24-month completion time for fully litigated rate cases, made it very difficult for APS to earn authorized returns. In recent years, regulatory lag has decreased and financial performance has improved because of interim rates, recovery of certain post-test-year costs, and an improved 11% authorized equity return in the previous general rate case. Slower growth and the addition of several rate riders that allow the company to true up certain costs outside of the general rate case process have mitigated the need to file large cases frequently. However, capital spending remains high due to replacements and renewable spending, necessitating a continued reliance on rate increases.

APS has a well-diversified power supply portfolio that supports the excellent business profile, consisting of the following energy sources in 2010: 36.6% coal, 26.8% nuclear, 24.3% purchases, and about 12.3% owned gas generation and other sources. The company is highly exposed to nuclear power availability and nuclear operations at Palo Verde Nuclear Generating Station, its largest single generating resource. Palo Verde has a history of mixed results tied to problems at the plant that appear to have been corrected. In April of 2011 operating licenses for all three reactor units were extended 20 years beyond the current 40-year licenses, allowing Unit 1 to operate through 2045, Unit 2 through 2046, and Unit 3 through 2047. We expect the company's purchased power obligations to steadily climb because solar energy remains a top public policy objective in Arizona and because significant portions will come from purchases. Construction is underway at Abengoa's 280-megawatt (MW) Solana concentrating solar plant after the U.S. Department of Energy approved a loan late last year. The loan and tax credits will help to blunt the impact of this resource on customer bills, which will represent a significant purchase commitment by APS. APS needs to meet Arizona renewable portfolio standards (RPS) of 10% by 2015 and 15% by 2025, with 30% of the total RPS coming from small-scale distributed resources by 2012. The company has a surcharge to collect the costs of RPS compliance, and this lessens the financial burden on the company.

APS is purchasing Southern California Edison's (SCE) 48% interest (739 MW) in Units 4 and 5 of the Four Corners Plant in New Mexico for $294 million. APS now owns a 15% interest in each unit. APS operates the plant and also owns 100% (560 MW) of Units 1 to 3. APS has announced that it will use the capacity to shut down Units 1 to 3, which are older and less efficient and which would be subject to significant environmental upgrades under rules proposed by the U.S. Environmental Protection Agency. The sale awaits regulatory approvals from the respective commissions and the Federal Energy Regulatory Commission. We view the transaction favorably from a credit perspective, assuming that it does not increase debt leverage and that the ACC approves all costs.

The aggressive financial risk profile of PWCC and APS reflects slightly higher leverage and adjusted funds from operations (FFO) to total debt that has averaged 20% over the past three years. We believe that rates will continue to support cash flows at the current rating level and possibly higher levels, rising as we expect new rates to take effect next year. Financial performance will continue to depend on the management of regulatory risk in Arizona and on the company's financing decisions regarding the usage of debt and equity as capital investments ramp up in 2012 and 2013. Average adjusted debt to total capital was around 60% at the end of 2009 (adjusted for items such as power purchase contracts, operating leases, and pension and other postretirement benefit obligations), but had improved to 55% by the end of 2010 due to the equity issuance and a reduction of debt.

We expect APS to maintain the ratings by funding its capital spending program with a balanced capital structure. The company had $748 million in capital expenditures in the 12 months ended Dec. 31, 2010, and plans to spend $960 million in 2011 and $1.33 billion in 2012 for renewable generation, environmental compliance, the Four Corners purchase, and system maintenance. A troubled real estate market in Arizona's historically high-growth service area has increased planning uncertainty, but slower growth has mitigated some spending pressure and rate lag, allowing the company to further its renewable investments and other infrastructure without the added burden of high customer growth contributing to rate lag pressure. Customer growth averaged 4% a year for 2005 through 2007, but has been nearly flat since. The resumption of growth levels witnessed during the previous housing boom could place renewed pressure on the company's financial profile, given high capital expenditure levels, but mechanisms and other factors that now exist would lessen the impact.

Liquidity

The short-term rating on APS and PWCC is 'A-2'. Consolidated liquidity is adequate under our corporate liquidity methodology, which categorizes liquidity under five standard descriptors. Under our analysis, projected sources of liquidity (mainly operating cash flow, available bank lines, and share issuances) exceed projected uses (mainly necessary capital expenditures, debt maturities, and common dividends), absent access to capital markets, by more than 1.2x for the upcoming 12 months. Liquidity may be pressured in 2011

or 2012 due to high capital expenditures that the company expects to incur, but we expect liquidity to remain adequate.

As of March 2011, PWCC had $183 million available under its $200 million unsecured revolving credit facility, expiring in 2013, and APS had $980 million available under its combined $1 billion unsecured revolving credit facilities. Half expires in 2013, and the remainder in 2015. SunCor is liquidating real estate assets to repay debt under its non-recourse secured credit facility. SunCor's liquidity and debt are not a factor in PWCC's or APS' overall liquidity position. The company's long-term debt maturities in 2011 total about $575 million.

Outlook

The positive outlook reflects our view that we could raise the long-term credit rating another notch if regulatory dealings remain constructive and if the company continues to manage the balance sheet with equity issuances that offset high capital spending in the next 18 months. APS' progress in managing its regulatory agenda in Arizona provides a platform for higher ratings contingent on financial prudence in containing costs and financing capital investments. Specifically, we may raise the ratings one notch if the company demonstrates sustained financial performance above our forecast levels of adjusted FFO to debt of 20% and adjusted debt to capital of 55%. Minimizing rate lag and earning close to authorized equity returns would help achieve such financial metrics. We will likely leave the rating the same if the company does not demonstrate continued financial improvement or the ability to further its regulatory agenda.

Related Criteria And Research

- Criteria Methodology: Business Risk/Financial Risk Matrix Expanded, May 27, 2009
- Assessing U.S. Utility Regulatory Environments, Nov. 7, 2007
- 2008 Corporate Criteria: Analytical Methodology, April 15, 2008

Ratings List

Upgraded

Pinnacle West Capital Corp.		
Arizona Public Service Co.		
Corporate credit rtg	BBB/Positive/A-2	BBB-/Positive/A-3
Commercial paper	A-2	A-3
Arizona Public Service Co.		
Senior unsecured	BBB	BBB-

Complete ratings information is available to subscribers of RatingsDirect on the Global Credit Portal at www.globalcreditportal.com. All ratings affected

by this rating action can be found on Standard & Poor's public Web site at www.standardandpoors.com. Use the Ratings search box located in the left column.

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ATTACHMENT 4

MOODY'S
INVESTORS SERVICE

Credit Opinion: Arizona Public Service Company

Global Credit Research - 25 Feb 2011

Phoenix, Arizona, United States

Ratings

Category	Moody's Rating
Outlook	Stable
Issuer Rating	Baa2
Sr Unsec Bank Credit Facility	Baa2
Senior Unsecured	Baa2
Bkd Commercial Paper	P-2
Parent: Pinnacle West Capital Corporation	
Outlook	Stable
Issuer Rating	Baa3
Sr Unsec Bank Credit Facility	Baa3
Senior Unsecured Shelf	(P)Baa3
Subordinate Shelf	(P)Ba1
Preferred Shelf	(P)Ba2
Commercial Paper	P-3

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Key Indicators

Arizona Public Service Company

ACTUALS	2010	2009	2008	2007
(CFO Pre-W/C + Interest) / Interest Expense [1][2]	4.8x	5.4x	5.0x	4.2x
(CFO Pre-W/C) / Debt [2]	24.5%	26.4%	22.8%	18.3%
(CFO Pre-W/C - Dividends) / Debt [2]	19.9%	22.1%	18.8%	14.0%
Debt / Book Capitalization	42.1%	45.4%	47.2%	45.9%

[1] CFO pre-W/C, which is also referred to as FFO in the Global Regulated Electric Utilities Rating Methodology, is equal to net cash flow from operations less net changes in working capital items [2] Changes in margin and collateral accounts are excluded from CFO Pre-W/C

Note: For definitions of Moody's most common ratio terms please see the accompanying User's Guide.

Opinion

Rating Drivers

Predominantly regulated operations

Regulatory supportiveness increasing, though lag persists

Low growth in service territory

Stronger financial metrics offset weaker regulatory environment

Corporate Profile

Arizona Public Service (APS: Baa2 senior unsecured, stable) is a vertically integrated electric utility that provides electric service to most of the state of Arizona with the major exceptions of about one-half of the Phoenix metropolitan area and the Tucson metropolitan area. APS is the primary subsidiary of Pinnacle West Capital Corporation (Pinnacle: Baa3 senior unsecured, stable), a holding company that through its other subsidiaries sells energy related services. In 2010, Pinnacle completed the divestitures of much of its remaining non-regulated businesses.

DETAILED RATING CONSIDERATIONS

Regulatory supportiveness showing signs of improving, though process still lengthy and lag persists

APS' operations are regulated by the Arizona Corporation Commission (ACC), an elected commission that has tended to render its decisions after prolonged consideration. As a result, APS' ability to earn reasonable returns has been limited due to significant regulatory lag. APS has generally been awarded relatively reasonable ROEs and equity ratios, including an ROE of 11% and an equity ratio of 53.8% as part of its $207.5 million net base rate increase in the ACC's December 2009 order (75% of APS' request).

Historically, the ACC has taken a year and a half to two years to render decisions in APS' rate cases including its December 2009 order. Generally the length of time required by the rate decision process coupled with the use of a historic test year means that rates may reflect a rate base that is more than two years old. On February 1, 2011, APS filed a notice with the ACC that it intends to file a rate case on June, 1, 2011 using a year-end 2010 test year and will request new rates be in effect by July 1, 2012. This planned 13-month timeline was mentioned in the ACC's December 2009 order and would be significantly shorter than historic rate case timelines. Also as part of the order, APS is prohibited from filing another rate case until June 2013.

The significant regulatory lag and uncertain timing of rate case resolutions causes APS to map to a factor in the Ba range for its Regulatory Framework within Moody's Rating Methodology for Regulated Electric and Gas Utilities (the Methodology) which is below the Baa average for the regulated utility industry in the U.S.

Improved cost recovery

Although regulatory lag continues, APS utilizes several mechanisms that allow its rates to be adjusted outside of a general rate case. Moody's generally views these mechanisms as being supportive of credit quality as they tend to result in a more timely recovery of costs. APS' rates are adjusted annually to recover 90% of the difference between its costs for fuel and purchased power and the amounts included in base rates, limiting APS' exposure to volatile power and gas prices. The fuel recovery factor includes a forward estimate of power costs, which further helps to limit cost deferrals.

APS also has adjustment mechanisms that allow the utility to recover its costs for renewable energy, efficiency and demand side management programs. Transmission costs are recovered through a transmission cost adjustor which resets annually based on changes in APS' Federal Energy Regulatory Commission approved formula-based tariffs. APS is also currently able to recover its costs for new customer hookups via line extension payments from customers.

In December 2010, the ACC issued a policy statement supporting decoupling rate structures implemented through rate cases over a three year evaluation period. We generally view decoupling mechanisms as supportive to credit quality as they are intended to improve a utility's fixed cost recovery. No Arizona utilities currently have a decoupling mechanism; implementation is intended to occur during the next rate case process.

Due to APS' adequate ability to recover most non-base costs, APS maps to a factor in the Baa range for Factor 2: Ability to Recover Costs and Earn Returns within the Methodology.

Low customer growth in service territory

APS' service territory incorporates a majority of Arizona including significant parts of metropolitan Phoenix. As such, within the framework of the Methodology, for Factor 3: Diversification - Market Position, APS maps to a factor in the Baa range. Customer growth is expected to be 1-1.5% over the near-term.

Reasonably diverse generation capacity

APS has a fairly diverse, low-cost generation fleet including 1,747 MW of coal capacity and 1,146 MW of nuclear capacity which in 2010 provided approximately 37% and 27%, respectively, of its total energy needs. In November 2010, as part of a plan to comply with the EPA's BART ruling, APS announced it had agreed to acquire an additional 740 MW of capacity at Units 4 and 5 of the Four Corners coal plant from Southern California Edison and shutdown 560 MW of capacity at Units 1-3. The transaction is expected to close by year-end 2012. Pollution control equipment is expected to be installed on Units 4 and 5 to get the plant in compliance with the EPA's BART determination. This acquisition will moderately increase coal's contribution to APS' fuel mix but it does provide a low-cost fuel option and it will reduce emissions in the region. Within the framework of the Methodology, APS maps to a factor within the Baa range for Factor 3: Diversification - Generation and Fuel.

Financial Metrics

Since 2008, APS' key financial metrics have improved to levels which map to a low A factor, reflecting improved cost control, cost recovery mechanisms and moderating capital expenditures. Over the near-term, APS' credit metrics could remain comparable to 2010 levels due to the benefits of bonus depreciation assuming adequate regulatory treatment. In general, Moody's looks for APS to have financial metrics that are stronger than comparably rated utility operating companies operating in regulatory environments that are more supportive of credit quality.

Liquidity Profile

APS' cash flows and credit facilities generally are a stable source of liquidity. In 2010, APS' cash from operations covered 76% of its $732 million of capital expenditures and $182 million of dividends to Pinnacle. The shortfall was funded by an equity contribution from the parent. Capital expenditures are expected to be in the range of $1 - 1.3 billion annually over the near-term and financed with a combination of internal and external sources including periodic equity injections from Pinnacle. As part of APS' last rate case, Pinnacle is required to infuse $700 million of equity by December 2014; Pinnacle infused $253 million in proceeds from the issuance of new equity in 2010.

In 2010, APS increased its dividend modestly to Pinnacle. Moody's expects APS' future dividends to increase somewhat, but generally to remain in line with its current payout ratio of 70 to 75%.

APS' short-term liquidity sources include a commercial paper program sized at $250 million. The program is currently supported by two committed lines of credit totaling $1 billion consisting of a $500 million line that expires February 2013 and a $500 million line that expires February 2015. The facility expiring in 2015 replaces the a $489 million facility which was set to mature September 2011. As of December 31,

2010, APS had $20 million of letters of credit outstanding, no borrowings under its credit facilities and $100 million of cash on hand. APS also has approximately $44 million of variable rate pollution control bonds (PCB's) supported by letters of credit; of which, $26 million expire September 2011 and the remainder expire in 2013.

APS' credit agreements both have one financial covenant that requires the ratio of debt to total capitalization not exceed 65%. As of December 31, 2010, APS' debt to total capitalization ratio, calculated in accordance with the credit documents, was approximately 46%. The credit agreements do not require a material adverse change (MAC) representation for revolver borrowings. No rating triggers exist in any APS credit facilities though interest costs may increase under various financing agreements if a downgrade occurs. In addition to the letters of credit supporting the PCB's expiring September 2011, APS has $400 million of unsecured notes due October 2011 and $375 million of unsecured notes due March 2012.

The rating assumes APS will continue to prudently manage its liquidity. Within the framework of the Methodology, APS maps to a factor within the Baa range for Factor 4 - Liquidity.

Rating Outlook

The stable outlook reflects APS' predominately regulated cash flows and Moody's view that its credit metrics are likely to be sustainable at levels appropriate for the current ratings. The outlook assumes APS will be reasonably successful in managing its regulatory relationships and that capital expenditures will be financed in a balanced manner with a goal of maintaining or improving APS' current position of financial strength.

What Could Change the Rating - Up

APS' rating is not likely to be revised upward in the near-to-medium term. Longer term, an upgrade could be possible if there is consistent supportive regulatory treatment resulting in material, timely rate increases, or if there are material reductions in costs or leverage such that Moody's could anticipate key financial ratios improving significantly from their current levels, if for example, a ratio of CFO pre -WC / debt could be maintained in the mid-twenty percent range, there could be upward pressure on the rating.

What Could Change the Rating - Down

A downgrade could result if regulatory lag for capital spending becomes more pronounced, or if Palo Verde experiences an extended outage and APS is unable to recover higher maintenance and purchased power costs in a timely manner. A downgrade could result if Moody's expects a sustained weakening of financial metrics, if for example, the ratio of CFO pre -WC / debt would remain in the mid-teens for an extended period.

Rating Factors

Arizona Public Service Company

Regulated Electric and Gas Utilities Industry [1][2]	Current FYE 2010		Moody's 12-18 Month Forward View As of February 24, 2011	
Factor 1: Regulatory Framework (25%)	Measure	Score	Measure	Score
a) Regulatory Framework		Ba		Ba
Factor 2: Ability To Recover Costs And Earn Returns (25%)				
a) Ability To Recover Costs And Earn Returns		Baa		Baa
Factor 3: Diversification (10%)				
a) Market Position (5%)		Baa		Baa
b) Generation and Fuel Diversity (5%)		Baa		Baa
Factor 4: Financial Strength, Liquidity And Key Financial Metrics (40%)				
a) Liquidity (10%)		Baa		Baa
b) CFO pre-WC + Interest/ Interest (3 Year Avg) (7.5%)	5.1x	A	4.6x-4.9x	A
c) CFO pre-WC / Debt (3 Year Avg) (7.5%)	24.6%	A	22-25%	A
d) CFO pre-WC - Dividends / Debt (3 Year Avg) (7.5%)	20.3%	A	17-21%	A
e) Debt/Capitalization (3 Year Avg) (7.5%)	44.9%	A	40-45%	A
Rating:				
a) Indicated Rating from Grid		Baa2		Baa2
b) Actual Rating Assigned		Baa2		Baa2

* THIS REPRESENTS MOODY'S FORWARD VIEW; NOT THE VIEW
OF THE ISSUER; AND UNLESS NOTED IN THE TEXT DOES NOT INCORPORATE SIGNIFICANT ACQUISITIONS OR DIVESTITURES

[1] All ratios are calculated using Moody's Standard Adjustments. [2] As of 12/31/2010; Source: Moody's Financial Metrics

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BEFORE THE ARIZONA CORPORATION COMMISSION

GARY PIERCE
Chairman
BOB STUMP
Commissioner
SANDRA D. KENNEDY
Commissioner
PAUL NEWMAN
Commissioner
BRENDA BURNS
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	)	DOCKET NO. E-01345A-11-0224

DIRECT

TESTIMONY

OF

HOWARD SOLGANICK

FOR THE

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

NOVEMBER 18, 2011

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EXECUTIVE SUMMARY
ARIZONA PUBLIC SERVICE COMPANY
DOCKET NO. E-01345A-11-0224

My testimony reviews the Arizona Public Service Company's ("Company") proposed Efficiency and Infrastructure Account ("EIA") mechanism. Staff recommends that the Arizona Corporation Commission should reject the Company's EIA proposal as it is very broad and addresses risks such as weather and economic conditions.

In recognition of the Company's energy efficiency and distributed generation requirements and plans, I developed a Lost Fixed Cost Revenue ("LFCR") mechanism that is related to the Company's plans and performance. This mechanism, built upon the Company's disaggregated costs, recognizes that many of the Company's costs are not impacted by energy efficiency and distributed generation measures. The LFCR mechanism provides an appropriate adjustment based on the Company's energy efficiency and distributed generation performance.

INTRODUCTION

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

A. My name is Howard Solganick. I am a Principal at Energy Tactics & Services, Inc. My business address is 810 Persimmon Lane, Langhorne, PA 19047. I am performing this assignment under subcontract to Blue Ridge Consulting Services, Inc.

Q. Please summarize your qualifications and experience.

A. I am licensed as a Professional Engineer in Pennsylvania (active) and New Jersey (inactive). I hold a Professional Planner's license (inactive) in New Jersey. I served on the Electric Power Research Institute's Planning Methods Committee and on the Edison Electric Institute Rate Research Committee. I have been appointed as an arbitrator in cases involving a pricing dispute between a municipal entity and an on-site power supplier and a commercial landlord-tenant case concerning submetering and billing. I also previously served on two New Jersey Zoning Boards of Adjustment as Chairman and member and a Pennsylvania Township Planning Commission as Chairman and member.

I have been actively engaged in the utility industry for over 35 years, holding utility management positions in generation, rates, planning, operational auditing, facilities permitting, and power procurement. I have delivered expert testimony in utility planning and operations, including rate design and cost of service, tariff administration, generation, transmission, distribution and customer service operations, load forecasting, demand side management, capacity and system planning, and regulatory issues.

I have also led and/or participated in consulting projects to develop, design, optimize, and implement both traditional utility operations and e-commerce businesses. These projects

focused on the marketing, sale and delivery of retail energy, energy related products and services, and support services provided to utilities and retailers.

I have been engaged by clients to review proposed distributed generation contracts and the operation and integration of generating assets within power pool operations, and have advised the Board of Directors of a public power utility consortium. For a period of four years I was engaged by a multiple site commercial real estate organization to manage its solicitation for the purchase of retail energy. As a subcontractor, I have performed management audits for the Connecticut Department of Public Utility Control and the Public Utilities Commission of Ohio. I also provide (as a subcontractor) support for the Staff and Commissioners of the District of Columbia Public Service Commission for electric rate cases.

I have also been engaged to review utility performance before, during and after outages resulting from major storms including Hurricane Ike.

From 1994 to the present, I have been President of Energy Tactics & Services, Inc. From 1996 to 1998, I was a Managing Consultant for AT&T Solutions. From 1990 to 1994, I was Vice President of Business Development for Cogeneration Partners of America. In that position, I was responsible for the development of independent power facilities, most of which were fueled by natural gas and oil.

From 1978 to 1990, I held progressively increasing positions of responsibility with Atlantic City Electric Company in generation, regulatory, performance, planning, major procurement, and permitting areas.

From 1971 to 1978, I was an Engineer or Project Engineer for Univac, Soabar, Bickley Furnaces and deLaval Turbine, designing card handling equipment, tagging and printing machines, high temperature industrial furnaces, and utility and industrial power generation equipment, respectively.

I received a Bachelor of Science in Mechanical Engineering (minor in Economics) from Carnegie-Mellon University and a Master of Science in Engineering Management (minor in Law) from Drexel University. I have also taken courses on arbitration and mediation presented by the American Arbitration Association, scenario planning presented by the Electric Power Research Institute and load research presented by the Association of Edison Illuminating Companies. I have also taken courses in zoning and planning theory, practice and implementation in both New Jersey and Pennsylvania.

Q. Have you previously submitted testimony in regulatory proceedings?

A. Yes. I have testified and/or presented testimony (summarized in Attachment HS-1) before the following regulatory bodies.

- Delaware Public Service Commission
- Georgia Public Service Commission
- Jamaica (West Indies) Electricity Appeals Tribunal
- Maine Public Utilities Commission
- Maryland Public Service Commission
- Michigan Public Service Commission
- Missouri Public Service Commission
- New Jersey Board of Public Utilities
- Public Utilities Commission of Ohio

- Pennsylvania Public Utility Commission
- Public Utility Commission of Texas

Q. For whom are you appearing in this proceeding?

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

Q. What is the purpose of your testimony?

A. My testimony analyzes decoupling proposal of the Arizona Public Service Company ("Company").

Based on my review of the Company's application, supporting testimony, and responses to data requests, I make the following recommendations:

- The Commission should reject the Company's decoupling proposal.
- The Commission should allow the Company to receive the "lost fixed cost revenue" only for distribution service as modified to reflect the stability of demand charges and any excess basic service charge ("BSC") revenues.

Q. What is revenue decoupling?

A. Decoupling is the term used to define a rate design that is designed to disconnect a utility's earnings or revenue from sales of energy or commodity. Decoupled rates can be designed to eliminate or reduce the utility's disincentive to encourage energy conservation, impacts of the business cycle and/or the effects of weather.

Q. Have you reviewed specific decoupled rate design proposals in other jurisdictions?

A. I have reviewed proposals for decoupled electric and gas rate designs in Delaware for the Staff of the Delaware Public Service Commission where I am also assisting in the pre-implementation education process. I have also reviewed decoupling proposals by gas utilities and offered testimony in Maryland for the People's Counsel and in Michigan for the Attorney General. In addition, I assisted the Staff of the District of Columbia Public Service Commission in the evaluation and implementation of a decoupled rate design for delivery of electricity.

Q. When a regulatory commission implements a decoupling proposal, is there a compensating benefit to customers?

A. When certain forms of decoupling are implemented customers subject to decoupling usually see at least two benefits. The utility's return on equity is reduced by 0 to 50 basis points to reflect the reduced business risk that is the result of a more stable revenue stream to the utility. The second benefit that commonly precedes or occurs simultaneously with a decoupling proposal is an aggressive utility sponsored or supported energy efficiency program to assist customers within the rate class to reduce their energy consumption and energy costs.

Q. Please describe the Company's decoupling proposal.

A. The Company's proposal is to establish an Efficiency and Infrastructure Account ("EIA") mechanism[1] that is focused on recovering fixed revenue per customer[2] on an annual basis.[3] The proposed EIA would exclude fuel and transmission charges because those areas are already subject to an adjustment mechanism or annual formula.[4] The EIA is

[1] Snook Direct 1:25
[2] Snook Direct 14:8 and Snook Direct Attachment LRS-1, page 2
[3] Snook Direct 15:7
[4] Snook Direct 15:19

proposed to include all customer classes except for street lighting, unmetered accounts and merchant generation station power.[5] For calculation purposes the EIA proposal uses two classes, residential and the applicable remaining non-residential customers, which I call "super" classes for identification.

The calculation of any overrecovery or shortfall is based on the Allowed Fixed Cost Revenue per Customer ($/customer-year) (calculated at the close of a rate case). That rate is multiplied by the average annual number of active meters to develop the Allowed Fixed Cost Recovery per Class ($)[6].

To determine the Actual Recovery of Fixed Costs per Class the EIA proposal then switches to a calculation that multiplies the Actual Annual Sales (kWh) times the Allowed Fixed Cost Revenue per Customer Rate per Class ($/kWh).[7] This calculation is made individually for each of the two "super" classes. The EIA proposal aggregates all underrecovery or overrecovery (from the two "super" classes) on an annual basis and recovers or repays those sums over the following twelve-month period beginning March 1st. The process would lump together all amounts from the two "super" classes and recover/repay the amount from all classes covered by the EIA on an equal percentage of total bill basis.[8]

In the event of overrecovery there would be no cap on the repayments. If underrecovery occurs, the repayment cap would be 3 percent[9] with the remaining balance plus interest carried to the next period.[10]

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[5] Snook Direct 17:6
[6] Snook Direct Attachment LRS-1, page 2, Item 3
[7] This value is also calculated at the completion of a rate case based on Test Year data. Snook Direct Attachment LRS-1, page 2, Item 2
[8] Snook Direct 19:11
[9] Snook Direct 21:11

Q. Is the switch from revenue per customer to revenue per kWh a flaw within the Company's EIA proposal?

A. From the Company's standpoint there is no flaw. The switch in basis provides the Company with recovery of lost fixed costs that occur from its energy efficiency program along with any changes in sales due to weather, economic conditions and/or other events. The methodology proposed transfers the Company's existing business risks due to weather and economic conditions to its customers.

Q. The Company describes its decoupling proposal as "modernizing" its rate structure. Is this accurate?

A. No. The Company is not proposing to significantly change its rate structure. For example it is not proposing to use any of the capabilities of its investment in advanced metering infrastructure ("AMI") to measure demand and apply a new distribution rate form to additional customers, instead its EIA proposal is a band-aid.

Q. What elements of the Company's revenue stream would be covered by the Company's revenue decoupling proposal?

A. Using the breakdown of costs from a Staff data request,[11] the Company is proposing to decouple the following cost areas:

- Production Demand
- Regulatory Assets
- Distribution
- Customer Management
    - Customer accounts and sales

[10] Snook Direct Attachment LRS-1, page 3, Item 4
[11] APS Response to Staff Data Request 3.27

- Metering
- Billing
- Meter Reading
- System Benefits[12]

Q. What elements of the Company's revenue stream would not be covered by the Company's decoupling proposal?

A. The Company is proposing not to decouple the following cost areas because they are already subject to adjustment mechanisms[13]:

- Energy
- Transmission

Q. What risks would be shifted from the Company to customers under the Company's revenue decoupling proposal?

A. The Company's EIA proposal compares the revenue per customer from the test year to actual annual energy sales times the test year rate. Any deviation from Test Year per customer sales is recaptured or repaid. This mechanism does not differentiate between changes in sales due to weather, economic activity or conservation. Therefore, the Company's proposal shifts all of these risks to its customers.

[12] APS Response to Staff Data Request 10.1
[13] Snook Direct 15:18

Q. Does the Company's cost of capital witness William Avera analyze the stability of the Company's revenue stream?

A. My review of that testimony did not find any analysis except for a discussion of attrition. He discusses mechanisms that shift away from volumetric recovery of fixed costs "preclude the prospects of greater earnings due to higher consumption."[14]

Q. Does the Company offer an adjustment in its return on equity to reflect its proposal to shift weather and economic risk to customers?

A. The Company witness Avera opines, "... there is certainly no evidence to suggest that these provisions would justify any adjustment to the ROE range determined earlier."[15]

Q. Can revenue decoupling aggravate the impact of adverse weather or economic conditions?

A. One year after a cool summer, the customer would receive a rate increase to recapture the Company's revenue shortfall. If a cool summer is then followed by a hot summer, the Company's proposed EIA would pancake the cost recovery on top of consumption increased by weather and increase the costs above what customers would have expected, thus creating a real detriment. A similar situation would occur during a multi-year economic recession.

Q. Is there any mechanism within the Company's decoupling proposal to adjust for increasing productivity by the Company over time?

A. No. The EIA proposal fixes all elements of the calculation based on the rate case Test Year. In this case that would be calendar 2010. As the Company increases its productivity the EIA would not change. For example, as the Company continued its

[14] Avera Direct 75:20
[15] Avera Direct 76:8

rollout of AMI throughout its service territory in 2012 and 2013 and changed its processes[16] to reduce its customer service and metering costs the EIA cost recovery component would not change and customers would see no productivity benefits.

Q. What areas of the Company's revenue do not require revenue decoupling?

A. Based on my analysis the following cost areas do not require decoupling protection in whole or in part:

- Production Demand
- Energy
- Regulatory Assets
- Transmission
- Distribution (partial)
- Customer Management
  - Customer Accounts and Sales
  - Metering
  - Billing
  - Meter Reading
- System Benefits

Q. What is the Company's forecast for sales?

A. The intent of decoupling is to hold the Company's recovery of fixed costs harmless from sales decreases due to the EE program. The Company's Load Forecast does not show a consistent decline in total sales to retail customers, but an increasing trend.

[16] APS Data Response to Staff 20.5

Year	Retail Sales (MWh)[17]
2011	28,202,200
2012	28,185,608
2013	28,405,734
2014	28,996,045
2015	29,541,216

The output of the Company's generating system is fungible. The generating system is not affected if energy is delivered to a new customer, an existing customer using slightly less energy, non-AZCC jurisdictional customers or sold off-system. Therefore, the Company has many opportunities to sell the output of its generating system and it is planning to do just that as its forecast demonstrates.

Q. Why is decoupling not necessary for Production Demand?

A. As I have demonstrated above, the Company does not forecast any decrease in long-term sales and thus the fungible output of the generating system will be sold to its retail customers per its forecast. In the event that the forecast is wrong the Company has other opportunities to sell the marginal output of its generating system.

Q. Did you explore this issue with the Company?

A. This question was raised during the Company's Technical Conference and a subsequent offline conference. The Company's informal response[18] offers the rationale to include production costs because "The question assumes fixed production costs remain constant and therefore do not increase over time. ... Whether these specific fixed costs increase proportionately with customer growth is another question ..."

[17] APS Data Response to Staff 3.11 APS 14607 (Total Sales less Resale)
[18] Informal Response 1.4

Based on this response, the Company is proposing to apply its decoupling mechanism to production fixed costs in an attempt to derive additional revenue (as the annual number of customers increases) to offset expected capital additions to its current production plant.

The Company's position describes how it has created a revenue raising mechanism unrelated to capital additions and not offset by its concurrent ERA proposal. If the Company's rationale were accepted along with the proposed ERA then double compensation might occur. Therefore, I reject the Company's proposal to decouple production fixed costs.

Q. Why is decoupling not necessary for Regulatory Assets?

A. Regulatory Assets are allocated consistent with Production Demand and Energy and should be treated in the same manner for the same reasons.[19]

Q. Is decoupling needed for distribution revenue?

A. Distribution costs are not as fungible and distribution assets cannot serve other customers within the short term. Therefore a reduction in per customer sales may result in a shortfall in revenues to cover fixed costs. Decoupling is needed to recapture the portion of distribution costs that are collected on a volumetric (per kWh basis). Many of the Company's rate schedules collect distribution costs using demand charges, which will remain constant or change slower than a straight volumetric rate.

For some rate schedules, the Company is proposing to include within the Basic Service Charge ("BSC") a portion of its distribution costs (transformation).[20] If this proposal is accepted then there would be no need to decouple that portion of distribution costs.

[19] ZJF_WP1 and 3 Adjusted Cost of Service Study TYE 12-31-2010, Sheet Cost of Service, Rows 74, 101, 123 and 124

Q. Why is decoupling not necessary for the existing Basic Service Charges?

A. As a customer takes advantage of energy efficiency or distributed generation the BSC is collected (on a per day basis) regardless of usage. Therefore, there is no need to decouple the BSC revenue.

Q. Why is decoupling not necessary for the existing System Benefits charges?

A. The System Benefits charge has generally remained fixed between rate cases, and the Company has not addressed why this precedent should be changed.

Q. Has the Company provided a long-term plan to modernize its rate structure?

A. The Company is proposing a number of modifications to individual rate schedules along with the elimination of some schedules that are used by few customers. However, in light of its installation of AMI, I am surprised that the Company has not presented a rate research plan to determine how the more detailed metering information can be used.

Q. Is the Company subject to an energy efficiency goal?

A. The rules[21] (the "Rules") set cumulative (and incremental) savings (based on prior year sales) as follows:

[20] APS Response to Staff Data Request 3.27 APS 14583
[21] Arizona Administrative Code R14-2-2401, et seq (effective January 1, 2011)

Year	Cumulative Savings %[22]	Incremental Savings %	Prorated Incremental Savings %	Prorated Cumulative Savings %
2011	1.25	1.25	Not applicable	Not applicable
2012	3.00	1.75	0.875	0.875
2013	5.00	2.00	2.00	2.875
2014	7.25	2.25	2.25	5.125
2015	9.50	2.25	2.25	7.375

Q. Is energy efficiency cost effective for customers?

A. Yes. The analyses explored during the decoupling workshop proceedings forecast cost savings for customers as a result of a long-term energy efficiency program.

Q. Has the Company developed an energy efficiency plan?

A. Yes. The Company has proposed its 2012 Revised Demand Side Management Implementation Plan ("Plan"). The Plan is designed to meet the 2012 goal of a 1.75 percent reduction in sales amounting to 533,000 MWh.[23] The Plan provides estimates of the annual MWh saved for residential and non-residential customers.[24] The Plan provides a short description of the Measurement, Evaluation and Research ("MER") component including the contractor and budget.[25] The Company is requesting approval of its Plan before the end of 2011.

[22] Arizona Administrative Code R14-2-2404, Table 1 (effective January 1, 2011)
[23] APS 2012 Revised Demand Side Management Implementation Plan, Docket No. E-01345A-11-0232, Table 2 (June 24, 2011)
[24] APS 2012 Revised Demand Side Management Implementation Plan, Docket No. E-01345A-11-0232, Table 7 (June 24, 2011)
[25] APS 2012 Revised Demand Side Management Implementation Plan Page 38

Q. Without some mechanism would the Company's Plan have a measureable impact on the Company's revenue?

A. Yes. The Rules require reductions in the Company's sales compared to each prior year. Absent a rate case adjustment if the Company meets those goals then a portion of the Company's distribution revenue could be impacted.

Q. What is the impact of APS' 2012 REST Plan?

A. This plan provides details of the Company's program to encourage distributed generation including "behind the meter" generation, which reduces the Company's sales to a customer that installs on-site generation.

Q. How should distributed generation be treated?

A. If the Company can document the "behind the meter" generation that offsets retail sales, as opposed to feeding into the distribution grid to serve other customers, the energy consumed on-site should be treated similarly to energy efficiency. The measurement protocol could include a production meter installed at the interface between the distributed generation and the customer's load (behind the meter). The readings from the production meter would be reduced by any excess energy delivered to the distribution grid.

Q. Have you developed an alternative that addresses the potential for lost distribution revenue as a result of the Company's Plan?

A. I recommend that a decoupling mechanism should be implemented based on lost fixed cost revenue ("LFCR").

Q. What risks would this LFCR mechanism cover?

A. The LFCR mechanism I recommend focuses specifically on the portion of the distribution revenue affected by the Company's compliance with its Plan.

Q. What about risks that arise from weather and changing economic conditions?

A. The Company presently accepts these risks and under the lost fixed cost revenue mechanism the risks remain with the Company; therefore, the Company's risk profile does not change.

Q. How would the lost fixed cost revenue mechanism operate?

A. I would adopt and/or modify certain aspects of the Company's decoupling proposal. These include:

- Use the fixed costs finally determined in this case's Test Year[26]
- Compute the lost fixed cost revenues on an annual basis
- Prorate (normalize) the lost fixed cost recovery revenues for partial year implementation[27]
- Perform the calculation in February and provide at least forty-five days for Staff to review the calculation[28]
- Implement the recovery of lost fixed costs in April for a twelve month period[29]
- Include the same customer classes[30]
- Compute the lost fixed cost revenues separately for residential and other customers (two "super" classes)[31]

[26] Snook Direct 21:23
[27] Snook Direct 21:24
[28] Snook Direct Attachment LRS-1 page 3 Filing and Procedural Deadlines
[29] Snook Direct 21:22
[30] Snook Direct 16:26
[31] Snook Direct Attachment LRS-1 pages 6 and 7

- Apply the recovery mechanism across the board to both of the "super" customer classes[32]
- Cap the annual adjustment for lost fixed cost revenue[33]
- Provide a Compliance Report annually[34]

The LFCR mechanism operates as follows:

- Derive the distribution lost fixed costs per kWh for the two "super" classes (see Attachment HS-2). In response to Staff Data Request 3.27 in APS 14600 the Company calculated the Distribution $/kWh (for example residential distribution is $ 0.0283 per kWh). After the conclusion of this case the Company can adjust the CCOSS to reflect the final decision and update APS 14600.

- Reduce the distribution lost fixed costs per kWh by 75 percent of the more stable distribution demand revenue from the Company's final revenue proof in this case similar to Work Paper CAM_WP13 for each of the two "super" classes (see Attachment HS-3 for the residential example). Although the demand revenue is subject to less impact from energy efficiency, I acknowledge that some energy efficiency efforts will impact demand revenue.

- Reduce the distribution lost fixed cost per kWh by the excess BSC (and adders) compared to the customer management costs as illustrated in Attachment HS-4.

[32] Snook Direct 19:9 and Attachment LRS-1 page 8
[33] Snook Direct 20:26
[34] Snook Direct Attachment LRS-1 page 4 Compliance Reports

- Adopt the energy efficiency goal required by the rules for the previous calendar year. Multiplying the reduction goals by the prior year sales provides the initial estimate of the lost kWh for each of the two "super" classes. Also include the production measured from "behind the meter" distributed generation. Together this is the lost kWh.

- Multiplying the adjusted distribution lost fixed cost per kWh by the lost kWh for each of the two "super" classes computes the lost fixed cost revenue for the prior year. The LFCR are recovered in the same manner as the Company proposed in its EIA (see Attachment HS-5).

- Prorate the LFCR. The lost fixed cost revenues for 2012 would be prorated by the number of days the rates from this case were in effect in 2012. In future years, proration would be necessary to reflect base rate changes and the results of a new test year. The Company recognized this in its Informal Response 1.5.

In the following year the Company must make a retrospective adjustment to its LFCR by providing the results of its MER for the year. Results above the Rules would be capped at 25 percent with the excess available to be carried over to a following period, but still subject to the annual 25 percent excess limitation. Should the MER demonstrate that the Company did not achieve the savings as proposed by its Plan, the Company would refund the overrecovery with interest during the following period.

Q. What are the advantages of the LFCR mechanism?

A. The LFCR mechanism is based upon information readily available within the Company's Test Year filing, updated to reflect the results of this case. The mechanism recognizes the

impact on the Company due to energy efficiency and distributed generation and recovers only the fixed costs that the Company actually loses (distribution) as opposed to all of the Company's non-variable costs. The Company continues to retain its weather and economic risks.

Q. What monitoring do you recommend for the LFCR mechanism?

A. Because any decoupling mechanism is new and untried, I recommend that the Company provide the Staff with quarterly reports (provided thirty days after the end of the quarter) that include an estimate of "saved" kWh and distributed generation and the expected value of the LFCR adjustment for that year. When the MER results are available for the prior year the Company should also apply that information to the calculation.

Q. Do you recommend a customer education plan for decoupling?

A. If either the LFCR or the EIA is approved for implementation the Company should submit a plan to Staff for customer education. In my experience this is an important element to make decoupling understandable to customers.

Q. In the unlikely event that the proposed EIA is approved should there be additional safeguards?

A. Yes, the EIA transfers a significant amount of risks such as weather and economic conditions from the Company to customers at a high per kilowatt hour rate and there could be detrimental effects.

Q. What additional safeguards should be included for the EIA?

A. The Staff should perform or have a consultant perform an annual review of the EIA mechanism, the Company's efforts to meet energy efficiency and distributed energy goals

and the impact of the EIA on customers and the Company. The Company should fund this review.

Q. Should there be an earning surveillance mechanism for the Company if the EIA is implemented?

A. Yes. A decoupling mechanism is designed to correct disincentives, not enrich the Company. The implementation of the EIA can have unintended consequences and therefore earnings surveillance should be required.

Q. Do you have concerns about the existing, inactive but connected residential homes?

A. The present economic conditions have left the Company with "41,404 installed residential meters … currently inactive as of August 17, 2011."[35] These meters are installed on residential locations that have service drops, distribution facilities and transformation in place and are in ratebase. At the conclusion of this case, the distribution lost fixed cost per kWh rate for residential customers would include the costs of these assets. Reconnection of these inactive locations would incur incremental costs for meter reading, billing and customer accounting (all covered by the BSC collected) but no incremental cost for the distribution facilities already in place. This is one of the reasons for my recommendation for earnings surveillance.

Q. Should the EIA be time limited?

A. The ACC Policy Statement suggests, "In lieu of pilot adoption, an initial three-year review period should be utilized which allows for evaluation and redress of decoupling models and related issues."[36]

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[35] APS Data Response to Staff 6.28

[36] ACC Policy Statement Regarding Utility Disincentives to Energy Efficiency and Decoupled Rate Structures – paragraph 5

The Rules provide for annual reductions based on prior year sales that become cumulative and therefore the decoupling adjustment becomes larger each year. At the same time the 2010 Test Year costs become stale due to innovation and productivity improvements such as the distribution and customer management benefits that derive from AMI. The EIA shifts weather and economic risks to customers. Further the EIA rewards the Company with a substantially larger per kilowatt hour rate. Together the EIA could have a massive effect over time. Therefore the EIA should expire at the end of three years to avoid an adjustment factor on customers' bills that may optically seem larger than their perceived savings due to conservation. The Company would have the ability to petition the Commission to retain the EIA.

Q. How long should decoupling (whether an EIA or a LFCR) remain in place?

A. While the Company characterizes decoupling as modernizing the rate structure[37] it is merely a band-aid on an old rate structure. The Company does offer demand based rate structures for some rate classes and subclasses but with the advent of AMI it now has the technical capability to change from a volumetric focused rate structure.

Due to the complexity of the Company's tariff, frozen rate schedules and the advent of AMI, the Company should have offered a long-term process to modernize its tariff including consideration of higher demand charges in the short term and the examination of straight fixed variable ("SFV") or modified SFV rates for all or a portion (distribution) of its rate structure in the long term.

Changing the foundation of the rate structure requires research and an effective customer education plan to demonstrate to customers that they have the capability to reduce both

[37] Snook Direct 14:10

their demand and energy consumption and a corresponding rate structure that accurately charges for those elements.

Over time a true modern rate structure will obviate the need for a decoupling mechanism. If the rate research effort is executed appropriately the decoupling mechanism can be eliminated before its effects become too large to avoid a negative public perception.

Q. **Does this conclude your testimony?**

A. Yes.

Direct Testimony of Howard Solganick
Docket No. E-01345A-11-0224
Attachment HS-1

Testimony - Howard Solganick

Public Service Commission of Delaware
Case - Delmarva Power & Light Company Docket No. 10-237 (October 2010)
Client - Staff of the Delaware Public Service Commission
Scope - Testimony covered cost of service, revenue allocation, rate design and other related issues including revenue stabilization and miscellaneous charges.

Case - Delmarva Power & Light Company Docket No. 09-414 (February 2010)
Client - Staff of the Delaware Public Service Commission
Scope - Testimony covered cost of service, revenue allocation, rate design and other related issues including revenue stabilization and weather normalization.

Case - Delmarva Power & Light Company Docket No. 09-277T (November 2009)
Client - Staff of the Delaware Public Service Commission
Scope - Testimony covered an analysis of a straight fixed variable rate design for small gas customers and implementation issues.

Case - Delmarva Power & Light Company Docket No. 06-284 (January 2007)
Client - Staff of the Delaware Public Service Commission
Scope - Testimony covered cost of service, revenue allocation, rate design and other related issues including revenue stabilization or normalization.

Georgia Public Service Commission
Case – Atlanta Gas Light Company Docket No. 31647 (August 2010)
Client – Public Interest Advocacy Staff of the Georgia Public Service Commission
Scope - Testimony covered revenue forecast, cost of service, revenue allocation, rate design and other related issues.

Case – Atmos Energy Corporation Docket No. 27163 (July 2008)
Client – Public Interest Advocacy Staff of the Georgia Public Service Commission
Scope - Testimony covered rate design and other related issues.

Jamaica (West Indies) Office of Utility Regulation
Case - Electricity Appeals Tribunal (August 2007)
Client - Jamaica public Service Company, Ltd.
Scope - "Witness Statement" on behalf of the Jamaica Public Service Company Limited. This Statement covered issues relating to recovery of expenses incurred due to Hurricane Ivan.

Maine Public Utilities Commission
Case - Northern Utilities, Accelerated Cast Iron Replacement Program Docket No. 2005-813 (2005)
Client - Public Advocate of the State of Maine
Scope - Testimony covered an analysis of the program's economics and implementation.

Public Service Commission of Maryland
Case - Chesapeake Utilities Corporation Case No. 9062 (August 2006)
Client - Office of the Maryland People's Counsel
Scope - Testimony covered cost of service, rate design and other related issues.

Case - Baltimore Gas & Electric's (1993)
Client - As president of the Mid Atlantic Independent Power Producers
Scope - Testimony covered BG&E's capacity procurement plans.

Michigan Public Service Commission
Case - Consumers Energy Company Case No. U-15245 (November 2007)
Client - Attorney General Michael A. Cox (Don Erickson, Esq.)
Scope - Testimony covered cost of service, rate design and revenue allocation.

Case - Consumers Energy Company Case No. U-15190 (July 2007)
Client - Attorney General Michael A. Cox (Don Erickson, Esq.)
Scope - Testimony covered issues related to Consumers Energy's gas revenue decoupling proposal.

Case - Consumers Energy Company Case No. U-15001 (June 2007)
Client - Attorney General Michael A. Cox (Don Erickson, Esq.)
Scope - Testimony covered issues related to Consumers Energy and the MCV Partnership.

Case - Consumers Energy Company Case No. U-14981 (September 2006)
Client - Attorney General Michael A. Cox (Don Erickson, Esq.)
Scope - Testimony covered issues relating to the sale of Consumers interest in the Midland Cogeneration Venture.

Case - Consumers Energy Company Case No. U-14347 (June 2005)
Client - Attorney General Michael A. Cox (Don Erickson, Esq.)
Scope – Testimony covered cost of service and revenue allocation.

Missouri Public Service Commission
Case – AmerenUE Storm Adequacy Review (July 2008)
Client – KEMA/AmerenUE
Scope – Oral testimony covered KEMA's review of AmerenUE's system major storm restoration efforts.

Case – Veolia Energy Kansas City, Inc. File No. HR-2011-0241 (September 2011)
Client – City of Kansas City, Missouri
Scope – Testimony covered various aspects of the Company's tariff provisions and the impact on the City of Kansas City.

New Jersey Board of Public Utilities
Case - Cogeneration and Alternate Energy Docket # 8010-687 (1981)
Case - PURPA Rate Design and Lifeline Docket # 8010-687 (1981)

Case - Atlantic Electric Rate Case - Phases I & II Docket # 822-116 (1982)
Case - Power Supply Contract Litigation – Wilmington Thermal Systems Docket # 2755-89 (1989)
Case - NJBPU Atlantic Electric Rate Case - Phase II (1980-81) Docket # 7911-951 (Before the Commissioners of the New Jersey Board of Public Utilities)
Client - Employer was Atlantic City Electric Company.
Scope - The cases listed above covered load forecasting, capacity planning, load research, cost of service, rate design and power procurement.

Public Utilities Commission of Ohio
Case - The Application of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company Case 07-551-EL-AIR (January 2008)
Client - Ohio Schools Council
Scope - Testimony covers issues related to rate treatment of schools.

Case - The Application of the Columbus Southern Power Company 08-917-EL-SSO and the Ohio Power Company Case 08-918-EL-SSO (October 2008)
Client - Ohio Hospital Association
Scope - Testimony covers issues related to rates for net metering and alternate feed service and related treatment of hospitals.

Pennsylvania Public Utilities Commission
Case - York Water Company Docket No. R-00061322 (July 2006)
Client - Pennsylvania Office of Consumer Advocate
Subject - Testimony covered cost of service, rate design and other related issues, also supported the settlement process.

Case – Pennsylvania- American Water Company Docket No. R-2008-232689 (August 2010)
Client – Municipal Sewer Group
Subject - Testimony covered capacity planning, construction, treatment of future load and associated revenue, cost of service, rate design, capacity fee and other related issues.

Case – Pennsylvania- American Water Company Docket No. R-2008-232689 (August 2008)
Client – Municipal Sewer Group
Subject - Testimony covered cost of service, rate design, capacity fee and other related issues, also supported the settlement process.

Public Utilities Commission of Texas
Case – Determination of Hurricane Restoration Costs Docket No. 36918 (April 2009)
Client – CenterPoint Energy Houston Electric, LLC
Subject – Testimony covered the reasonableness of the client's Hurricane Ike restoration process for an outage covering over two million customers and a restoration period of 18 days.

Net Lost Fixed Cost Revenue per Kilowatthour

Line No.		"Super" Residential	$/kWh	"Super" C & I Customers	$/kWh	General Service	$/kWh	Water Pumping	$/kWh
1	# of Customers (average annual bi	989,989		124,171		122,721		1,450	
2									
3	MWh sold (adjusted)	13,098,283		14,425,069		14,111,761		313,308	
4									
5	Distribution Costs	370,422,838	0.02828	192,480,168	0.01334	190,450,620	0.0135	2,029,549	0.0065
6									
7									
8	Adjustments								
9									
10	Delivery Demand Charge Adjustment ($/kWh)		-0.0014		0	TO BE COMPUTED POST DECISION			
11									
12	Excess BSC Adjustment ($/kWh)		-0.0019		########				
13									
14									
15	Net Lost Fixed Cost ($/kWh)		0.02491		0.01261				

Delivery Demand Charge Adjustment

Line No.	Customer Classification and Current Rate Designation	(A) Billing Determinant	(B) Proposed Delivery Demand $/kW	(C) E-3 E-4 Discount Factor	(D) Annual Delivery Demand Revenue $/year (B)*(C)*(D)
1	**Residential**				
2	ECT-2				
3	Summer	1,969,123	4.004	1.000	7,884,368
4	Winter	1,174,921	2.191	1.000	2,574,252
5					
6					
7	ECT-2 L				
8	Block 1				
9	Summer	261	3.682	0.750	721
10	Winter	911	2.015	0.750	1,377
11	Block 2				
12	Summer	2,472	3.682	1.000	9,102
13	Winter	6,778	2.015	1.000	13,658
14	Block 3				
15	Summer	5,171	3.682	1.000	19,040
16	Winter	10,067	2.015	1.000	20,285
17	Block 4				
18	Summer	58,391	3.682	1.000	214,996
19	Winter	23,149	2.015	1.000	46,645
20					
21	ECT-1R				
22	Summer	2,574,758	4.001	1.000	10,301,607
23	Winter	1,726,284	2.190	1.000	3,780,562
24					
25	ECT-1R L				
26	Block 1				
27	Summer	79	3.612	0.750	214
28	Winter	525	1.977	0.750	778
29	Block 2				
30	Summer	1,259	3.612	1.000	4,548
31	Winter	3,960	1.977	1.000	7,829
32	Block 3				
33	Summer	3,341	3.612	1.000	12,068
34	Winter	7,046	1.977	1.000	13,930
35	Block 4				
36	Summer	38,349	3.612	1.000	138,517
37	Winter	16,111	1.977	1.000	31,851
38					
39	**Total Residential Demand $**				25,076,346
40					
41	Estimated Stability Factor				75.0%
42					
43					
44	Estimated Stable Demand Delivery Revenue				18,807,260
45					
46	Residential MWh Sold (adjusted)				13,098,283
47					
48	Demand Charge Adjustment ($/kWh)				(0.00144)

Customer Classification and Current Rate Designal	(E) Annual Delivery Demand Revenue $/year
C & I Customers	
E-20	
E-30	
E-32 XS	
E-32 S	
E-32 M	
E-32 L	
E-32 TOU XS	
E-32 TOU S	
E-32 TOU M	
E-32 TOU L	
E-34	
E-35	
E-221	
	TO BE COMPUTED POST DECISION
Total C & I Demand $	0
	75%
	-
	14,425,069
	-

Excess Basic Service Charge Adjustment

Line No.	Customer Classification and Current Rate Designation	(A) Average Number of Customers	(B) Proposed BSC $/day	(C) Annual BSC Revenue $/year 365*(B)*(C)
1	**Residential**			
2	E-12	449,101	0.390	63,929,527
3	ET-1	278,353	0.579	58,825,731
4	ET-2	114,450	0.579	24,187,291
5	ECT-2	38,017	0.579	8,034,323
6	ECT-1R	47,380	0.579	10,013,052
7	ET-SP	108	0.579	22,824
8	E-12 Low income	36,296	0.345	4,570,574
9	ET-1 low income	15,267	0.579	3,226,451
10	ET-2 low income	8,588	0.579	1,814,945
11	ECT-2 low income	1,431	0.579	302,420
12	ECT-1R Low income	998	0.579	210,912
13	**Total Residential**	989,989		175,138,051
14				
15				
16	Customer accts/sales			67,807,220
17	Metering			49,235,438
18	Billing			18,765,643
19	Meter Reading			13,931,056
20	Total Customer Mgt Costs			149,739,357
21				
22	Excess BSC Revenue over Customer Mgt Costs			25,398,694
23				
24	"Super" Class MWh Sold (adjusted)			13,098,283
25				
26	BCS Adjustment ($/kWh)			(0.00194)

Customer Classification and Current Rate Designa	(D) Annual BSC Revenue $/year
C & I Customers	
E-20	135,929
E-30	516,999
E-32 XS	20,570,535
E-32 S	12,284,498
E-32 M	2,166,573
E-32 L	593,030
E-32 TOU XS	48,410
E-32 TOU S	78,679
E-32 TOU M	21,891
E-32 TOU L	25,924
E-34	223,112
E-35	104,080
E-221	310,093
Total C & I	37,079,753
	8,464,918
	13,972,972
	2,342,652
	1,739,147
	26,519,689
	10,560,064
	14,425,069
	(0.00073)

Data Source
(A) CAM_WP13 Schedule H-2 Col (B)
(B) CAM_WP13 Proposed BSC Unbundled Rate by Schedule
Total Customer Management Costs STF 3.27 APS 14600 page 6

Annual Lost Fixed Cost Adjustment Calculation

Line No.		"Super" Residential		"Super" C & I Customers
1	Prior Year Prorated "Savings" (MWh)			
2				
3	Prior Year "Savings" (MWh)			
4				
5	MER Verified Savings			
6	2012 (Prorated)			
7	2013			
8	2014			
9				
10	Total "Savings" (MWh)	0		0
11				
12	Prior Year Prorated Distributed Generation Production			
13				
14	Prior Year Distributed Generation Production			
15	Total Distributed Generation	0		0
16				
17	Total "Lost" Energy	0		0
18				
19	Net Lost Fixed Cost ($/kWh)	0.02491		0.01261
20				
21	Total "Super" Class Lost Fixed Cost Revenue	$0		$0
22				
23	Total Lost Fixed Cost Revenue		$0	
24				
25	Clawback for Excess "Savings"			
26	Interest on Clawback			
27				
28	Net Lost Fixed Cost Revenue		$0	
29				
30	Total Company Revenues Prior Year			
31				
32	Total LFCR Adjustment for Current Period			

BEFORE THE ARIZONA CORPORATION COMMISSION

GARY PIERCE
Chairman
BOB STUMP
Commissioner
SANDRA D. KENNEDY
Commissioner
PAUL NEWMAN
Commissioner
BRENDA BURNS
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	)	DOCKET NO. E-01345A-11-0224

DIRECT

TESTIMONY

OF

MICHAEL J. MCGARRY, SR.

ON BEHALF OF THE

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

NOVEMBER 18, 2011

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EXECUTIVE SUMMARY
ARIZONA PUBLIC SERVICE COMPANY
DOCKET NO. E-01345A-11-0224

ENVIRONMENTAL AND RELIABILITY ACCOUNT (ERA)

Arizona Public Service Company ("APS" or "Company") is proposing to implement what the Company has named the Environmental and Reliability Account ("ERA"), an infrastructure tracker mechanism, to recover the capital costs for environmental projects which the Company claims will be necessary to meet "increasingly stringent environmental rules" for APS to be compliant with environmental mandates required or anticipated to be required by federal, state, tribal, and local laws or regulations. In addition, the Company is proposing to include significant generation plant capacity acquisitions or additions. Finally, the Company is proposing to eliminate the Environmental Improvement Surcharge ("EIS"), which is currently in place and provides revenues to APS to offset the cost of certain environmental projects.

The investments the Company proposes to include in the ERA are projects that are placed in service after the new rates go into effect and as such are not reflected in this case. The Company is proposing an ERA as a means to recover costs associated with increasingly stringent environmental rules, which will require the Company to invest a significant amount of capital to remain in compliance with environmental regulations. The ERA would begin in March 2013 with the Company's initial filing and be included in customer bills beginning with the first billing cycle for April 2013. The Company estimates the first ERA could range from an increase of 0.0045 percent to 2.2805 percent depending on whether the Arizona Corporation Commission ("Commission") allows inclusion of the costs associated with APS' acquisition of Four Corners.

Utilities Division Staff ("Staff") is recommending that the Commission reject the ERA as being overly broad and includes costs not typical for a tracker and does not conform to precedence established in previous cases. Further, Staff is recommending the Commission reject the recommendation to eliminate the EIS.

POWER SUPPLY ADJUSTOR ("PSA")

APS proposes two modifications to the current PSA. The first is to eliminate the current 90/10 sharing provision required by the Plan of Administration ("POA"). The 90/10 sharing provision was intended by the Commission to encourage prudent management by APS in the procurement of fuel. The second modification is to include in the PSA the cost of certain chemicals needed to operate environmental equipment at Company power plants.

Staff is recommending the Commission accept the Company's proposal to eliminate the 90/10 provision. However, Staff is also recommending a change to the interest calculation for over and under recoveries to provide incentive for the Company to manage those over/under-recoveries. With respect to the request for certain chemicals to be included, Staff is recommending the Commission reject the Company's proposal.

Staff is also recommending the Commission accept the revised base fuel costs ($909.370 million or $3.2071¢ per kWh) as presented by the Company in its response to STF 22.9.

TRANSMISSION COST ADJUSTOR ("TCA")

APS proposes two modifications to the current TCA. The first is to remove the unbundled transmission services charges from the individual rate plans and consolidate these charges in the TCA along with the other transmission charges already processed through the TCA. The second is to reset the charges in the TCA according to and at the time of FERC's annual establishment of the adjustor rate without additional action by the Commission.

Staff is recommending that the Commission reject the Company's proposal to consolidate the unbundled transmission services charges in the TCA. The Company has not demonstrated any particular benefit for this change. With respect to the implementation date, Staff is recommending approval of the request as that date is determined by FERC.

SERVICE SCHEDULES

In general, there were no concerns regarding APS' proposed changes to the existing service schedules. Issues and approval associated with Service Schedule 3 - Conditions Governing Extensions of Electric Distribution Lines and Services is being addressed in a separate proceeding, Docket No. E-01345A-11-0207.

However, Staff has a recommendation for Service Schedule 1 and recommends rejecting Service Schedule 9. With respect to Service Schedule 1, Staff is recommending that the Company present as part of its next rate case a cost study to show the appropriateness of the various charges, such as meter reread, in light of the Company investment and deployment of AMI. With respect to Service Schedule 9 which encourages economic development by offering discounts to large general service customers who may be attracted to APS' service territory and bring new jobs and economic benefits, Staff is recommending that these discounts be handled through individual special contract offers where Staff and other interest parties can evaluate the proposed offer and make specific recommendations to the Commission on the costs and benefits of the specific special contract.

INTRODUCTION

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

A. My name is Michael J. McGarry, Sr. I am President and CEO of Blue Ridge Consulting Services, Inc. My business address is 2131 Woodruff Road, Suite 2100, PMB 309, Greenville, SC 29607.

BACKGROUND AND QUALIFICATIONS

Q. Please state your experience and educational background.

A. I have been President of Blue Ridge Consulting Services, Inc. since 2004. In my career, I have overseen or been part of numerous rate case audits, prudency reviews, and management and operational audits. I have worked with clients to manage various aspects of the regulatory and rate case process; prepared supporting analyses and testimony for submission to regulatory bodies and interveners; prepared revenue requirement and cost of service analyses; and developed complex revenue requirement models to present alternative positions to a utility's proposed rate request. Prior to assuming my present position, I was Vice President of East Coast Operations from July 2003 to June 2004 with Hawks, Giffels & Pullin (HGP), Inc. In that position, I was responsible for developing and overseeing client engagements in utility regulatory affairs, management audits, and rate case management. From August 2001 to July 2003, I was an independent consultant working on a number of different projects, including a renewal/update of delivery service tariffs for Illinois Power and several utility street lighting cost benefit assessment projects. From June 2000 until August 2001, I was a senior consultant with Denali Consulting, Inc., a utility supply chain and e-procurement strategy and implementation firm. From October 1997 through June 2000, I was employed by Navigant Consulting, Inc. and several of its predecessors or acquired firms working on a number of different projects, including a management audit of Southern Connecticut Gas Company and the original delivery

service tariff filing for Illinois Power. From July 1985 through October 1997, I was employed by the New York State Department of Public Service ("NYSDPS") in its Utility Operational Audit Section in which the staff conducted focused operational audits in many facets of utility operations for all sectors of the utility industry, including gas, electric, telecommunications, and water. Prior to my employment with the NYSDPS, I was a rate analyst with Orange and Rockland Utilities (1981 to 1983) and then Seminole Electric Cooperative (1983 to 1985). I received my Masters of Business Administration from the State University of New York at Buffalo in 1996 and a Bachelor of Arts in Economics from Potsdam College (SUNY) in 1981.

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

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

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

A. No.

Q. Have you testified before commissions in other jurisdictions?

A. Yes. I have presented or supported testimony in Colorado, Delaware, Illinois, Maine, Maryland, Michigan, Missouri, New York, North Dakota, Nova Scotia, Ohio, Pennsylvania, and Utah. These proceedings included testimony involving revenue requirements, power supply costs, management decisions and prudence impacts, operations and maintenance expenses, capital investments, and project management. A complete list is included in Attachment MJM-1.

I have also presented topics before staff groups from regulatory commissions, NARUC sub-committee groups, and as a program faculty member for the Institute of Public Utilities at Michigan State University during the last two years. Topics presented include management auditing and prudence reviews, service company costs and allocations, forecasting methodology and modeling, revenue requirements, rate base, and price regulation theory.

PURPOSE OF TESTIMONY

Q. On whose behalf are you testifying?

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

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

A. I am presenting the Staff's position with respect to (1) Arizona Public Service Company's ("APS" or "Company") proposed Environmental and Reliability Adjustment ("ERA"), including the Company's proposed elimination of the Environmental Improvemental Surcharge ("EIS"), (2) APS' proposed changes to the Power Supply Adjustor ("PSA"), (3) APS' proposed changes to the Transmission Cost Adjustor ("TCA") and (4) discussion of my findings and conclusions related to certain Service Schedules.

Q. Was this testimony and the supporting analyses prepared by you or under your direct supervision?

A. Yes, it was.

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

A. I have reviewed the Company's testimony and exhibits and data request responses provided by the Company.

CONTENT OF ATTACHMENTS TO TESTIMONY

Q. Have you attached any exhibits to your testimony?

A. Yes. The following Exhibits are included with my testimony.

MJM-1	Michael J. McGarry, Sr. Experience and Qualifications
MJM-2	The Environmental and Reliability Account Plan of Administration, Leland R. Snook, Attachment LRS-3
MJM-3	Monthly PSA Balance – Interest Comparison Calculation, 2008, 2009, 2010
MJM-4	APS Response to Staff Data Request STF 14 and STF 18
MJM-5	Company response to Staff Data Request STF12.2.
MJM-6	Company response to Staff Data Request STF 4.2.
MJM-7	Company response to Staff Data Request STF 4.3.
MJM-8	National Regulatory Research Institute paper dated September 2009.
MJM-9	December 2008, 2009, and 2010 Power Supply Adjustor Reports.
MJM-10	Workpaper PME-WP2.
MJM-11	Company response to Staff Data Request STF 22.9 supplemental
MJM-12	Company response to Staff Data Request STF 31.1
MJM-13	Company response to Staff Data Request STF 28.1

ENVIRONMENTAL AND RELIABILITY ACCOUNT ("ERA")

Q. Please describe the ERA proposed by the Company.

A. APS is proposing to implement what the Company has named the ERA,[1] an infrastructure tracker mechanism, to recover the capital costs for environmental projects which the Company claims will be necessary to meet "increasingly stringent environmental rules"[2] for APS to be compliant with environmental mandates required, or anticipated to be

[1] Direct testimony of Leland R. Snook, page 24, lines 17-20.
[2] Direct testimony of Leland R. Snook, page 23, line 19.

required, by federal, state, tribal, local laws, or regulations. In addition, the Company is proposing to include significant generation plant capacity acquisitions or additions.[3] The investments the Company proposes to include in the ERA are projects that are placed in service after the new rates go into effect and as such are not reflected in this case.[4]

Q. Why does the Company believe that an ERA is necessary?

A. The Company is proposing an ERA as a means to recover costs associated with possibly increasingly stringent environmental rules, which the Company claims will require it to invest a significant amount of capital to remain in compliance with environmental regulations.[5] APS states that it will invest significant capital in what it classifies as "qualified investments"[6] that will not be eligible for recovery from the ratepayer in ratebase until the next ratecase.[7] The ERA would allow APS to recover the return on and return of the investments, along with other costs, between rate cases through the use of a surcharge or tracker. APS believes that this recovery will allow them to secure capital funds at a more reasonable rate[8] because the investment community will look more favorably on this type of mechanism since it provides revenue to the Company and reduces the regulatory lag.

[3] Direct testimony of Leland R. Snook, page 24, lines 17-20.
[4] Direct testimony of Leland R. Snook, page 23, lines 23-24.
[5] Direct testimony of Leland R. Snook, page 23 lines 17-21.
[6] Exhibit ____ (MJM-2) The Environmental and Reliability Account Plan of Administration, Leland R. Snook, Attachment LRS-3.
[7] Direct testimony of Leland R. Snook, page 24, lines 22-23.
[8] Direct testimony of Leland R. Snook, page 25, lines 12-13.

Q. Is APS' proposal intended to recover only the qualified capital investments in Environmental projects?

A. No. The Company proposes to recover both the return ***on*** the capital investment as well as the return ***of*** the investment through depreciation expense. In addition, APS is proposing to include the revenue requirement components of these projects, including income and property taxes, deferred taxes, tax credits where appropriate, and operations and maintenance expenses ("O&M").[9] [10]

Q. What types of investments is APS proposing to include in the ERA?

A. APS Witness Leland R. Snook stated in his direct testimony, the Company intends to include:

> "Environmental improvement projects which are designed to comply with current or prospective environmental standards required by federal, state, tribal, or local laws or regulations. These standards and criteria for water, waste, and air include but are not limited to new and expected limits for carbon dioxide (CO2), sulfur oxide (SOx), nitrogen oxide (NOx), particulate matter (PM), volatile organic compounds (VOC) and toxics such as mercury (Hg), coal ash management, and requirements under the clean and safe drinking water acts;
>
> And,
>
> "Generation plant capacity acquisitions, efficiency projects or the construction of new generating plant. For example, APS' pending acquisition of Southern California Edison's share of Four Corners Units 4 and 5 would be Qualified Investments for inclusion in the ERA in the year following the close of the transaction."[11]

[9] Exhibit ____ (MJM-2) The Environmental and Reliability Account Plan of Administration, Leland R. Snook, Attachment LRS-3.
[10] Direct testimony of Leland R. Snook, page 26, lines 19-25.
[11] Direct testimony of Leland R. Snook, page 25, lines 21-26 and page 26, line 1-8.

Q. How will the ERA work?

A. Beginning on March 1, 2013, and each year thereafter,[12] the Company will submit its annual ERA filing. The filing will include the percentage to be recovered from customers based on the prior calendar year along with supporting detail. The rate will become effective with the first billing cycle for April unless suspended by the Commission.[13] This filing will be in accordance with the procedures and calculations submitted by APS included in the ERA Plan of Administration.[14] As proposed, the Commission Staff and any interested party would have only 30 days from the ERA filing on March 1st to the first billing cycle in April to review the new rate before the Commission would approve the rate. The amount of the surcharge would be based on a typical revenue requirement calculation for the "qualified investments" and then be applied as a percent increase to all customer bills based on the relationship of the ERA revenue requirement to total customer revenues. Included as Exhibit____ (MJM-2) is a copy the ERA Plan of Administration. Page 6 of 6 shows the methodology of the proposed calculation.

Q. When would the ERA start?

A. As mentioned above, the first filing would be March 1, 2013, with the first surcharge being included in customer's bills commencing with the April 2013 billing cycle.

Q. Did the Company provide an initial estimate of what the ERA surcharge would be in April 2013 with its filing?

A. No. However, through the discovery process, Staff requested that APS provide an initial estimate.

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[12] Exhibit ___ (MJM-5) See Response to Staff Data Requests STF 12.2.
[13] Direct testimony of Leland R. Snook, page 27, lines 11-18.
[14] Exhibit ____ (MJM-2) The Environmental and Reliability Account Plan of Administration, Leland R. Snook, Attachment LRS-3.

Q. What will be the estimated charge to customers for the initial ERA?

A. APS estimates that the initial revenue requirement for the ERA will be $133,305, which is based on a net plant of $772,086 and a pre-tax weighted cost of capital of 12.748 percent, resulting in a composite return on the investment of $98,426. Including depreciation expense ($29,201) and property tax ($5,678), the total estimate revenue requirement of $133,305.[15] This amount **does not** include the Company's proposed investment in Four Corners. The resulting impact on customer bills is estimated to be a surcharge amount of 0.0045 percent.[16] However, if the Commission approves the Company's proposals for the ERA and the investment in Four Corners, the ERA could have a significant impact on customer bills. Based on the Company's estimate, the revenue requirement for the ERA, if Four Corners is included, would increase to $67,166,099 or a 2.2805 percent surcharge on customer bills beginning with the April 2013 billing cycle.[17]

Q. Are any of the projects included in the estimated ERA calculation mandatory?

A. Neither project included in the initial estimate of the ERA calculation appears to be mandated by any Federal, State, Local, Tribal, or other entity.

Q. How would APS propose to define "qualified investments"?

A. APS would define a "qualified investment" for purposes of inclusion in the ERA as follows:[18]

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[15] Exhibit ___(MJM-5) Company response to Staff Data Request STF 12.2 Schedule 2 Page 1 of 2 (APS14759).
[16] Exhibit ___(MJM-5) Company response to Staff Data Request STF 12.2 Schedule 2 Page 1 of 2 line 16 (APS14759).
[17] Exhibit ___(MJM-5) Company response to Staff Data Request STF 12.2 Schedule 2 Page 2 of 2 line 16 (APS14759).
[18] *Exhibit ____ (MJM-2)* The Environmental and Reliability Account Plan of Administration, Leland R. Snook, Attachment LRS-3.

- Investments in Environmental Improvement Projects and Generation plant that are classified in one or more of the FERC plant accounts (300 accounts), can be tracked by specific project number, and exceed $500,000 in capital investment on an Arizona Jurisdictional basis.[19]

- Qualified Improvement projects designed to comply with current or prospective environmental standards required by federal, state, tribal or local law, and regulation.[20]

- Generation plant capacity acquisitions, existing generating plant efficiency projects, or the construction of new generating plant.[21]

Q. In your opinion, is the ERA intended as a form of interim rate relief between rate cases?

A. Yes.

Q. The Company already has an EIS mechanism in place as a result of Commission Decision No. 69663. What is the difference between the proposed ERA and the current EIS?

A. The EIS collects a fixed nominal rate ($.000016/kWh) from all customers.[22] Collections offset project costs and are recorded as a contribution in aid of construction ("CIAC").[23] The ERA is an adjustor mechanism with a broader scope than the EIS and is designed to collect expenses associated with qualified environmental improvement projects as well as

[19] Exhibit ____ (MJM-2) The Environmental and Reliability Account Plan of Administration, Leland R. Snook, Attachment LRS-3.
[20] Direct testimony of Leland R. Snook, page 25, lines 21-23.
[21] Direct testimony of Leland R. Snook, page 26, lines 3-4.
[22] Exhibit_____(MJM-6) Company response to Staff Data Request STF 4.2.
[23] Direct testimony of Leland R. Snook, page 28, lines 16-17.

reliability-related capital costs associated with generation plant capacity acquisitions, existing generation plant efficiency projects, or the construction of new generation plant.[24] [25] The rate charged to the customer under the ERA is variable and will change April 1.[26] The cash generated from customers under the ERA will be recorded as revenue.

Q. Did the Company give specific reasons that it is now proposing a mechanism to replace the EIS?

A. The Company gave the following reasons why the ERA should replace the EIS:

- Recovering expanded costs over time would smooth the customer bill impact of environmental upgrades and reliability additions, resulting in more gradual base rate increases over time and potentially less frequent general rate cases relative to what they would have been absent the ERA.[27]

- The ERA would provide more accurate price signals to customers by better aligning the Company rates with its costs in a timelier manner.[28]

- Customers benefit from the environmental and generation assets, whose revenue requirement would be recovered through the ERA.[29]

- Unlike the cap imposed in the EIS, the ERA more accurately reflects the costs associated with making investments in qualified projects.

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[24] Exhibit ____(MJM-6) Company response to Staff Data Request STF 4.2.
[25] Direct testimony of Leland R. Snook, page 28, lines 19-21.
Exhibit ____ (MJM-2) The Environmental and Reliability Account Plan of Administration, Leland R. Snook, Attachment LRS-3.
[27] Exhibit ____(MJM-7) Company response to Staff Data Request STF 4.3.
[28] Exhibit ____(MJM-7) Company response to Staff Data Request STF 4.3.
[29] Exhibit ____(MJM-7) Company response to Staff Data Request STF 4.3.

- Providing timely recovery of required environmental improvement projects and generation plant capacity acquisitions will better enable the Company to secure capital at a reasonable cost and make these capital investments.[30]

Q. What issues should the Commission consider when deciding whether to approve a cost tracker such as the ERA?

A. To allow a cost tracker which provides a utility the opportunity to collect additional revenues outside the normal rate case process should be based on individual utility circumstances and not on a one-plan fits all method. Any utility would want a cost tracker as it avoids and mitigates the impact that the regulatory process, often referred to as regulatory lag, has on a utility's ability to earn its allowed rate of return. A tracker has the ability to provide additional funds for operation which may reduce the need for short-term debt, thus saving ratepayers interest costs. However, these reasons alone are not sufficient to circumvent the regulatory process. There are significant downsides to cost trackers.

Q. What are the downsides of a cost tracker such as the ERA?

A. The disadvantages related to cost tracker overuse include:

- Weakening the incentive of a utility to control costs
- Undercutting the positive effects of regulatory lag
- Biasing a utility's technological and investment decisions
- Motivating utilities to shift more costs to functions subject to trackers, diluting frequency and quality of cost reviews
- Having the tendency to be more complicated and burdensome to both the Commission staff and to consumers

[30] Exhibit ____(MJM-8) National Regulatory Research Institute paper dated September 2009.

- Producing a negative perception by consumers due to more frequent press reports of "rate increase"

Q. Under what circumstances might the Commission approve a tracker such as the ERA?

A. The primary circumstance in which the Commission should consider approving a tracker such as the ERA would be when the utility is mandated to make significant capital expenditures to meet mandates of others on the utility. As such, federal, state, local, tribal, and other mandates involving significant or extraordinary capital investment to meet environmental statutes, rules, and/or regulations that could significantly harm the utility's financial well-being would be one reason for a tracker. However, the Commission should also consider the ability of the utility to fund the investment either by its own internal cash or financing before asking ratepayers to incur the additional hardship a tracker would place on them. Another important variable would be whether the costs are expected to be volatile, unpredictable, and outside the utility's control and thereby potentially causing significant financial harm to the utility and ultimately its ratepayers. The Commission's PSA fits into this category. The costs are significant and can be volatile, and price spikes from unforeseen events (such as a major hurricane in the Gulf of Mexico) can have a significant impact on the financial health of a utility while also negatively impacting its ratepayers.

Q. Do you recommend that the Commission approve the ERA proposed by APS?

A. No. The Commission should reject the ERA as currently proposed by the Company.

Q. Why?

A. The ERA as presented by APS is too broad and includes capital investments that are not mandated or in anticipation of being mandated by law or regulation. It also includes other types of costs that are not capital in nature such as O&M and property taxes.[31] Trackers are implicitly an interim measure to provide relief to a utility for costs which are mandated, significant, potentially volatile, and out of the utility's control. A tracker is not intended as a permanent fix to make up for the regulatory lag in the ratemaking process.

Q. Are you aware of any extraordinary events where the Commission dealt with the possible effects of a federal mandate that could have had considerable negative impact on a group of utilities?

A. Yes. An example is the circumstances surrounding the arsenic water remediation cases in Arizona.[32] It is my understanding that both Staff and ultimately the Commission were concerned that if the water utilities in Arizona were not provided interim rate relief in the form of a tracker that the financial consequences could have been staggering even to the point of one or more of the utilities filing for bankruptcy. Even worse was the possibility that if a water utility was unable to comply with the EPA mandates, the EPA could have shut down the utility forcing its customers to find other sources of water. A tracker was implemented for water utilities to meet the federal mandates associated with water utilities' ability to install the capital equipment necessary to meet the new and more stringent requirements related to arsenic in Arizona wells which was based on specific circumstances and conditions.[33]

[31] Exhibit ____ (MJM-2) The Environmental and Reliability Account Plan of Administration, Leland R. Snook, Attachment LRS-3.
[32] ACC Decision No. 66400.
[33] ACC Decision No. 66400.

Q. What were those conditions?

A. The conditions under which the Commission approved the tracker included:

- The tracker was temporary and had a two-step filing process.[34]
- The tracker was focused on only those projects related to arsenic remediation.[35]
- The tracker included limited amounts of O&M with a deferral mechanism set up to recover costs at a later date.[36]
- The company would set a specific date for the next rate filing.[37]
- The EPA mandates had severe and significant consequences.[38]

Q. Are the proposed ERA and the Arsenic water mandates similar?

A. No. Both are intended to provide the utilities interim relief between rate cases for capital expenditures that are legally mandated. However, APS' proposed ERA differs significantly in that it may include costs for projects that are not yet mandated (only anticipated); includes non-capital costs not typically included such as depreciation, taxes, and O&M; includes generation projects which are not environmentally related (such as the Four Corners acquisition); and may or may not be significant, as demonstrated by the two estimates of the ERA without Four Corners ($133,305) and with Four Corners ($67.2 million). Notably, APS' tracker would appear to be a permanent tracker updated annually, which is unlike the arsenic water cases, which were temporary and included specific timeframes for rate filings. Finally, the ERA does not afford customers any prescribed protection from substantial rate increases as the result of the tracker and its updates. The

[34] ACC Decision No. 66400, page 21, lines 27-28.
[35] Id., page 22, lines 1-2.
[36] Id., page 6, lines 23-25, page 7, lines 1-2 and page 19, lines 26-28.
[37] Id., page 10, lines 8-10.
[38] ACC Decision No. 66400, page 3, line 26 and page 4, lines 1-4.

Company has not proposed any cap such as the one proposed for the Efficiency and Infrastructure Account ("EIA").[39]

Q. Did you review the Liberty Benchmarking Study ("Study") dated February 28, 2011[40]

A. Yes I did.

Q. Did the study in any way support the use of an ERA?

A. The study was written during the period when the EIS was in effect and included discussions related to Company financing and also environmental emission issues relative to power plants. However, the study did not discuss an infrastructure tracking mechanism.

Q. What did the study discuss that may have had applicability to the EIS?

A. The study discussed how the Company ranked among its peers in nitrogen oxide ("NOX"), sulfur oxide ("SO_2") and carbon dioxide ("CO_2") emissions which could correlate with capital spending

Q. How did the Company rank among its peers?

A. The Company ranked worst in NOX emissions then all of its peers, and ranked best in SO_2 emissions as compared to its peers. CO_2 emissions ranked worst than average among peers.

[39] Direct testimony of Leland R. Snook, page 21, Line 11. Company proposes that the EIA would be capped at 3%.
[40] Benchmarking Study of Arizona Public Service Company's Operations, Cost, and Financial Performance Docket No. E-01345A-08-0172

Q Did Liberty indicate that the APS ranking was problematic?

A. Liberty indicated that most of the problem with CO_2 emissions related to large plants and that they did not see it as necessarily a problem because absolute data can be misleading. In the area of NOX, Liberty did not give a reason why the Company ranked low.

Q What did Liberty recommend?

A. Liberty did not offer recommendations because the Company already had initiatives under way to address the issues.

Q What did Liberty say about the ability of the Company to secure financing?

A. The rate case settlement in 2009 was viewed as a positive from a credit perspective. The Company filed a finance plan with the Commission that proposed streamlined rate cases to mitigate the regulatory lag, along with other measures. As a result Standard & Poor's raised the Company's credit rating to positive for 2010.

Q Can you draw any conclusions from either the environmental discussion or the credit discussion in the study?

A. Yes. It appears that the Company is addressing environmental issues and also its credit rating is improving.

Q Do these conclusions, in your opinion, support changing from the EIS, currently in place, to an ERA?

A. No. The Liberty study was written during the period when the current EIS was in effect. We cannot conclude that the Company's improvements directly or indirectly related to the use of the EIS. However, it is possible that the EIS played a part in the improvement of the benchmarks that Liberty evaluated.

Q Should the Commission approve the ERA as proposed by the Company?

A. No. I recommend that the Commission reject the ERA proposed by APS as the Company has not demonstrated that circumstances warrant an extraordinary action as was the case with the arsenic problem for water utilities.

POWER SUPPLY ADJUSTOR ("PSA")

Q What is the PSA?

A. The PSA is a cost tracking mechanism designed to allow APS to recover costs associated with obtaining power supplies in a more time effective manner due to the short-term volatility in power costs. According to the PSA's Plan of Administration, the PSA:

> "provides for the recovery of fuel and purchased power costs, to the extent that actual fuel and purchased power costs deviate from the amount recovered through APS' Base Cost of Fuel and Purchased Power."[41]

Further, the PSA is:

> "a combination of three rate components that track changes in the cost of obtaining power supplies based upon forward-looking estimates of PSA Costs that are eventually reconciled to actual costs experienced. This PSA allows for special Commission consideration of extreme volatility in costs or recovery by means of a mid-year rate correction, and provides for a reconciliation between actual and estimated costs of the last two months of estimated costs used in Historical Component calculations."[42]

Q Please describe your understanding of the Company's proposal regarding modification to the PSA.

A. APS proposes two modifications to the current PSA. The first is to eliminate the current 90/10 sharing provision required by the Plan of Administration ("POA"). The 90/10

[41] Company Witness Ewen, Direct Testimony, Attachment PME-9, page 1.
[42] Company Witness Ewen, Direct Testimony, Attachment PME-9, pages 7-8.

sharing provision was intended by the Commission to encourage prudent management by APS in the procurement of fuel. The second modification is to include in the PSA the cost of certain chemicals needed to operate environmental equipment at Company power plants.[43]

Q. Please explain the 90/10 sharing mechanism.

A. The 90/10 sharing provision is a Commission-mandated incentive tool to encourage prudent management of fuel procurement. If fuel costs are greater than the base fuel rate, the Company may recover 90 percent of the cost over base. If fuel costs are less than the base fuel rate, the Company may keep 10 percent of the reduction under base.[44]

Q. Has the 90/10 sharing mechanism been effective in encouraging the Company to prudently manage its fuel costs?

A. Without an in-depth study into this question, it is difficult to verify with certainty the effectiveness of the provision. However, from certain facts presented in this case potential conclusions can be drawn. As shown in Mr. Ewen's Direct Testimony at page 15, Chart 1 Pre-Tax Income Effect of 90/10 Sharing Feature of PSA for five of the last six years (2005-2009), fuel costs have been greater than base, keeping APS from recovering the full amount of the cost for fuel. While some of this could be under the management control of the Company, the consistency of the penalty posture year after year would imply that factors other than management control (such as market prices) were also affecting the cost. The Company has noted several items supporting sound procurement practices:

[43] Company Witness Ewen, Direct Testimony, 13:22-25.
[44] Company Witness Ewen, Direct Testimony, 15:5-8.

1. An audit of the Company's fuel procurement practices conducted by Liberty Consulting Group (Liberty) in 2006, evaluated APS' hedging and procurement practices and deemed them to be sound.
2. A recent (2010) Liberty benchmarking study confirmed the results of Liberty's 2006 evaluation.
3. The Commission, through the recent adoption of the new Integrated Resource Planning Rules will effectively approve the Company's proposed resource mix.

Staff notes that the IRP rules provide for the Commission to review and acknowledge a resource plan, but the Commission would not approve the plan.

Q. Have there been other negative consequences because of the 90/10 sharing provision?

A. Yes. The one year when fuel costs were below base was the most recent year—2010. In this year, ratepayers were harmed by the 10 percent adder to fuel costs to pay the Company's incentive. This harm to ratepayers occurred during a year in which the national economy was also struggling, exacerbating the effect of the 10 percent burden ratepayers had to bear.

Q What do you recommend?

A. The 90/10 sharing mechanism should be removed from the PSA to avoid harming ratepayers again during years in which circumstances are similar to those that occurred in 2010.

Q Does your recommendation leave the Company without incentive to manage fuel procurement prudently?

A. No. Utilities in general do what they can to mitigate fuel costs, manage those costs effectively, and leverage their investment in the fuel inventories via a number of management and financial means. However to provide additional incentive to manage over and under recoveries, I am also recommending a change to the applicable interest definition of the PSA POA. This change should add an incentive for the Company to manage fuel procurement prudently without potential harm to ratepayers.

Q What interest application is the subject of your recommendation?

A. The PSA balance changes each month based on the difference of actual power costs to base rate power supply costs. This difference may be an over collection or an under collection based on whether actual costs were greater or less than base costs. Each month interest is calculated on either the over collection (amount due back to ratepayers) or the under collection (additional amount due to the Company). The interest is calculated based on the "Applicable Interest" rate. According to the PSA POA, Applicable Interest is "[b]ased on one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release H-15. The interest rate is adjusted annually on the first business day of the calendar year." This same rate is applied to both over and under collections. For 2010, the rate was set at 0.45 percent.

Q Why would you change this interest rate?

A. The Nominal Treasury Constant Maturities interest rate from the Federal Reserve bears little relationship to PSA over or under collections. To compensate in months where there is an under recovery and the Company had to borrow money on a short-term basis, it would have to pay its short-term borrowing rate. On the other hand, over collections

would reduce the need for the Company to obtain additional short-term cash. Therefore, the average short-term borrowing rate available to the Company during a particular month should be considered in calculating interest on that month's PSA balance.

Q What other factor should be considered in calculating interest on a month's PSA over/under collection balance?

A. There would not be a reason for the Company to be allowed to earn more than its allowed rate of return on equity in any situation when there is an under collection.

Q What, then, should be the interest rate applied to under collections?

A. Considering the factors just discussed concerning short-term borrowing rates and rate of return on equity, for under collections, the interest rate applied to a particular month's PSA balance should be either (1) the average short-term borrowing rate available to the Company for that year or (2) the allowed rate of return on equity, *whichever is lower*. While interest rates are low, the short-term borrowing rate would be applied and, although it has been many years since interest rates were high, the possibility does exist that at some time in the future interest rates could be higher than the Company's allowed rate of return. In that situation, however unlikely at this point in time, the protection to ratepayers to prevent the Company from earning more than its allowed rate of return needs to be in place.

Q What should the interest rate be for over collections?

A. In order to provide incentive for APS to continue to manage its fuel procurement process prudently, the Commission should require the Company to calculate interest on monthly over collection balances at the rate of either (1) the average short-term borrowing rate available to the Company for that year or (2) the allowed rate on common equity,

whichever is greater. The same principles mentioned above apply here. By requiring the Company to pay an interest rate equal to the usually greater rate of return on equity, the Company has an incentive to manage fuel procurement costs well and also to refrain from using the ratepayers as a "bank" for short-term borrowing disguised as over collections.

Q What would the source of the short term borrowing rate be?

A. I would recommend the Company's short term debt rate as published in its 10-K report for September 30 of each year. This should align the rate with the Company's annual PSA filing.

Q Had the interest structure you recommend been in place for 2010, how would the PSA balance have differed?

A. During 2010, both the Forward Component Tracking Account and the Historical Component Tracking Account had over collection balances in every month. Those balances would have triggered the use of the authorized rate of return on equity to calculate interest. Exhibit___ MJM-3 Schedule 1 - 2010, using Company data,[45] shows the calculation of balances for the PSA Forward Component and Historical Component Tracking Accounts (lines 1-16). In the same exhibit schedule (lines 17-32), the same calculations with the same amounts were performed except that the Authorized Rate of Return on Equity was substituted for the current PSA interest rate. The current PSA method for calculating interest had determined $382,000 of interest for 2010 was owed to ratepayers. Using the recommended interest application, $9,778,000 of interest would have been accumulated in 2010 and due to the ratepayers. This is a difference of $9,396,000.

[45] Exhibit____(MJM-9) December 2008, 2009, and 2010 Power Supply Adjustor Reports.

Q Is this a reasonable amount to assume for incentive purposes to promote prudent fuel procurement practices?

A. Yes. The roughly $9 million in interest is only half the penalty paid by the Company under the 90/10 sharing provision in 2006 and 2008, and only one third the penalty of 2007. Additionally, in 2010 under the 90/10 sharing provision, ratepayers were harmed by having to give up $14.5 million (10 percent of the Company's over collection). Had my recommended interest incentive been in place, ratepayers would instead have received $9 million in interest.

Q Have you calculated the impact for a period when there was an under collection?

A. Yes.

Q What was the result of that analysis?

A. Table 1 on the following page shows the impact of my proposed methodology for the three years 2008 through 2010. The Forward and Historical Tracking Accounts for 2008 revealed an under collection balance, while 2009 and 2010 were both years of over collection of base fuel costs. Customers would have owed the Company $1.061 million less in 2008 associated with the under collection of base fuel costs. Customers would have been paid an additional $4.557 million and $9.411 million in 2009 and 2010, respectively, with the change in interest on the over collections in those two years. Based on this illustration using my proposed methodology, customers would have benefitted $15.029 million over the three years. Details of my calculations are included as Exhibit___(MJM-3) Schedules 1 (2010), 2 (2008), and 3 (2009).

Table 1: Effect on PSA Balance with Proposed Interest Rates

Line No	Year	Federal Treasury Rate	APS Short-Term Debt	Difference	Approved ROE	Change to Collection Balance favoring Ratepayers
	(a)	(b)	(c)	(d)	(e)	(f)
1	2008	3.17%	2.24%	-0.0093	10.75%	$1,061
2	2009	0.37%	1.09%	0.0072	10.75%	$4,557
3	2010	0.45%	0.84%	0.0039	11.0%	$9,311
4					Total	$14,929

Q Is your recommendation concerning PSA interest rate being used in any other jurisdiction?

A. While I do not know how many jurisdictions are using this interest rate structure for their fuel cost trackers, I do know that it is being used for utilities with fuel cost trackers in Michigan.[46]

Q Please summarize your recommendation involving the change in PSA application of interest.

A. To reflect more accurately the cost of money and to encourage the Company to minimize over collections, the interest applied monthly to PSA over and under collections should be done in the following manner: (1) for over collections, the interest rate applied should be the greater of the most recently Commission-approved rate of return on equity or the Company's average short-term borrowing rate available to the Company for the year, and (2) for under collections, the interest rate applied should be the lesser of the most recently Commission-approved rate of return on equity or the Company's average short-term borrowing rate available to the Company for the year.

[46] Michigan Compiled Laws (MCL) 460.6(j)(16).

Q Please explain the Company's proposal to include the cost of certain chemicals in the PSA process.

A. APS proposes to include in the PSA those environmental chemical costs that are used in power generation in direct proportion to fuel. These chemicals would include predominantly lime, ammonia, and sulfur "used to scrub the emissions from a coal plant."[47] Based on the association of the chemicals with fuel used in production, APS proposes that "annual changes in the chemical cost expense associated with power plant emission controls be included in the calculation of the PSA deferrals and rate recovery."[48]

Q Do you agree with the Company's reasoning?

A. No. Fuel cost trackers are in place to provide the Company with an opportunity to recover the highly volatile cost and consumption of fuel. Those items included in the fuel cost tracker, therefore, should relate specifically with fuel cost/consumption and not simply with production/generation. Although there is a correlation between fuel costs and the cost of production chemicals, the fluctuation of chemical costs is not as volatile as fuel costs, and it is the volatility of fuel *costs* (not just consumption) that provides much of the justification for having the fuel cost tracker. If the Commission were to allow any costs associated with production/generation to be included in the PSA, it would open the door to other normal operational costs that may have some discernible correlation to production.

Q What is your recommendation?

A. I recommend disallowing the Company's proposal to include chemical costs in the PSA process.

[47] Company Witness Ewen, Direct Testimony, 16:2-5.
[48] Company Witness Ewen, Direct Testimony, 16:7-9.

Q Did you review the details associated with the amounts of fuel costs that APS is requesting in base rates?

A. Yes.

Q What were the results of that analysis?

A. The actual base fuel costs for 2010 was $940.133 million or 3.3486¢ per kWh.[49] Through a series of data requests[50] and a meeting with the Company, I was able to confirm that the information included in the Company's presentation and workpaper PME-WP2[51] matched information contained in the Company's books and records.

Q What is the relationship between the Company's presentation of the actual 2010 base fuel costs and what the Company is proposing for inclusion in base rates in this case?

A. Aside from the informational value of the 2010 actual number and the ability to review whether the actual information ties to the Company's books and records, there is none. The amounts included in the filing for calculating base rates are derived from the Company's 2012 sales and generation forecast models. These forecasting models are complicated and use a number of forecasted inputs such as coal, gas, and nuclear prices along with dispatch requirements, outage information for the generating units, and available interchange resources to develop the necessary resources and costs to meet the Company's customers needs. However, the two pieces of information, the actual base fuel for 2010 and the forecasted amount for 2012, do provide for the ability to see if there is a significant unexplained change that may warrant future investigation. In this case, any significant variances were adequately explained by the Company.

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[49] Attachment PME-3 Page 1 of 4.
[50] Exhibit____(MJM-4) APS response to Staff Data Request STF 14 and STF 18.
[51] Exhibit____(MJM-10) Workpaper PME-WP2

Q Were there any costs that you could determine that should be excluded from the base fuel costs?

A. No. However, I did not review the detailed journal entries and supporting documentation. That scope of work is typically included in a fuel procurement audit which was not included within the scope of this rate case proceeding.

Q Did you review the Company's proposed base fuel rate?

A. Yes.

Q What were the results of that analysis?

A. APS' initial filing included $928.986 million or 3.2415¢ per kWh in its proposed rates.[52] This amount is based on the Company's detailed in-house modeling and forecasting of sales and how it would meet the energy and demand needs of its customers. At a high level, the information provided by APS is not unreasonable. However, during our review of the base fuel costs APS indicated that, as a result of its own internal review of the information included in the base fuel calculation, the Company would update the base fuel numbers to make certain corrections and update its fuel cost analysis for more recent prices and sales forecasts. The Company indicated that it would revise its proposed base fuel costs to $909.4 million or 3.2071¢ per kWh. This represents a reduction of $19.6 million to base fuel costs than that was originally filed.[53]

Q Do you accept this amount?

A. Absent the results of a detail fuel procurement audit, a detailed review of the Company's hedging program and a review of its generation forecasting model, there is no reason to reject this revised amount.

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[52] Attachment PME-3 page 2 of 4.
[53] Exhibit____(MJM-11) Response to Staff Data Request STF 22.9 supplemental.

TRANSMISSION COST ADJUSTOR ("TCA")

Q What is the TCA?

A. The TCA is a cost tracker designed to recover costs associated with changes in the Company's open access transmission tariff.

Q Please describe your understanding of the Company's proposal regarding modification to the TCA.

A. APS proposes two modifications to the current TCA. The first is to remove the unbundled transmission services charges from the individual rate plans and consolidate these charges in the TCA along with the other transmission charges already processed through the TCA.[54] The second is to reset the charges in the TCA according to and at the time of FERC's annual establishment of the adjustor rate without additional action by the Commission.[55]

Q. What reasons does the Company proffer for these modifications?

A. APS states that consolidation of all transmission charges into one rate schedule is justified because the transmission revenue requirement in total is approved by FERC. Therefore, removing all transmission charges from base rates (the domain of the Commission) provides a "clean delineation of these separate rate setting processes."[56] Furthermore, since it is the FERC process that establishes the adjustor rate and additional action by the Commission is not necessary, the change in rate should become effective at the point of FERC approval.[57]

[54] Company Application, 8:3-10.
[55] Company Witness Miessner, Direct Testimony, 30:16-19.
[56] Company Witness Miessner, Direct Testimony, 30:25.
[57] Company Witness Miessner, Direct Testimony, 30:16-19.

Q. What impacting factors should be considered with these TCA proposals?

A. Cost trackers are one way the Commission can assist a utility meet its obligation to provide safe and reliable service at a reasonable cost when those costs are significant, time dependent, volatile and could harm the financial health of the utility. However, as discussed earlier, there are disadvantages related to the over use of cost trackers. Again, these include:

- Weakening the incentive of a utility to control costs
- Undercutting the positive effects of regulatory lag
- Biasing a utility's technological and investment decisions
- Motivating utilities to shift more costs to functions subject to trackers, diluting frequency and quality of cost reviews
- Having the tendency to be more complicated and burdensome to both the Commission staff and to consumers
- Producing a negative perception by consumers due to more frequent press reports of "rate increase"

Although all of these reasons certainly do not apply in the Company's specific proposal in this case, they are concerns which should inform and caution the Commission's general approach to cost trackers. The Commission should consider eligibility criteria for creating and expanding cost trackers. One criterion would be to allow a cost tracker only for extraordinary circumstances, such as costs outside a utility's control, costs that are unpredictable and volatile, and costs that are substantial and recurring. Additionally, another criterion for allowing a cost tracker would be to mitigate severe financial consequences.

Q. In this case, has the Company provided sufficient reason to remove unbundled transmission service charges from base rates?

A. No. While certain efficiencies could be theorized concerning combining all transmission costs in the TCA process, the Company has not provided sufficient compelling reason to abandon the standard base rate process in establishing certain transmission costs. While the Commission is involved in the FERC process for setting the adjustor rate, the Company has not demonstrated how the advantages in public awareness, level of scrutiny, and other possible qualitative controls regarding potential intended or unintended cost shifts, would be maintained as they are currently achieved through Commission review in the standard base rate process.

Q What is your recommendation with respect to unbundling the TCA from base rates?

A. I recommend disallowing the proposed change to move all TCA charges from base rates to the TCA.

Q What is the effect of your recommendation on the Company's revenue requirement?

A. APS reflected its proposal as a change to rate design only. The Company has included the full fair value effect of the amount that would otherwise be reflected in base rates in its revenue requirement and revenue deficiency calculation. For simplification purposes, APS deducted the $129.301 million by rate class in its cost of service study. Schedule H-2 demonstrates the Company's methodology and the following is an excerpt from Schedule H-2 showing that methodology.

ARIZONA PUBLIC SERVICE COMPANY
ANALYSIS OF BASE REVENUES BY DETAILED CLASS
TEST YEAR ENDING DECEMBER 31, 2010, ADJUSTED
Excerpt of Schedule H-2 – Columns F though K only

(F)	(G)	(H)	(I)	(J)	(K)	
	Proposed Revenue			Increase -Base Rates		
	Base	Transmission	Total			
Proposed	Revenues	Revenue [7]	Revenue	Amount		Line
Rate Designation	($000)	($000)	($000)	($000)	%	No.
				(I) - (E)	(J) / (E)	
						1.
E-12	460,759	19,267	480,026	15,668	3.37%	2.
ET-1	459,350	21,553	480,903	18,566	4.02%	3.
ET-2	248,466	11,604	260,070	10,039	4.02%	4.
ECT-2	103,099	5,533	108,632	4,194	4.02%	5.
ECT-1R	119,047	6,250	125,297	4,837	4.02%	6.
ET-SP	219	10	229	8	3.62%	7.
E-12 Low income	29,609	1,434	31,043	2,035	7.02%	8.
ET-1 low income	18,961	997	19,958	1,309	7.02%	9.
ET-2 low income	16,379	753	17,132	1,124	7.02%	10.
ECT-2 low income	3,016	182	3,198	210	7.03%	11.
ECT-1R Low income	1,641	109	1,750	114	6.97%	12.
Total Residential	1,460,546	67,692	1,528,238	58,104	3.95%	13.
						14.
						15.
E-20	3,741	296	4,037	151	3.89%	16.
E-30	1,414	27	1,441	35	2.49%	17.
See note 9						18.
E-32 XS	197,575	6,037	203,612	4,435	2.23%	19.
E-32 S	282,470	13,992	296,462	6,441	2.22%	20.
E-32 M	311,476	14,631	326,107	8,791	2.77%	21.
E-32 L	298,567	13,649	312,216	8,418	2.77%	22.
E-32 TOU XS	626	20	646	13	2.05%	23.
E-32 TOU S	4,371	171	4,542	88	1.98%	24.
E-32 TOU M	6,301	242	6,543	158	2.47%	25.
E-32 TOU L	22,672	880	23,552	635	2.77%	26.
E-34	79,241	3,832	83,073	2,476	3.07%	27.
E-35	110,711	5,070	115,781	3,772	3.37%	28.
Total General Service	1,319,165	58,847	1,378,012	35,413	2.64%	29.
						30.
Irrigation and Water Pumping	25,566	2,069	27,635	966	3.62%	31.
						32.
						33.
E-58	10,340	138	10,478	371	3.67%	34.
E-59	9,651	396	10,047	346	3.57%	35.
Contract 12	1,006	42	1,048	35	3.46%	36.
E-67	174	13	187	9	5.06%	37.
Total Outdoor Lighting	21,171	589	21,760	761	3.62%	38.
						39.
Dusk to Dawn Lighting	8,602	104	8,706	249	2.94%	40.
						41.
	2,835,050	129,301	2,964,351	95,493	3.33%	42.

Q What does this schedule show?

A. Column G, line 42, shows the proposed revenues the Company intends to collect from base rates of $2,835,050,000. The amount shown in column H is the revenue requirement

associated with the portion of the TCA that is in base rates, $129,301,000. The total in Column I is what the Company is proposing to collect from customers, $2,964,351,000 from base rates and the TCA. The Company confirmed[58] that the total in Column I is the full revenues needed to meet the deficiency shown on Schedule A-2. In summary, the Company determined what the total revenue deficiency was with the portion of the TCA still in the revenue requirement and then deducted that amount from the base rates in its rate design as shown in column H above. Working with APS and Staff Witness Ralph Smith, we are confident that no other pro formas or calculation are necessary to reflect our recommendation that Company's proposal to remove the base rate portion of the TCA is needed to establish the revenue requirement. Mr. Smith's revenue requirement should reflect this recommendation.

Q With respect to the Company's proposal to have the effective date of any change in the TCA be the same date as that approved by the Federal Energy Regulatory Commission ("FERC"), what is your position on this proposal?

A. I recommend accepting the Company's proposal to have the TCA rate effective on the approved effective date as set by FERC. This slight change will allow the Company to recover any incremental changes in the TCA revenue requirement and mitigate the impact of any regulatory lag associated with the portion included in base rates. APS shall be required to file a notice with Docket Control that includes its revised TCA tariff, along with a copy of its FERC informational filing of its annual update of transmission service rates pursuant to its Open Access Transmission tariff ("OATT"). This notice should be filed with the Commission at the same time that APS makes its FERC filing. APS could automatically adjust its transmission rates on June 1, unless Staff requests Commission review.

[58] Exhibit____(MJM-12) Company Response to Staff Data Request STF 31.1

SERVICE SCHEDULES

Q What are your findings and conclusions concerning the Company's service schedules?

A. I reviewed the Company's proposed changes to the Service Schedules to determine if there were any customer service or revenue impacts from those changes. In generally, I did not find any problems with the Company's proposed changes to its service schedules. However, I do have some specific comments related to several of the schedules.

Q Please continue.

A. With respect to Service Schedule 1 which contains the terms and conditions for standard offer and direct access, I requested that the Company demonstrate that it had reviewed the charges contained on pages 2 of 18 and 3 of 18 of Schedule 1 in light of the Company's deployment of Advanced Metering Infrastructure ("AMI"). Specifically, I wanted to determine if the Company had reviewed charges such as meter re-read ($16.50 per reread) that will be affected by having remote capabilities to re-read, turn-on, turn-off the meter. The Company indicated the following: (1) Most of the charges included in Service Schedule 1 are based on 2002 test year cost data except "after hours trip charge" which was based on a 2005 test year. (2) Cost reductions associated with AMI are reflected in its proposed revenue requirement in this case. (3) The revenue from these charges on Service Schedule 1 are credited to revenue requirements for ratemaking purposes so any reduction to the charges would require an increase in the revenue requirement for a like amount to recover the test year revenue requirement for these charges.[59] However, the Company intends to revise these charges "in a future rate case when AMI is fully deployed."[60] I am concerned that the Company had an opportunity to evaluate these charges in this case and did not. Revenues associated with just one of these fees is in excess of $4 million. The

[59] Exhibit ____(MJM-13) Company response to Staff Data Request STF 28.1.
[60] Exhibit ____(MJM-13) Company response to Staff Data Request STF 28.1.

Company missed an opportunity in this case to provide relief to customers from certain charges that will be affected by AMI. I recommend that the Commission direct that APS conduct a full evaluation of the costs associated with these charges and present the results in the next rate case.

Q Do you have any other comments on other Service Schedules?

A. Yes. Modifications to Service Schedule 3, Conditions Governing Extensions of Electric Distribution Lines and Services, are being addressed in a separate case before the Commission (Docket No. E-01345A-11-0207). This matter was heard and voted upon by the Commission at its November 8-9, 2011 Open Meeting. The Decision is expected to be issued soon.

Q Is the Company proposing any new Services Schedules?

A. Yes. Service Schedule 9 is an economic development schedule.

Q Please explain the terms of this schedule and any concerns you might have.

A. APS Witness Miessner proposes this new service schedule to promote economic development and offers a discount to a limited segment of large commercial and industrial customers who are new customers or are significantly expanding and increasing load. The purpose of the schedule is "to reduce average system costs by increasing sales beyond otherwise obtainable levels at prices that, though lower than standard rates, will recover all variable costs and contribute to fixed costs."[61] Access to this schedule will be limited to existing customers on service rates E-34 and E-35 (extra large general service rates) who increase load by 500 kW or new customers with a minimum of 1,000 kW of new load. The discount would be for a period of up to five years and would decline yearly. As stated

[61] Attachment CAM-13 Service Schedule 9.

in the Service Schedule 9, Section 3.1, the "customer satisfying the eligibility and customer criteria may receive a discount, which may vary over the term of the contract, from his otherwise applicable base bill (excluding taxes and adjustments), but in no case will the discounted energy charges be below the Company's marginal cost. For current customers adding load, the discount will apply only to the added load. Example: A qualified customer may receive a discount of 20 percent from its base bill in years one and two, 15 percent in years three and four and no discount in year five."[62]

Q What is your recommendation concerning Service Schedule 9?

A. In consultation with Staff and considering the policy implications of such an offering, I recommend that the Commission reject this service schedule and direct the Company to file individual special contracts which will delineate the specific discounts, terms, and conditions for each situation where APS wants to negotiate a discount with a customer who is expanding or adding new load to its service territory. Staff and interested parties would have an opportunity to review the particulars and evaluate the costs and benefits of such a proposal and then present the Commission with arguments for or against the proposed discount. If at some time in the future it seems that such special contracts are all very similar and becoming routine, the Commission at the time could consider putting this issue into tariff for similar to what the Company has requested in this case. This way the public interest of protecting all customers is best served.

Q Does this conclude your testimony?

A. Yes, it does.

[62] Attachment CAM-13 Service Schedule 9 Section 3.1.

Experience and Qualification of Michael J. McGarry, Sr.

Summary

Mr. McGarry's professional experience spans thirty years within the private and public sectors. He has conducted over thirty comprehensive management and operational audits of investor-owned energy, telecommunications, and water utilities. These audits have included comprehensive management audits and/or operational audits on most utility functions including corporate governance, strategic planning, internal auditing, capital and operating budget process and practices, distribution operations and maintenance, fuel procurement, supply chain management, demand side management, crew operations, affiliates transactions, commodity trading, and construction program practices.

Project Management

Mr. McGarry's experience includes management of multi-discipline teams for a wide range of client engagements, development and implementation of detailed work plans and project schedules. He has analyzed and planned interdivisional resource utilization; supervised, developed and coached interdivisional team members; and created numerous executive reports, briefings, and presentations.

Regulatory and Rate Case Management

Mr. McGarry has worked with clients to manage all aspects of the regulatory and rate case process. He has developed efficient processes to prepare supporting analyses and testimony for submission to the regulatory bodies and interveners. He is a seasoned project manager and has analytical expertise to respond to interrogatories and data requests from all rate case interveners in a timely manner. Mr. McGarry has assisted a number of clients in preparing revenue requirement and cost of service analyses. He has also developed rate structure and billing determinant information analyses, time of day and interruptible rates analyses, fuel and purchased power reports, and annual wholesale rates for member cooperatives. He has developed complex revenue requirement models to present alternative positions to a utility's proposed rate request.

Testimony and Witness Preparation

Mr. McGarry has proffered and /or supported testimony in Colorado, Delaware, Illinois, Maine, Michigan, Maryland, New York, Nova Scotia, Ohio, Pennsylvania and Utah. These proceedings included testimony involving management decision and prudence impacts, operations and maintenance expenses, capital investments, revenue requirements, project management, and others.

Utility Management and Operational Audits

Mr. McGarry has conducted over thirty comprehensive management and operational audits of investor-owned energy and telecommunications utilities. These audits have included comprehensive management audits and/or operational audits on most functions within the utility environment including corporate governance, strategic planning, internal auditing, capital and operating budget processes and practices, distribution operations and maintenance, fuel procurement, supply chain management,

demand side management, crew operations, affiliates transactions, commodity trading, and construction program practices.

Restructuring, Unbundling, and Cost Allocation

Mr. McGarry has developed the supporting analyses and regulatory filing requirements needed to support unbundling rates for utilities. This has included detailed studies where the company's plant-in-service and depreciation reserve was allocated to each unbundled function. He has assessed utility management actions to prepare the company for competition, including the processes and practices used by the utility to prepare to enter new markets and offer new services.

Training and Public Speaking

Mr. McGarry has presented topics before Commission staff groups, NARUC sub-committee groups, and as a program faculty member (2010) for the Institute of Public Utilities at Michigan State University. Topics presented include management auditing and prudence reviews, service company costs and allocations, forecasting methodology and modeling, revenue requirements, rate base, and price regulation theory.

Education

Potsdam College, B.A., Economics, 1981
University at Buffalo School of Management, MBA, 1996

Regulatory Experience

Before the Connecticut Department of Public Utility Control (CTDPUC)

Docket 10-02-13 *Application of Aquarion Water Company to Amend its Rate Schedules*
On behalf of the CTDPUC, April-August 2010
Project Manager. Oversaw rate case analysis and assessment of company's proposed revenue requirement specifically related to cash working capital and test year expenses. Assisted with analysis of specific issues and preparation of Commission's recommended decision.

Docket 07-07-01 *Diagnostic Management Audit of Connecticut Light & Power Company.*
On behalf of the Staff of the CTDPUC, July 2008-June 2009
Project Manager. Performed overall day to day project management responsibilities to conduct a diagnostic management audit of the Connecticut Light & Power Company (CL&P). Managed a project team of accountants, engineers and industry specialists who were responsible for evaluating the effectiveness of the management and operations of all aspects of the company. In addition, managed a focused prudency review of Northeast Utilities' (CL&P's parent company) development and implementation of a $122 million customer information system known as CustomerCentral or C2.

Before the Delaware Public Service Commission (DEPSC)

Docket No. 09-414 *On behalf of the Staff of the DEPSC in the matter of the application Delmarva Power & Light Company (DPL) for approval of modifications to its electric base rates,* September 2009-May 2010

Project Manager. Oversaw rate case analysis and assessment of company's proposed revenue requirement. Assisted with analysis of specific issues and preparation of witness testimony.

Docket No. 07-239F *On behalf of the Staff of the DEPSC in the matter of the application DPL for approval of modifications to its gas cost rates,* October 2007-April 2008
Project Manager and Testifying Witness. Oversaw review of DPL gas hedging program.

Docket No. 06-287 *On behalf of the Staff of the DEPSC in the matter of Chesapeake Gas Corporation's implementation of a Gas Hedging program,* June-August 2007
Project Manager. Provided industry expertise and suggestions to the Commission on a proposal plan to implement a gas hedging procurement program at the Company.

Docket No. 06-284 *On behalf of the Staff of the DEPSC in the matter of DPL's request for a $15M increase in gas base rates,* October 2006-March 2007
Project Manager and Testifying Witness. Testified on several rate base and revenue requirement issues. Recommended Commission reduce proposed rate increase request to $8.4M (56%).

Before the District of Columbia Public Service Commission (DCPSC)
Formal Case No. 1076 *In the Matter of the Application of the Potomac Electric Power Company (PEPCO) for Authority to Increase Existing Retail Rates and Charges for Electric Distribution Service.*
On Behalf of the DCPSC, July-June 2010
Project Manager. Advised Commission Staff on the Company's and intervener's filings and testimony regarding revenue requirements, rate base, cost of service, rate design, bill stabilization, and depreciation.

Formal Case No. 1053 - *Technical consultant for the DCPSC in the matter of PEPCO's request for a $50.4 million increase in base rates,* February 2007-June 2008
Project Manager. Provide technical expertise to Commission in evaluating the Company's rate case filing. Commission accepted adjustments which reduced the allowed increase by a significant percentage.

Formal Case No. 1032 *In the Matter of the Investigation into PEPCO's Distribution Service Rates*
On Behalf of the DCPSC, January-March 2005
Project Manager. Review and evaluation of PEPCO compliance filings for class cost of service and revenue requirements for distribution service pursuant to a settlement approved in May 2002. Provided analysis and recommended adjustments to Staff on 23 designated issues and 13 Company proposed adjustments. Proceeding was settled in anticipation of a full rate case for rates to be effective August 8, 2007.

Formal Case No. 1016 *In the Matter of the Application of Washington Gas Light Company (WGL), District of Columbia Division, for Authority to Increase Existing Rates and Charges for Gas Service*
On Behalf of the DCPSC, June-December 2003
Project Manager and Consultant to Commissioners and Staff. Project Manager for the analysis of WGL's rate filings. Provided analysis and recommended adjustments to the DCPSC Staff on WGL's proposed increase to base rates. Advised the Commission during deliberations on party positions and possible recommendations.

Before the Hawaii Public Utilities Commission
Docket No. 05-0075 *In the matter of a proceeding to investigate Kauai Island Utility Coop's Proposed Revised Integrated Resource Plan and Demand Side Management Framework*, June-November 2005
Project Manager. Managed a team of consultants responsible for evaluating the impact of the changes proposed by the Company.

Before the Illinois Commerce Commission (ILCC)
Case: 05-0597 *On behalf of the Illinois Citizens Utility Board, Cook County States Attorney's Office and City of Chicago,* November 2005-May 2006
Project Manager and Testifying Witness. Provided analysis and recommended adjustments in the general rate increase of 20.1% or $320 million filed by ComEd.

Consultant to Illinois Power Company. Conducted mandated compliance filing to un-bundle utility's rate tariffs. Prepared filing requirements and all support schedules analysis to justify allocation of generation, transmission and distribution. Prepared testimony on behalf of the Company's Controller.

Consultant to Illinois Power Company. Prepared 2001 required update filing for the ILCC compliance filing to un-bundle utility's rate tariffs. Prepared filing requirements and all support schedules analysis to justify allocation of generation, transmission and distribution. Prepared testimony on behalf of the Company's Controller.

Before Maine Public Utilities Commission (MEPUC)
Case No 2008-151 *MEPUC Investigation into Maintenance and Replacement Program for Northern Utilities Inc.'s Cast Iron Facilities (Phase II)*
On behalf of Maine Public Advocate, July 2008-July 2010
Project Manager and Testifying Witness. Litigated proceeding and led a consultant team to assist the State of Maine Public Advocate to follow-up on investigation for the need for the program and the Company's management of the repair or replacement of its cast iron facilities.

Case No 2004-813 *MEPUC Investigation into Maintenance and Replacement Program for Northern Utilities Inc.'s Cast Iron Facilities (Phase I)*
On behalf of Maine Public Advocate, November 2004-March 2005

Project Manager and Testifying Witness. Litigated proceeding and led a consultant team to assist the State of Maine Public Advocate to investigate the need for the program and the company's management of the repair or replacement of its cast iron facilities.

Before the Maryland Public Service Commission

Case No. 9092/9093 (Phase II) *On behalf of the Staff of the Commission in Base Rate Proceeding for PEPCO and Delmarva Power & Light Company* December-March 2008
Project Manager and Testifying Witness. Provided rebuttal testimony on behalf of the Commission related to the reasonableness of the costs and charges of Pepco Holdings, Inc. Service Company.

Case No. 9092 *On behalf of the Staff of the Commission in Base Rate Proceeding for PEPCO,* January-June 2007
Project Manager. Reviewed and analyzed company's base increase request and all pro formas, adjustments to test year revenue requirement and supported witness testimony. Commission approved less than 20% of Company's original request.

Case No. 9062 *On behalf of the Staff of the Commission in the matter of the application of Chesapeake Utilities Corporation for authority to revise its rates and charges for gas service,* May-October 2006
Project Manager. Managed a project team responsible for providing expert witness testimony in the areas of revenue requirements, rate base, cost of service, revenue allocation, rate design, revenue normalization, and cost of capital.

Before the Massachusetts Department of Public Utilities (MADPU)

Case No. D.P.U. 08-110 *On behalf of the MDPU regarding the Petition and Complaint of the Massachusetts Attorney General for an Audit of New England Gas Company,* February-August 2010
Project Manager. Managed a project team of accountants and industry specialists who were responsible for evaluating the accuracy of the accounting records, practices and procedures used in the development of the Company's revenue requirements calculations in the Company's base rate request.

Before the Michigan Public Service Commission

Case No. U-16432 *On behalf of the Attorney General of the State of Michigan in the matter of Consumers Energy Company's Application to Implement a Power Supply Cost Recovery Plan for 2011* February-June 2011
Project Manager. Reviewed cost recovery plan requirements and provided analysis and testimony concerning prior year under-recovery, generation dispatch and purchased power, purchased power agreements, emission control expenses including appropriateness of mercury filter expenses as part of PSCR process.

Case No. U-16434 *On behalf of the Attorney General of the State of Michigan in the matter of Detroit Edison Company's Application to Implement a Power Supply Cost Recovery Plan for 2011* February-June 2011

Project Manager and Testifying Witness. Reviewed cost recovery plan requirements and provided analysis concerning prior year under-recovery, generation dispatch and purchased power, purchased power agreements, emission control expenses including appropriateness of coal refinement expenses as part of PSCR process.

Case No. U-16472 *In the matter of the application of The Detroit Edison Company (DetEd) for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority.* February-June 2011
Project Manager and Testifying Witness. Review of Advanced Metering Infrastructure program cost benefits and tariffs filed and potential witness to same.

Case No. U-16407 *On behalf of the Attorney General of the State of Michigan in the matter of the application of Michigan Consolidated Gas Company (MichCon) for approval of a detailed plan for main renewal, including a long-term plan to significantly reduce the amount of cast iron main in its system.* Nov 2010-May 2011
Project Manager and Testifying Witness. Reviewed Company's proposed plan with respect to whether a cost recovery mechanism can be designed to minimize the impact on ratepayers. Testified as to the reasonableness of cost benefit of replacements as well as to the capital cost recovery as it affects future rate cases.

Case No. U-16300 *On behalf of the Attorney General of the State of Michigan in the matter of the application of Consumers Energy Company (CECO) for authority to reconcile its renewable energy plan (REP) costs associated with the plan approved in Case No. U-15805.* November 2010-January 2011
Project Manager and Testifying Witness. Reviewed the Company's REP Cost Reconciliation for 2009 to ensure the adherence to approved processes and reasonable and prudent costs. Testified as to significant concerns with respect to the transfer price for renewable energy resources proposed by the Company.

Case No. U-16356 *On behalf of the Attorney General of the State of Michigan in the matter of the application of DetEd for authority to reconcile its REP costs associated with the plan approved in Case No. U-15806-RPS.* October 2010-March 2011
Project Manager and Testifying Witness. Reviewed the Company's REP Cost Reconciliation for 2009 to ensure adherence to approved processes and reasonable and prudent costs.

Case No. U-15675-R *On behalf of the Attorney General of the State of Michigan in the matter of the application of CECO for the reconciliation of power supply cost recovery (PSCR) costs and revenues for the calendar year 2009,* October 2010-January 2011
Project Manager and Testifying Witness. Reviewed PSCR plan requirements and testified to transfer price, replacement power costs, and reasonableness of including excess fuel and variable O&M expenses proffered by various intervenors.

Case No. U-15677-R *On behalf of the Attorney General of the State of Michigan in the matter of the application of The Detroit Edison Company for reconciliation of its PSCR plan for the calendar year 2009,* September-December 2010
Project Manager and Testifying Witness. Reviewed PSCR reconciliation and testified with respect to the transfer price for renewable energy source flowing into the PSCR proposed by the Company.

Case No. U-16047 *On behalf of the Attorney General of the State of Michigan in the matter of the application of DetEd for authority to implement a PSCR Plan in its rate schedules for 2010 metered jurisdictional sales of electricity*, January-May 2010
Project manager and Testifying Witness. Reviewed PSCR plan requirements and testified to appropriateness of specific components of that factor.

Case No. U-15415-R *On behalf of the Attorney General of the State of Michigan in the matter of the application of CECO for the reconciliation of PSCR costs and revenues for the calendar year 2008 and for other relief related to pension and OPEB costs,* May-November 2009
Project Manager and Testifying Witness. Reviewed PSCR reconciliation, provided analysis of potential issues, and developed recommendations including basis, past precedence, and/or industry expertise.

Case No. U-15806/U-15890 *On behalf of the Attorney General of the State of Michigan in the matter of DetEd and MichCon to comply with Public Acts 286 and 296 regarding their REP and Energy Optimization Plan (EOP)*, March-June 2009
Project Manager and Testifying Witness. Reviewed the EOPs of both DetEd and MichCon and provided analysis of issues and shortcomings concerning the plans in relation to the specifications of the Act and the benefit to customers.

Case No. U-15805/15889 *On behalf of the Attorney General of the State of Michigan in the matter of CECO to comply with Public Acts 286 and 295 regarding its REP and EOP,* March-June 2009
Project Manager and Testifying Witness. Reviewed the EOP of CECO and provided analysis of issues and shortcomings concerning the plans in relation to the specifications of the Act and the benefit to customers.

Case No. U-15677 *On behalf of the Attorney General of the State of Michigan in the matter of the application of DetEd for authority to implement a PSCR plan in its rate schedules for 2009 metered jurisdictional sales of electricity,* January 2009-June 2010
Project manager. Reviewed PSCR plan requirements and testified to appropriateness of specific components of that factor.

Case No. U-15415 *On behalf of the Attorney General of the State of Michigan in the matter of the application of CECO for approval of a PSCR plan and for authorization of monthly PSCR factors for the year 2008,* January-March 2008

Project Manager. Reviewed PSCR plan requirements and provided summary briefing to Michigan Attorney General.

Case No. U-15320 *On behalf of the Attorney General of the State of Michigan in the matter of the application of Midland Cogeneration Venture Limited Partnership for the Commission to eliminate the "availability caps" which limit CECO's recovery of capacity payments with respect to its power purchase agreement with Midland Cogeneration Venture Limited Partnership*, October 2007-June 2008
Project Manager. Oversaw project to provide industry expertise to evaluate issue in case and recommend alternative arguments.

Case No. U-15245 *On behalf of the Attorney General of the State of Michigan in the matter of the application of CECO for authority to increase its rates for the generation and distribution of electricity and for other relief,* July 2007-April 2008
Project Manager and Testifying Witness. Provided expert testimony on partial and interim rate relief, CECO's decision to acquire Zeeland Power Company from Broadway Gen Funding, LLC. Provided testimony in permanent phase to reduce company's net operating income to more closely reflect the expected costs in 2008.

Case No U-15244 *On behalf of the Attorney General of the State of Michigan in the matter of the application of DetEd for authority to increase its electric base rates*, September 2007-October 2008
Project Manager and Testifying Witness. Testified regarding revenue requirements.

Case No U-15190 *On behalf of the Attorney General of the State of Michigan in Base Rate Proceeding for CECO,* March-September 2007
Project Manager. Reviewed the revenue decoupling proposal and supported the witness testimony.

Case No U-15040 *On behalf of the Attorney General of the State of Michigan in Gas Cost Recovery (GCR) 2007/08 Plan proceeding,* March-August 2007
Project Manager and Testifying Witness. Reviewed GCR plan requirements and provided analysis of the potential benefits of gas procurement hedging program.

Case No. U-15001 *On behalf of the Attorney General of the State of Michigan in PSCR 2007/08 Plan proceeding,* November 2006-August 2007
Project Manager and Testifying Witness. Reviewed PSCR plan requirements and testified to appropriateness of specific components of that factor.

Case No. U-14701-R *On behalf of the Attorney General of the State of Michigan in PSCR 2006/07 reconciliation proceeding,* June-November 2007
Project Manager and Testifying Witness. Reviewed PSCR reconciliation and testified to eliminate some expenses used in the company's calculation of its under-recovery PSCR reconciliation for 2006.

Case No. U-14547 *On behalf of the Attorney General of the State of Michigan in the matter of the application of CECO for authority to increase rates for the distribution of natural gas and for other relief,* December 2005-April 2006
Expert Witness and Project Manager. Provided analysis, recommended adjustments, and filed testimony for the Attorney General on CECO's proposed increase to base rates.

New Mexico Public Service Commission (NMPSC)
Special Case Study: Public Service Company of New Mexico (PNM) NM PRC Docket No. 10-00086-UT, August 2010
Blue Ridge worked with QSI Consulting, Inc. to conduct a training session for the NMPSC Staff and develop training materials for presentation to Staff on the basic elements of future test year proceedings, how those may differ from traditional rate cases, and how to apply and interpret the forecasting methodologies and modeling that will come into play; and analyze the pending PNM rate case and provide an analytic framework for Staff to apply to the forecasting issues in the case.

Before the Missouri Public Service Commission (NDPSC)
Veolia Energy Company (Veolia) 2011 and 2012 Request for Authority to Increase Electric Rates in Missouri (Case No. PU-10-657/PU-11-55) April 2011-present
Project Manager and Testifying Witness. Led a team of consultants engaged to review Veolia's proposed adjustments, rate base, revenues and expenses, affiliate transactions and allocations, revenue requirement, cost of capital, and cost of service and rate design. Evaluated Veolia's proposed revenue requirement and testified before the NDPSC to proposed adjustments to the revenue requirements filed by the company in its application.

Before the North Dakota Public Service Commission
Northern States Power Company (NSP) 2011 and 2012 Request for Authority to Increase Electric Rates in North Dakota (Case No. PU-10-657/PU-11-55) April 2011-present
Project Manager and Testifying Witness. Led a team of consultants engaged to review NSP's proposed adjustments, rate base, revenues and expenses, affiliate transactions and allocations, revenue requirement, cost of capital, and cost of service and rate design. Evaluated NSP's proposed revenue requirement and testified before the NDPSC to proposed adjustments to the revenue requirements filed by the company in its application

Before the Nova Scotia Utility and Review Board
Case No. P-886 *On behalf of the Consumer Advocate of the Province of Nova Scotia in the base rate proceeding of Nova Scotia Power,* December 2006-March 2007
Project Manager and Testifying Witness. Provided an evaluation of a management audit of Nova Scotia Power and that report's usefulness to assess the Company's management performance and operational efficiency within the context of that proceeding.

Before the Public Utilities Commission of Ohio (PUCO)
Case No. 08-0917-EL-SSO *On behalf of the Ohio Hospital Association in the matter of the Application of American Electric Power of Ohio for authority to increase rates for distribution of electric service.* (Hired by Ohio Hospital Association's attorney for utility

matters, Bricker and Eckler, to provide expertise in negotiating rate with American Electric Power.), September 2008-March 2009
Evaluated revenue and rate impact on member hospitals.

On behalf of the Staff of the PUCO

- Case #08-0072-GA-AIR *Columbia Gas of Ohio for an increase in gas rates,* April-August 2008
- Case #07-0829-GA-AIR *Dominion East Ohio for an increase in gas rates,* November 2007-July 2008
- Case #07-0589-GA-AIR *Duke Energy Ohio for an increase in gas rates,* November 2007-Februrary 2008

Project Manager. Oversaw multi-discipline team of accountants, auditors, engineers and analysts to conduct a comprehensive rate case audit of the Company's gas base rate filing. Primary goal of project was to validate information in filing, provide findings conclusions and recommendations concerning the reliability of information and data in the filing and support Staff in its evaluation of the reasonableness of the filing.

Case No. 07-0551-EL-UNC *On behalf of the Ohio Schools Council in the matter of the Application of First Energy Ohio (and its operating companies Ohio Edison, Cleveland Electric and Toledo Edison) for authority to Increase rates for distribution service, modify certain accounting practices and for tariff approval*, August 2007-April 2008
Project Manager. Hired by Ohio Schools Council's attorney for utility matters (Bricker and Eckler, LLP) to provide industry expertise in reviewing First Energy's application with respect to cost of service and rate design and the resulting impact on Council's member school systems' energy costs.

Case No. 06-0986-EL-UNC *On behalf of the City of Cincinnati in the matter of the Application of Duke Energy Ohio, Inc., to modify its market-based Standard service over,* May-August 2007
Project Manager. Hired by City of Cincinnati's Water and Sewer District attorney for utility matters (Bricker and Eckler, LLP) to provide industry expertise in reviewing the Company's proposal and impact on City's project energy costs.

Oregon Public Utilities Commission (OPUC)
Docket No UP205 *Examination of NW Natural's Rate Base and Affiliated Interests Issues* Co-sponsored between NW Natural, Staff, Northwest Industrial Gas Users, Citizens Utility Board, August 2005-January 2006
Project Manager. Led a team that conducted a management audit of NW Natural Gas that included an evaluation of rate base issues for Financial Instruments (gas and financial hedging) Deferred Taxes, Tax Credits, Cost for a Distribution System, Security Issuance Costs and AFUDC calculations as well as Affiliate Transactions for Cost Allocations and Transfer Pricing, Labor Loading, Segregation of Regulated Rate Base and Subsidiary Investments and Properties, and validation of tax paid from/to affiliates are proper. Audit

was to ensure Company compliance with orders, rules and regulations of the OPUC, with Company policy and with Generally Accepted Accounting Principles.

Utah Division of Public Utilities

Docket No. 09-035-23 *In the Matter of the Application of Rocky Mountain Power (RMP) for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations,* June-December 2009

Project Manager and Testifying Witness. Verified the reasonableness of the revenue requirements as provided by the company in its application and testified before the Public Service Commission of Utah.

Docket No. 09-035-15 *In the Matter of the Application of RMP for Approval of its Proposed Energy Cost Adjustment Mechanism (ECAM) - Net Power Cost Evaluation (NPC), RMP 2009 General Rate Case,* July-December 2009

Project Manager and Testifying Witness. Analyzed the reasonableness and technical accuracy of the RMP's NPC request, performed a comprehensive review of the Company's NPC estimate and developed recommendations to ensure an accurate baseline for the ECAM, analyzed special issues addressed in the NPC portion of the case, analyzed the Company's fuel price hedging policies and provided recommendations appropriate for the ECAM, and reviewed intervener NPC issues as well as analyzing additional issues as raised by the Company and testified to hedging issues.

Before the Washington Utilities and TraVeoliaortation Commission (WUTC)

Independent Third-Party Evaluation of Puget Sound Energy's (PSE) Conservation Incentive Mechanism (ECIM) under the co-direction of PSE and the WUTC Staff, Phase I: July-October 2009; Phase II: October 2009-September 2010

Project Manager: Assess the extent to which the design and implementation of the incentive mechanism addressed key issues and objectives required by the Commission: accuracy of implementation in calculations of incentives or penalties, compliance with the conditions and requirements of the pilot program, proper use of the calculation methodology, and which assumptions or methods were used to calculate and verify the savings report.

Before the Public Utilities Commission of the State of Colorado (COPUC)

Docket No. 04A-050E *Review of the Electric Commodity Trading Operations of Public Service Company of Colorado (PSCo)*

On behalf of the COPUC Staff, March-September 2004

Project Manager. Focused operational audit within the bounds of a litigated proceeding to determine if ratepayers were subsidizing or negatively impacted by PSCo's energy trading function.

South Carolina State Senator
Advised Senator on regulatory process for requesting States Public Service Commission for a comprehensive review of Duke Power Company's storm and restoration and right of way management. Reviewed and advised Senator of results of report finding.

Before the Missouri Public Service Commission
Consultant to Ameren UE. Conducted revenue requirement analysis in preparation of Missouri Public Service Commission compliance filing to un-bundle utility's rate tariffs. Prepared the filing requirements and all support schedules analysis to justify allocations of generation, transmission and distribution.

Southern Connecticut Gas
Consultant. As part of a team that conducted a comprehensive management audit of the management and operations of the Company, completed the capital budgeting area of the audit.

Before the New York Public Service Commission
Case: 94-C-0657
Commission Staff. Proceeding to evaluate the compliance of NYNEX with Commission rules and orders related to operational support system costs to competitors. Part of staff panel to facilitate discussion between company and potential competitors (i.e., users of operational support systems) and report back to Commission.

Focused review of the preparedness of Rochester Gas and Electric (RG&E) and Consolidated Edison (ConEd) for competition in the electric industry. Evaluated all aspects of the company's management actions to prepare for competition including strategic planning, goals and objectives and senior management's attention to the company operations in a de-regulated industry

Case: 97-M-0567
Commission Staff. Litigated proceeding to determine the benefits of a proposed merger of Long Island Lighting Company / Brooklyn Union Gas. Analyzed the proposed synergy savings.

Case: 96-E-0132 *Show Cause Proceeding Regarding Rate Relief for Ratepayers of LILCO*
Commission Staff and Testifying Witness. Litigated proceeding where Staff proffered testimony containing a benchmark study showing that LILCO's operations and maintenance expenses were excessive compared to a peer group of 24 utilities. Panel testimony concerning the findings and conclusions resulting from the benchmark study.

Case: 96-M-0858 *Prudence Investigation into the Scrap Handling Practices in the Western Division of Niagara Mohawk Power Company (NIMO)*
Commission Staff and Testifying Witness. Litigated proceeding as a result of allegations of bribery and corruption in company practices related to a specific vendor who

purchased company scrap metal. Lead team of 10 staff examiners to quantify the extent to which the Company paid excessive rates to this vendor. Testified to the findings of the analysis. Case settled with ratepayers receiving a credit to bills

Case: 91-C-0613 *Operational Audit of the Outside Plant Construction and Rehabilitation Program of New York Telephone Company*
Commission Staff. Comprehensive operational audit of the company's management and implementation of a $150M capital program to rehabilitate the outside plant distribution network. Served as Staff Examiner responsible for crew supervision, goals monitoring, contractor oversight, and report preparation.

Case: 91-W-0583 *Prudence Proceeding Regarding the Operations and Management of Jamaica Water*
Commission Staff and Testifying Witness. Litigated proceeding as a result of audit to determine extent to which management inattention and inappropriate practices resulted in excessive costs to rate payers. Testified on a Staff panel to the excessive costs associated with management's inattention to sound business practices related to the design, purchase and installation of the Company customer information system.

Case: 92-W-0030 *Operational Audit of Jamaica Water Operations and Management*
Commission Staff. Comprehensive management audit of company operations. Responsible for work plan development, and specific topics areas including engineering, contracting, and information technology. Findings led to prudence proceeding.

Case: 92-M-0973 *Management Audit of RG&E*
Commission Staff. Comprehensive management audit of company operations. Responsible for work plan development, supervision of staff and specific topics areas including purchasing and internal controls.

Case: 93-E-0918 *Operational Audit of the Demand Side Management Function at RG&E*
Commission Staff. Comprehensive operational audit of the demand side management function including program planning, management and energy savings verification. Developed and supervised the implementation of the work plan.

Case: 88005 *Operational Audit of Materials and Supply Function at National Fuel Gas*
Commission Staff. Comprehensive operational audit of the materials and supplies function including warehouse operations, inventory control and procurement. Developed and implemented the work plan for this project.

Operational Audit of the Fuel Procurement and Contracting of LILCO
Commission Staff. Comprehensive operational audit to determine effectiveness of ratepayer funds spent on non-nuclear fuel. Provided research and data evaluation expertise to the project.

Operational Audit of the Fuel Procurement and Contracting of ConEd
Commission Staff. Comprehensive operational audit to determine effectiveness of ratepayer funds spent on non-nuclear fuel. Provided research and data evaluation expertise to the project

Case: 90007 Operational Audit of the Fuel Procurement and Contracting of Central Hudson Gas and Electric
Commission Staff. Comprehensive operational audit to determine effectiveness of ratepayer funds spent on non-nuclear fuel. Provided research and data evaluation expertise to the project

Operational Audit of Fuel Procurement and Contracting of Orange & Rockland Utilities
Commission Staff. Comprehensive operational audit to determine effectiveness of ratepayer funds spent on non-nuclear fuel. Provided research and data evaluation expertise to the project

Operational Audit of the Fuel Procurement and Contracting of RG&E
Commission Staff. Comprehensive operational audit to determine effectiveness of ratepayer funds spent on nuclear fuel. Provided research and data evaluation expertise.

Case: 88-E-115 *Prudence Proceeding to Investigate the Construction Costs Associated with the Homer City Coal Cleaning Plant (HCCCP)*
Commission Staff and Testifying Witness. Litigated proceeding as a result of audit to determine extent to which management inattention and inappropriate practices resulted in excessive construction charges related to the HCCCP. Testified on a Staff panel to the fuel price differential costs resulting from the failure of the coal cleaning plant to function as designed as well as surrebuttal testimony on the cost of a flu-gas de-sulfurization plant and ancillary equipment and facilities. Case settled. Customers received $125M credit.

Case: 87003 *Operational Audit of the HCCCP*
Commission Staff. Comprehensive operational audit to determine effectiveness of ratepayer funds spent on the construction of the HCCCP jointly owned by New York State Electric and Gas (NYSEG) and Penelec. Responsible for fuel and construction costs analysis, benchmarking costs and alternative methods for meeting EPA Clean air restrictions, contracting practices and report preparation.

Case: 87003 *Operational Audit of the Fuel Procurement and Contracting of NYSEG*
Commission Staff. Comprehensive operational audit to determine effectiveness of ratepayer funds spent on non-nuclear fuel. Responsible for fuel cost analysis, benchmarking costs, contracting practices and report preparation.

Case: 86007 *Operational Audit of the Field Crew Supervision and Utilization of NYSEG*
Commission Staff. Comprehensive operational audit to determine effectiveness of field crew utilization and supervision. Staff examiner responsible for verifying supervisor activities, reporting, goals attainment and report preparation.

Case: 86005 *Prudence Proceeding to Investigate the Fuel Procurement and Contracting Practices at NIMO*
Commission Staff. Litigated proceeding as a result of audit to determine extent to which management inattention and inappropriate practices resulted in excessive fuel charges to customers. Responsible for fuel cost analysis and benchmarking costs, contracting practices, and testimony preparation. Case settled with customers receiving $66M credit.

Case: 86005 *Operational Audit of the Fuel Procurement and Contracting of NIMO*
Commission Staff. Comprehensive operational audit to determine effectiveness of ratepayer funds spent on non-nuclear fuel. Responsible for fuel cost analysis and benchmarking costs, contracting practices and report preparation.

Case: 85001 *Operational Audit of the Research and Development Function of ConEd*
Commission Staff. Comprehensive operational audit to determine effectiveness of ratepayer funds spent on R&D activities. Staff examiner on the project responsible for reviewing projects documentation and control, outside contracting a report preparation.

Testimony filed by Mr. McGarry

Before the Delaware Public Service Commission

- Delmarva Power and Light Company - Docket No. 07-239F
- Delmarva Power and Light Company - Docket No. 06-284

Before the Illinois Commerce Commission

- Commonwealth Edison - Case: 05-0597

Before Maine Public Utilities Commission

- Northern Utilities Inc. - Case No. 2008-151
- Northern Utilities Inc. - Case No. 2004-813

Before the Maryland Public Service Commission

- PEPCO and Delmarva Power and Light Company - Case No. 9092/9093

Before the Michigan Public Service Commission

- Detroit Edison - Case No. U-16434
- Detroit Edison - Case No. U-16472
- Michigan Consolidated Gas Company - Case No. U-16407
- Detroit Edison Company - Case No. U-16356
- Consumers Energy Company - Case No. U-16300
- Detroit Edison Company - Case No. U-16047
- Detroit Edison and Michigan Consolidated Gas - Case No. U-15806/U-15890
- Consumers Energy Company - Case No. U-15805/15889
- Detroit Edison Company - Case No. U-15677-R
- Consumers Energy Company - Case No. U-15675-R
- Consumers Energy Company - Case No. U-15415-R
- Consumers Energy Company - Case No. U-15245
- Detroit Edison Company - Case No. U-15244

- Michigan Gas Utilities, Corporation - Case No. U-15040
- Consumers Energy Company - Case No. U-15001
- Consumers Energy Company - Case No. U-14701-R
- Consumer Energy Company - Case No. U-14547

Before the Nova Scotia Utility and Review Board

- Nova Scotia Power - Case No. P-886

Utah Division of Public Utilities

- Rocky Mountain Power - Docket No. 09-035-23

Before the New York Public Service Commission

- Long Island Lighting Company - Case: 96-E-0132
- Niagara Mohawk Power Company - Case: 96-M-0858
- Jamaica Water - Case: 91-W-0583
- New York State Electric & Gas Homer City Prudence Review - Case: 98-E-115

Rev 7/19/2011

Environmental and Reliability Account ("ERA") Plan of Administration

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1. General Description

This document describes the plan for administering the Environmental and Reliability Account ("ERA") approved for the Arizona Public Service Company ("APS") by the Arizona Corporation Commission ("ACC" or "Commission") on [insert date] in Decision No. XXXXX. The ERA provides for the recovery of the revenue requirement effect of actual environmental or generation plant additions or efficiency projects made by APS and not already recovered in base rates approved in Decision No. XXXXX or recovered through another Commission approved adjustment. The ERA will be calculated annually based on the ERA Qualified Investments closed to plant-in-service during the preceding calendar year.

2. Definitions

ERA Qualified Investments – Investments in Qualified Environmental Improvement Projects and Qualified Generation Plant. Each ERA Qualified Investments must: (1) be classified in one or more of the FERC plant accounts as listed in section 3 of this document, or any other successor FERC account, upon going into service, (2) be tracked by a specific project number, and (3) exceed $500,000 in capital investment.

Qualified Environmental Improvement Projects - Projects designed to comply with current or prospective environmental standards required by federal, state, tribal, or local laws and regulations. These standards and criteria for water, waste, and air include but are not limited to new and expected limits for carbon dioxide (CO_2), sulfur oxide (SO_x), nitrogen oxide (NO_x), particulate matter (PM), volatile organic compounds (VOC), and toxics such as mercury (Hg), coal ash management, and requirements under the clean and safe drinking water acts.

Qualified Generation Plant - Generation plant capacity acquisitions, existing generating plant efficiency projects or the construction of new generating plant.

Total Company Revenues – The net amount annually recorded in FERC Form 1, in accounts titled "Sales to Ultimate Customers" and "Provision for Rate Refunds."

3. Qualified FERC Accounts

1. Steam Production
   - FERC Account 310 – Land and Land Rights
   - FERC Account 311 – Structures and Improvements
   - FERC Account 312 – Boiler Plant Equipment
   - FERC Account 313 – Engines and Engine-Driven Generators
   - FERC Account 314 – Turbogenerator Units
   - FERC Account 315 – Accessory Electric Equipment
   - FERC Account 316 – Miscellaneous Power Plant Equipment

2. Nuclear Production
   - FERC Account 320 – Land and Land Rights
   - FERC Account 321 – Structures and Improvements
   - FERC Account 322 – Reactor Plant Equipment
   - FERC Account 323 – Turbogenerator Units
   - FERC Account 324 – Accessory Electric Equipment
   - FERC Account 325 – Miscellaneous Power Plant Equipment

3. Other Production
   - FERC Account 340 – Land and Land Rights
   - FERC Account 341 – Structures and Improvements
   - FERC Account 342 – Fuel Holders, Products, and Accessories
   - FERC Account 343 – Prime Movers
   - FERC Account 344 – Generators
   - FERC Account 345 – Accessory Electric Equipment
   - FERC Account 346 – Miscellaneous Power Plant Equipment

Please note this list may expand to include other accounts approved by the ACC in the future.

4. Calculation of ERA Revenue Requirement

The ERA Adjustment Percentage will recover capital expenditures and operations and maintenance ("O&M") costs for ERA Qualified Investments.

ERA Revenue Requirement used in calculating the ERA Adjustment Percentage will include: (1) Return on ERA Qualified Investments based on the Company's Weighted Average Cost of Capital ("WACC") approved by the Commission in the Company's

preceding general rate case; (2) depreciation expense; (3) income taxes; (4) property taxes; (5) deferred taxes and tax credits where appropriate and (6) associated O&M. ERA Qualified Projects and the ERA Revenue Requirement calculation will be submitted by the Company to the ACC in the form of Schedule 1 and Schedule 2 as attached to this document.

5. Calculation of ERA Adjustment Percentage

The ERA Adjustment Percentage to be applied to customers' bill (excluding Adjustment Schedule EIA, sales tax, transaction privilege tax, regulatory assessments and franchise fees) will equal a percentage calculated by dividing the total ERA Revenue Requirement by Total Company Revenues.

6. Filing and Procedural Deadlines

APS will file the calculated ERA Adjustment Percentage including all supporting data, with the Commission for the previous year on or before March 1st (please see "Compliance Report" section for a description of the filed reports).

The Commission Staff and interested parties shall have the opportunity to review the ERA filing and supporting data in the adjustor calculation. Unless the Commission has otherwise acted by April 1st, the new ERA Rate proposed by APS will go into effect with the first billing cycle in April (and will not be prorated) and will remain in effect for the following 12-month period.

7. Compliance Reports

APS will provide an annual report to Staff's Compliance Section and the Residential Utility Consumer Office detailing all calculations related to the ERA Adjustment Percentage. The reports will include at minimum the following:

1. List of Qualified Investments by;
    a. Project Tracking Number
    b. Project Name
    c. Project Purpose
    d. Plant In-service Date
    e. Project Cost
2. Adjustments to Plant including;
    a. Accumulated Depreciation
    b. Cumulative Deferred Tax/Tax Credits
3. Annual Depreciation of Plant in Service for Qualified Projects
4. Applicable Property Tax associated with Qualified Projects

PLAN OF ADMINISTRATION
ENVIROMENTAL AND RELIABILITY ACCOUNT

5. Associated O&M Expense for Qualified Projects
6. Total Company Revenues
7. The Annual ERA Revenue Requirement ($000); and
8. The ERA Adjustment Percentage (%) to be in effect for the following 12-month period.

Attached is the compliance report that will be submitted annually.

Schedule 1: Qualified Investments for ERA Adjustment
Electric Plant in Service for Calendar Year 20XX

Line No.	Project Tracking Number	Project Name	Purpose	In-Service Date	Total Cost	ACC Jurisdictional
	A	B	C	D	E	F
	Environmental Improvement Projects					
1.	XXXXX	Project A	Project A Purpose Description	MM/YY	$ -	$ -
2.	XXXXX	Project B	Project B Purpose Description	MM/YY	-	-
3.	XXXXX	Project C	Project C Purpose Description	MM/YY	-	-
4.		**Total**			**$ -**	**$ -**
	New Generation Capacity - Plant Construction					
5.	XXXXX	Project A	Project A Purpose Description	MM/YY	$ -	$ -
6.	XXXXX	Project B	Project B Purpose Description	MM/YY	-	-
7.	XXXXX	Project C	Project C Purpose Description	MM/YY	-	-
8.		**Total**			**$ -**	**$ -**
	New Generation Capacity - Plant Acquisitions					
9.	XXXXX	Project A	Project A Purpose Description	MM/YY	$ -	$ -
10.	XXXXX	Project B	Project B Purpose Description	MM/YY	-	-
11.	XXXXX	Project C	Project C Purpose Description	MM/YY	-	-
12.		**Total**			**$ -**	**$ -**
	Existing Generation Plant - Efficiency Projects					
13.	XXXXX	Project A	Project A Purpose Description	MM/YY	$ -	$ -
14.	XXXXX	Project B	Project B Purpose Description	MM/YY	-	-
15.	XXXXX	Project C	Project C Purpose Description	MM/YY	-	-
16.		**Total**			**$ -**	**$ -**

Schedule 2: Revenue Requirement and Adjustor Calculation
Plant in Service for Calendar Year 20XX
Billing Period 4/1/20XX-3/30/XX

Line No.	ERA Calculation		
	Qualified Plant		
1.	Environmental Improvement Projects (Schedule 2, Line 4, Column F)	$	-
2.	New Generation Capacity - Plant Construction (Schedule 2, Line 8, Column F)	$	-
3.	New Generation Capacity - Plant Acquisition (Schedule 2, Line 12, Column F)	$	-
4.	Existing Generation Plant - New Efficiency Projects (Schedule 2, Line 16, Column F)	$	-
5.	Plant Balance - ERA Qualified Investments (Line 1 + Line 2 + Line 3 + Line 4)	$	-
	Adjustment to Plant		
6.	Accumulated Depreciation	$	-
7.	Cumulative Deferred Tax/Tax Credits	$	-
8.	ERA Net Plant (Line 5 - Line 6 - Line 7)	$	-
9.	Pre-tax Weighted Average Cost of Capital		0.00%
	Revenue Requirement		
10.	Composite Return on ERA Net Plant (Line 8 * Line 9)	$	-
11.	Annual Depreciation of Plant In Service	$	-
12.	Applicable Property Tax	$	-
13.	Associated O&M Expense	$	-
14.	Total ERA Revenue Requirement (Line 10 + Line 11 + Line 12 + Line 13)	$	-
15.	Total Company Revenues	$	-
16	ERA Adjustment Percentage (Line 14 / Line 15)		0.0%

Note: This information is confidential until APS's FERC Form 1 has been filed.

Arizona Corporation Commission
Docket No. E-01345A-11-0224
Exhibit: MJM-3
Schedule 1

Arizona Public Service
Analysis of Staff's Proposed Interest Rate Calculations
Monthly PSA Balance - 2010
($ in thousands)

Chart 1a: Based on August 2010 Schedule 6 (Jan - Aug) and August 2010 Monthly PSA Balance (Sep - Dec)
Source: Response to DR Staff 12.6, Attachments APS14750, Page 7 of 9, and APS14751, Page 13 of 16

Line No.	Description	Annual Interest Rate	Sept. Rate Change	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total Interest
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(o)	(p)	(q)
	Forward Component Tracking Account															
1	Beginning Balance			$ (66,586)	$ (18,579)	$ (29,171)	$ (39,541)	$ (49,700)	$ (53,223)	$ (49,996)	$ (42,041)	$ (28,786)	$ (16,571)	$ (20,112)	$ (29,783)	
2	Xfers to 2009 Histl Comp Tracking Acct			$ 66,586	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
3	Monthly Interest Rate[1]	0.4521%	0.5069%	0.0377%	0.0377%	0.0377%	0.0377%	0.0377%	0.0377%	0.0377%	0.0377%	0.0422%	0.0422%	0.0422%	0.0422%	
4	Monthly Interest			$ -	$ (7)	$ (11)	$ (15)	$ (19)	$ (20)	$ (19)	$ (16)	$ (12)	$ (7)	$ (8)	$ (13)	
5	Post-Sharing (Over)/Under Collection			$ (15,420)	$ (13,954)	$ (13,853)	$ (13,340)	$ (6,751)	$ (1,101)	$ 2,649	$ 7,876	$ 6,914	$ (7,917)	$ (13,082)	$ (21,127)	
6	Collections			$ 3,159	$ (3,369)	$ (3,494)	$ (3,196)	$ (3,247)	$ (4,348)	$ (5,324)	$ (5,395)	$ (5,313)	$ (4,383)	$ (3,420)	$ (3,657)	
7	Ending Balance with Interest			$ (18,579)	$ (29,171)	$ (39,541)	$ (49,700)	$ (53,223)	$ (49,996)	$ (42,041)	$ (28,786)	$ (16,571)	$ (20,112)	$ (29,783)	$ (47,266)	
	Historical Component Tracking Account															
8	Beginning Balance			$ (13,728)	$ (78,090)	$ (72,871)	$ (68,087)	$ (63,438)	$ (58,427)	$ (52,365)	$ (44,557)	$ (36,650)	$ (28,842)	$ (22,400)	$ (17,373)	
9	Xfers fr/ 2009 For Com Tracking Acct			$ (66,586)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
10	Xfers fr/ Old PSA & Surcharge Accts			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
11	Monthly Interest Rate[1]	0.4521%	0.5069%	0.0377%	0.0377%	0.0377%	0.0377%	0.0377%	0.0377%	0.0377%	0.0377%	0.0422%	0.0422%	0.0422%	0.0422%	
12	Monthly Interest			$ (30)	$ (29)	$ (27)	$ (26)	$ (24)	$ (22)	$ (20)	$ (17)	$ (15)	$ (12)	$ (9)	$ (7)	
13	Collections			$ (2,254)	$ (5,249)	$ (4,811)	$ (4,675)	$ (5,035)	$ (6,084)	$ (7,827)	$ (7,924)	$ (7,824)	$ (6,454)	$ (5,036)	$ (5,366)	
14	Ending Balance with Interest			$ (78,090)	$ (72,871)	$ (68,087)	$ (63,438)	$ (58,427)	$ (52,365)	$ (44,557)	$ (36,650)	$ (28,842)	$ (22,400)	$ (17,373)	$ (12,015)	
15	Combined Balance			$ (96,669)	$ (102,042)	$ (107,628)	$ (113,138)	$ (111,649)	$ (102,360)	$ (86,599)	$ (65,437)	$ (45,413)	$ (42,512)	$ (47,156)	$ (59,280)	
16	Combined Monthly Interest			$ (30)	$ (36)	$ (38)	$ (41)	$ (43)	$ (42)	$ (39)	$ (33)	$ (28)	$ (19)	$ (18)	$ (20)	$ (386)

CHART 1b: Based on Chart 1 above except Interest recalculated at proposed rates

		ROE Rate	Short Term Debt	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
	Forward Component Tracking Account															
17	Beginning Balance			$ (66,586)	$ (18,579)	$ (29,334)	$ (39,962)	$ (50,473)	$ (54,439)	$ (51,691)	$ (44,192)	$ (31,326)	$ (19,386)	$ (23,098)	$ (32,972)	
18	Xfers to 2009 Hist Comp Tracking Acct			$ 66,586	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
19	Monthly Interest Rate[2]	11.00%	0.84%	0.9167%	0.9167%	0.9167%	0.9167%	0.9167%	0.9167%	0.9167%	0.9167%	0.9167%	0.9167%	0.9167%	0.9167%	
20	Monthly Interest			$ -	$ (170)	$ (269)	$ (366)	$ (463)	$ (499)	$ (474)	$ (405)	$ (287)	$ (178)	$ (212)	$ (302)	
21	Post-Sharing (Over)/Under Collection			$ (15,420)	$ (13,954)	$ (13,853)	$ (13,340)	$ (6,751)	$ (1,101)	$ 2,649	$ 7,876	$ 6,914	$ (7,917)	$ (13,082)	$ (21,127)	
22	Collections			$ 3,159	$ (3,369)	$ (3,494)	$ (3,196)	$ (3,247)	$ (4,348)	$ (5,324)	$ (5,395)	$ (5,313)	$ (4,383)	$ (3,420)	$ (3,657)	
23	Ending Balance with Interest			$ (18,579)	$ (29,334)	$ (39,962)	$ (50,473)	$ (54,439)	$ (51,691)	$ (44,192)	$ (31,326)	$ (19,386)	$ (23,098)	$ (32,972)	$ (50,744)	
	Historical Component Tracking Account															
24	Beginning Balance			$ (13,728)	$ (78,796)	$ (74,270)	$ (70,139)	$ (66,107)	$ (61,678)	$ (56,160)	$ (48,847)	$ (41,371)	$ (33,926)	$ (27,783)	$ (23,002)	
25	Xfers fr/ 2009 For Com Tracking Acct			$ (66,586)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
26	Xfers fr/ Old PSA & Surcharge Accts			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
27	Monthly Interest Rate[2]	11.00%	0.84%	0.9167%	0.9167%	0.9167%	0.9167%	0.9167%	0.9167%	0.9167%	0.9167%	0.9167%	0.9167%	0.9167%	0.9167%	
28	Monthly Interest			$ (736)	$ (722)	$ (681)	$ (643)	$ (606)	$ (565)	$ (515)	$ (448)	$ (379)	$ (311)	$ (255)	$ (211)	
29	Collections			$ (2,254)	$ (5,249)	$ (4,811)	$ (4,675)	$ (5,035)	$ (6,084)	$ (7,827)	$ (7,924)	$ (7,824)	$ (6,454)	$ (5,036)	$ (5,366)	
30	Ending Balance with Interest			$ (78,796)	$ (74,270)	$ (70,139)	$ (66,107)	$ (61,678)	$ (56,160)	$ (48,847)	$ (41,371)	$ (33,926)	$ (27,783)	$ (23,002)	$ (17,847)	
31	Combined Balance			$ (97,375)	$ (103,604)	$ (110,102)	$ (116,580)	$ (116,117)	$ (107,851)	$ (93,039)	$ (72,697)	$ (53,313)	$ (50,881)	$ (55,974)	$ (68,591)	
																TOTAL INT
32	Combined Monthly Interest			$ (736)	$ (893)	$ (950)	$ (1,009)	$ (1,069)	$ (1,064)	$ (989)	$ (853)	$ (666)	$ (489)	$ (466)	$ (513)	$ (9,697)
																$ (9,311)

[1] one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release H-15
[2] Authorized Rate of Return on Equity or short term debt rate
Short term debt rate obtained from Company 10-Ks

Arizona Corporation Commission
Docket No. E-01345A-11-0224
Exhibit: MJM-3
Schedule 2

Arizona Public Service
Analysis of Staff's Proposed Interest Rate Calculations
Monthly PSA Balance - 2008
($ in thousands)

CHART 2a: Based on December 31, 2008 PSA Report, p.11 of 12

Line No.	Description	Annual Interest Rate	Jan Change	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total Interest
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(o)	(p)	(q)
	Forward Component Tracking Account															
1	Beginning Balance			$ 40,010	$ 43,023	$ (9,663)	$ (25,095)	$ (33,695)	$ (33,983)	$ (9,300)	$ 19,928	$ 38,499	$ 41,535	$ 31,773	$ 14,304	
2	Xfers to 2009 Histl Comp Tracking Acct			$ -	$ (43,023)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
3	Monthly Interest Rate[1]	3.1700%	4.6300%	0.3858%	0.2642%	0.2642%	0.2642%	0.2642%	0.2642%	0.2642%	0.2642%	0.2642%	0.2642%	0.2642%	0.2642%	
4	Monthly Interest			$ 154	$ -	$ (26)	$ (66)	$ (89)	$ (90)	$ (25)	$ 53	$ 102	$ 110	$ 84	$ 38	
5	Post-Sharing (Over)/Under Collection			$ 2,858	$ (3,720)	$ (9,818)	$ (2,844)	$ 5,765	$ 32,109	$ 38,259	$ 27,719	$ 11,681	$ (2,476)	$ (11,341)	$ (10,832)	
6	Collections			$ -	$ 5,942	$ 5,588	$ 5,690	$ 5,964	$ 7,337	$ 9,008	$ 9,200	$ 8,746	$ 7,396	$ 6,212	$ 5,958	
7	Ending Balance with Interest			$ 43,023	$ (9,663)	$ (25,095)	$ (33,695)	$ (33,983)	$ (9,300)	$ 19,928	$ 38,499	$ 41,535	$ 31,773	$ 14,304	$ (2,448)	
	Historical Component Tracking Account															
8	Beginning Balance			$ -	$ -	$ 41,066	$ 39,191	$ 37,271	$ 35,253	$ 32,741	$ 29,630	$ 26,442	$ 23,406	$ 20,844	$ 18,702	
9	Xfers fr/ 2009 For Com Tracking Acct			$ -	$ 43,023	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
10	Xfers fr/ Old PSA & Surcharge Accts			$ -	$ 124	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
11	Monthly Interest Rate[1]	3.1700%	1.8000%	0.1500%	0.1500%	0.2642%	0.2642%	0.2642%	0.2642%	0.2642%	0.2642%	0.2642%	0.2642%	0.2642%	0.2642%	
12	Monthly Interest			$ -	$ 65	$ 108	$ 104	$ 98	$ 93	$ 86	$ 78	$ 70	$ 62	$ 55	$ 49	
13	Collections			$ -	$ 2,146	$ 1,984	$ 2,023	$ 2,117	$ 2,605	$ 3,198	$ 3,266	$ 3,105	$ 2,624	$ 2,196	$ 2,125	
14	Ending Balance with Interest			$ -	$ 41,066	$ 39,191	$ 37,271	$ 35,253	$ 32,741	$ 29,630	$ 26,442	$ 23,406	$ 20,844	$ 18,702	$ 16,627	
15	Combined Balance			$ 43,023	$ 31,403	$ 14,096	$ 3,576	$ 1,270	$ 23,441	$ 49,558	$ 64,941	$ 64,941	$ 52,617	$ 33,006	$ 14,179	
																TOTAL INT
16	Combined Monthly Interest			$ 154	$ 65	$ 83	$ 37	$ 9	$ 3	$ 62	$ 131	$ 172	$ 172	$ 139	$ 87	$ 1,114

CHART 2b: Based on Chart 1 above except Interest recalculated at proposed rates

		ROE Int Rate	Short Term Debt	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
	Forward Component Tracking Account															
17	Beginning Balance			$ 40,010	$ 42,943	$ (9,662)	$ (25,155)	$ (33,914)	$ (34,417)	$ (9,953)	$ 19,208	$ 37,763	$ 40,769	$ 30,973	$ 13,478	
18	Xfers to 2009 Hist Comp Tracking Acct			$ -	$ (42,943)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
19	Monthly Interest Rate[2]	10.75%	2.24%	0.1867%	0.1867%	0.8958%	0.8958%	0.8958%	0.8958%	0.8958%	0.1867%	0.1867%	0.1867%	0.1867%	0.1867%	
20	Monthly Interest			$ 75	$ (0)	$ (87)	$ (225)	$ (304)	$ (308)	$ (89)	$ 36	$ 70	$ 76	$ 58	$ 25	
21	Post-Sharing (Over)/Under Collection			$ 2,858	$ (3,720)	$ (9,818)	$ (2,844)	$ 5,765	$ 32,109	$ 38,259	$ 27,719	$ 11,681	$ (2,476)	$ (11,341)	$ (10,832)	
22	Collections			$ -	$ 5,942	$ 5,588	$ 5,690	$ 5,964	$ 7,337	$ 9,008	$ 9,200	$ 8,746	$ 7,396	$ 6,212	$ 5,958	
23	Ending Balance with Interest			$ 42,943	$ (9,662)	$ (25,155)	$ (33,914)	$ (34,417)	$ (9,953)	$ 19,208	$ 37,763	$ 40,769	$ 30,973	$ 13,478	$ (3,287)	
	Historical Component Tracking Account															
24	Beginning Balance			$ -	$ -	$ 41,082	$ 39,174	$ 37,224	$ 35,177	$ 32,638	$ 29,500	$ 26,289	$ 23,234	$ 20,653	$ 18,495	
25	Xfers fr/ 2009 For Com Tracking Acct			$ -	$ 43,023	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
26	Xfers fr/ Old PSA & Surcharge Accts			$ -	$ 124	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
27	Monthly Interest Rate[2]	10.75%	2.24%	0.1867%	0.1867%	0.1867%	0.1867%	0.1867%	0.1867%	0.1867%	0.1867%	0.1867%	0.1867%	0.1867%	0.1867%	
28	Monthly Interest			$ -	$ 81	$ 77	$ 73	$ 69	$ 66	$ 61	$ 55	$ 49	$ 43	$ 39	$ 35	
29	Collections			$ -	$ 2,146	$ 1,984	$ 2,023	$ 2,117	$ 2,605	$ 3,198	$ 3,266	$ 3,105	$ 2,624	$ 2,196	$ 2,125	
30	Ending Balance with Interest			$ -	$ 41,082	$ 39,174	$ 37,224	$ 35,177	$ 32,638	$ 29,500	$ 26,289	$ 23,234	$ 20,653	$ 18,495	$ 16,405	
31	Combined Balance			$ 42,943	$ 31,419	$ 14,019	$ 3,310	$ 760	$ 22,684	$ 48,709	$ 64,053	$ 64,002	$ 51,626	$ 31,973	$ 13,118	
																TOTAL INT
32	Combined Monthly Interest			$ 75	$ 81	$ (10)	$ (152)	$ (234)	$ (243)	$ (28)	$ 91	$ 120	$ 119	$ 96	$ 60	$ (26)
																$ (1,140)

[1] one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release H-15
[2] Authorized Rate of Return on Equity or short term debt rate
Short term debt rate obtained from Company 10-Ks

Arizona Corporation Commission
Docket No. E-01345A-11-0224
Exhibit: MJM-3
Schedule 3

Arizona Public Service
Analysis of Staff's Proposed Interest Rate Calculations
Monthly PSA Balance - 2009
($ in thousands)

CHART 3a: Based on December 31, 2009 PSA Report, p.10 of 11

Line No.	Description	Annual Interest Rate	Change	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total Interest
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(o)	(p)	(q)
	Forward Component Tracking Account															
1	Beginning Balance			$ (2,448)	$ (19,888)	$ (19,411)	$ (35,723)	$ (45,937)	$ (49,263)	$ (53,552)	$ (42,253)	$ (35,333)	$ (40,163)	$ (44,414)	$ (51,204)	
2	Xfers to 2009 Histl Comp Tracking Acct			$ -	$ 19,888	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
3	Monthly Interest Rate[1]	0.3700%		0.0308%	0.0308%	0.0308%	0.0308%	0.0308%	0.0308%	0.0308%	0.0308%	0.0308%	0.0308%	0.0308%	0.0308%	
4	Monthly Interest			$ (1)	$ 0	$ (6)	$ (11)	$ (15)	$ (16)	$ (18)	$ (14)	$ (12)	$ (13)	$ (15)	$ (17)	
5	Post-Sharing (Over)/Under Collection			$ (11,306)	$ (9,699)	$ (6,987)	$ (1,077)	$ 7,685	$ 8,373	$ 26,421	$ 22,609	$ 10,078	$ 7,537	$ 2,740	$ (5,285)	
6	Collections			$ 6,133	$ 9,712	$ 9,319	$ 9,126	$ 10,995	$ 12,646	$ 15,105	$ 15,674	$ 14,896	$ 11,774	$ 9,516	$ 10,079	
7	Ending Balance with Interest			$ (19,888)	$ (19,411)	$ (35,723)	$ (45,937)	$ (49,263)	$ (53,552)	$ (42,253)	$ (35,333)	$ (40,163)	$ (44,414)	$ (51,204)	$ (66,586)	
	Historical Component Tracking Account															
8	Beginning Balance			$ 16,627	$ 14,457	$ (7,545)	$ (7,826)	$ (8,488)	$ (9,053)	$ (9,692)	$ (10,499)	$ (11,294)	$ (12,085)	$ (12,704)	$ (13,217)	
9	Xfers fr/ 2009 For Com Tracking Acct			$ -	$ (19,888)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
10	Xfers fr/ Old PSA & Surcharge Accts			$ -	$ (1,607)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
11	Monthly Interest Rate[1]	0.3700%		0.0308%	0.0308%	0.0308%	0.0308%	0.0308%	0.0308%	0.0308%	0.0308%	0.0308%	0.0308%	0.0308%	0.0308%	
12	Monthly Interest			$ 6	$ (2)	$ (3)	$ (3)	$ (3)	$ (3)	$ (3)	$ (3)	$ (4)	$ (4)	$ (4)	$ (4)	
13	Collections			$ 2,175	$ 505	$ 278	$ 660	$ 562	$ 636	$ 804	$ 791	$ 788	$ 615	$ 509	$ 507	
14	Ending Balance with Interest			$ 14,457	$ (7,545)	$ (7,826)	$ (8,488)	$ (9,053)	$ (9,692)	$ (10,499)	$ (11,294)	$ (12,085)	$ (12,704)	$ (13,217)	$ (13,728)	
15	Combined Balance			$ (5,431)	$ (26,956)	$ (43,549)	$ (54,425)	$ (58,316)	$ (63,244)	$ (52,752)	$ (46,627)	$ (52,248)	$ (57,118)	$ (64,421)	$ (80,314)	
																TOTAL INT
16	Combined Monthly Interest			$ 5	$ (2)	$ (9)	$ (14)	$ (18)	$ (19)	$ (21)	$ (17)	$ (16)	$ (17)	$ (19)	$ (21)	$ (167)

CHART 3b: Based on Chart 1 above except Interest recalculated at proposed rates

		ROE Int Rate	Short Term Debt	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	Forward Component Tracking Account														
17	Beginning Balance			$ (2,448)	$ (19,909)	$ (19,432)	$ (35,912)	$ (46,437)	$ (50,163)	$ (54,885)	$ (44,061)	$ (37,520)	$ (42,675)	$ (47,294)	$ (54,494)
18	Xfers to 2009 Hist Comp Tracking Acct			$ -	$ 19,888	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
19	Monthly Interest Rate[2]	10.75%	1.09%	0.8958%	0.0908%	0.8958%	0.8958%	0.8958%	0.8958%	0.8958%	0.8958%	0.8958%	0.8958%	0.8958%	0.8958%
20	Monthly Interest			$ (22)	$ (0)	$ (174)	$ (322)	$ (416)	$ (449)	$ (492)	$ (395)	$ (336)	$ (382)	$ (424)	$ (488)
21	Post-Sharing (Over)/Under Collection			$ (11,306)	$ (9,699)	$ (6,987)	$ (1,077)	$ 7,685	$ 8,373	$ 26,421	$ 22,609	$ 10,078	$ 7,537	$ 2,740	$ (5,285)
22	Collections			$ 6,133	$ 9,712	$ 9,319	$ 9,126	$ 10,995	$ 12,646	$ 15,105	$ 15,674	$ 14,896	$ 11,774	$ 9,516	$ 10,079
23	Ending Balance with Interest			$ (19,909)	$ (19,432)	$ (35,912)	$ (46,437)	$ (50,163)	$ (54,885)	$ (44,061)	$ (37,520)	$ (42,675)	$ (47,294)	$ (54,494)	$ (70,346)
	Historical Component Tracking Account														
24	Beginning Balance			$ 16,627	$ 14,467	$ (7,539)	$ (7,885)	$ (8,615)	$ (9,255)	$ (9,974)	$ (10,867)	$ (11,755)	$ (12,649)	$ (13,377)	$ (14,006)
25	Xfers fr/ 2009 For Com Tracking Acct			$ -	$ (19,888)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26	Xfers fr/ Old PSA & Surcharge Accts			$ -	$ (1,607)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27	Monthly Interest Rate[2]	10.75%	1.09%	0.0908%	0.0908%	0.8958%	0.8958%	0.8958%	0.8958%	0.8958%	0.8958%	0.8958%	0.8958%	0.8958%	0.0908%
28	Monthly Interest			$ 15	$ (6)	$ (68)	$ (71)	$ (77)	$ (83)	$ (89)	$ (97)	$ (105)	$ (113)	$ (120)	$ (13)
29	Collections			$ 2,175	$ 505	$ 278	$ 660	$ 562	$ 636	$ 804	$ 791	$ 788	$ 615	$ 509	$ 507
30	Ending Balance with Interest			$ 14,467	$ (7,539)	$ (7,885)	$ (8,615)	$ (9,255)	$ (9,974)	$ (10,867)	$ (11,755)	$ (12,649)	$ (13,377)	$ (14,006)	$ (14,525)
31	Combined Balance			$ (5,442)	$ (26,971)	$ (43,797)	$ (55,052)	$ (59,417)	$ (64,859)	$ (54,928)	$ (49,276)	$ (55,323)	$ (60,671)	$ (68,499)	$ (84,871)
															TOTAL INT
32	Combined Monthly Interest			$ (7)	$ (6)	$ (242)	$ (392)	$ (493)	$ (532)	$ (581)	$ (492)	$ (441)	$ (496)	$ (544)	$ (501) $ (4,727)
															$ (4,560)

[1] one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release H-15
[2] Authorized Rate of Return on Equity or short term debt rate
Short term debt rate obtained from Company 10-Ks

Arizona Corporation Commission
Docket No. E-01345A-11-0224
Exhibit: MJM-3
Schedule 3

Arizona Public Service
Analysis of Staff's Proposed Interest Rate Calculations
Monthly PSA Balance - 2009
($ in thousands)

CHART 3a: Based on December 31, 2009 PSA Report, p.10 of 11

Line No.	Description	Annual Interest Rate	Change	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total Interest
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(o)	(p)	(q)
	Forward Component Tracking Account															
1	Beginning Balance			$ (2,448)	$ (19,888)	$ (19,411)	$ (35,723)	$ (45,937)	$ (49,263)	$ (53,552)	$ (42,253)	$ (35,333)	$ (40,163)	$ (44,414)	$ (51,204)	
2	Xfers to 2009 Histl Comp Tracking Acct			$ -	$ 19,888	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
3	Monthly Interest Rate[1]	0.3700%		0.0308%	0.0308%	0.0308%	0.0308%	0.0308%	0.0308%	0.0308%	0.0308%	0.0308%	0.0308%	0.0308%	0.0308%	
4	Monthly Interest			$ (1)	$ 0	$ (6)	$ (11)	$ (15)	$ (16)	$ (18)	$ (14)	$ (12)	$ (13)	$ (15)	$ (17)	
5	Post-Sharing (Over)/Under Collection			$ (11,306)	$ (9,699)	$ (6,987)	$ (1,077)	$ 7,685	$ 8,373	$ 26,421	$ 22,609	$ 10,078	$ 7,537	$ 2,740	$ (5,285)	
6	Collections			$ 6,133	$ 9,712	$ 9,319	$ 9,126	$ 10,995	$ 12,646	$ 15,105	$ 15,674	$ 14,896	$ 11,774	$ 9,516	$ 10,079	
7	Ending Balance with Interest			$ (19,888)	$ (19,411)	$ (35,723)	$ (45,937)	$ (49,263)	$ (53,552)	$ (42,253)	$ (35,333)	$ (40,163)	$ (44,414)	$ (51,204)	$ (66,586)	
	Historical Component Tracking Account															
8	Beginning Balance			$ 16,627	$ 14,457	$ (7,545)	$ (7,826)	$ (8,488)	$ (9,053)	$ (9,692)	$ (10,499)	$ (11,294)	$ (12,085)	$ (12,704)	$ (13,217)	
9	Xfers fr/ 2009 For Com Tracking Acct			$ -	$ (19,888)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
10	Xfers fr/ Old PSA & Surcharge Accts			$ -	$ (1,607)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
11	Monthly Interest Rate[1]	0.3700%		0.0308%	0.0308%	0.0308%	0.0308%	0.0308%	0.0308%	0.0308%	0.0308%	0.0308%	0.0308%	0.0308%	0.0308%	
12	Monthly Interest			$ 6	$ (2)	$ (3)	$ (3)	$ (3)	$ (3)	$ (3)	$ (3)	$ (4)	$ (4)	$ (4)	$ (4)	
13	Collections			$ 2,175	$ 505	$ 278	$ 660	$ 562	$ 636	$ 804	$ 791	$ 788	$ 615	$ 509	$ 507	
14	Ending Balance with Interest			$ 14,457	$ (7,545)	$ (7,826)	$ (8,488)	$ (9,053)	$ (9,692)	$ (10,499)	$ (11,294)	$ (12,085)	$ (12,704)	$ (13,217)	$ (13,728)	
15	Combined Balance			$ (5,431)	$ (26,956)	$ (43,549)	$ (54,425)	$ (58,316)	$ (63,244)	$ (52,752)	$ (46,627)	$ (52,248)	$ (57,118)	$ (64,421)	$ (80,314)	
																TOTAL INT
16	Combined Monthly Interest			$ 5	$ (2)	$ (9)	$ (14)	$ (18)	$ (19)	$ (21)	$ (17)	$ (16)	$ (17)	$ (19)	$ (21)	$ (167)

CHART 3b: Based on Chart 1 above except Interest recalculated at proposed rates

		ROE Int Rate	Short Term Debt	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
	Forward Component Tracking Account															
17	Beginning Balance			$ (2,448)	$ (19,909)	$ (19,432)	$ (35,912)	$ (46,437)	$ (50,163)	$ (54,885)	$ (44,061)	$ (37,520)	$ (42,675)	$ (47,294)	$ (54,494)	
18	Xfers to 2009 Hist Comp Tracking Acct			$ -	$ 19,888	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
19	Monthly Interest Rate[2]	10.75%	1.09%	0.8958%	0.0908%	0.8958%	0.8958%	0.8958%	0.8958%	0.8958%	0.8958%	0.8958%	0.8958%	0.8958%	0.8958%	
20	Monthly Interest			$ (22)	$ (0)	$ (174)	$ (322)	$ (416)	$ (449)	$ (492)	$ (395)	$ (336)	$ (382)	$ (424)	$ (488)	
21	Post-Sharing (Over)/Under Collection			$ (11,306)	$ (9,699)	$ (6,987)	$ (1,077)	$ 7,685	$ 8,373	$ 26,421	$ 22,609	$ 10,078	$ 7,537	$ 2,740	$ (5,285)	
22	Collections			$ 6,133	$ 9,712	$ 9,319	$ 9,126	$ 10,995	$ 12,646	$ 15,105	$ 15,674	$ 14,896	$ 11,774	$ 9,516	$ 10,079	
23	Ending Balance with Interest			$ (19,909)	$ (19,432)	$ (35,912)	$ (46,437)	$ (50,163)	$ (54,885)	$ (44,061)	$ (37,520)	$ (42,675)	$ (47,294)	$ (54,494)	$ (70,346)	
	Historical Component Tracking Account															
24	Beginning Balance			$ 16,627	$ 14,467	$ (7,539)	$ (7,885)	$ (8,615)	$ (9,255)	$ (9,974)	$ (10,867)	$ (11,755)	$ (12,649)	$ (13,377)	$ (14,006)	
25	Xfers fr/ 2009 For Com Tracking Acct			$ -	$ (19,888)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
26	Xfers fr/ Old PSA & Surcharge Accts			$ -	$ (1,607)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
27	Monthly Interest Rate[2]	10.75%	1.09%	0.0908%	0.0908%	0.8958%	0.8958%	0.8958%	0.8958%	0.8958%	0.8958%	0.8958%	0.8958%	0.8958%	0.0908%	
28	Monthly Interest			$ 15	$ (6)	$ (68)	$ (71)	$ (77)	$ (83)	$ (89)	$ (97)	$ (105)	$ (113)	$ (120)	$ (13)	
29	Collections			$ 2,175	$ 505	$ 278	$ 660	$ 562	$ 636	$ 804	$ 791	$ 788	$ 615	$ 509	$ 507	
30	Ending Balance with Interest			$ 14,467	$ (7,539)	$ (7,885)	$ (8,615)	$ (9,255)	$ (9,974)	$ (10,867)	$ (11,755)	$ (12,649)	$ (13,377)	$ (14,006)	$ (14,525)	
31	Combined Balance			$ (5,442)	$ (26,971)	$ (43,797)	$ (55,052)	$ (59,417)	$ (64,859)	$ (54,928)	$ (49,276)	$ (55,323)	$ (60,671)	$ (68,499)	$ (84,871)	
																TOTAL INT
32	Combined Monthly Interest			$ (7)	$ (6)	$ (242)	$ (392)	$ (493)	$ (532)	$ (581)	$ (492)	$ (441)	$ (496)	$ (544)	$ (501)	$ (4,727)
																$ (4,560)

[1] one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release H-15
[2] Authorized Rate of Return on Equity or short term debt rate
Short term debt rate obtained from Company 10-Ks

aps

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Jeffrey.Johnson@aps.com

September 30, 2011

Constance Fitzsimmons
Arizona Corporation Commission
1200 W. Washington
Phoenix, AZ 85007

RE: Arizona Public Service Company's 2010 Test Year Rate Case
Docket No. E-01345A-11-0224

Attached, please find Arizona Public Service Company's Response to Staff's Fourteenth Set of Data Requests in the above-referenced matter.

If you have any questions regarding this information, please contact Zachary Fryer at (602)250-4167.

Sincerely,

Jeffrey W. Johnson

JJ/cd
Attachment

cc: Michael J. McGarry, Blue Ridge Consulting Services, Inc.

ARIZONA CORPORATION COMMISSION
STAFF'S FOURTEENTH SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
SEPTEMBER 20, 2011

Staff 14.1: **PSA**: Workpaper PME-WP02 provides fuel categories Nuclear, Coal, Natural Gas/Oil, and Purchased Power.

a. Please provide the source documents for **all** amounts shown on PME-WP02.

b. Please identify the 2010 General Ledger account entries (as provided in Pre-Filed 1.04_APS Test Year General Ledger_APS14048) showing all calculations and necessary references to support the information included on PME-WP02.

c. Please reconcile any differences between Workpaper PME-WP02 and the APS Test year General Ledger.

Response: (a) - (c) Attached as APS14826 is the requested information. Also attached as APS14841 is a revised PME_WP2 page 1 that corresponds to the reconciled data provided above. Please note that the net base fuel cost decreased by approximately $72k due to the reconciling differences.

Witness: Pete Ewen

Nuclear

Account	Account Description	Budget Item	GL	PME WP2
5180000	Nuclear Fuel Expense	ISFSI PRE SD-99	7,471,114	
5180000	Nuclear Fuel Expense	ISFSI PST SD-99	1,543,752	
5180000	Nuclear Fuel Expense	NUCLEAR FUEL-99	65,413,606	
Total Nuclear			**74,428,472**	**74,428,472**

Account	Account Description	Budget Item	Resource Category	GL	PME WP2
5180000	Nuclear Fuel Expense	ISFSI PRE SD-99	669	4,441,669	
5180000	Nuclear Fuel Expense	ISFSI PST SD-99	669	791,772	
Total ISFSI Amortization				**5,233,441**	**5,233,461**

Coal

Operating Unit	Account	Account Description	Budget Item	GL	PME WP2
GFC1	5010000	Steam Power - Fuel	FERC BEN-10	(178,351.92)	
GFC2	5010000	Steam Power - Fuel	FERC BEN-10	(178,351.92)	
GFC3	5010000	Steam Power - Fuel	FERC BEN-10	(178,405.27)	
GFC4	5010000	Steam Power - Fuel	FERC BEN-10	(47,944.60)	
GFC5	5010000	Steam Power - Fuel	FERC BEN-10	(70,241.20)	
GFCCMMN	5010000	Steam Power - Fuel	FERC BEN-10	(157,918.82)	
GCH1	5010000	Steam Power - Fuel	FERC BEN-30	(225,024.28)	
GCH2	5010000	Steam Power - Fuel	FERC BEN-30	(264,620.96)	
GCH3	5010000	Steam Power - Fuel	FERC BEN-30	(292,706.02)	
GCHCMMN	5010000	Steam Power - Fuel	FERC BEN-30	(79,540.11)	
GFC5	5010000	Steam Power - Fuel	FERC BEN-99	0.02	
GFCCMMN	5010000	Steam Power - Fuel	FERC BEN-99	(0.02)	
GFNONPLT	5010000	Steam Power - Fuel	FERC BEN-99	(327,928.43)	
GNA	5010000	Steam Power - Fuel	FERC BEN-99	(19,862.93)	
GFC1	5010000	Steam Power - Fuel	FERC ID-10	(4,318.43)	
GFC2	5010000	Steam Power - Fuel	FERC ID-10	(4,318.43)	
GFC3	5010000	Steam Power - Fuel	FERC ID-10	(4,319.72)	
GFC4	5010000	Steam Power - Fuel	FERC ID-10	(1,160.91)	
GFC5	5010000	Steam Power - Fuel	FERC ID-10	(1,700.76)	
GFCCMMN	5010000	Steam Power - Fuel	FERC ID-10	(3,823.73)	
GCH1	5010000	Steam Power - Fuel	FERC ID-30	(5,448.54)	
GCH2	5010000	Steam Power - Fuel	FERC ID-30	(6,407.29)	
GCH3	5010000	Steam Power - Fuel	FERC ID-30	(7,087.30)	
GCHCMMN	5010000	Steam Power - Fuel	FERC ID-30	(1,925.92)	
GFC5	5010000	Steam Power - Fuel	FERC ID-99	0.01	
GFNONPLT	5010000	Steam Power - Fuel	FERC ID-99	(8,862.91)	
GNA	5010000	Steam Power - Fuel	FERC ID-99	(536.85)	
GFC1	5010000	Steam Power - Fuel	FERC TAX-10	(40,522.79)	
GFC2	5010000	Steam Power - Fuel	FERC TAX-10	(40,522.79)	
GFC3	5010000	Steam Power - Fuel	FERC TAX-10	(40,532.22)	
GFC4	5010000	Steam Power - Fuel	FERC TAX-10	(9,767.50)	
GFC5	5010000	Steam Power - Fuel	FERC TAX-10	(14,709.21)	
GFCCMMN	5010000	Steam Power - Fuel	FERC TAX-10	(28,875.20)	
GCH1	5010000	Steam Power - Fuel	FERC TAX-30	(46,253.27)	
GCH2	5010000	Steam Power - Fuel	FERC TAX-30	(54,077.88)	
GCH3	5010000	Steam Power - Fuel	FERC TAX-30	(59,732.13)	
GCHCMMN	5010000	Steam Power - Fuel	FERC TAX-30	(16,249.63)	
GFC4	5010000	Steam Power - Fuel	FERC TAX-99	(0.01)	
GFCCMMN	5010000	Steam Power - Fuel	FERC TAX-99	(0.01)	
GFNONPLT	5010000	Steam Power - Fuel	FERC TAX-99	(64,829.27)	
GNA	5010000	Steam Power - Fuel	FERC TAX-99	(4,365.02)	
GFC1	5010000	Steam Power - Fuel	FSL COAL HND-10	352,640.64	
GFC2	5010000	Steam Power - Fuel	FSL COAL HND-10	352,640.64	
GFC3	5010000	Steam Power - Fuel	FSL COAL HND-10	352,728.91	
GFC4	5010000	Steam Power - Fuel	FSL COAL HND-10	65,580.32	
GFC5	5010000	Steam Power - Fuel	FSL COAL HND-10	65,607.45	
GFCCMMN	5010000	Steam Power - Fuel	FSL COAL HND-10	732,046.89	
GCH1	5010000	Steam Power - Fuel	FSL COAL HND-30	500,487.38	
GCH2	5010000	Steam Power - Fuel	FSL COAL HND-30	862,826.98	
GCH3	5010000	Steam Power - Fuel	FSL COAL HND-30	1,107,075.91	
GCHCMMN	5010000	Steam Power - Fuel	FSL COAL HND-30	51,590.89	
GFNONPLT	5010000	Steam Power - Fuel	FSL COAL HND-99	(0.00)	
GNA	5010000	Steam Power - Fuel	FSL COAL HND-99	561,788.83	
GFC1	5010000	Steam Power - Fuel	FSL COAL OTH-10	21,929,076.48	
GFC2	5010000	Steam Power - Fuel	FSL COAL OTH-10	19,425,647.98	
GFC3	5010000	Steam Power - Fuel	FSL COAL OTH-10	27,377,203.84	
GFC4	5010000	Steam Power - Fuel	FSL COAL OTH-10	8,085,060.30	
GFC5	5010000	Steam Power - Fuel	FSL COAL OTH-10	13,363,146.61	
GFCCMMN	5010000	Steam Power - Fuel	FSL COAL OTH-10	1,304,928.00	
GCH1	5010000	Steam Power - Fuel	FSL COAL OTH-99	17,679,299.24	
GCH2	5010000	Steam Power - Fuel	FSL COAL OTH-99	28,559,970.77	
GCH3	5010000	Steam Power - Fuel	FSL COAL OTH-99	37,719,862.94	
GNA	5010000	Steam Power - Fuel	FSL COAL OTH-99	39,732,410.41	
GFC1	5010000	Steam Power - Fuel	FSL GAS FUEL-10	219,824.73	
GFC2	5010000	Steam Power - Fuel	FSL GAS FUEL-10	441,737.42	
GFC3	5010000	Steam Power - Fuel	FSL GAS FUEL-10	278,197.51	
GFC4	5010000	Steam Power - Fuel	FSL GAS FUEL-10	197,797.17	
GFC5	5010000	Steam Power - Fuel	FSL GAS FUEL-10	28,599.13	
GFCCMMN	5010000	Steam Power - Fuel	FSL GAS FUEL-10	2,724.73	
GCH1	5010000	Steam Power - Fuel	FSL GAS FUEL-99	36,494.02	

Coal

Operating Unit	Account	Account Description	Budget Item	GL	PME WP2	
GFNONPLT	5010000	Steam Power - Fuel	FSL GAS HAND-99	1,062,215.19		
GFC1	5010000	Steam Power - Fuel	FSL GEN OPS-10	(0.00)		
GFC2	5010000	Steam Power - Fuel	FSL GEN OPS-10	0.00		
GFC3	5010000	Steam Power - Fuel	FSL GEN OPS-10	0.00		
GFC4	5010000	Steam Power - Fuel	FSL GEN OPS-10	(0.00)		
GFC5	5010000	Steam Power - Fuel	FSL GEN OPS-10	(0.01)		
GCH1	5010000	Steam Power - Fuel	FSL GEN OPS-30	(109,286.69)		
GCH2	5010000	Steam Power - Fuel	FSL GEN OPS-30	(146,837.76)		
GCH3	5010000	Steam Power - Fuel	FSL GEN OPS-30	(247,833.04)		
GCH2	5010000	Steam Power - Fuel	FSL OIL FUEL-99	179,532.29		
GCH3	5010000	Steam Power - Fuel	FSL OIL FUEL-99	241,099.42		
GNA	5010000	Steam Power - Fuel	FSL OIL FUEL-99	805,913.67		
GCH2	5010000	Steam Power - Fuel	FSL OIL HAND-30	18,318.33		
GCH3	5010000	Steam Power - Fuel	FSL OIL HAND-30	27,687.75		
GCHCMMN	5010000	Steam Power - Fuel	FSL OIL HAND-30	632.25		
GFNONPLT	5010000	Steam Power - Fuel	FSL OIL HAND-99	471,448.93		
GCHCMMN	5010000	Steam Power - Fuel	FSL OTH HAND-30	4,190.57		
GFNONPLT	5010000	Steam Power - Fuel	FSL OTH HAND-99	0.00		
GFC1	5010000	Steam Power - Fuel	FSL RES WSTE-10	622,420.04		
GFC2	5010000	Steam Power - Fuel	FSL RES WSTE-10	622,420.04		
GFC3	5010000	Steam Power - Fuel	FSL RES WSTE-10	622,581.84		
GFC4	5010000	Steam Power - Fuel	FSL RES WSTE-10	278,210.86		
GFC5	5010000	Steam Power - Fuel	FSL RES WSTE-10	478,386.96		
GFCCMMN	5010000	Steam Power - Fuel	FSL RES WSTE-10	133,707.26		
GCH1	5010000	Steam Power - Fuel	FSL RES WSTE-30	130,760.87		
GCH2	5010000	Steam Power - Fuel	FSL RES WSTE-30	(22,108.54)		
GCH3	5010000	Steam Power - Fuel	FSL RES WSTE-30	(594,885.24)		
GCHCMMN	5010000	Steam Power - Fuel	FSL RES WSTE-30	329,853.29		
GNA	5010000	Steam Power - Fuel	FSL RES WSTE-99	(350,441.22)		
				223,453,739	**223,453,739**	**(0.01)**

Less Adjustments

Operating Unit	Account	Account Description	Budget Item	GL		
GFCCMMN	5010000	Steam Power - Fuel	FSL COAL OTH-10	1,304,928.00	**1,305,000**	**72**
		Coal Reclamation Amort		**1,304,928**		

Operating Unit	Account	Account Description	Budget Item	GL		
GFC1	5010000	Steam Power - Fuel	FSL GAS FUEL-10	**219,825**		
GFC2	5010000	Steam Power - Fuel	FSL GAS FUEL-10	**441,737**		
GFC3	5010000	Steam Power - Fuel	FSL GAS FUEL-10	**278,198**		
GFC4	5010000	Steam Power - Fuel	FSL GAS FUEL-10	**197,797**		
GFC5	5010000	Steam Power - Fuel	FSL GAS FUEL-10	**28,599**		
GFCCMMN	5010000	Steam Power - Fuel	FSL GAS FUEL-10	**2,725**		
GCH1	5010000	Steam Power - Fuel	FSL GAS FUEL-99	**36,494**		
GCH2	5010000	Steam Power - Fuel	FSL OIL FUEL-99	**179,532**		
GCH3	5010000	Steam Power - Fuel	FSL OIL FUEL-99	**241,099**		
GNA	5010000	Steam Power - Fuel	FSL OIL FUEL-99	**805,914**		
		Gas/Oil Used at Coal Plants		**2,431,920**	**1,477,000**	**(954,920)**
	5470002	Oth Prod Fuel Ops-Sys Sl Fuel	SURPLUS GEN-99	**20,494,208**		
		Off-system sales		**20,494,208**	**20,494,000**	**(208)**
CHOLL	5010000	Steam Power - Fuel	FERC BEN-30	**(1,240,477)**		
CHOLL	5010000	Steam Power - Fuel	FERC ID-30	**(30,036)**		
CHOLL	5010000	Steam Power - Fuel	FERC TAX-30	**(253,847)**		
CHOLL	5010000	Steam Power - Fuel	FSL COAL HND-30	**4,055,275**		
CHOLL	5010000	Steam Power - Fuel	FSL OIL HAND-30	**88,522**		
FOURC	5010000	Steam Power - Fuel	FERC BEN-10	**(1,734,449)**		
FOURC	5010000	Steam Power - Fuel	FERC ID-10	**(41,996)**		
FOURC	5010000	Steam Power - Fuel	FERC TAX-10	**(360,019)**		
FOURC	5010000	Steam Power - Fuel	FSL COAL HND-10	**3,828,628**		
		Fuel Handling		**4,311,600**	**4,504,000**	**192,400**

Natural Gas and Oil

Operating Unit	Account	Account Description	Budget Item	GL	PME WP2		
GOC1CT	5470000	Oth Prod Fuel Ops-NL Fuel	FSL GAS FUEL-99	260,621.14			
GOC1ST	5010000	Steam Power - Fuel	FSL GAS FUEL-99	1,377,477.51			
GOC2CT	5470000	Oth Prod Fuel Ops-NL Fuel	FSL GAS FUEL-99	142,004.01			
GOC2ST	5010000	Steam Power - Fuel	FSL GAS FUEL-99	1,313,613.35			
GRH1	5470000	Oth Prod Fuel Ops-NL Fuel	FSL GAS FUEL-99	52,164,477.44			
GRH2	5470000	Oth Prod Fuel Ops-NL Fuel	FSL GAS FUEL-99	60,456,195.67			
GSG1CT	5470000	Oth Prod Fuel Ops-NL Fuel	FSL GAS FUEL-99	55,621.69			
GSG1ST	5010000	Steam Power - Fuel	FSL GAS FUEL-99	(23,443.27)			
GSG2CT	5470000	Oth Prod Fuel Ops-NL Fuel	FSL GAS FUEL-99	51,379.24			
GSG2ST	5010000	Steam Power - Fuel	FSL GAS FUEL-99	23,421.77			
GSG3CT	5470000	Oth Prod Fuel Ops-NL Fuel	FSL GAS FUEL-99	418,065.13			
GSN1CT	5470000	Oth Prod Fuel Ops-NL Fuel	FSL GAS FUEL-99	519,480.94			
GSN2CT	5470000	Oth Prod Fuel Ops-NL Fuel	FSL GAS FUEL-99	496,096.61			
GSN3CT	5470000	Oth Prod Fuel Ops-NL Fuel	FSL GAS FUEL-99	584,516.02			
GSN4CT	5470000	Oth Prod Fuel Ops-NL Fuel	FSL GAS FUEL-99	535,942.29			
GSN5CT	5470000	Oth Prod Fuel Ops-NL Fuel	FSL GAS FUEL-99	562,496.23			
GSN6CT	5470000	Oth Prod Fuel Ops-NL Fuel	FSL GAS FUEL-99	546,189.88			
GSN7CT	5470000	Oth Prod Fuel Ops-NL Fuel	FSL GAS FUEL-99	527,873.67			
GSN8CT	5470000	Oth Prod Fuel Ops-NL Fuel	FSL GAS FUEL-99	493,889.58			
GSN9CT	5470000	Oth Prod Fuel Ops-NL Fuel	FSL GAS FUEL-99	502,509.33			
GSN10CT	5470000	Oth Prod Fuel Ops-NL Fuel	FSL GAS FUEL-99	425,220.12			
GSNCMMN	5470000	Oth Prod Fuel Ops-NL Fuel	FSL GAS FUEL-99	(256,076.97)			
GWP1CC	5470000	Oth Prod Fuel Ops-NL Fuel	FSL GAS FUEL-99	6,552,072.66			
GWP1CT	5470000	Oth Prod Fuel Ops-NL Fuel	FSL GAS FUEL-99	203,850.67			
GWP2CC	5470000	Oth Prod Fuel Ops-NL Fuel	FSL GAS FUEL-99	4,066,530.13			
GWP2CT	5470000	Oth Prod Fuel Ops-NL Fuel	FSL GAS FUEL-99	99,438.27			
GWP3CC	5470000	Oth Prod Fuel Ops-NL Fuel	FSL GAS FUEL-99	4,224,194.15			
GWP4CC	5470000	Oth Prod Fuel Ops-NL Fuel	FSL GAS FUEL-99	4,377,260.87			
GWP5CC	5470000	Oth Prod Fuel Ops-NL Fuel	FSL GAS FUEL-99	44,831,846.45			
GYU1CT	5470000	Oth Prod Fuel Ops-NL Fuel	FSL GAS FUEL-99	(17,817.57)			
GYU2CT	5470000	Oth Prod Fuel Ops-NL Fuel	FSL GAS FUEL-99	12,063.03			
GYU3CT	5470000	Oth Prod Fuel Ops-NL Fuel	FSL GAS FUEL-99	204,421.26			
GYU4CT	5470000	Oth Prod Fuel Ops-NL Fuel	FSL GAS FUEL-99	19,598.06			
GYU5CT	5470000	Oth Prod Fuel Ops-NL Fuel	FSL GAS FUEL-99	1,961,155.10			
GYU6CT	5470000	Oth Prod Fuel Ops-NL Fuel	FSL GAS FUEL-99	2,080,368.16			
GYU3CT	5470000	Oth Prod Fuel Ops-NL Fuel	FSL OIL FUEL-99	583.58			
GYU4CT	5470000	Oth Prod Fuel Ops-NL Fuel	FSL OIL FUEL-99	72,862.00			
GDG1CT	5470000	Oth Prod Fuel Ops-NL Fuel	FSL OIL FUEL-99	68,400.32			
NTVLDAPS	5470000	Oth Prod Fuel Ops-NL Fuel	NATIVE LOAD-99	$1,046,190.91			
				190,980,689.43			
GFNONPLT	5470000	Oth Prod Fuel Ops-NL Fuel	FSL GAS HAND-99	739,760.96			
GFNONPLT	5470000	Oth Prod Fuel Ops-NL Fuel	FSL OIL HAND-99	204,649.98			
GFNONPLT	5010000	Steam Power - Fuel	EXPENSE-99	0.10			
GDG1CT	5470000	Oth Prod Fuel Ops-NL Fuel	FSL OIL HAND-99	6,677.89			
GSGCMMN	5470000	Oth Prod Fuel Ops-NL Fuel	FSL GEN OPS-99	6,664.87			
GSGST	5010000	Steam Power - Fuel	FSL OTH HAND-99	20.00			
GWPCC	5470000	Oth Prod Fuel Ops-NL Fuel	FSL OIL HAND-99	1,017.03			
GYU5CT	5470000	Oth Prod Fuel Ops-NL Fuel	FSL GAS HAND-99	304,131.89			
GYUCMMN	5470000	Oth Prod Fuel Ops-NL Fuel	FSL OIL HAND-99	143.45			
GYUCT	5470000	Oth Prod Fuel Ops-NL Fuel	FSL OIL HAND-99	12,948.90			
				1,276,015.07			
GENTOLL	5470000	Oth Prod Fuel Ops-NL Fuel	FSL GAS FUEL-99	91,698,097.28	91,698,097	(0)	
Charge No.							
99-547-003	5470000	Oth Prod Fuel Ops-NL Fuel	FSL GAS FUEL-99	53,924,077			
1547-111	5470000	Oth Prod Fuel Ops-NL Fuel	NATIVE LOAD-99	21,819,205			
PM239	5470000	Oth Prod Fuel Ops-NL Fuel	NATIVE LOAD-99	120,350,488			
PM205	5470000	Oth Prod Fuel Ops-NL Fuel	NATIVE LOAD-99	15,428,139			
1547-112	5470000	Oth Prod Fuel Ops-NL Fuel	NATIVE LOAD-99	1,087,783			
PM120	5470000	Oth Prod Fuel Ops-NL Fuel	NATIVE LOAD-99	(1,086,908)			
		Gas Hedged and Mark to Market Expense		157,598,707	157,598,707	(0)	
Total Natural Gas/Oil				495,477,585.82	495,478,000	414	
Less Adjustments							
				GL	PME WP2		
1547-111	5470000	Oth Prod Fuel Ops-NL Fuel	NATIVE LOAD-99	21,819,205			
1547-112	5470000	Oth Prod Fuel Ops-NL Fuel	NATIVE LOAD-99	1,087,783			
		FAS 133 Mark-to-Market		22,906,988	22,907,000	12	
	5470002	Oth Prod Fuel Ops-Sys Sl Fuel	SURPLUS GEN-99	49,231,885			
		Percentage applied to Natural Gas		58%			
		Off-system sales		28,793,002	28,793,000	(2)	
99-547-003	5470000	Oth Prod Fuel Ops-NL Fuel	FSL GAS FUEL-99	53,924,077			
		Firm Gas Transport		53,924,077	55,455,000	1,530,923	2009 EPNG Refund accrued in 2010
	5470000	Oth Prod Fuel Ops-NL Fuel	FSL GAS HAND-99	1,274,938			
	5010000	Steam Power - Fuel	FSL GAS HAND-99	1,062,215			
	5470000	Oth Prod Fuel Ops-NL Fuel	FSL OIL HAND-99	306,910			
	5010000	Steam Power - Fuel	FSL OIL HAND-99	471,449			
	5010000	Steam Power - Fuel	FSL OTH HAND-30	10,807			
	5010000	Steam Power - Fuel	FSL OTH HAND-99	20			
GWP4CC	5470000	Steam Power - Fuel	FERC BEN-99	(167)			
GYU5CT	5470000	Steam Power - Fuel	FERC BEN-99	(3,857)			
GWP4CC	5470000	Steam Power - Fuel	FERC ID-99	(5)			
GYU5CT	5470000	Steam Power - Fuel	FERC ID-99	(104)			
GWP4CC	5470000	Steam Power - Fuel	FERC TAX-99	(32)			
GYU5CT	5470000	Steam Power - Fuel	FERC TAX-99	(825)			
		Fuel Handling		3,121,350	3,123,000	1,650	

Purchased Power

Account	Account Description	Budget Item	Charge Number	GL	PME WP2	
4560009	Other Electric Rev-NL Prch Pwr	NATIVE LOAD-99		(705,676)		
5550000	Purchased Power-Native Load	NATIVE LOAD-99		274,022,573		
5550000	Purchased Power-Native Load	EPS		8,200,983		
5550003	Purchased Power-Sys Sls Rev	OFFSYSTEM-99		20,176,680		
5550004	Purchased Power-Rtl Ld Hdg Mgt	NATV LD HEDG-99		7,850,798		
5550005	Purchased Power-System Sales	OFFSYSTEM-99		1,411,326		
5550094	Purchased Power-Rtl Ld Hdg IU	NATV LD HEDG-99		48,761,656		
5570001	Other Pwr Sup Exp-NL Purch Pwr	NATIVE LOAD-99		183,557		
5570009	Other Pwr Sup Exp-Offsys Rev	OFFSYSTEM-99		89,171		
5650000	Trans of Elec by Others-NL	GEN OPS OH 230		17,322,740		
5650002	Trans of Elec by Oth-SS Rev	GEN OPS GENERAL		338,073		
Total Purchased Power				**377,651,883**	**377,651,882**	**(1)**
Less Adjustments						
5550000	Purchased Power-Native Load	NATIVE LOAD-99	1555-111	17,397,263		
5550000	Purchased Power-Native Load	NATIVE LOAD-99	1555-200	(789,689)		
				16,607,573	**16,608,000**	**427**
5550003	Purchased Power-Sys Sls Rev	OFFSYSTEM-99	1555-018	20,941,514		
5550005	Purchased Power-System Sales	OFFSYSTEM-99	1555-030	922,811		
				21,864,325	**21,960,000**	**95,675**
5470000	Oth Prod Fuel Ops-NL Fuel	NATIVE LOAD-99	1547-120	2,748,981		
5550000	Purchased Power-Native Load	NATIVE LOAD-99	1555-037	29,220,433		
5650002	Trans of Elec by Oth-SS Rev	GEN OPS GENERAL		338,073		
				32,307,488	**32,217,219**	**(90,269)**
4470003	Sales for Resale-Rtl Ld Hg Mgt	NATV LD HEDG-99		**39,282,636**	**39,283,000**	**364**
5550000	Purchased Power-Native Load	NATIVE LOAD-99	1555-036 (Renewables Only)	**37,418,937**	**37,420,517**	**1,580**
5550000	Purchased Power-Native Load	EPS		**8,200,983**	**8,219,601**	**18,618**
	Total Purchased Power Adjustments			**155,681,942**	**155,708,337**	**26,395**

Off System Sales

Account	Account Description	Budget Item	Charge Number	GL	PME WP2	
4470003	Sales for Resale-Rtl Ld Hg Mgt	NATV LD HEDG-99		(39,282,636)		
4470004	Sales for Resale-Sys Sls Rev	OFFSYSTEM-99		(25,872,034)		
4470004	Sales for Resale-Sys Sls Rev	SURPLUS GEN-99		(80,408,015)		
4560007	Other Electric Rev-Sys Sales	NONTRADING-99		79,230		
				(145,483,454)	(145,483,454)	0
4560007	Other Electric Rev-Sys Sales	NONTRADING-99	1456-110	(1,508,339)		
4560007	Other Electric Rev-Sys Sales	NONTRADING-99	1456-109	419,105		
	Total FAS 133 Mark-to-Market			(1,089,235)	(1,089,000)	235

Reconciliation of Gross Fuel and Purchased Power Expense to Net Base Fuel Cost
($000)

	Nuclear	Coal	Natural Gas/Oil	Purchased Power	Purchased Renewables	Gas Transport/ Fuel Handling	Subtotal	Off-System Revenues/ Margin	Total System
Total (from Monthly Detail, Recorded Gross)	74,428	223,454	495,478	377,652	-	-	1,171,012	(145,483)	1,025,528
less Adjustments:									
Nuclear ISFSI Amortization	5,233	-	-	-	-	-	5,233	-	5,233
Coal Reclamation Amortization	-	1,305	-	-	-	-	1,305	-	1,305
Gas/Oil Used at Coal Plants	-	2,432	(2,432)	-	-	-	-	-	-
FAS 133 Mark-to-Market	-	-	22,907	16,608	-	-	39,515	(1,089)	38,426
Off-System Sales	-	20,494	28,793	21,864	-	-	71,151	(71,151)	-
ED 3/CoW Sales	-	-	-	32,307	-	-	32,307	-	32,307
Hedge Sales Recorded as Revenue Credit	-	-	-	39,283	-	-	39,283	(39,283)	-
Firm Gas Transportation	-	-	55,455	-	-	(55,455)	-	-	-
Fuel Handling	-	4,312	3,121	-	-	(7,433)	-	-	-
Renewables in Purchased Power	-	-	-	37,419	(37,419)	-	-	-	-
Renewables Above Market	-	-	-	8,201	-	-	8,201	-	8,201
Total Adjustments	5,233	28,542	107,844	155,683	(37,419)	(62,888)	196,996	(111,523)	85,473
Net Base Fuel Cost	69,195	194,911	387,633	221,969	37,419	62,888	974,015	(33,960)	940,055

ARIZONA CORPORATION COMMISSION
STAFF'S FOURTEENTH SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
SEPTEMBER 20, 2011

Staff 14.2: **PSA**: Workpaper PME-WP02 shows several adjustments to fuel categories (e.g., Nuclear ISFSI Amortization and Coal Reclamation Amortization, as well as several others). Please identify and provide the sources (accounts and 2010 General Ledger entries) from which these items and all related adjustments included in the workpaper are derived.

Response: Please see APS's response to Staff 14.1.

Witness: Pete Ewen

ARIZONA CORPORATION COMMISSION
STAFF'S FOURTEENTH SET OF DATA REQUESTS
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DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
SEPTEMBER 20, 2011

Staff 14.3: **PSA**: Please provide all source documents, work papers, and calculations for Production GWH shown on PME-3 page 1 (Actuals 2010).

Response: Please see Pete Ewen's workpaper, PME_WP2 page 2 of 3 for the total production (GWH) by fuel source

The attached document, APS14827, reconciles the total energy production from PME_WP2 to the Native Load Energy Production on Attachment PME-3.

In the initial filing of Attachment PME-3, the native load energy was based on the sum of preliminary monthly estimates, which differ from the totals reported on PME_WP2. A revised PME-3 is attached as APS14828 which has the final native load production. Please note that this revision does not affect the calculation of the Net Retail Fuel Cost.

Witness: Pete Ewen

Total Production to Native Load Reconciliation

	Total Production (GWH) PME_WP2	Move Gila River and Arlington to Natural Gas	Move Renewables	Total Production (GWH)	Off-System Production (GWH)	Native Load Production (GWH) PME_3
Nuclear	9,079			9,079	-	9,079
Coal	12,383			12,383	1,173	11,210
Natural Gas	5,365	2,851		8,216	969	7,247
Purchased Power	6,982	(2,851)	(706)	3,425	1,253	2,172
Renewable			706	706	-	706
Total	33,809	-	-	33,809	3,395	30,414

Components of APS Base Fuel Rate
Actuals TME 12/31/2010

	Fuel Expense ($000)	Production (GWH)	Native Load Sales (GWH)	Share of Production (%)	Average Cost Not Weighted (¢/kWh)	Average Cost Weighted (¢/kWh)
Nuclear [1]	69,197	9,079	8,381	29.9%	0.83	0.25
Coal [2]	195,673	11,210	10,348	36.9%	1.89	0.70
Natural Gas [3]	386,676	7,247	6,689	23.8%	5.78	1.38
Purchased Power [4]	221,949	2,172	2,005	7.1%	11.07	0.79
Renewable [5, 6]	37,421	706	652	2.3%	5.74	0.13
Fixed Gas Transport and Fuel Handling	63,081	-	-	0.0%		0.22
Total Native Load	973,997	30,414	28,075	100.0%		3.4692
Off System Margin Credit to Retail	(33,864)		28,075			(0.1206)
Net Retail Fuel Cost	940,133		28,075			**3.3486**

1 - Excludes fixed ISFSI expense
2 - Excludes coal reclamation costs.
3 - Includes fuel costs associated with long-term tolling arrangements.
4 - Includes native load hedge liquidation costs.
5 - Excludes costs for above market purchase premiums which are recovered through RES.
6 - Includes generation associated with company owned facilities.

ARIZONA CORPORATION COMMISSION
STAFF'S FOURTEENTH SET OF DATA REQUESTS
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DOCKET NO. E-01345A-11-0224
SEPTEMBER 20, 2011

Staff 14.4: **PSA**: Please explain the difference between the Production GWH shown on PME-3 page 1 (Actuals 2010) and the corresponding amounts in PME-3 page 2 (Proposed using 3/31/11 Market Prices).

Response: The difference between the production GWH shown on PME-3 page 1 versus PME-3 page 2 is that PME-3 page 1 are actual results from the 2010 test year and PME-3 page 2 are forecast results for 2012. Please see PME_WP5 for the details that make up the 2012 forecast.

Witness: Pete Ewen

ARIZONA CORPORATION COMMISSION
STAFF'S FOURTEENTH SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
SEPTEMBER 20, 2011

Staff 14.5: **PSA**: Please provide all source documents, work papers, and calculations for Native Load Sales GWH shown on PME-3 page 1 (Actuals 2010).

Response: Please see Pete Ewen's workpaper, PME_WP4. For additional detail, please see APS's response to Pre-Filed 1.31, 2010 rev class.

Witness: Pete Ewen

ARIZONA CORPORATION COMMISSION
STAFF'S FOURTEENTH SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
SEPTEMBER 20, 2011

Staff 14.6: **PSA**: Please explain the difference between the Native Load Sales GWH shown on PME-3 page 1 (Actuals 2010) and the corresponding amounts in PME-3 page 2 (Proposed using 3/31/11 Market Prices).

Response: The difference between the native load sales GWH shown on PME-3 page 1 versus PME-3 page 2 is that PME-3 page 1 are actual results from the 2010 test year and PME-3 page 2 are forecast results for 2012. Please see PME_WP9 page 3 for the details that make up the 2012 forecast.

Witness: Pete Ewen

aps

JEFFREY W. JOHNSON
Regulatory Affairs Supervisor
State Regulation

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Tel 602-250-2661
Jeffrey.Johnson@aps.com

October 17, 2011

Constance Fitzsimmons
Arizona Corporation Commission
1200 W. Washington
Phoenix, AZ 85007

RE: Arizona Public Service Company's 2010 Test Year Rate Case
Docket No. E-01345A-11-0224

Attached, please find Arizona Public Service Company's Response to Staff's Eighteenth Set of Data Requests in the above-referenced matter.

If you have any questions regarding this information, please contact Zachary Fryer at (602)250-4167.

Sincerely,

Jeffrey W. Johnson

JJ/cd
Attachment

cc: Michael J. McGarry, Blue Ridge Consulting Services, Inc.

ARIZONA CORPORATION COMMISSION
STAFF'S EIGHTEENTH SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
OCTOBER 5, 2011

Staff 18.1: **PSA**: Reference Response to STF 14.1, Attachment APS14826 Page 1 of 6, ISFSI Amortization. For ISFSI Amortization Adjustment, Page 1 of APS14826 shows a Resource Category of 669. However, on the General Ledger provided in Pre-Filed 1.04_APS Test Year General Ledger_APS14048 does not identify entries according to this Resource Category. As requested in STF 14.1a and b, please identify the 2010 General Ledger account entries and/or other source documents or calculations from which the ISFSI Amortization Adjustment is derived.

Response: See APS14877, which reconciles to Pre-Filed 1.04_APS Test Year General Ledger_APS14048 and provides transactional detail by Resource Category 669.

See APS14878 and APS14879 for supporting Journal Voucher documentation related to the transactions captured above.

Witness: Pete Ewen

ACC DR 18.1
Pinnacle West

Budget Item / Resource Category / Business Unit	Account	Sub Budget	Description	Month Number	Description	GL Journal Category	GL Category Description		Quantity	Amount
ISFSI PRE SD-99										
300										
APSCO	5180000	NA	Materials&Supplies Default	201001	Nuclear Fuel Expense	515	APSNUCLEAR FUEL		0.00	$285,246.00
APSCO	5180000	NA	Materials&Supplies Default	201002	Nuclear Fuel Expense	515	APSNUCLEAR FUEL		0.00	$261,286.00
APSCO	5180000	NA	Materials&Supplies Default	201003	Nuclear Fuel Expense	515	APSNUCLEAR FUEL		0.00	$243,346.00
APSCO	5180000	NA	Materials&Supplies Default	201004	Nuclear Fuel Expense	515	APSNUCLEAR FUEL		0.00	$191,717.00
APSCO	5180000	NA	Materials&Supplies Default	201005	Nuclear Fuel Expense	515	APSNUCLEAR FUEL		0.00	$209,541.00
APSCO	5180000	NA	Materials&Supplies Default	201006	Nuclear Fuel Expense	515	APSNUCLEAR FUEL		0.00	$270,417.00
APSCO	5180000	NA	Materials&Supplies Default	201007	Nuclear Fuel Expense	515	APSNUCLEAR FUEL		0.00	$270,417.00
APSCO	5180000	NA	Materials&Supplies Default	201008	Nuclear Fuel Expense	515	APSNUCLEAR FUEL		0.00	$298,839.00
APSCO	5180000	NA	Materials&Supplies Default	201009	Nuclear Fuel Expense	515	APSNUCLEAR FUEL		0.00	$277,061.00
APSCO	5180000	NA	Materials&Supplies Default	201010	Nuclear Fuel Expense	515	APSNUCLEAR FUEL		0.00	$190,816.00
APSCO	5180000	NA	Materials&Supplies Default	201011	Nuclear Fuel Expense	515	APSNUCLEAR FUEL		0.00	$241,333.00
APSCO	5180000	NA	Materials&Supplies Default	201012	Nuclear Fuel Expense	515	APSNUCLEAR FUEL		0.00	$289,426.00
300 Total									**0.00**	**$3,029,445.00**
669										
APSCO	5180000	NA	Nuclear Fuel-Misc	201001	Nuclear Fuel Expense	515	APSNUCLEAR FUEL	See Journal ID 133884	0.00	$836,316.00
APSCO	5180000	NA	Nuclear Fuel-Misc	201002	Nuclear Fuel Expense	515	APSNUCLEAR FUEL	as APS 14878	0.00	$836,316.00
APSCO	5180000	NA	Nuclear Fuel-Misc	201003	Nuclear Fuel Expense	515	APSNUCLEAR FUEL		0.00	$836,296.00
APSCO	5180000	NA	Nuclear Fuel-Misc	201004	Nuclear Fuel Expense	515	APSNUCLEAR FUEL		0.00	$214,749.00
APSCO	5180000	NA	Nuclear Fuel-Misc	201005	Nuclear Fuel Expense	515	APSNUCLEAR FUEL		0.00	$214,749.00
APSCO	5180000	NA	Nuclear Fuel-Misc	201006	Nuclear Fuel Expense	515	APSNUCLEAR FUEL	See Journal ID 140347	0.00	$214,749.00
APSCO	5180000	NA	Nuclear Fuel-Misc	201007	Nuclear Fuel Expense	515	APSNUCLEAR FUEL	as APS 14879	0.00	$214,749.00
APSCO	5180000	NA	Nuclear Fuel-Misc	201008	Nuclear Fuel Expense	515	APSNUCLEAR FUEL		0.00	$214,749.00
APSCO	5180000	NA	Nuclear Fuel-Misc	201009	Nuclear Fuel Expense	515	APSNUCLEAR FUEL		0.00	$214,749.00
APSCO	5180000	NA	Nuclear Fuel-Misc	201010	Nuclear Fuel Expense	515	APSNUCLEAR FUEL		0.00	$214,749.00
APSCO	5180000	NA	Nuclear Fuel-Misc	201011	Nuclear Fuel Expense	515	APSNUCLEAR FUEL		0.00	$214,749.00
APSCO	5180000	NA	Nuclear Fuel-Misc	201012	Nuclear Fuel Expense	515	APSNUCLEAR FUEL		0.00	$214,749.00
669 Total									**0.00**	**$4,441,669.00**
ISFSI PRE SD-99 Total									**0.00**	**$7,471,114.00**

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of 5053.

ACC DR 18.1
Pinnacle West

Budget Item / Resource Category / Business Unit	Account	Sub Budget	Description	Month Number	Description	GL Journal Category	GL Category Description		Quantity	Amount
ISFSI PST SD-99										
300										
APSCO	5180000	NA	Materials&Supplies Default	201001	Nuclear Fuel Expense	515	APSNUCLEAR FUEL		0.00	$62,665.00
APSCO	5180000	NA	Materials&Supplies Default	201002	Nuclear Fuel Expense	515	APSNUCLEAR FUEL		0.00	$62,665.00
APSCO	5180000	NA	Materials&Supplies Default	201003	Nuclear Fuel Expense	515	APSNUCLEAR FUEL		0.00	$62,665.00
APSCO	5180000	NA	Materials&Supplies Default	201004	Nuclear Fuel Expense	515	APSNUCLEAR FUEL		0.00	$62,665.00
APSCO	5180000	NA	Materials&Supplies Default	201005	Nuclear Fuel Expense	515	APSNUCLEAR FUEL		0.00	$62,665.00
APSCO	5180000	NA	Materials&Supplies Default	201006	Nuclear Fuel Expense	515	APSNUCLEAR FUEL		0.00	$62,665.00
APSCO	5180000	NA	Materials&Supplies Default	201007	Nuclear Fuel Expense	515	APSNUCLEAR FUEL		0.00	$62,665.00
APSCO	5180000	NA	Materials&Supplies Default	201008	Nuclear Fuel Expense	515	APSNUCLEAR FUEL		0.00	$62,665.00
APSCO	5180000	NA	Materials&Supplies Default	201009	Nuclear Fuel Expense	515	APSNUCLEAR FUEL		0.00	$62,665.00
APSCO	5180000	NA	Materials&Supplies Default	201010	Nuclear Fuel Expense	515	APSNUCLEAR FUEL		0.00	$62,665.00
APSCO	5180000	NA	Materials&Supplies Default	201011	Nuclear Fuel Expense	515	APSNUCLEAR FUEL		0.00	$62,665.00
APSCO	5180000	NA	Materials&Supplies Default	201012	Nuclear Fuel Expense	515	APSNUCLEAR FUEL		0.00	$62,665.00
300 Total									**0.00**	**$751,980.00**
669										
APSCO	5180000	NA	Nuclear Fuel-Misc	201001	Nuclear Fuel Expense	515	APSNUCLEAR FUEL	See Journal ID133884	0.00	$65,981.00
APSCO	5180000	NA	Nuclear Fuel-Misc	201002	Nuclear Fuel Expense	515	APSNUCLEAR FUEL	as APS 14878	0.00	$65,981.00
APSCO	5180000	NA	Nuclear Fuel-Misc	201003	Nuclear Fuel Expense	515	APSNUCLEAR FUEL		0.00	$65,981.00
APSCO	5180000	NA	Nuclear Fuel-Misc	201004	Nuclear Fuel Expense	515	APSNUCLEAR FUEL		0.00	$65,981.00
APSCO	5180000	NA	Nuclear Fuel-Misc	201005	Nuclear Fuel Expense	515	APSNUCLEAR FUEL		0.00	$65,981.00
APSCO	5180000	NA	Nuclear Fuel-Misc	201006	Nuclear Fuel Expense	515	APSNUCLEAR FUEL		0.00	$65,981.00
APSCO	5180000	NA	Nuclear Fuel-Misc	201007	Nuclear Fuel Expense	515	APSNUCLEAR FUEL		0.00	$65,981.00
APSCO	5180000	NA	Nuclear Fuel-Misc	201008	Nuclear Fuel Expense	515	APSNUCLEAR FUEL		0.00	$65,981.00
APSCO	5180000	NA	Nuclear Fuel-Misc	201009	Nuclear Fuel Expense	515	APSNUCLEAR FUEL		0.00	$65,981.00
APSCO	5180000	NA	Nuclear Fuel-Misc	201010	Nuclear Fuel Expense	515	APSNUCLEAR FUEL		0.00	$65,981.00
APSCO	5180000	NA	Nuclear Fuel-Misc	201011	Nuclear Fuel Expense	515	APSNUCLEAR FUEL		0.00	$65,981.00
APSCO	5180000	NA	Nuclear Fuel-Misc	201012	Nuclear Fuel Expense	515	APSNUCLEAR FUEL		0.00	$65,981.00
669 Total									**0.00**	**$791,772.00**
ISFSI PST SD-99 Total									**0.00**	**$1,543,752.00** ✓

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ACC DR 18.1
Pinnacle West

Budget Item / Resource Category / Business Unit	Account	Sub Budget	Description	Month Number	Description	GL Journal Category	GL Category Description	Quantity	Amount
NUCLEAR FUEL-99									
300									
APSCO	5180000	NA	Materials&Supplies Default	201001	Nuclear Fuel Expense	515	APSNUCLEAR FUEL	0.00	$4,546,422.00
APSCO	5180000	NA	Materials&Supplies Default	201002	Nuclear Fuel Expense	515	APSNUCLEAR FUEL	0.00	$4,043,580.00
APSCO	5180000	NA	Materials&Supplies Default	201003	Nuclear Fuel Expense	515	APSNUCLEAR FUEL	0.00	$3,998,307.00
APSCO	5180000	NA	Materials&Supplies Default	201004	Nuclear Fuel Expense	515	APSNUCLEAR FUEL	0.00	$3,536,252.00
APSCO	5180000	NA	Materials&Supplies Default	201005	Nuclear Fuel Expense	515	APSNUCLEAR FUEL	0.00	$3,768,385.00
APSCO	5180000	NA	Materials&Supplies Default	201006	Nuclear Fuel Expense	515	APSNUCLEAR FUEL	0.00	$4,805,199.00
APSCO	5180000	NA	Materials&Supplies Default	201006	Nuclear Fuel Expense	HNA	Nuclear Accounting Hand Postings	0.00	$245,681.00
APSCO	5180000	NA	Materials&Supplies Default	201007	Nuclear Fuel Expense	515	APSNUCLEAR FUEL	0.00	$5,306,081.00
APSCO	5180000	NA	Materials&Supplies Default	201008	Nuclear Fuel Expense	515	APSNUCLEAR FUEL	0.00	$5,666,033.00
APSCO	5180000	NA	Materials&Supplies Default	201009	Nuclear Fuel Expense	515	APSNUCLEAR FUEL	0.00	$5,635,206.00
APSCO	5180000	NA	Materials&Supplies Default	201010	Nuclear Fuel Expense	515	APSNUCLEAR FUEL	0.00	$4,187,060.00
APSCO	5180000	NA	Materials&Supplies Default	201011	Nuclear Fuel Expense	515	APSNUCLEAR FUEL	0.00	$6,116,002.00
APSCO	5180000	NA	Materials&Supplies Default	201011	Nuclear Fuel Expense	HNA	Nuclear Accounting Hand Postings	0.00	($1,019,340.00)
APSCO	5180000	NA	Materials&Supplies Default	201012	Nuclear Fuel Expense	515	APSNUCLEAR FUEL	0.00	$6,089,112.00
300 Total								***0.00***	***$56,923,980.00***
669									
APSCO	5180000	NA	Nuclear Fuel-Misc	201001	Nuclear Fuel Expense	515	APSNUCLEAR FUEL	0.00	$800,653.00
APSCO	5180000	NA	Nuclear Fuel-Misc	201002	Nuclear Fuel Expense	515	APSNUCLEAR FUEL	0.00	$733,398.00
APSCO	5180000	NA	Nuclear Fuel-Misc	201003	Nuclear Fuel Expense	515	APSNUCLEAR FUEL	0.00	$683,042.00
APSCO	5180000	NA	Nuclear Fuel-Misc	201004	Nuclear Fuel Expense	515	APSNUCLEAR FUEL	0.00	$538,127.00
APSCO	5180000	NA	Nuclear Fuel-Misc	201005	Nuclear Fuel Expense	515	APSNUCLEAR FUEL	0.00	$588,159.00
APSCO	5180000	NA	Nuclear Fuel-Misc	201006	Nuclear Fuel Expense	515	APSNUCLEAR FUEL	0.00	$759,033.00
APSCO	5180000	NA	Nuclear Fuel-Misc	201007	Nuclear Fuel Expense	515	APSNUCLEAR FUEL	0.00	$795,861.00
APSCO	5180000	NA	Nuclear Fuel-Misc	201008	Nuclear Fuel Expense	515	APSNUCLEAR FUEL	0.00	$793,970.00
APSCO	5180000	NA	Nuclear Fuel-Misc	201009	Nuclear Fuel Expense	515	APSNUCLEAR FUEL	0.00	$773,778.00
APSCO	5180000	NA	Nuclear Fuel-Misc	201010	Nuclear Fuel Expense	515	APSNUCLEAR FUEL	0.00	$541,292.00
APSCO	5180000	NA	Nuclear Fuel-Misc	201011	Nuclear Fuel Expense	515	APSNUCLEAR FUEL	0.00	$673,999.00

ACC DR 18.1
Pinnacle West

Budget Item / Resource Category / Business Unit	Account	Sub Budget	Description	Month Number	Description	GL Journal Category	GL Category Description	Quantity	Amount
NUCLEAR FUEL-99									
669									
APSCO	5180000	NA	Nuclear Fuel-Misc	201012	Nuclear Fuel Expense	515	APSNUCLEAR FUEL	0.00	$808,314.00
669 Total								**0.00**	**$8,489,626.00**
NUCLEAR FUEL-99 Total								**0.00**	**$65,413,606.00**
								0.00	**$74,428,472.00**

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of 5053.

Journal Voucher Detail

Pinnacle West

Journal Id: 133884

Date Created: 02/01/2010
Time Created: 10:11:30
Month Number: 201001
Description: ISFSI/DRY CASK MONTHLY JRNL
Long Description: Record Ongoing Accrual to Expense
Record Amortization of Deferred Asset for January 2010

GL Journal Cat: 515
Reversing Journal: N
Creating User: [redacted]
Attachment Available: Y

Approval Status: Posted
Authorizer [redacted]
Date 2/1/2010 15:53:49

Debits/Credits: 1,284,370.00 / (1,284,370.00)

Month BU	Charge Number	Collector	Chg Dept	Home Dept	Res Cat	Op Unit	Acct	Budget Item	Sub Budget	Line Description	Amount
201001											
APSCO	99-1823102	99-1823102	8092	8092	300	GPV1	1823000	ISFSI UNIT 1	CONTRA	ISFSI LAYER 3	1,094.00
APSCO	99-1823202	99-1823202	8092	8092	300	GPV2	1823000	ISFSI UNIT 2	CONTRA	ISFSI LAYER 3	11,569.00
APSCO	99-1823302	99-1823302	8092	8092	300	GPV3	1823000	ISFSI UNIT 3	CONTRA	ISFSI LAYER 3	11,499.00
APSCO	99-5180001	99-5180001	8092	8092	669	GPV1	5180000	ISFSI PRE SI	NA	AMORT OF DEF ASSET - ISFSI	206,850.00
APSCO	99-5180002	99-5180002	8092	8092	669	GPV2	5180000	ISFSI PRE SI	NA	AMORT OF DEF ASSET - ISFSI	210,634.00
APSCO	99-5180003	99-5180003	8092	8092	669	GPV3	5180000	ISFSI PRE SI	NA	AMORT OF DEF ASSET - ISFSI	204,083.00
APSCO	99-5180101	99-5180101	8092	8092	669	GPV1	5180000	ISFSI PST SI	NA	AMORT OF DEF ASSET - ISFSI	17,813.00
APSCO	99-5180102	99-5180102	8092	8092	669	GPV1	5180000	ISFSI PRE SI	NA	AMORT OF DEF ASSET - ISFSI	71,583.00
APSCO	99-5180201	99-5180201	8092	8092	669	GPV2	5180000	ISFSI PST SI	NA	AMORT OF DEF ASSET - ISFSI	32,333.00
APSCO	99-5180202	99-5180202	8092	8092	669	GPV2	5180000	ISFSI PRE SI	NA	AMORT OF DEF ASSET - ISFSI	71,583.00
APSCO	99-5180301	99-5180301	8092	8092	669	GPV3	5180000	ISFSI PST SI	NA	AMORT OF DEF ASSET - ISFSI	15,835.00
APSCO	99-5180302	99-5180302	8092	8092	669	GPV3	5180000	ISFSI PRE SI	NA	AMORT OF DEF ASSET - ISFSI	71,583.00
APSCO	99-518A001	99-518A001	8092	8092	300	GPV1	5180000	ISFSI PRE SI	NA	DRY CASK ACCRUAL	92,631.00
APSCO	99-518A002	99-518A002	8092	8092	300	GPV2	5180000	ISFSI PRE SI	NA	DRY CASK ACCRUAL	96,598.00
APSCO	99-518A003	99-518A003	8092	8092	300	GPV3	5180000	ISFSI PRE SI	NA	DRY CASK ACCRUAL	96,017.00
APSCO	99-518A101	99-518A101	8092	8092	300	GPV1	5180000	ISFSI PST SI	NA	DRY CASK ACCRUAL	20,916.00
APSCO	99-518A201	99-518A201	8092	8092	300	GPV2	5180000	ISFSI PST SI	NA	DRY CASK ACCRUAL	20,833.00
APSCO	99-518A301	99-518A301	8092	8092	300	GPV3	5180000	ISFSI PST SI	NA	DRY CASK ACCRUAL	20,916.00
APSCO	99-1823001	99-1823001	8092	8092	669	GPVCMMN	1823000	ISFSI PRE SI	LAYER 1	AMORT OF DEF ASSET - ISFSI	(621,567.00)
APSCO	99-1823101	99-1823101	8092	8092	669	GPV1	1823000	ISFSI PST SI	LAYER 1	AMORT OF DEF ASSET - ISFSI	(17,813.00)
APSCO	99-1823102	99-1823102	8092	8092	300	GPV1	1823000	ISFSI UNIT 1	CONTRA	DRY CASK ACCRUAL	(113,547.00)
APSCO	99-1823103	99-1823103	8092	8092	669	GPV1	1823000	ISFSI UNIT 1	LAYER 2	AMORT OF DEF ASSET - ISFSI	(71,583.00)
APSCO	99-1823105	99-1823105	8092	8092	300	GPV1	1823000	ISFSI UNIT 1	LAYER 3	ISFSI LAYER 3	(11,094.00)
APSCO	99-1823201	99-1823201	8092	8092	669	GPV2	1823000	ISFSI PST SI	LAYER 1	AMORT OF DEF ASSET - ISFSI	(32,333.00)
APSCO	99-1823202	99-1823202	8092	8092	300	GPV2	1823000	ISFSI UNIT 2	CONTRA	DRY CASK ACCRUAL	(117,431.00)
APSCO	99-1823203	99-1823203	8092	8092	669	GPV2	1823000	ISFSI UNIT 2	LAYER 2	AMORT OF DEF ASSET - ISFSI	(71,583.00)
APSCO	99-1823205	99-1823205	8092	8092	300	GPV2	1823000	ISFSI UNIT 2	LAYER 3	ISFSI LAYER 3	(11,569.00)
APSCO	99-1823301	99-1823301	8092	8092	669	GPV3	1823000	ISFSI PST SI	LAYER 1	AMORT OF DEF ASSET - ISFSI	(15,835.00)

$\sum$ ① = 836,316

$\sum$ ② = 65,981

Journal Voucher Detail

Pinnacle West

Journal Id: 133884

Date Created: 02/01/2010
Time Created: 10:11:30
Month Number: 201001
Description: ISFSI/DRY CASK MONTHLY JRNL
Long Description: Record Ongoing Accrual to Expense
Record Amortization of Deferred Asset for January 2010

GL Journal Cat: 515
Reversing Journal: N
Creating User: [redacted]
Attachment Available: Y

Approval Status: Posted

Authorizer	Date
[redacted]	2/1/2010 15:53:49
-	
-	

Debits/Credits: 1,284,370.00 / (1,284,370.00)

Month BU	Charge Number	Collector	Chg Dept	Home Dept	Res Cat	Op Unit	Acct	Budget Item	Sub Budget	Line Description	Amount
201001											
APSCO	99-1823302	99-1823302	8092	8092	300	GPV3	1823000	ISFSI UNIT 3	CONTRA	DRY CASK ACCRUAL	(116,933.00)
APSCO	99-1823303	99-1823303	8092	8092	669	GPV3	1823000	ISFSI UNIT 3	LAYER 2	AMORT OF DEF ASSET - ISFSI	(71,583.00)
APSCO	99-1823305	99-1823305	8092	8092	300	GPV3	1823000	ISFSI UNIT 3	LAYER 3	ISFSI LAYER 3	(11,499.00)

Journal Voucher Detail

Pinnacle West

Journal Id: 140344

Date Created: 06/01/2010
Time Created: 12:54:50
Month Number: 201005
Description: ISFSI/DRY CASK MONTHLY JRNL
Long Description: Record Ongoing Accrual to Expense
Record Amortization of Deferred Asset for May 2010

GL Journal Cat: 515
Reversing Journal: N
Creating User: [redacted]
Attachment Available: Y

Approval Status: Posted

Authorizer	Date
[redacted]	6/1/2010 13:16:50
-	
-	

Debits/Credits: 578,031.00 / (578,031.00)

Month BU	Charge Number	Collector	Chg Dept	Home Dept	Res Cat	Op Unit	Acct	Budget Item	Sub Budget	Line Description	Amount
201005											
APSCO	99-1823102	99-1823102	8092	8092	300	GPV1	1823000	ISFSI UNIT 1	CONTRA	ISFSI LAYER 3	2,073.00
APSCO	99-1823202	99-1823202	8092	8092	300	GPV2	1823000	ISFSI UNIT 2	CONTRA	ISFSI LAYER 3	11,548.00
APSCO	99-1823302	99-1823302	8092	8092	300	GPV3	1823000	ISFSI UNIT 3	CONTRA	ISFSI LAYER 3	11,474.00
APSCO	99-5180101	99-5180101	8092	8092	669	GPV1	5180000	ISFSI PST SI	NA	AMORT OF DEF ASSET - ISFSI	17,813.00
APSCO	99-5180102	99-5180102	8092	8092	669	GPV1	5180000	ISFSI PRE SI	NA	AMORT OF DEF ASSET - ISFSI	71,583.00
APSCO	99-5180201	99-5180201	8092	8092	669	GPV2	5180000	ISFSI PST SI	NA	AMORT OF DEF ASSET - ISFSI	32,333.00
APSCO	99-5180202	99-5180202	8092	8092	669	GPV2	5180000	ISFSI PRE SI	NA	AMORT OF DEF ASSET - ISFSI	71,583.00
APSCO	99-5180301	99-5180301	8092	8092	669	GPV3	5180000	ISFSI PST SI	NA	AMORT OF DEF ASSET - ISFSI	15,835.00
APSCO	99-5180302	99-5180302	8092	8092	669	GPV3	5180000	ISFSI PRE SI	NA	AMORT OF DEF ASSET - ISFSI	71,583.00
APSCO	99-518A001	99-518A001	8092	8092	300	GPV1	5180000	ISFSI PRE SI	NA	DRY CASK ACCRUAL	17,313.00
APSCO	99-518A002	99-518A002	8092	8092	300	GPV2	5180000	ISFSI PRE SI	NA	DRY CASK ACCRUAL	96,423.00
APSCO	99-518A003	99-518A003	8092	8092	300	GPV3	5180000	ISFSI PRE SI	NA	DRY CASK ACCRUAL	95,805.00
APSCO	99-518A101	99-518A101	8092	8092	300	GPV1	5180000	ISFSI PST SI	NA	DRY CASK ACCRUAL	20,916.00
APSCO	99-518A201	99-518A201	8092	8092	300	GPV2	5180000	ISFSI PST SI	NA	DRY CASK ACCRUAL	20,833.00
APSCO	99-518A301	99-518A301	8092	8092	300	GPV3	5180000	ISFSI PST SI	NA	DRY CASK ACCRUAL	20,916.00
APSCO	99-1823101	99-1823101	8092	8092	669	GPV1	1823000	ISFSI PST SI	LAYER 1	AMORT OF DEF ASSET - ISFSI	(17,813.00)
APSCO	99-1823102	99-1823102	8092	8092	300	GPV1	1823000	ISFSI UNIT 1	CONTRA	DRY CASK ACCRUAL	(38,229.00)
APSCO	99-1823103	99-1823103	8092	8092	669	GPV1	1823000	ISFSI UNIT 1	LAYER 2	AMORT OF DEF ASSET - ISFSI	(71,583.00)
APSCO	99-1823105	99-1823105	8092	8092	300	GPV1	1823000	ISFSI UNIT 1	LAYER 3	ISFSI LAYER 3	(2,073.00)
APSCO	99-1823201	99-1823201	8092	8092	669	GPV2	1823000	ISFSI PST SI	LAYER 1	AMORT OF DEF ASSET - ISFSI	(32,333.00)
APSCO	99-1823202	99-1823202	8092	8092	300	GPV2	1823000	ISFSI UNIT 2	CONTRA	DRY CASK ACCRUAL	(117,256.00)
APSCO	99-1823203	99-1823203	8092	8092	669	GPV2	1823000	ISFSI UNIT 2	LAYER 2	AMORT OF DEF ASSET - ISFSI	(71,583.00)
APSCO	99-1823205	99-1823205	8092	8092	300	GPV2	1823000	ISFSI UNIT 2	LAYER 3	ISFSI LAYER 3	(11,548.00)
APSCO	99-1823301	99-1823301	8092	8092	669	GPV3	1823000	ISFSI PST SI	LAYER 1	AMORT OF DEF ASSET - ISFSI	(15,835.00)
APSCO	99-1823302	99-1823302	8092	8092	300	GPV3	1823000	ISFSI UNIT 3	CONTRA	DRY CASK ACCRUAL	(116,721.00)
APSCO	99-1823303	99-1823303	8092	8092	669	GPV3	1823000	ISFSI UNIT 3	LAYER 2	AMORT OF DEF ASSET - ISFSI	(71,583.00)
APSCO	99-1823305	99-1823305	8092	8092	300	GPV3	1823000	ISFSI UNIT 3	LAYER 3	ISFSI LAYER 3	(11,474.00)

Σ① = 214,749

ARIZONA CORPORATION COMMISSION
STAFF'S EIGHTEENTH SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
OCTOBER 5, 2011

Staff 18.2: **PSA**: Reference Response to STF 14.1, Attachment APS14826 Pages 2 & 3 of 6, Fuel Handling Adjustment. Totals for Coal Fuel Handling Adjustment categories (that together total 4,311,600) do not appear to match any individual amount entries totaled from categories on APS14826 Page 2 of 6 through the top half of Page 3 of 6. Please identify the Page 2 and top of Page 3 line items that make up each of the Fuel Handling Adjustment line items.

Response: Attached as APS14881 is a summary of the items that produce the fuel handling costs. The summarized information agrees to the Trial Balance provided in Pre-Filed Discovery APS 1.04 (Pages 4884-4887 and Page 4922).

Additional transactional detail supporting the summary items are also provided:

- APS14882 – Handling costs recorded to Account 501
- APS14883 – Handling costs recorded to Account 547

The schedules responding to Staff 14.1 attempted to correct the initial information provided in support of Pete Ewen's Direct Testimony, specifically workpaper PME_WP2. Upon further review the schedules provided in Staff 14.1 were not accurate and the initial information provided in PME_WP2 was correct. The schedules provided above support the information initially provided in PME_WP2.

Witness: Pete Ewen

ARIZONA PUBLIC SERVICE COMPANY
DR 18.2 - FUEL HANDLING

Account	Description	Budget Item	Coal & Res Waste Handling	Gas & Oil Handling	Total Handling
5010000	Steam Power - Fuel	FERC BEN-10	(811,213.73)		(811,213.73)
5010000	Steam Power - Fuel	FERC BEN-30	(861,891.37)		(861,891.37)
5010000	Steam Power - Fuel	FERC BEN-99	(347,791.36)		(347,791.36)
5010000	Steam Power - Fuel	FERC ID-10	(19,641.98)		(19,641.98)
5010000	Steam Power - Fuel	FERC ID-30	(20,869.05)		(20,869.05)
5010000	Steam Power - Fuel	FERC ID-99	(9,399.75)		(9,399.75)
5010000	Steam Power - Fuel	FERC TAX-10	(174,929.71)		(174,929.71)
5010000	Steam Power - Fuel	FERC TAX-30	(176,312.91)		(176,312.91)
5010000	Steam Power - Fuel	FERC TAX-99	(69,194.31)		(69,194.31)
5010000	Steam Power - Fuel	FSL COAL HND-10	1,921,244.85		1,921,244.85
5010000	Steam Power - Fuel	FSL COAL HND-30	2,521,981.16		2,521,981.16
5010000	Steam Power - Fuel	FSL COAL HND-99	561,788.83		561,788.83
5010000	Steam Power - Fuel	FSL GAS HAND-99		1,062,215.19	1,062,215.19
5010000	Steam Power - Fuel	FSL OIL HAND-30		46,638.33	46,638.33
5010000	Steam Power - Fuel	FSl OIL HAND-99		471,448.93	471,448.93
5010000	Steam Power - Fuel	FSL OTH HAND-30	4,190.57		4,190.57
5010000	Steam Power - Fuel	FSL OTH HAND-99	20.00		20.00
5010000	Steam Power - Fuel	FSL RES WSTE-10	2,757,727.00		2,757,727.00
5010000	Steam Power - Fuel	FSL-RES WSTE-30	(156,379.62)		(156,379.62)
5010000	Steam Power - Fuel	FSL-RES WSTE-99	(350,441.22)		(350,441.22)
5470000	Oth Prod Fuel Ops-NL Fuel	FERC BEN-99	(242,383.80)		(242,383.80)
5470000	Oth Prod Fuel Ops-NL Fuel	FERC ID-99	(6,550.93)		(6,550.93)
5470000	Oth Prod Fuel Ops-NL Fuel	FERC TAX-99	(63,786.40)		(63,786.40)
5470000	Oth Prod Fuel Ops-NL Fuel	FSL GAS HAND-99		1,274,937.99	1,274,937.99
5470000	Oth Prod Fuel Ops-NL Fuel	FSL OIL HAND-99		306,910.15	306,910.15
			$ 4,456,166.27	$ 3,162,150.59	$ 7,618,316.86

Account 5010000
✓ = Coal Ash Waste Handling
(✓) = Gas + Oil Handling

Budget Item Business Unit	Account	Description	Sub Budget	Operating Unit	Quantity		Amount
EXPENSE-99							
APSCO	5010000	Steam Power - Fuel	FUEL CMMN	GFNONPLT	0.00		$0.10
EXPENSE-99 Total					**0.00**		**$0.10**
FERC BEN-10							
APSCO	5010000	Steam Power - Fuel	FOURC	GFC1	0.00		($178,351.92)
APSCO	5010000	Steam Power - Fuel	FOURC	GFC2	0.00		($178,351.92)
APSCO	5010000	Steam Power - Fuel	FOURC	GFC3	0.00		($178,405.27)
APSCO	5010000	Steam Power - Fuel	FOURC	GFC4	0.00		($47,944.60)
APSCO	5010000	Steam Power - Fuel	FOURC	GFC5	0.00		($70,241.20)
APSCO	5010000	Steam Power - Fuel	FOURC	GFCCMMN	0.00		($157,918.82)
FERC BEN-10 Total					**0.00**	✓	**($811,213.73)**
FERC BEN-30							
APSCO	5010000	Steam Power - Fuel	CHOLL	GCH1	0.00		($225,024.28)
APSCO	5010000	Steam Power - Fuel	CHOLL	GCH2	0.00		($264,620.96)
APSCO	5010000	Steam Power - Fuel	CHOLL	GCH3	0.00		($292,706.02)
APSCO	5010000	Steam Power - Fuel	CHOLL	GCHCMMN	0.00		($79,540.11)
FERC BEN-30 Total					**0.00**	✓	**($861,891.37)**
FERC BEN-99							
APSCO	5010000	Steam Power - Fuel	APSCO	GFC5	0.00		$0.02
APSCO	5010000	Steam Power - Fuel	APSCO	GFCCMMN	0.00		($0.02)
APSCO	5010000	Steam Power - Fuel	APSCO	GFNONPLT	0.00		($327,928.43)
APSCO	5010000	Steam Power - Fuel	APSCO	GNA	0.00		($19,862.93)
FERC BEN-99 Total					**0.00**	✓	**($347,791.36)**
FERC ID-10							
APSCO	5010000	Steam Power - Fuel	FOURC	GFC1	0.00		($4,318.43)
APSCO	5010000	Steam Power - Fuel	FOURC	GFC2	0.00		($4,318.43)
APSCO	5010000	Steam Power - Fuel	FOURC	GFC3	0.00		($4,319.72)
APSCO	5010000	Steam Power - Fuel	FOURC	GFC4	0.00		($1,160.91)
APSCO	5010000	Steam Power - Fuel	FOURC	GFC5	0.00		($1,700.76)
APSCO	5010000	Steam Power - Fuel	FOURC	GFCCMMN	0.00		($3,823.73)
FERC ID-10 Total					**0.00**	✓	**($19,641.98)**
FERC ID-30							
APSCO	5010000	Steam Power - Fuel	CHOLL	GCH1	0.00		($5,448.54)
APSCO	5010000	Steam Power - Fuel	CHOLL	GCH2	0.00		($6,407.29)
APSCO	5010000	Steam Power - Fuel	CHOLL	GCH3	0.00		($7,087.30)
APSCO	5010000	Steam Power - Fuel	CHOLL	GCHCMMN	0.00		($1,925.92)
FERC ID-30 Total					**0.00**	✓	**($20,869.05)**
FERC ID-99							
APSCO	5010000	Steam Power - Fuel	APSCO	GFC5	0.00		$0.01
APSCO	5010000	Steam Power - Fuel	APSCO	GFNONPLT	0.00		($8,862.91)
APSCO	5010000	Steam Power - Fuel	APSCO	GNA	0.00		($536.85)
FERC ID-99 Total					**0.00**	✓	**($9,399.75)**
FERC TAX-10							
APSCO	5010000	Steam Power - Fuel	FOURC	GFC1	0.00		($40,522.79)

Budget Item Business Unit	Account	Description	Sub Budget	Operating Unit	Quantity	Amount
FERC TAX-10						
APSCO	5010000	Steam Power - Fuel	FOURC	GFC2	0.00	($40,522.79)
APSCO	5010000	Steam Power - Fuel	FOURC	GFC3	0.00	($40,532.22)
APSCO	5010000	Steam Power - Fuel	FOURC	GFC4	0.00	($9,767.50)
APSCO	5010000	Steam Power - Fuel	FOURC	GFC5	0.00	($14,709.21)
APSCO	5010000	Steam Power - Fuel	FOURC	GFCCMMN	0.00	($28,875.20)
FERC TAX-10 Total					**0.00**	**($174,929.71)**
FERC TAX-30						
APSCO	5010000	Steam Power - Fuel	CHOLL	GCH1	0.00	($46,253.27)
APSCO	5010000	Steam Power - Fuel	CHOLL	GCH2	0.00	($54,077.88)
APSCO	5010000	Steam Power - Fuel	CHOLL	GCH3	0.00	($59,732.13)
APSCO	5010000	Steam Power - Fuel	CHOLL	GCHCMMN	0.00	($16,249.63)
FERC TAX-30 Total					**0.00**	**($176,312.91)**
FERC TAX-99						
APSCO	5010000	Steam Power - Fuel	APSCO	GFC4	0.00	($0.01)
APSCO	5010000	Steam Power - Fuel	APSCO	GFCCMMN	0.00	($0.01)
APSCO	5010000	Steam Power - Fuel	APSCO	GFNONPLT	0.00	($64,829.27)
APSCO	5010000	Steam Power - Fuel	APSCO	GNA	0.00	($4,365.02)
FERC TAX-99 Total					**0.00**	**($69,194.31)**
FSL COAL HND-10						
APSCO	5010000	Steam Power - Fuel	FUEL APSCO	GFC1	0.00	$352,640.64
APSCO	5010000	Steam Power - Fuel	FUEL APSCO	GFC2	0.00	$352,640.64
APSCO	5010000	Steam Power - Fuel	FUEL APSCO	GFC3	0.00	$352,728.91
APSCO	5010000	Steam Power - Fuel	FUEL CMMN	GFCCMMN	0.00	$732,046.89
APSCO	5010000	Steam Power - Fuel	FUEL U4 5	GFC4	0.00	$65,580.32
APSCO	5010000	Steam Power - Fuel	FUEL U4 5	GFC5	0.00	$65,607.45
FSL COAL HND-10 Total					**0.00**	**$1,921,244.85**
FSL COAL HND-30						
APSCO	5010000	Steam Power - Fuel	FUEL APSCO	GCH1	0.00	$500,487.38
APSCO	5010000	Steam Power - Fuel	FUEL APSCO	GCH2	0.00	$862,826.98
APSCO	5010000	Steam Power - Fuel	FUEL APSCO	GCH3	0.00	$1,107,075.91
APSCO	5010000	Steam Power - Fuel	FUEL CMMN	GCHCMMN	0.00	$51,590.89
FSL COAL HND-30 Total					**0.00**	**$2,521,981.16**
FSL COAL HND-99						
APSCO	5010000	Steam Power - Fuel	FUEL APSCO	GNA	992.08	$561,788.83
APSCO	5010000	Steam Power - Fuel	FUEL CMMN	GFNONPLT	0.00	$0.00
FSL COAL HND-99 Total					**992.08**	**$561,788.83**
FSL COAL OTH-10						
APSCO	5010000	Steam Power - Fuel	FUEL APSCO	GFC1	0.00	$21,929,076.48
APSCO	5010000	Steam Power - Fuel	FUEL APSCO	GFC2	0.00	$19,425,647.98
APSCO	5010000	Steam Power - Fuel	FUEL APSCO	GFC3	0.00	$27,377,203.84
APSCO	5010000	Steam Power - Fuel	FUEL APSCO	GFC4	0.00	$8,085,060.30
APSCO	5010000	Steam Power - Fuel	FUEL APSCO	GFC5	0.00	$13,363,146.61

Budget Item Business Unit	Account	Description	Sub Budget	Operating Unit	Quantity	Amount
FSL COAL OTH-10						
APSCO	5010000	Steam Power - Fuel	FUEL APSCO	GFCCMMN	0.00	$1,304,928.00
FSL COAL OTH-10 Total					**0.00**	**$91,485,063.21**
FSL COAL OTH-99						
APSCO	5010000	Steam Power - Fuel	FUEL APSCO	GCH1	0.00	$17,679,299.24
APSCO	5010000	Steam Power - Fuel	FUEL APSCO	GCH2	0.00	$28,559,970.77
APSCO	5010000	Steam Power - Fuel	FUEL APSCO	GCH3	0.00	$37,719,862.94
APSCO	5010000	Steam Power - Fuel	FUEL APSCO	GNA	0.00	$39,732,410.41
FSL COAL OTH-99 Total					**0.00**	**$123,691,543.36**
FSL GAS FUEL-10						
APSCO	5010000	Steam Power - Fuel	FUEL APSCO	GFC1	0.00	$219,824.73
APSCO	5010000	Steam Power - Fuel	FUEL APSCO	GFC2	0.00	$441,737.42
APSCO	5010000	Steam Power - Fuel	FUEL APSCO	GFC3	0.00	$278,197.51
APSCO	5010000	Steam Power - Fuel	FUEL APSCO	GFC4	0.00	$197,797.17
APSCO	5010000	Steam Power - Fuel	FUEL APSCO	GFC5	0.00	$28,599.13
APSCO	5010000	Steam Power - Fuel	FUEL APSCO	GFCCMMN	0.00	$2,724.73
FSL GAS FUEL-10 Total					**0.00**	**$1,168,880.69**
FSL GAS FUEL-99						
APSCO	5010000	Steam Power - Fuel	FUEL APSCO	GCH1	0.00	$36,494.02
APSCO	5010000	Steam Power - Fuel	FUEL APSCO	GOC1ST	0.00	$1,377,477.51
APSCO	5010000	Steam Power - Fuel	FUEL APSCO	GOC2ST	0.00	$1,313,613.35
APSCO	5010000	Steam Power - Fuel	FUEL APSCO	GSG1ST	0.00	($23,443.27)
APSCO	5010000	Steam Power - Fuel	FUEL APSCO	GSG2ST	0.00	$23,421.77
FSL GAS FUEL-99 Total					**0.00**	**$2,727,563.38**
FSL GAS HAND-99						
APSCO	5010000	Steam Power - Fuel	FUEL CMMN	GFNONPLT	20,455.63	$1,062,215.19
FSL GAS HAND-99 Total					**20,455.63**	**$1,062,215.19**
FSL GEN OPS-10						
APSCO	5010000	Steam Power - Fuel	FUEL APSCO	GFC1	0.00	$0.00
APSCO	5010000	Steam Power - Fuel	FUEL APSCO	GFC2	0.00	$0.00
APSCO	5010000	Steam Power - Fuel	FUEL APSCO	GFC3	0.00	$0.00
APSCO	5010000	Steam Power - Fuel	FUEL U4 5	GFC4	0.00	$0.00
APSCO	5010000	Steam Power - Fuel	FUEL U4 5	GFC5	0.00	($0.01)
FSL GEN OPS-10 Total					**0.00**	**($0.01)**
FSL GEN OPS-30						
APSCO	5010000	Steam Power - Fuel	FUEL APSCO	GCH1	0.00	($109,286.69)
APSCO	5010000	Steam Power - Fuel	FUEL APSCO	GCH2	0.00	($146,837.76)
APSCO	5010000	Steam Power - Fuel	FUEL APSCO	GCH3	0.00	($247,833.04)
FSL GEN OPS-30 Total					**0.00**	**($503,957.49)**
FSL OIL FUEL-99						
APSCO	5010000	Steam Power - Fuel	FUEL APSCO	GCH2	0.00	$179,532.29
APSCO	5010000	Steam Power - Fuel	FUEL APSCO	GCH3	0.00	$241,099.42
APSCO	5010000	Steam Power - Fuel	FUEL APSCO	GNA	0.00	$805,913.67
FSL OIL FUEL-99 Total					**0.00**	**$1,226,545.38**

Budget Item Business Unit	Account	Description	Sub Budget	Operating Unit	Quantity		Amount
FSL OIL HAND-30							
APSCO	5010000	Steam Power - Fuel	FUEL APSCO	GCH2	0.00		$18,318.33
APSCO	5010000	Steam Power - Fuel	FUEL APSCO	GCH3	0.00		$27,687.75
APSCO	5010000	Steam Power - Fuel	FUEL CMMN	GCHCMMN	0.00		$632.25
FSL OIL HAND-30 Total					**0.00**	✓	**$46,638.33**
FSL OIL HAND-99							
APSCO	5010000	Steam Power - Fuel	FUEL CMMN	GFNONPLT	5,444.61		$471,448.93
FSL OIL HAND-99 Total					**5,444.61**	✓	**$471,448.93**
FSL OTH HAND-30							
APSCO	5010000	Steam Power - Fuel	FUEL CMMN	GCHCMMN	0.00		$4,190.57
FSL OTH HAND-30 Total					**0.00**	✓	**$4,190.57**
FSL OTH HAND-99							
APSCO	5010000	Steam Power - Fuel	FUEL APSCO	GSGST	0.00		$20.00
APSCO	5010000	Steam Power - Fuel	FUEL CMMN	GFNONPLT	40.00		$0.00
FSL OTH HAND-99 Total					**40.00**	✓	**$20.00**
FSL RES WSTE-10							
APSCO	5010000	Steam Power - Fuel	FUEL APSCO	GFC1	0.00		$622,420.04
APSCO	5010000	Steam Power - Fuel	FUEL APSCO	GFC2	0.00		$622,420.04
APSCO	5010000	Steam Power - Fuel	FUEL APSCO	GFC3	0.00		$622,581.84
APSCO	5010000	Steam Power - Fuel	FUEL APSCO	GFC4	0.00		$278,210.86
APSCO	5010000	Steam Power - Fuel	FUEL APSCO	GFC5	0.00		$478,386.96
APSCO	5010000	Steam Power - Fuel	FUEL CMMN	GFCCMMN	0.00		$133,707.26
FSL RES WSTE-10 Total					**0.00**	✓	**$2,757,727.00**
FSL RES WSTE-30							
APSCO	5010000	Steam Power - Fuel	FUEL APSCO	GCH1	0.00		$130,760.87
APSCO	5010000	Steam Power - Fuel	FUEL APSCO	GCH2	0.00		($22,108.54)
APSCO	5010000	Steam Power - Fuel	FUEL APSCO	GCH3	0.00		($594,885.24)
APSCO	5010000	Steam Power - Fuel	FUEL CMMN	GCHCMMN	0.00		$329,853.29
FSL RES WSTE-30 Total					**0.00**	✓	**($156,379.62)**
FSL RES WSTE-99							
APSCO	5010000	Steam Power - Fuel	FUEL APSCO	GNA	0.00		($350,441.22)
FSL RES WSTE-99 Total					**0.00**	✓	**($350,441.22)**
					26,932.32		**$226,144,828.47**

✓ = Coal Handling + Res Waste

(✓) = Gas + Oil Handling

Arizona Corporation Commission
Docket No. E-01345A-11-0224
Exhibit: MSM-4

✓ = Res Dusk Handling

(✓) = Gas + Oil Handling

ACC DR 18.2

Pinnacle West

Budget Item Business Unit	Account	Description	Sub Budget	Operating Unit	Quantity	Amount
FERC BEN-99						
APSCO	5470000	Oth Prod Fuel Ops-NL Fuel	APSCO	GFNONPLT	0.00	($238,360.17)
APSCO	5470000	Oth Prod Fuel Ops-NL Fuel	APSCO	GWP4CC	0.00	($166.99)
APSCO	5470000	Oth Prod Fuel Ops-NL Fuel	APSCO	GYU5CT	0.00	($3,856.64)
FERC BEN-99 Total					**0.00**	✓ **($242,383.80)**
FERC ID-99						
APSCO	5470000	Oth Prod Fuel Ops-NL Fuel	APSCO	GFNONPLT	0.00	($6,442.18)
APSCO	5470000	Oth Prod Fuel Ops-NL Fuel	APSCO	GWP4CC	0.00	($4.51)
APSCO	5470000	Oth Prod Fuel Ops-NL Fuel	APSCO	GYU5CT	0.00	($104.24)
FERC ID-99 Total					**0.00**	✓ **($6,550.93)**
FERC TAX-99						
APSCO	5470000	Oth Prod Fuel Ops-NL Fuel	APSCO	GFNONPLT	0.00	($62,929.50)
APSCO	5470000	Oth Prod Fuel Ops-NL Fuel	APSCO	GWP4CC	0.00	($31.59)
APSCO	5470000	Oth Prod Fuel Ops-NL Fuel	APSCO	GYU5CT	0.00	($825.31)
FERC TAX-99 Total					**0.00**	✓ **($63,786.40)**
FSL GAS FUEL-99						
APSCO	5470000	Oth Prod Fuel Ops-NL Fuel	APSCO RH1	GRH1	0.00	$52,164,477.44
APSCO	5470000	Oth Prod Fuel Ops-NL Fuel	APSCO RH2	GRH2	0.00	$60,456,195.67
APSCO	5470000	Oth Prod Fuel Ops-NL Fuel	APSCO SGCT	GSG3CT	0.00	$418,065.13
APSCO	5470000	Oth Prod Fuel Ops-NL Fuel	APSCO WP4	GWP4CC	8.00	$4,377,463.96
APSCO	5470000	Oth Prod Fuel Ops-NL Fuel	APSCO WP5	GWP5CC	0.00	$44,831,846.45
APSCO	5470000	Oth Prod Fuel Ops-NL Fuel	FIRM RES	GFNONPLT	0.00	$53,924,077.32
APSCO	5470000	Oth Prod Fuel Ops-NL Fuel	FUEL APSCO	GENTOLL	0.00	$91,698,097.28
APSCO	5470000	Oth Prod Fuel Ops-NL Fuel	FUEL APSCO	GOC1CT	0.00	$260,621.14
APSCO	5470000	Oth Prod Fuel Ops-NL Fuel	FUEL APSCO	GOC2CT	0.00	$142,004.01
APSCO	5470000	Oth Prod Fuel Ops-NL Fuel	FUEL APSCO	GSG1CT	0.00	$55,621.69
APSCO	5470000	Oth Prod Fuel Ops-NL Fuel	FUEL APSCO	GSG2CT	0.00	$51,379.24
APSCO	5470000	Oth Prod Fuel Ops-NL Fuel	FUEL APSCO	GSN10CT	0.00	$425,220.12
APSCO	5470000	Oth Prod Fuel Ops-NL Fuel	FUEL APSCO	GSN1CT	0.00	$519,480.94
APSCO	5470000	Oth Prod Fuel Ops-NL Fuel	FUEL APSCO	GSN2CT	0.00	$496,096.61
APSCO	5470000	Oth Prod Fuel Ops-NL Fuel	FUEL APSCO	GSN3CT	0.00	$584,516.02
APSCO	5470000	Oth Prod Fuel Ops-NL Fuel	FUEL APSCO	GSN4CT	0.00	$535,942.29
APSCO	5470000	Oth Prod Fuel Ops-NL Fuel	FUEL APSCO	GSN5CT	0.00	$562,496.23
APSCO	5470000	Oth Prod Fuel Ops-NL Fuel	FUEL APSCO	GSN6CT	0.00	$546,189.88
APSCO	5470000	Oth Prod Fuel Ops-NL Fuel	FUEL APSCO	GSN7CT	0.00	$527,873.67
APSCO	5470000	Oth Prod Fuel Ops-NL Fuel	FUEL APSCO	GSN8CT	0.00	$493,889.58
APSCO	5470000	Oth Prod Fuel Ops-NL Fuel	FUEL APSCO	GSN9CT	0.00	$502,509.33
APSCO	5470000	Oth Prod Fuel Ops-NL Fuel	FUEL APSCO	GSNCMMN	0.00	($256,076.97)
APSCO	5470000	Oth Prod Fuel Ops-NL Fuel	FUEL APSCO	GWP1CC	0.00	$6,552,072.66
APSCO	5470000	Oth Prod Fuel Ops-NL Fuel	FUEL APSCO	GWP1CT	0.00	$203,850.67
APSCO	5470000	Oth Prod Fuel Ops-NL Fuel	FUEL APSCO	GWP2CC	0.00	$4,066,630.13
APSCO	5470000	Oth Prod Fuel Ops-NL Fuel	FUEL APSCO	GWP2CT	0.00	$99,438.27
APSCO	5470000	Oth Prod Fuel Ops-NL Fuel	FUEL APSCO	GWP3CC	0.00	$4,224,194.15
APSCO	5470000	Oth Prod Fuel Ops-NL Fuel	FUEL APSCO	GYU1CT	0.00	($17,817.57)
APSCO	5470000	Oth Prod Fuel Ops-NL Fuel	FUEL APSCO	GYU2CT	0.00	$12,063.03
APSCO	5470000	Oth Prod Fuel Ops-NL Fuel	FUEL APSCO	GYU3CT	0.00	$204,421.26

Budget Item Business Unit	Account	Description	Sub Budget	Operating Unit	Quantity	Amount
FSL GAS FUEL-99						
APSCO	5470000	Oth Prod Fuel Ops-NL Fuel	FUEL APSCO	GYU4CT	0.00	$19,598.06
APSCO	5470000	Oth Prod Fuel Ops-NL Fuel	FUEL APSCO	GYU5CT	0.00	$1,961,155.10
APSCO	5470000	Oth Prod Fuel Ops-NL Fuel	FUEL APSCO	GYU6CT	0.00	$2,080,368.16
FSL GAS FUEL-99 Total					**8.00**	**$332,723,960.95**
FSL GAS HAND-99						
APSCO	5470000	Oth Prod Fuel Ops-NL Fuel	FUEL APSCO	GYU5CT	255.03	$308,918.08
APSCO	5470000	Oth Prod Fuel Ops-NL Fuel	FUEL CMMN	GFNONPLT	8,011.45	$966,019.91
FSL GAS HAND-99 Total					**8,266.48**	**$1,274,937.99**
FSL GEN OPS-99						
APSCO	5470000	Oth Prod Fuel Ops-NL Fuel	OTHER OM	GSGCMMN	4.00	$6,664.87
FSL GEN OPS-99 Total					**4.00**	**$6,664.87**
FSL OIL FUEL-99						
APSCO	5470000	Oth Prod Fuel Ops-NL Fuel	FUEL APSCO	GDG1CT	0.00	$68,400.32
APSCO	5470000	Oth Prod Fuel Ops-NL Fuel	FUEL APSCO	GYU3CT	0.00	$583.58
APSCO	5470000	Oth Prod Fuel Ops-NL Fuel	FUEL APSCO	GYU4CT	0.00	$72,862.00
FSL OIL FUEL-99 Total					**0.00**	**$141,845.90**
FSL OIL HAND-99						
APSCO	5470000	Oth Prod Fuel Ops-NL Fuel	FUEL APSCO	GDG1CT	4.00	$6,677.89
APSCO	5470000	Oth Prod Fuel Ops-NL Fuel	FUEL APSCO	GWPCC	0.00	$1,017.03
APSCO	5470000	Oth Prod Fuel Ops-NL Fuel	FUEL APSCO	GYUCMMN	2.00	$143.45
APSCO	5470000	Oth Prod Fuel Ops-NL Fuel	FUEL APSCO	GYUCT	4.00	$12,948.90
APSCO	5470000	Oth Prod Fuel Ops-NL Fuel	FUEL CMMN	GFNONPLT	3,294.68	$286,122.88
FSL OIL HAND-99 Total					**3,304.68**	**$306,910.15**
NATIVE LOAD-99						
APSCO	5470000	Oth Prod Fuel Ops-NL Fuel	FUTURES NG	NTVLDAPS	18.00	$14,341,230.35
APSCO	5470000	Oth Prod Fuel Ops-NL Fuel	GAS SFR	NTVLDAPS	202.00	$72,164,794.22
APSCO	5470000	Oth Prod Fuel Ops-NL Fuel	SFAS 133	PWRTRDG	0.00	$22,906,988.23
NATIVE LOAD-99 Total					**220.00**	**$109,413,012.80**
REGULATORY-99						
APSCO	5470005	Oth Prod Fuel Ops-Def Fuel	PSA	APSCORP	0.00	($21,704,205.36)
REGULATORY-99 Total					**0.00**	**($21,704,205.36)**
SURPLUS GEN-99						
APSCO	5470002	Oth Prod Fuel Ops-Sys Sl Fuel	RLZD PHYS	PWRMKTG	12.00	$49,231,885.15
SURPLUS GEN-99 Total					**12.00**	**$49,231,885.15**
					11,815.16	**$471,082,291.32**

✓ = Coal Handling + Res Waste
(✓) = Gas + Oil Handling

ARIZONA CORPORATION COMMISSION
STAFF'S EIGHTEENTH SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
OCTOBER 5, 2011

Staff 18.3: **PSA**: Reference Response to STF 14.1, Attachment APS14826 Page 4 of 6, Natural Gas and Oil. Several differences seem to exist between Attachment APS14826 page 4 of 6 and the General Ledger entries in Pre-Filed 1.04_APS Test Year General Ledger_APS14048. The excel spreadsheet attached to this data request, "APS14826 Gas Compare GL," provides a side-by-side listing of entries from each of the above-identified documents (with APS14826 page 4 provided in its entirety). The rows marked in red in spreadsheet column G either have no corresponding entry in the other document or the entries are not equal. Please either identify the correct General Ledger entries corresponding to the APS14826 problem rows or explain the difference.

Response: See APS14885 for references to supporting general ledger detail presented on APS14886 (FERC Account 501) and APS14887 (FERC Account 547).

Witness: Pete Ewen

Arizona Corporation Commission Docket No. E-1345A-11-0224
ACC Workpaper - APS14826 and GL Gas Comparison

Response to STAFF 14.1, APS14826, Page 4 of 6, Natural Gas and Oil

Pre-Filed 1.04_APS
Test Year General Ledger_APS14048

OPER UNIT	ACCOUNT	ACCOUNT DESCRIPTION	BUDGET ITEM		Reference to Staff 18.3 Attachments APS14886 and APS14887		BUDGET ITEM	SUB-BUDGET	PAGE LOCATION
GOC1CT	5470000	Oth Prod Fuel Ops-NL Fuel	FSL GAS FUEL-99	260,621.14	1				
GOC1ST	5010000	Steam Power - Fuel	FSL GAS FUEL-99	1,377,477.51	2				
GOC2CT	5470000	Oth Prod Fuel Ops-NL Fuel	FSL GAS FUEL-99	142,004.01	3				
GOC2ST	5010000	Steam Power - Fuel	FSL GAS FUEL-99	1,313,613.35	4				
GRH1	5470000	Oth Prod Fuel Ops-NL Fuel	FSL GAS FUEL-99	52,164,477.44		52,164,477.44	FSL GAS FUEL-99	APSCO RH1	page 4922 of 5053
GRH2	5470000	Oth Prod Fuel Ops-NL Fuel	FSL GAS FUEL-99	60,456,195.67		60,456,195.67	FSL GAS FUEL-99	APSCO RH2	page 4922 of 5053
GSG1CT	5470000	Oth Prod Fuel Ops-NL Fuel	FSL GAS FUEL-99	55,621.69	5				
GSG1ST	5010000	Steam Power - Fuel	FSL GAS FUEL-99	(23,443.27)	6				
GSG2CT	5470000	Oth Prod Fuel Ops-NL Fuel	FSL GAS FUEL-99	51,379.24	7				
GSG2ST	5010000	Steam Power - Fuel	FSL GAS FUEL-99	23,421.77	8				
GSG3CT	5470000	Oth Prod Fuel Ops-NL Fuel	FSL GAS FUEL-99	418,065.13		418,065.13	FSL GAS FUEL-99	APSCO SGCT	page 4922 of 5053
GSN1CT	5470000	Oth Prod Fuel Ops-NL Fuel	FSL GAS FUEL-99	519,480.94	9				
GSN2CT	5470000	Oth Prod Fuel Ops-NL Fuel	FSL GAS FUEL-99	496,096.61	10				
GSN3CT	5470000	Oth Prod Fuel Ops-NL Fuel	FSL GAS FUEL-99	584,516.02	11				
GSN4CT	5470000	Oth Prod Fuel Ops-NL Fuel	FSL GAS FUEL-99	535,942.29	12				
GSN5CT	5470000	Oth Prod Fuel Ops-NL Fuel	FSL GAS FUEL-99	562,496.23	13				
GSN6CT	5470000	Oth Prod Fuel Ops-NL Fuel	FSL GAS FUEL-99	546,189.88	14				
GSN7CT	5470000	Oth Prod Fuel Ops-NL Fuel	FSL GAS FUEL-99	527,873.67	15				
GSN8CT	5470000	Oth Prod Fuel Ops-NL Fuel	FSL GAS FUEL-99	493,889.58	16				
GSN9CT	5470000	Oth Prod Fuel Ops-NL Fuel	FSL GAS FUEL-99	502,509.33	17				
GSN10CT	5470000	Oth Prod Fuel Ops-NL Fuel	FSL GAS FUEL-99	425,220.12	18				
GSNCMMN	5470000	Oth Prod Fuel Ops-NL Fuel	FSL GAS FUEL-99	(256,076.97)	19				
GWP1CC	5470000	Oth Prod Fuel Ops-NL Fuel	FSL GAS FUEL-99	6,552,072.66	20				
GWP1CT	5470000	Oth Prod Fuel Ops-NL Fuel	FSL GAS FUEL-99	203,850.67	21				
GWP2CC	5470000	Oth Prod Fuel Ops-NL Fuel	FSL GAS FUEL-99	4,066,630.13	22				
GWP2CT	5470000	Oth Prod Fuel Ops-NL Fuel	FSL GAS FUEL-99	99,438.27	23				
GWP3CC	5470000	Oth Prod Fuel Ops-NL Fuel	FSL GAS FUEL-99	4,224,194.15	24				
GSP4CC	5470000	Oth Prod Fuel Ops-NL Fuel	FSL GAS FUEL-99	4,377,260.87		4,377,463.96	FSL GAS FUEL-99	APSCO WP4	page 4922 of 5053
GWP5CC	5470000	Oth Prod Fuel Ops-NL Fuel	FSL GAS FUEL-99	44,831,846.45		44,831,846.45	FSL GAS FUEL-99	APSCO WP5	page 4922 of 5053
GYU1CT	5470000	Oth Prod Fuel Ops-NL Fuel	FSL GAS FUEL-99	(17,817.57)	25				
GYU2CT	5470000	Oth Prod Fuel Ops-NL Fuel	FSL GAS FUEL-99	12,063.03	26				
GYU3CT	5470000	Oth Prod Fuel Ops-NL Fuel	FSL GAS FUEL-99	204,421.26	27				
GYU4CT	5470000	Oth Prod Fuel Ops-NL Fuel	FSL GAS FUEL-99	19,598.06	28				
GYU5CT	5470000	Oth Prod Fuel Ops-NL Fuel	FSL GAS FUEL-99	1,961,155.10	29				
GYU6CT	5470000	Oth Prod Fuel Ops-NL Fuel	FSL GAS FUEL-99	2,080,368.16	30				
GYU3CT	5470000	Oth Prod Fuel Ops-NL Fuel	FSL OIL FUEL-99	583.58		141,845.90	FSL GAS FUEL-99	FUEL APSCO	page 4922 of 5053
GYU4CT	5470000	Oth Prod Fuel Ops-NL Fuel	FSL OIL FUEL-99	72,862.00					
GDG1CT	5470000	Oth Prod Fuel Ops-NL Fuel	FSL OIL FUEL-99	68,400.32					
NTVLDAPS	5470000	Oth Prod Fuel Ops-NL Fuel	NATIVE LOAD-99	1,046,190.91	31				
				190,980,689.43		162,389,894.55			

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ACC Workpaper - APS14826 and GL Gas Comparison

Response to STAFF 14.1, APS14826, Page 4 of 6, Natural Gas and Oil

Pre-Filed 1.04_APS
Test Year General Ledger_APS14048

OPER UNIT	ACCOUNT	ACCOUNT DESCRIPTION	BUDGET ITEM		Reference to *Staff 18.3* Attachments APS14886 and APS14887		BUDGET ITEM	SUB-BUDGET	PAGE LOCATION
GFNONPLT	5470000	Oth Prod Fuel Ops-NL Fuel	FSL GAS HAND-99	739,760.96	*32*	966,019.91	FSL GAS HAND-99	FUEL CMMN	page 4922 of 5053
GFNONPLT	5470000	Oth Prod Fuel Ops-NL Fuel	FSL OIL HAND-99	204,649.98	*33*	286,122.88	FSL OIL HAND-99	FUEL CMMN	page 4922 of 5053
GFNONPLT	5010000	Steam Power - Fuel	EXPENSE-99	0.10		0.10	EXPENSE-99	FUEL CMMN	page 4884 of 5053
GDG1CT	5470000	Oth Prod Fuel Ops-NL Fuel	FSL OIL HAND-99	6,677.89	*34*	20,787.27	FSL OIL HAND-99	FUEL APSCO	page 4922 of 5053
GSGCMMN	5470000	Oth Prod Fuel Ops-NL Fuel	FSL GEN OPS-99	6,664.87		6,664.87	FSL GEN OPS-99	OTHER OM	page 4922 of 5053
GSGST	5010000	Steam Power - Fuel	FSL OTH HAND-99	20.00		20.00	FSL OTH HAND-99	FUEL APSCO	page 4886 of 5053
GWPCC	5470000	Oth Prod Fuel Ops-NL Fuel	FSL OIL HAND-99	1,017.03					
GYUSCT	5470000	Oth Prod Fuel Ops-NL Fuel	FSL GAS HAND-99	304,131.89	*35*	308,918.08	FSL GAS HAND-99	FUEL APSCO	page 4922 of 5053
GYUCMMN	5470000	Oth Prod Fuel Ops-NL Fuel	FSL OIL HAND-99	143.45					
GYUCT	5470000	Oth Prod Fuel Ops-NL Fuel	FSL OIL HAND-99	12,948.90					
				1,276,015.07		1,588,533.11			
GENTOLL	5470000	Oth Prod Fuel Ops-NL Fuel	FSL GAS FUEL-99	91,698,097.28	*36*	116,551,834.98	FSL GAS FUEL-99	FUEL APSCO	page 4922 of 5053
Charge No.									
99-547-003	5470000	Oth Prod Fuel Ops-NL Fuel	FSL GAS FUEL-99	53,924,077.00		53,924,077.32	FSL GAS FUEL-99	FIRM RES	page 4922 of 5053
					37A	14,341,230.35	NATIVE LOAD-99	FUTURES NG	page 4923 of 5053
					38A	72,164,794.22	NATIVE LOAD-99	GAS SFR	page 4923 of 5053
					39C	22,906,988.23	NATIVE LOAD-99	SFAS 133	page 4923 of 5053
1547-111	5470000	Oth Prod Fuel Ops-NL Fuel	NATIVE LOAD-99	21,819,205	*40*				
PM239	5470000	Oth Prod Fuel Ops-NL Fuel	NATIVE LOAD-99	120,350,488	*41*				
PM205	5470000	Oth Prod Fuel Ops-NL Fuel	NATIVE LOAD-99	15,428,139	*42*				
1547-112	5470000	Oth Prod Fuel Ops-NL Fuel	NATIVE LOAD-99	1,087,783	*43*				
PM120	5470000	Oth Prod Fuel Ops-NL Fuel	NATIVE LOAD-99	(1,086,908)	*44*				
		Gas Hedged and Mark to Market Expense		157,598,707		109,413,012.80			
				495,477,585.78		443,867,352.76			

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Response to STAFF 14.1, APS14826, Page 4 of 6, Natural Gas and Oil

Pre-Filed 1.04_APS
Test Year General Ledger_APS14048

OPER UNIT	ACCOUNT	ACCOUNT DESCRIPTION	BUDGET ITEM		Reference to Staff 18.3 Attachments APS14886 and APS14887		BUDGET ITEM	SUB-BUDGET	PAGE LOCATION
Less Adjustments									
1547-111	5470000	Oth Prod Fuel Ops-NL Fuel	NATIVE LOAD-99	21,819,205	*45*	?			
1547-112	5470000	Oth Prod Fuel Ops-NL Fuel	NATIVE LOAD-99	1,087,783	*46*	?			
		FAS 133 Mark-to-Market		22,906,988					
	5470002	Oth Prod Fuel Ops-Sys SI Fu	SURPLUS GEN-99	49,231,885		49,231,885.15	SURPLUS GEN-99	RLZD PHYS	page 4923 of 5053
		Percentage applies to Natural Gas		58%		58%			
		Off-system sales		28,793,002		28,793,002.00	(split with coal at 42%)		
99-547-003	5470000	Oth Prod Fuel Ops-NL Fuel	FSL GAS FUEL-99	53,924,077		53,924,077.32	FSL GAS FUEL-99	FIRM RES	page 4922 of 5053
		Firm Gas Transport		53,924,077		53,924,077.32			
	5470000	Oth Prod Fuel Ops-NL Fuel	FSL GAS HAND-99	1,274,938		1,274,937.99	FSL GAS HAND-99	FUEL CMMN & APSCO	page 4922 of 5053
	5010000	Steam Power - Fuel	FSL GAS HAND-99	1,062,215		1,062,215.19	FSL GAS HAND-99	FUEL CMMN	page 4886 of 5053
	5470000	Oth Prod Fuel Ops-NL Fuel	FSL OIL HAND-99	306,910		306,910.15	FSL OIL HAND-99	FUEL CMMN & APSCO	page 4922 of 5053
	5010000	Steam Power - Fuel	FSL OIL HAND-99	471,449		471,448.93	FSL OIL HAND-99	FUEL CMMN	page 4886 of 5053
	5010000	Steam Power - Fuel	FSL OTH HAND-30	10,807	*47*	4,190.57	FSL OTH HAND-30	FUEL CMMN	page 4886 of 5053
	5010000	Steam Power - Fuel	FSL OTH HAND-99	20		20.00	FSL OTH HAND-99	FUEL APSCO	page 4886 of 5053
GWP4CC	5470000	Steam Power - Fuel	FERC BEN-99	(167)	*48*	?			
GYUSCT	5470000	Steam Power - Fuel	FERC BEN-99	(3,857)	*49*	?			
GWP4CC	5470000	Steam Power - Fuel	FERC ID -99	(5)	*50*	?			
GYUSCT	5470000	Steam Power - Fuel	FERC ID-99	(104)	*51*	?			
GWP4CC	5470000	Steam Power - Fuel	FERC TAX-99	(32)	*52*	?			
GYUSCT	5470000	Steam Power - Fuel	FERC TAX-99	(825)	*53*	?			
		Fuel Handling		3,121,349		3,119,722.83			

ACC DR 18.3
Pinnacle West

Budget Item Business Unit	Account	Description	Sub Budget	Operating Unit	Quantity	Amount
FSL GAS FUEL-99						
APSCO	5010000	Steam Power - Fuel	FUEL APSCO	GCH1	0.00	$36,494.02
APSCO	5010000	Steam Power - Fuel	FUEL APSCO	GOC1ST	0.00	$1,377,477.51 (2)
APSCO	5010000	Steam Power - Fuel	FUEL APSCO	GOC2ST	0.00	$1,313,613.35 (4)
APSCO	5010000	Steam Power - Fuel	FUEL APSCO	GSG1ST	0.00	($23,443.27) (6)
APSCO	5010000	Steam Power - Fuel	FUEL APSCO	GSG2ST	0.00	$23,421.77 (8)
FSL GAS FUEL-99 Total					**0.00**	**$2,727,563.38**
				See APS Pre-Filed	**0.00**	**$2,727,563.38**

1.04, APS14048

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Budget Item Business Unit	Account	Sub Budget	Operating Unit	Description	Quantity	Amount	
FERC BEN-99							
APSCO	5470000	APSCO	GFNONPLT	Oth Prod Fuel Ops-NL Fuel	0.00	($238,360.17)	
APSCO	5470000	APSCO	GWP4CC	Oth Prod Fuel Ops-NL Fuel	0.00	($166.99)	48
APSCO	5470000	APSCO	GYU5CT	Oth Prod Fuel Ops-NL Fuel	0.00	($3,856.64)	49
FERC BEN-99 Total					**0.00**	**($242,383.80)**	
FERC ID-99							
APSCO	5470000	APSCO	GFNONPLT	Oth Prod Fuel Ops-NL Fuel	0.00	($6,442.18)	
APSCO	5470000	APSCO	GWP4CC	Oth Prod Fuel Ops-NL Fuel	0.00	($4.51)	50
APSCO	5470000	APSCO	GYU5CT	Oth Prod Fuel Ops-NL Fuel	0.00	($104.24)	51
FERC ID-99 Total					**0.00**	**($6,550.93)**	
FERC TAX-99							
APSCO	5470000	APSCO	GFNONPLT	Oth Prod Fuel Ops-NL Fuel	0.00	($62,929.50)	
APSCO	5470000	APSCO	GWP4CC	Oth Prod Fuel Ops-NL Fuel	0.00	($31.59)	52
APSCO	5470000	APSCO	GYU5CT	Oth Prod Fuel Ops-NL Fuel	0.00	($825.31)	53
FERC TAX-99 Total					**0.00**	**($63,786.40)**	
FSL GAS FUEL-99							
APSCO	5470000	APSCO RH1	GRH1	Oth Prod Fuel Ops-NL Fuel	0.00	$52,164,477.44	
APSCO	5470000	APSCO RH2	GRH2	Oth Prod Fuel Ops-NL Fuel	0.00	$60,456,195.67	
APSCO	5470000	APSCO SGCT	GSG3CT	Oth Prod Fuel Ops-NL Fuel	0.00	$418,065.13	
APSCO	5470000	APSCO WP4	GWP4CC	Oth Prod Fuel Ops-NL Fuel	8.00	$4,377,463.96	
APSCO	5470000	APSCO WP5	GWP5CC	Oth Prod Fuel Ops-NL Fuel	0.00	$44,831,846.45	
APSCO	5470000	FIRM RES	GFNONPLT	Oth Prod Fuel Ops-NL Fuel	0.00	$53,924,077.32	
APSCO	5470000	FUEL APSCO	GENTOLL	Oth Prod Fuel Ops-NL Fuel	0.00	$91,698,097.28	30
APSCO	5470000	FUEL APSCO	GOC1CT	Oth Prod Fuel Ops-NL Fuel	0.00	$260,621.14	1
APSCO	5470000	FUEL APSCO	GOC2CT	Oth Prod Fuel Ops-NL Fuel	0.00	$142,004.01	3
APSCO	5470000	FUEL APSCO	GSG1CT	Oth Prod Fuel Ops-NL Fuel	0.00	$55,621.69	5
APSCO	5470000	FUEL APSCO	GSG2CT	Oth Prod Fuel Ops-NL Fuel	0.00	$51,379.24	7
APSCO	5470000	FUEL APSCO	GSN10CT	Oth Prod Fuel Ops-NL Fuel	0.00	$425,220.12	18
APSCO	5470000	FUEL APSCO	GSN1CT	Oth Prod Fuel Ops-NL Fuel	0.00	$519,480.94	9
APSCO	5470000	FUEL APSCO	GSN2CT	Oth Prod Fuel Ops-NL Fuel	0.00	$496,096.61	10
APSCO	5470000	FUEL APSCO	GSN3CT	Oth Prod Fuel Ops-NL Fuel	0.00	$584,516.02	11
APSCO	5470000	FUEL APSCO	GSN4CT	Oth Prod Fuel Ops-NL Fuel	0.00	$535,942.29	12
APSCO	5470000	FUEL APSCO	GSN5CT	Oth Prod Fuel Ops-NL Fuel	0.00	$562,496.23	13
APSCO	5470000	FUEL APSCO	GSN6CT	Oth Prod Fuel Ops-NL Fuel	0.00	$546,189.88	14
APSCO	5470000	FUEL APSCO	GSN7CT	Oth Prod Fuel Ops-NL Fuel	0.00	$527,873.67	15
APSCO	5470000	FUEL APSCO	GSN8CT	Oth Prod Fuel Ops-NL Fuel	0.00	$493,889.58	16
APSCO	5470000	FUEL APSCO	GSN9CT	Oth Prod Fuel Ops-NL Fuel	0.00	$502,509.33	17
APSCO	5470000	FUEL APSCO	GSNCMMN	Oth Prod Fuel Ops-NL Fuel	0.00	($256,076.97)	19
APSCO	5470000	FUEL APSCO	GWP1CC	Oth Prod Fuel Ops-NL Fuel	0.00	$6,552,072.66	20
APSCO	5470000	FUEL APSCO	GWP1CT	Oth Prod Fuel Ops-NL Fuel	0.00	$203,850.67	21
APSCO	5470000	FUEL APSCO	GWP2CC	Oth Prod Fuel Ops-NL Fuel	0.00	$4,066,630.13	22
APSCO	5470000	FUEL APSCO	GWP2CT	Oth Prod Fuel Ops-NL Fuel	0.00	$99,438.27	23
APSCO	5470000	FUEL APSCO	GWP3CC	Oth Prod Fuel Ops-NL Fuel	0.00	$4,224,194.15	24
APSCO	5470000	FUEL APSCO	GYU1CT	Oth Prod Fuel Ops-NL Fuel	0.00	($17,817.57)	25
APSCO	5470000	FUEL APSCO	GYU2CT	Oth Prod Fuel Ops-NL Fuel	0.00	$12,063.03	26
APSCO	5470000	FUEL APSCO	GYU3CT	Oth Prod Fuel Ops-NL Fuel	0.00	$204,421.26	27

Budget Item Business Unit	Account	Sub Budget	Operating Unit	Description	Quantity	Amount
FSL GAS FUEL-99						
APSCO	5470000	FUEL APSCO	GYU4CT	Oth Prod Fuel Ops-NL Fuel	0.00	$19,598.06 28
APSCO	5470000	FUEL APSCO	GYU5CT	Oth Prod Fuel Ops-NL Fuel	0.00	$1,961,155.10 29
APSCO	5470000	FUEL APSCO	GYU6CT	Oth Prod Fuel Ops-NL Fuel	0.00	$2,080,368.16 30
FSL GAS FUEL-99 Total					**8.00**	**$332,723,960.95**
FSL GAS HAND-99						
APSCO	5470000	FUEL APSCO	GYU5CT	Oth Prod Fuel Ops-NL Fuel	255.03	$308,918.08 D
APSCO	5470000	FUEL CMMN	GFNONPLT	Oth Prod Fuel Ops-NL Fuel	8,011.45	$966,019.91 E
FSL GAS HAND-99 Total					**8,266.48**	**$1,274,937.99**
FSL GEN OPS-99						
APSCO	5470000	OTHER OM	GSGCMMN	Oth Prod Fuel Ops-NL Fuel	4.00	$6,664.87
FSL GEN OPS-99 Total					**4.00**	**$6,664.87**
FSL OIL FUEL-99						
APSCO	5470000	FUEL APSCO	GDG1CT	Oth Prod Fuel Ops-NL Fuel	0.00	$68,400.32
APSCO	5470000	FUEL APSCO	GYU3CT	Oth Prod Fuel Ops-NL Fuel	0.00	$583.58
APSCO	5470000	FUEL APSCO	GYU4CT	Oth Prod Fuel Ops-NL Fuel	0.00	$72,862.00
FSL OIL FUEL-99 Total					**0.00**	**$141,845.90**
FSL OIL HAND-99						
APSCO	5470000	FUEL APSCO	GDG1CT	Oth Prod Fuel Ops-NL Fuel	4.00	$6,677.89 34
APSCO	5470000	FUEL APSCO	GWPCC	Oth Prod Fuel Ops-NL Fuel	0.00	$1,017.03
APSCO	5470000	FUEL APSCO	GYUCMMN	Oth Prod Fuel Ops-NL Fuel	2.00	$143.45
APSCO	5470000	FUEL APSCO	GYUCT	Oth Prod Fuel Ops-NL Fuel	4.00	$12,948.90
APSCO	5470000	FUEL CMMN	GFNONPLT	Oth Prod Fuel Ops-NL Fuel	3,294.68	$286,122.88 F
FSL OIL HAND-99 Total					**3,304.68**	**$306,910.15**
NATIVE LOAD-99						
APSCO	5470000	FUTURES NG	NTVLDAPS	Oth Prod Fuel Ops-NL Fuel	18.00	$14,341,230.35 A
APSCO	5470000	GAS SFR	NTVLDAPS	Oth Prod Fuel Ops-NL Fuel	202.00	$72,164,794.22 B
APSCO	5470000	SFAS 133	PWRTRDG	Oth Prod Fuel Ops-NL Fuel	0.00	$22,906,988.23 C
NATIVE LOAD-99 Total					**220.00**	**$109,413,012.80**
REGULATORY-99						
APSCO	5470005	PSA	APSCORP	Oth Prod Fuel Ops-Def Fuel	0.00	($21,704,205.36)
REGULATORY-99 Total					**0.00**	**($21,704,205.36)**
SURPLUS GEN-99						
APSCO	5470002	RLZD PHYS	PWRMKTG	Oth Prod Fuel Ops-Sys Sl Fuel	12.00	$49,231,885.15
SURPLUS GEN-99 Total					**12.00**	**$49,231,885.15**
					11,815.16	**$471,082,291.32**

Sub Budget Business Unit	Account	Budget Item	Operating Unit	Charge Number	Description	Quantity	Amount
FUTURES NG							
APSCO	5470000	NATIVE LOAD-99	NTVLDAPS	PM120	Oth Prod Fuel Ops-NL Fuel	18.00	($1,086,908.40)
APSCO	5470000	NATIVE LOAD-99	NTVLDAPS	PM205	Oth Prod Fuel Ops-NL Fuel	0.00	$15,428,138.75
FUTURES NG Total						**18.00**	**$14,341,230.35**
GAS SFR							
APSCO	5470000	NATIVE LOAD-99	NTVLDAPS	1547-100	Oth Prod Fuel Ops-NL Fuel	24.00	($51,980,866.50)
APSCO	5470000	NATIVE LOAD-99	NTVLDAPS	1547-120	Oth Prod Fuel Ops-NL Fuel	12.00	$2,748,981.35
APSCO	5470000	NATIVE LOAD-99	NTVLDAPS	PM239	Oth Prod Fuel Ops-NL Fuel	165.00	$120,350,488.46
APSCO	5470000	NATIVE LOAD-99	NTVLDAPS	PM243	Oth Prod Fuel Ops-NL Fuel	1.00	$1,046,190.91
GAS SFR Total						**202.00**	**$72,164,794.22**
SFAS 133							
APSCO	5470000	NATIVE LOAD-99	PWRTRDG	1547-111	Oth Prod Fuel Ops-NL Fuel	0.00	$21,819,204.78
APSCO	5470000	NATIVE LOAD-99	PWRTRDG	1547-112	Oth Prod Fuel Ops-NL Fuel	0.00	$1,087,783.45
SFAS 133 Total						**0.00**	**$22,906,988.23**
						220.00	**$109,413,012.80**

Sub Budget Business Unit	Account	Budget Item	Resource Category	Description	Quantity	Amount
FUEL APSCO						
APSCO	5470000	FSL GAS HAND-99	111	Oth Prod Fuel Ops-NL Fuel	187.76	$7,729.19
APSCO	5470000	FSL GAS HAND-99	112	Oth Prod Fuel Ops-NL Fuel	21.77	$1,225.62
APSCO	5470000	FSL GAS HAND-99	113	Oth Prod Fuel Ops-NL Fuel	0.00	$1,468.54
APSCO	5470000	FSL GAS HAND-99	121	Oth Prod Fuel Ops-NL Fuel	19.50	$1,316.92
APSCO	5470000	FSL GAS HAND-99	131	Oth Prod Fuel Ops-NL Fuel	0.00	$49.82
APSCO	5470000	FSL GAS HAND-99	300	Oth Prod Fuel Ops-NL Fuel	1.00	$4,708.02
APSCO	5470000	FSL GAS HAND-99	403	Oth Prod Fuel Ops-NL Fuel	0.00	$77.97
APSCO	5470000	FSL GAS HAND-99	409	Oth Prod Fuel Ops-NL Fuel	0.00	$32.40
APSCO	5470000	FSL GAS HAND-99	601	Oth Prod Fuel Ops-NL Fuel	1.00	$53.23
APSCO	5470000	FSL GAS HAND-99	812	Oth Prod Fuel Ops-NL Fuel	6.00	$56,259.01
APSCO	5470000	FSL GAS HAND-99	869	Oth Prod Fuel Ops-NL Fuel	18.00	$231,211.17
APSCO	5470000	FSL GAS HAND-99	902	Oth Prod Fuel Ops-NL Fuel	0.00	$825.31
APSCO	5470000	FSL GAS HAND-99	903	Oth Prod Fuel Ops-NL Fuel	0.00	$104.24
APSCO	5470000	FSL GAS HAND-99	911	Oth Prod Fuel Ops-NL Fuel	0.00	$3,856.64
FUEL APSCO Total					**255.03**	**$308,918.08** D
FUEL CMMN						
APSCO	5470000	FSL GAS HAND-99	111	Oth Prod Fuel Ops-NL Fuel	5,774.85	$291,665.41
APSCO	5470000	FSL GAS HAND-99	112	Oth Prod Fuel Ops-NL Fuel	1,713.60	$119,482.76
APSCO	5470000	FSL GAS HAND-99	113	Oth Prod Fuel Ops-NL Fuel	0.00	$55,416.40
APSCO	5470000	FSL GAS HAND-99	115	Oth Prod Fuel Ops-NL Fuel	398.00	$7,866.00
APSCO	5470000	FSL GAS HAND-99	132	Oth Prod Fuel Ops-NL Fuel	0.00	$225,060.66
APSCO	5470000	FSL GAS HAND-99	300	Oth Prod Fuel Ops-NL Fuel	0.00	$385.78
APSCO	5470000	FSL GAS HAND-99	305	Oth Prod Fuel Ops-NL Fuel	4.00	$1,407.58
APSCO	5470000	FSL GAS HAND-99	401	Oth Prod Fuel Ops-NL Fuel	0.00	$2,421.75
APSCO	5470000	FSL GAS HAND-99	402	Oth Prod Fuel Ops-NL Fuel	0.00	$1,796.26
APSCO	5470000	FSL GAS HAND-99	403	Oth Prod Fuel Ops-NL Fuel	0.00	$1.82
APSCO	5470000	FSL GAS HAND-99	404	Oth Prod Fuel Ops-NL Fuel	0.00	$36.25
APSCO	5470000	FSL GAS HAND-99	409	Oth Prod Fuel Ops-NL Fuel	0.00	$2,274.02
APSCO	5470000	FSL GAS HAND-99	542	Oth Prod Fuel Ops-NL Fuel	0.00	$2,659.79
APSCO	5470000	FSL GAS HAND-99	555	Oth Prod Fuel Ops-NL Fuel	1.00	$106.25
APSCO	5470000	FSL GAS HAND-99	601	Oth Prod Fuel Ops-NL Fuel	0.00	$0.01
APSCO	5470000	FSL GAS HAND-99	606	Oth Prod Fuel Ops-NL Fuel	24.00	$936.00
APSCO	5470000	FSL GAS HAND-99	620	Oth Prod Fuel Ops-NL Fuel	0.00	$34.08
APSCO	5470000	FSL GAS HAND-99	640	Oth Prod Fuel Ops-NL Fuel	0.00	$4,609.67
APSCO	5470000	FSL GAS HAND-99	805	Oth Prod Fuel Ops-NL Fuel	0.00	$9.18
APSCO	5470000	FSL GAS HAND-99	834	Oth Prod Fuel Ops-NL Fuel	0.00	$1,797.00
APSCO	5470000	FSL GAS HAND-99	835	Oth Prod Fuel Ops-NL Fuel	0.00	$787.72
APSCO	5470000	FSL GAS HAND-99	837	Oth Prod Fuel Ops-NL Fuel	80.00	$1,972.80
APSCO	5470000	FSL GAS HAND-99	840	Oth Prod Fuel Ops-NL Fuel	15.00	$375.11
APSCO	5470000	FSL GAS HAND-99	869	Oth Prod Fuel Ops-NL Fuel	1.00	$15,000.58
APSCO	5470000	FSL GAS HAND-99	893	Oth Prod Fuel Ops-NL Fuel	0.00	$15.00
APSCO	5470000	FSL GAS HAND-99	899	Oth Prod Fuel Ops-NL Fuel	0.00	$3,643.08
APSCO	5470000	FSL GAS HAND-99	902	Oth Prod Fuel Ops-NL Fuel	0.00	$48,964.37
APSCO	5470000	FSL GAS HAND-99	903	Oth Prod Fuel Ops-NL Fuel	0.00	$4,665.65

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Sub Budget Business Unit	Account	Budget Item	Resource Category	Description	Quantity	Amount
FUEL CMMN						
APSCO	5470000	FSL GAS HAND-99	911	Oth Prod Fuel Ops-NL Fuel	0.00	$172,628.93
FUEL CMMN Total					**8,011.45**	**$966,019.91**
					8,266.48	**$1,274,937.99**

Sub Budget Business Unit	Account	Budget Item	Resource Category	Description	Quantity	Amount
FUEL APSCO						
APSCO	5470000	FSL OIL HAND-99	409	Oth Prod Fuel Ops-NL Fuel	0.00	$13.00
APSCO	5470000	FSL OIL HAND-99	819	Oth Prod Fuel Ops-NL Fuel	2.00	$143.45
APSCO	5470000	FSL OIL HAND-99	869	Oth Prod Fuel Ops-NL Fuel	8.00	$19,613.79
APSCO	5470000	FSL OIL HAND-99	899	Oth Prod Fuel Ops-NL Fuel	0.00	$1,017.03
FUEL APSCO Total					**10.00**	**$20,787.27**
FUEL CMMN						
APSCO	5470000	FSL OIL HAND-99	111	Oth Prod Fuel Ops-NL Fuel	2,146.16	$80,107.20
APSCO	5470000	FSL OIL HAND-99	112	Oth Prod Fuel Ops-NL Fuel	1,077.52	$82,324.48
APSCO	5470000	FSL OIL HAND-99	113	Oth Prod Fuel Ops-NL Fuel	0.00	$15,220.36
APSCO	5470000	FSL OIL HAND-99	132	Oth Prod Fuel Ops-NL Fuel	0.00	$21,849.31
APSCO	5470000	FSL OIL HAND-99	300	Oth Prod Fuel Ops-NL Fuel	0.00	$224.42
APSCO	5470000	FSL OIL HAND-99	305	Oth Prod Fuel Ops-NL Fuel	2.00	$1,133.82
APSCO	5470000	FSL OIL HAND-99	401	Oth Prod Fuel Ops-NL Fuel	0.00	$65.34
APSCO	5470000	FSL OIL HAND-99	402	Oth Prod Fuel Ops-NL Fuel	0.00	$48.30
APSCO	5470000	FSL OIL HAND-99	403	Oth Prod Fuel Ops-NL Fuel	0.00	$4.01
APSCO	5470000	FSL OIL HAND-99	409	Oth Prod Fuel Ops-NL Fuel	0.00	$298.17
APSCO	5470000	FSL OIL HAND-99	542	Oth Prod Fuel Ops-NL Fuel	0.00	$99.65
APSCO	5470000	FSL OIL HAND-99	555	Oth Prod Fuel Ops-NL Fuel	0.00	$35.75
APSCO	5470000	FSL OIL HAND-99	601	Oth Prod Fuel Ops-NL Fuel	0.00	$0.00
APSCO	5470000	FSL OIL HAND-99	620	Oth Prod Fuel Ops-NL Fuel	0.00	$74.98
APSCO	5470000	FSL OIL HAND-99	805	Oth Prod Fuel Ops-NL Fuel	0.00	$20.16
APSCO	5470000	FSL OIL HAND-99	834	Oth Prod Fuel Ops-NL Fuel	0.00	$1,241.90
APSCO	5470000	FSL OIL HAND-99	837	Oth Prod Fuel Ops-NL Fuel	57.00	$1,405.62
APSCO	5470000	FSL OIL HAND-99	840	Oth Prod Fuel Ops-NL Fuel	12.00	$340.56
APSCO	5470000	FSL OIL HAND-99	869	Oth Prod Fuel Ops-NL Fuel	0.00	$0.00
APSCO	5470000	FSL OIL HAND-99	893	Oth Prod Fuel Ops-NL Fuel	0.00	$33.00
APSCO	5470000	FSL OIL HAND-99	899	Oth Prod Fuel Ops-NL Fuel	0.00	$122.95
APSCO	5470000	FSL OIL HAND-99	902	Oth Prod Fuel Ops-NL Fuel	0.00	$13,965.13
APSCO	5470000	FSL OIL HAND-99	903	Oth Prod Fuel Ops-NL Fuel	0.00	$1,776.53
APSCO	5470000	FSL OIL HAND-99	911	Oth Prod Fuel Ops-NL Fuel	0.00	$65,731.24
FUEL CMMN Total					**3,294.68**	**$286,122.88**
					3,304.68	**$306,910.15**

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ARIZONA CORPORATION COMMISSION
STAFF'S EIGHTEENTH SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
OCTOBER 5, 2011

Staff 18.4: **PSA**: Reference Response to STF 14.1, Attachment APS14826 Page 5 of 6, Purchased Power. While we could trace back all Purchased Power entries on APS14826 page 5 of 6 to the General Ledger provided in Pre-Filed 1.04_APS Test Year General Ledger_APS14048, certain items in the Purchased Power Adjustment section could not be verified with the General Ledger provided. The excel spreadsheet attached to this data request, "APS14826 Purchased Power Compare GL," provides a side-by-side listing of entries from each of the above-identified documents (with APS14826 page 5 provided in its entirety). The rows marked in red in spreadsheet column G either have no corresponding entry in the other document or the entries are not equal. Please either identify the correct General Ledger entries corresponding to the APS14826 problem rows or explain the difference.

Response: See APS14888 for references to reconciling general ledger detail on APS14889 (FERC Account 5470), APS14890 (FERC Account 555-0), APS14891 (FERC Account 555-5) and supporting schedule detail on APS14892 (Renewable Energy Analysis).

Witness: Pete Ewen

Arizona Corporation Commission Docket No. E-1345A-11-0224
ACC Workpaper - APS14826 and GL Purchased Power Comparison

Response to STAFF 14.1, APS14826, Page 5 of 6, Natural Gas and Oil					A	Pre-Filed 1.04_APS Test Year General Ledger_APS14048			
ACCOUNT	ACCOUNT DESCRIPTION	BUDGET		AMOUNT		Amount	BUDGET	SUB-BUDGET	PAGE LOCATION
4560009	Other Electric Rev-NL Prch Pwr	NATIVE LOAD-99		(705,676)		(705,675.91)	NATIVE LOAD-99	WHEELING	page 4881 of 5053
5550000	Purchased Power-Native Load	NATIVE LOAD-99		274,022,573		274,022,573.05	NATIVE LOAD-99	(various)	page 4932 of 5053
5550000	Purchased Power-Native Load	EPS		8,200,983		8,200,983.40	EPS	ENERGY PUR	page 4932 of 5053
5550003	Purchased Power-Sys Sls Rev	OFFSYSTEM-99		20,176,680		20,176,680.05	OFFSYSTEM-99	(various)	page 4932 of 5053
5550004	Purchased Power-Rtl Ld Hdg Mgt	NATV LD HEDG-99		7,850,798		7,850,798.23	NATV LD HEDG-99	INTERCHG	page 4932 of 5053
5550005	Purchased Power-System Sales	OFFSYSTEM-99		1,411,326		1,411,326.28	OFFSYSTEM-99	(various)	page 4932-4933 of 5053
5550094	Purchased Power-Rtl Ld Hdg IU	NATV LD HEDG-99		48,761,656		48,761,655.60	NATV LD HEDG-99	INTRAFILAT	page 4933 of 5053
5570001	Other Pwr Sup Exp-NL Purch Pwr	NATIVE LOAD-99		183,557		183,557.25	NATIVE LOAD-99	BROKER FEE	page 4935 of 5053
5570009	Other Pwr Sup Exp-Offsys Rev	OFFSYSTEM-99		89,171		89,171.24	OFFSYSTEM-99	BROKER FEE	page 4935 of 5053
5650000	Trans of Elec by Others-NL	GEN OPS OH 230		17,322,740		17,322,740.29	GEN OPS OH 230	WHEELING	page 4946 of 5053
5650002	Trans of Elec by Oth-SS Rev	GEN OPS GENERAL		338,073		338,073.33	GEN OPS GENERAL	WHEELING	page 4946 of 5053
Total Purchased Power				**377,651,881**		**377,651,882.81**			
Less Adjustments									
5550000	Purchased Power-Native Load	NATIVE LOAD-99	1555-111	17,397,263					
5550000	Purchased Power-Native Load	NATIVE LOAD-99	1555-200	(789,689)					
				16,607,574		**0.00**			
5550003	Purchased Power-Sys Sls Rev	OFFSYSTEM-99	1555-018	20,941,514		20,941,513.65	OFFSYSTEM-99	INTERCHG	page 4932 of 5053
5550005	Purchased Power-System Sales	OFFSYSTEM-99	1555-030	922,811					
				21,864,325		**20,941,513.65**			
5470000	Oth Prod Fuel Ops-NL Fuel	NATIVE LOAD-99	1547-120	2,748,981					
5550000	Purchased Power-Native Load	NATIVE LOAD-99	1555-037	29,220,433					
5650002	Trans of Elec by Oth-SS Rev	GEN OPS GENERAL		338,073		338,073.33	GEN OPS GENERAL	WHEELING	page 4946 of 5053
				32,307,487		**338,073.33**			
4470003	Sales for Resale-Rtl Ld Hg Mgt	NATV LD HEDG-99		**39,282,636**		(39,282,635.52)	NON UTIL OTH-99	ELEC REV	page 4873 of 5053
5550000	Purchased Power-Native Load	NATIVE LOAD-99	1555-036 (Renewables Only)	**37,418,937**					
5550000	Purchased Power-Native Load	EPS		**8,200,983**		8,200,983.40	EPS	ENERGY PUR	page 4932 of 5053
	Total Purchased Power Adjustments			**155,681,942**		(9,802,065.14)			

A See APS14889 - APS14891 for detailed general ledger supporting information.

Sub Budget Business Unit	Account	Budget Item	Charge Number	Description	Quantity	Amount
FUTURES NG						
APSCO	5470000	NATIVE LOAD-99	PM120	ED3 Gas Hedge Liquidation	18.00	($1,086,908.40)
APSCO	5470000	NATIVE LOAD-99	PM205	NATIVE LOAD GAS OPTIONS	0.00	$15,428,138.75
FUTURES NG Total					**18.00**	**$14,341,230.35**
GAS SFR						
APSCO	5470000	NATIVE LOAD-99	1547-100	NATIVE LOAD GAS BURNS	24.00	($51,980,866.50)
APSCO	5470000	NATIVE LOAD-99	1547-120	Fuel Costs ED3	12.00	$2,748,981.35 4
APSCO	5470000	NATIVE LOAD-99	PM239	NATIVE LOAD GAS SALES	165.00	$120,350,488.46
APSCO	5470000	NATIVE LOAD-99	PM243	Gas Storage Expense	1.00	$1,046,190.91
GAS SFR Total					**202.00**	**$72,164,794.22**
SFAS 133						
APSCO	5470000	NATIVE LOAD-99	1547-111	SFAS 133 GAS FUEL EXP.-CURRENT	0.00	$21,819,204.78
APSCO	5470000	NATIVE LOAD-99	1547-112	SFAS 133 Fuel Native Load Requireme	0.00	$1,087,783.45
SFAS 133 Total					**0.00**	**$22,906,988.23**
					220.00	**$109,413,012.80** ✓

See APS Pre-Filed 1.04, APS14048 Page 4923 of 5053.

Sub Budget Business Unit	Account	Budget Item	Charge Number	Description	Quantity	Amount
BANKED						
APSCO	5550000	NATIVE LOAD-99	1555-014	BANKED ENERGY	0.00	$3,632,759.61
BANKED Total					**0.00**	**$3,632,759.61**
EXCHG						
APSCO	5550000	NATIVE LOAD-99	1555-015	PACIFICORP EXCHANGE ENERGY	19.00	($4,020,088.51)
EXCHG Total					**19.00**	**($4,020,088.51)**
INTERCHG						
APSCO	5550000	NATIVE LOAD-99	1555-004	Interchange Clearing	250.00	$0.00
APSCO	5550000	NATIVE LOAD-99	1555-036	Native Load Purchased Power	13.00	$119,147,842.62
APSCO	5550000	NATIVE LOAD-99	1555-037	Native Load Purchased Pwr Requirem	12.00	$29,220,433.46 5
APSCO	5550000	NATIVE LOAD-99	1555-039	NL Requirements Power Financials	0.00	$0.00
APSCO	5550000	NATIVE LOAD-99	1555-044	Green Power Premiums	12.00	($8,200,983.40)
INTERCHG Total					**287.00**	**$140,167,292.68**
ISDA PWR						
APSCO	5550000	NATIVE LOAD-99	1555-028	POWER FINANCIAL TRADES	3.00	($74.50)
ISDA PWR Total					**3.00**	**($74.50)**
ISO ADJUST						
APSCO	5550000	NATIVE LOAD-99	99-555-005	ISO ADJUSTMENTS	2.00	$1,724,350.29
ISO ADJUST Total					**2.00**	**$1,724,350.29**
ISO PMT						
APSCO	5550000	NATIVE LOAD-99	99-555-004	ISO PAYMENTS	9.00	($29,483.92)
APSCO	5550000	NATIVE LOAD-99	99-555-007	Cal Power Exchge Fees	2.00	$38,564.80
ISO PMT Total					**11.00**	**$9,080.88**
OPTNS PWR						
APSCO	5550000	NATIVE LOAD-99	1555-034	Native Load Options	0.00	$12,727,000.00
OPTNS PWR Total					**0.00**	**$12,727,000.00**
PURCH PWR						
APSCO	5550000	NATIVE LOAD-99	1555-115	PGR Purchased Power	0.00	$43,337,202.73
APSCO	5550000	NATIVE LOAD-99	1555-118	Arlington Purchased Power	0.00	$40,850,513.66
PURCH PWR Total					**0.00**	**$84,187,716.39**
SFAS 133						
APSCO	5550000	NATIVE LOAD-99	1555-111	SFAS 133 PURCHASED PWR EXP CUR	0.00	$17,397,262.68 1
APSCO	5550000	NATIVE LOAD-99	1555-200	SFAS 133 Power Native Load Requirem	0.00	($789,689.19) 2
SFAS 133 Total					**0.00**	**$16,607,573.49**
SRP TC						
APSCO	5550000	NATIVE LOAD-99	1555-112	SRP T&C PURCHASED POWER	48.00	$18,890,356.47
SRP TC Total					**48.00**	**$18,890,356.47**

Sub Budget Business Unit	Account	Budget Item	Charge Number	Description	Quantity	Amount
SRSG						
APSCO	5550000	NATIVE LOAD-99	1555-010	SRSG PURCHASED POWER	0.00	$96,606.25
SRSG Total					**0.00**	**$96,606.25**
					370.00	**$274,022,573.05**

See APS Pre-Filed 1.04, APS14048 PAGE 4932 OF 5053

Arizona Corporation Commission
Docket No. E-01345A-11-0224
Exhibit: MJM-4

Sub Budget Business Unit	Account	Budget Item	Charge Number	Description	Quantity	Amount
INTERCHG						
APSCO	5550005	OFFSYSTEM-99	1555-030	OFF SYSTEM SRP T&C	7.00	$922,811.17 3
APSCO	5550005	OFFSYSTEM-99	1555-035	Purchased Power Agreements	0.00	$235,655.10
INTERCHG Total					**7.00**	**$1,158,466.27**
ISO ADJUST						
APSCO	5550005	OFFSYSTEM-99	1555-019	NONTRADING ISO ADJUSTMENT	1.00	$252,860.01
ISO ADJUST Total					**1.00**	**$252,860.01**
					8.00	**$1,411,326.28** 4

See APS Pre-Filed 1.04, APS14048 Page 4933 of 5053,

Renewable Energy Summary
2010

	Final + Trade Adjustments					
	Green MW	Non-Green MW	Total MW	Total $	Purch Pwr $	RES $
Jan-10	57,409	-	57,409	$3,718,249.49	$3,041,673.74	$676,575.75
Feb-10	38,975	-	38,975	$2,553,192.52	$2,092,602.05	$460,590.47
Mar-10	61,285	-	61,285	$3,988,296.39	$3,272,696.81	$715,599.58
Apr-10	67,846	-	67,846	$4,373,909.40	$3,665,419.63	$708,489.77
May-10	70,390	-	70,390	$4,528,772.58	$3,740,013.44	$788,759.14
Jun-10	50,956	-	50,956	$3,372,868.42	$2,774,769.51	$598,098.91
Jul-10	39,327	-	39,327	$2,603,334.86	$2,102,353.82	$500,981.04
Aug-10	34,320	-	34,320	$2,187,166.49	$1,776,710.22	$410,456.27
Sep-10	57,037	116	57,153	$3,764,451.00	$3,031,457.39	$732,993.61
Oct-10	63,315	34	63,349	$4,302,808.69	$3,448,120.56	$854,688.13
Nov-10	73,136	-	73,136	$4,733,785.80	$3,946,078.67	$787,707.13
Dec-10	83,658	-	83,658	$5,512,107.52	$4,527,040.96	$985,066.56
	697,654	**150**	**697,804**	**$45,638,943.16**	**$37,418,936.81**	**$8,220,006.35**
				a	b	c

(a) Please see page 326.3 through 326.6 in the 2010 FERC form 1. The dollar amounts for the following companies make up the gross amount of the renewable adjustment:
Aragonne Wind LLC
Glendale Energy LLC
High Lonesome Wind Ranch, LLC
Snowflake Power LLC
Snowflake White Mountain Power LLC
CE Turbo LLC

(b) Renewables adjustment (Reference 7 on the Lead Summary Sheet)

(c) Represents the above market value of these Purchased Power contracts recovered through Renewable Energy Surcharge (RES)

ARIZONA CORPORATION COMMISSION
STAFF'S TWELFTH SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
SEPTEMBER 15, 2011

Staff 12.2: **Environmental and Reliability Account (ERA):** Please provide the following:

a. The expected implementation date of the initial ERA.

b. The estimated charge to customers based on the initial ERA formula.

Response:

a. The expected implementation date of the initial ERA is April 1, 2013.

b. The estimated charge to customers for the initial ERA formula without and with the APS's acquisition of Southern California Edison's (SCE) share of Four Corners generation plant unit 4 and 5 are 0.0045% and 2.2805% respectively. See APS14759 for the charge calculation.

Note that the Total Company Revenues used in the calculation are for the 2010 Test Year rather than a forecast of 2012.

The associated O&M with Four Corners is based on Units 1 through 3 shutting down concurrently with the acquisition of units 4 and 5. If these units continued to operate through 2013, the O&M amount would increase in the ERA calculation but would be more than offset by reductions in costs passed through the Power Supply Adjustor.

Witness: Leland R Snook

Schedule 2: Revenue Requirement and Adjustor Calculation
Plant in Service for Calendar Year 2012
Estimated Calculation (Excluding 4Corners)

Line No.	ERA Calculation		YR1
	Qualified Plant		
1.	Environmental Improvement Projects (Schedule 1, Line 4, Column F)	$	976,626
2.	New Generation Capacity - Plant Construction (Schedule 1, Line 8, Column F)		-
3.	New Generation Capacity - Plant Acquisition (Schedule 1, Line 12, Column F)		-
4.	Existing Generation Plant - New Efficiency Projects (Schedule 1, Line 16, Column F)		-
5.	Plant Balance - ERA Qualified Investments (Line 1 + Line 2 + Line 3 + Line 4)	$	976,626
	Adjustment to Plant		
6.	Accumulated Depreciation	$	2,433
7.	Cumulative Deferred Tax/Tax Credits		202,107
8.	ERA Net Plant (Line 5 - Line 6 - Line 7)	$	772,086
9.	Pre-tax Weighted Average Cost of Capital		12.7480%
	Revenue Requirement		
10.	Composite Return on ERA Net Plant (Line 8 * Line 9)	$	98,426
11.	Annual Depreciation of Plant In Service		29,201
12.	Applicable Property Tax		5,678
13.	Associated O&M Expense		-
14.	Total ERA Revenue Requirement (Line 10 + Line 11 + Line 12 + Line 13)	$	133,305
15.	Total Company Revenues	$	2,945,170,227
16	ERA Adjustment Percentage (Line 14 / Line 15)		0.0045%

Note: This information is confidential until APS's FERC Form 1 has been filed.

Schedule 2: Revenue Requirement and Adjustor Calculation
Plant in Service for Calendar Year 2012
Estimated Calculation (including 4Corners)

Line No.	ERA Calculation		YR1
	Qualified Plant		
1.	Environmental Improvement Projects (Schedule 1, Line 4, Column F)	$	976,626
2.	New Generation Capacity - Plant Construction (Schedule 1, Line 8, Column F)		-
3.	New Generation Capacity - Plant Acquisition (Schedule 1, Line 12, Column F)		284,004,000
4.	Existing Generation Plant - New Efficiency Projects (Schedule 1, Line 16, Column F)		-
5.	Plant Balance - ERA Qualified Investments (Line 1 + Line 2 + Line 3 + Line 4)	$	284,980,626
	Adjustment to Plant		
6.	Accumulated Depreciation	$	4,880,733
7.	Cumulative Deferred Tax/Tax Credits		6,592,446
8.	ERA Net Plant (Line 5 - Line 6 - Line 7)	$	273,507,447
9.	Pre-tax Weighted Average Cost of Capital		12.7480%
	Revenue Requirement		
10.	Composite Return on ERA Net Plant (Line 8 * Line 9)	$	34,866,729
11.	Annual Depreciation of Plant In Service	$	19,542,401
12.	Applicable Property Tax		7,830,278
13.	Associated O&M Expense		4,926,600
14.	Total ERA Revenue Requirement (Line 10 + Line 11 + Line 12 + Line 13)	$	67,166,009
15.	Total Company Revenues	$	2,945,170,227
16	ERA Adjustment Percentage (Line 14 / Line 15)		2.2805%

Note: This information is confidential until APS's FERC Form 1 has been filed.

ARIZONA CORPORATION COMMISSION
STAFF'S FOURTH SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
JULY 25, 2011

Staff 4.2: **Environmental and Reliability Account (ERA):** Please explain in detail the major differences between the proposed ERA and the existing Environmental Improvement Surcharge (EIS).

Response: The EIS collects a small fixed amount of funds ($0.00016/kWh) for qualified environmental projects. Collections are required to offset project costs and are recorded as Contribution In Aid of Construction ("CIAC"). The ERA is an adjustor mechanism with a broader scope than the EIS and is designed to collect expenses associated with qualified environmental improvement projects, as well as reliability costs related to generation plant capacity acquisitions, existing generating plant efficiency projects or the construction of new generation plant. The new ERA charge will be calculated based upon historical capital costs and operating expenses associated with the qualifying projects.

Please see Mr. Snook's testimony, pages 23-29, and the ERA Plan of Administration, Attachment LRS-3 for additional detail.

Witness: Leland Snook

ARIZONA CORPORATION COMMISSION
STAFF'S FOURTH SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
JULY 25, 2011

Staff 4.3: **Environmental and Reliability Account (ERA):** Please explain why the ERA is more advantageous to the ratepayer then the EIS.

Response: The Environmental and Reliability Account (ERA) described in the testimony of Leland Snook will target generation capacity additions and environmental upgrades. Recovering these costs concurrently over time through the proposed ERA would smooth the customer bill impact of these environmental and reliability additions, resulting in more gradual base rate increases over time and potentially less frequent general rate cases relative to what they would have been absent the ERA. The proposed ERA mechanism would also provide more accurate price signals to customers by better aligning APS's rates with its costs in a more timely manner. Customers also clearly benefit from the environmental and generation assets, whose revenue requirement would be recovered through the ERA.

Unlike the cap imposed on the EIS, the ERA more accurately reflects the costs associated with making investments in qualified projects. As stated by Mr. Snook in his direct testimony; at page 25, beginning with line 7:

"The ERA will provide a number of service and rate benefits to customers. APS has the obligation to serve its customers with electric power that is safe, reliable, and environmentally responsible. To fulfill this obligation, APS must be able to raise enough capital for the necessary investments in generating facilities. By providing timely recovery of required environmental improvement projects and generation capacity acquisitions or additions between rate proceedings, the ERA will better enable APS to secure capital at a reasonable cost and make these capital investments. Thus, passing these savings onto customers."

Witness: Leland Snook

Arizona Corporation Commission
Docket No. E-01345A-11-0224
Exhibit: MJM-8

National Regulatory
Research Institute

How Should Regulators View Cost Trackers?

Ken Costello, Principal

National Regulatory Research Institute

September 2009

09–13

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Acknowledgments

The author wishes to thank Mr. Scott Hempling and Mr. Adam Pollock, both of NRRI; Professor Dr. Douglas N. Jones of The Ohio State University; Mr. Michael McFadden of McFadden Consulting Group; Professor Carl Peterson of the University of Illinois Springfield; and Mr. Joseph W. Rogers of the Massachusetts Attorney General Office for their comments on an earlier draft of this paper. The author is responsible for any remaining errors in the document.

Online Access

The reader can find this paper on the Web at http://www.nrri.org/pubs/gas/NRRI_cost_trackers_sept09-13.pdf.

Executive Summary

A cost tracker allows a utility to recover its actual costs from customers for a specified function on a periodical basis outside of a rate case. This paper discusses the major issues that state public utility commissions face in evaluating the costs and benefits of these devices.

Several state commissions have approved new cost trackers for a wide array of utility functions in both the electric and natural gas sectors. State commissions have traditionally limited the use of cost trackers, partially because of the perception that they create "bad" incentives and shift risks to a utility's customers. The recent approvals depart from past regulatory practices that sanction trackers only under highly restricted conditions.

The author asserts that state commissions have not given adequate attention to the negative features of cost trackers, which are at odds with the public interest. Specifically, cost trackers diminish the positive effects of regulatory lag and retrospective reviews in deterring utility waste and cost inefficiency. Trackers also could reduce regulatory scrutiny in evaluating cost prudence.

This paper contends that regulators should view cost recovery in a rate case as the "default" practice. A rate case assures scrutiny of a utility's costs and provides strong motivation for the utility to control those costs between rate cases. The utility therefore bears burden to show why a cost tracker is in the public interest. The utility should demonstrate that it would suffer severe financial difficulties under "extraordinary circumstances" without the tracker.

This paper also recommends that regulators consider the advantages of replacing cost trackers (excluding fuel and purchased gas cost trackers) with a single rate-of-return tracker in the form of an earnings-sharing mechanism. This alternative can overcome some of the problems with cost trackers, namely perverse or weak incentives for cost control, the mismatching of total costs and revenues, and inadequate regulatory oversight of costs. An earnings-sharing mechanism also achieves the major objective of cost trackers, which is to prevent a utility from suffering serious financial problems between rate cases.

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How Should Regulators View Cost Trackers?

This paper discusses the major issues regulators face in evaluating the costs and benefits of cost trackers.[1] This paper responds to state public utility commissions' recent actions in approving new cost trackers for a wide array of utility functions in both the electric and natural gas sectors. Historically, state commissions have limited the use of cost trackers, partially because of the perception that they create "bad" incentives and shift risks to a utility's customers. The recent approvals differ from past regulatory practices that sanctioned trackers only under highly restricted conditions.

The author contends that state commissions have not given adequate attention to the negative features of cost trackers. By conflicting with certain regulatory objectives, cost trackers thwart the public interest. Cost trackers undercut the positive effects of regulatory lag and retrospective reviews in deterring utility waste and cost inefficiency. They also could lessen regulatory scrutiny in evaluating the prudence of costs.

This paper defines cost trackers and discusses how they benefit utilities. It then provides the rationales for cost trackers and how they relate to regulatory principles for cost recovery. The paper examines two scenarios; in the first, regulators allow comprehensive cost trackers, while in the second they allow none. The paper ends by recommending a regulatory policy and identifying questions regulators should ask when investigating cost trackers.

I. The Definition and Mechanics of a Cost Tracker

A cost tracker allows a utility to recover its actual costs from customers for a specified function on a periodical basis outside of a rate case.[2] A tracker, in other words, involves the recovery of a utility's actual costs in the periods between rate cases. These costs could include

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[1] Regulators sometimes refer to cost trackers as "riders."

[2] A cost tracker can either provide interim rate relief for a utility or be a permanent fixture that adjusts rates between rate cases based on upward and downward movements in those costs specified in a tracker. As an alternative to a cost tracker, a utility can file for emergency rate relief whenever it encounters a serious financial problem. The commission can specify conditions under which a utility can file an emergency or interim rate filing petitioning for immediate rate relief. This paper does not examine the different regulatory approaches to relieving utilities of any temporary or more permanent serious financial problems. Such a study could compare each approach, including cost trackers, based on its effect on different regulatory objectives.

those that deviate from some baseline or are zero-based.[3] Baseline costs, for example, could include bad debt costs[4] reflected in present rates as determined in the last rate case. A cost tracker could allow adjustments in rates when actual bad-debt costs depart from the baseline level. These adjustments would occur periodically as prescribed previously by a commission.

To benefit customers when actual cost falls below the baseline level, a cost tracker must be "symmetrical." The unpredictability of a cost item—which, as this paper discusses later, is one underlying rationale for a cost tracker—means that test-year cost estimates can overstate or understate the actual costs. Virtually all fuel and purchased gas cost trackers are symmetrical, with customers benefiting when commodity-energy costs fall (e.g., since the autumn of 2008).

Cost trackers also could apply to all of the costs associated with a particular business function or task. Under this zero-based approach, for example, the entire cost of a gas utility's new investments in upgrading the safety of its distribution system would be amortized and recovered later from customers in lieu of inclusion in base rates. The same cost recovery procedure can occur for a utility's energy-efficiency initiatives.

Some cost trackers, such as fuel adjustment clauses (FAC) and purchased gas adjustments (PGAs), adjust rates in response to changes in the price of fuels used by generating facilities and purchased gas for gas utilities.[5] Certain cost trackers approved over the last couple of years allow for rate adjustments when the cost for a particular business function, for whatever reason, changes. A tracker for bad debt, for example, does not distinguish between an increase because of a greater number of nonpaying customers or higher debt per customer.

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[3] "Zero-based" refers to *all* the costs associated with a specific function, rather than just increments or decrements from test-year costs.

[4] These costs represent money owed by customers to a utility that the utility has determined to be uncollectible.

[5] NRRI has conducted several studies on FACs and PGAs. *See*, for example, Robert E. Burns, Mark Eifert, Peter Nagler, *Current PGA and FAC Practices: Implications for Ratemaking in Competitive Markets* (Columbus, Ohio: NRRI, November 1991), NRRI 91-13; Robert E. Burns and Mark Eifert, "Designing Fuel and Purchased Gas Adjustment Clauses to Provide for Incentive Compatibility in a More Competitive Environment," *Proceedings of the Eighth NARUC Biennial Regulatory Information Conference* (Columbus, Ohio: NRRI, September 1992); Kevin A. Kelly, Timothy Pryor, Nat Simons, *Electric Fuel Adjustment Clause Design* (Columbus, Ohio: NRRI, 1979), NRRI 79-3; and Douglas N. Jones, Russell J. Profozich, Timothy Biggs, *Electric and Gas Utility Rate and Fuel Adjustment Clause Increases, 1978 and 1979* (Columbus, Ohio: NRRI, 1981), NRRI 81-5.

II. Principles for Cost Recovery

A. "Reasonable opportunity" criterion

State commissions have applied myriad criteria for utility cost recovery. Regulators are legally bound to allow utilities the opportunity to recover prudently incurred costs. Prudent costs reflect utility management that makes rational and well-informed decisions. The word "opportunity" can refer to the utility having a good chance of earning its authorized rate of return and is distinct from an entitlement.[6] "Earning the authorized rate of return" means that the utility recovers its prudent variable costs (e.g., operations and maintenance) and earns a return of and on prudently incurred fixed costs, including its cost of capital as determined in the last rate case.

B. Incentive effects of cost trackers

Commissions traditionally allow cost recovery only after a rate case review. Other alternatives such as a cost tracker would require that a utility show violation of the "opportunity" condition for particular cost items. A violation can occur when a certain cost is substantial, unpredictable, and generally beyond a utility's control. Other than costs relating to fuel and purchased power and gas, few other costs fall within the confines of "special circumstances."[7] Parties to regulatory proceedings naturally disagree over when these circumstances exist. To clarify their positions to utilities, intervening groups, and the general public, commissions should consider issuing policy statements articulating standards for the recovery of costs through trackers.

Regulators, until recently, have taken a cautious approach to trackers, partially because they weaken the incentive of a utility to control its costs.[8] Controlling utility costs is a primary

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[6] One interpretation is that the utility earns its authorized rate of return over a number of years, rather than each year. Regulators, investors, and utilities do not expect uniform rates of return across years. Instead, they ostensibly presume that in some years the rate of return will be below the authorized level, while in other years it would be above the authorized level. Regulators, for example, set rates based on "normal" weather. They expect that summer weather will be hotter than normal in some years and cooler than normal in others. For a typical electric utility, having a hotter-than-normal summer and a cooler-than-normal summer often means the utility earns a high rate of return and a low rate of return for those years respectively. But regulators expect normal weather over a number of years.

[7] An exception also might include the costs associated with a major storm causing extensive damage to a utility's infrastructure.

[8] The cost trackers discussed in this paper assume price adjustments based on changes in the actual cost of the utility. If instead price adjustments relate to cost changes for a peer group or other factors outside the control of the utility, the incentive problems identified in this paper would mostly disappear. Some cost trackers attempt to incorporate benchmarks that reflect performance exogenous to an individual utility. Defining the appropriate benchmark is a crucial but difficult task in designing a performance-based tracker. *See*, for example, Ken Costello and

objective of regulators because it contributes to lower rates and reflects efficient utility management. Cost trackers can, in various ways, result in higher utility costs.[9] First, they undercut the positive effects of regulatory lag on a utility's costs. "Regulatory lag" refers to the time gap between when a utility undergoes a change in cost or sales levels and when the utility can reflect these changes in new rates. Economic theory predicts that the longer the regulatory lag, the more incentive a utility has to control its costs; when a utility incurs costs, the longer it has to wait to recover those costs, the lower its earnings are in the interim. The utility, consequently, would have an incentive to minimize additional costs. Commissions rely on regulatory lag as an important tool for motivating utilities to act efficiently.[10] As economist and regulator Alfred Kahn once remarked:

> Freezing rates for the period of the lag imposes penalties for inefficiency, excessive conservatism, and wrong guesses, and offers rewards for their

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James F. Wilson, *A Hard Look at Incentive Mechanisms for Natural Gas Procurement*, NRRI 06-15, November 2006, at http://www.nrri.org/pubs/gas/06-15.pdf.

[9] Theoretical and empirical studies provide some evidence of the incentive problems associated with one kind of cost trackers, FACs. *See*, for example, David P. Baron and Raymond R. DeBondt, "Fuel Adjustment Mechanisms and Economic Efficiency," *Journal of Industrial Economics*, Vol. 27 (1979): 243-69; David P. Baron and Raymond R. DeBondt, "On the Design of Regulatory Price Adjustment Mechanisms," *Journal of Economic Theory*, Vol. 24 (1981): 70-94; David L. Kaserman and Richard C. Tepel, "The Impact of the Automatic Adjustment Clause on Fuel Purchase and Utilization Practices in the U.S. Electric Utility Industry," *Southern Economics Journal*, Vol. 48 (1982): 687-700; and Frank A. Scott, Jr., "The Effect of a Fuel Adjustment Clause on a Regulated Firm's Selection of Inputs," *The Energy Journal*, Vol. 6 (1985): 117-126. The first two studies applied a general model to show that FACs tend to cause a utility to overuse fuel relative to other inputs, pay more for fuel prices, and choose non-optimal, fuel-intensive generation technologies. The third study provided empirical support for this prediction. The fourth study showed that some types of FACs cause bias in fuel use and that FACs in general weaken the incentive of a utility to search for lower-priced fuel. It provided empirical evidence that electric utilities with an FAC pay higher fuel prices than utilities without an FAC.

[10] Regulatory lag is a less-than-ideal method, however, for rewarding an efficient, and penalizing an inefficient, utility. Some of the additional costs could fall outside the control of a utility (e.g., increase in the price of materials), and any cost declines might not correlate with a more managerially efficient utility (e.g., deflationary conditions in the general economy). As discussed elsewhere in this paper, regulators are more receptive to cost trackers when: (1) regulatory lag can cause a substantial movement in a utility's rate of return between rate cases, and (2) the utility has little control over how much its actual costs will deviate from its test-year costs.

> opposites; companies can for a time keep the higher profits they reap from a superior performance and have to suffer the losses from a poor one.[11]

Rational utility management, as a general rule, would exert minimal effort in controlling costs if it has no effect on the utility's profits.[12] This condition occurs when a utility is able to pass through (with little or no regulatory scrutiny) higher costs to customers with minimal consequences for sales. Cost containment constitutes a real cost to management. Without any expected benefits, management would exert minimum effort on cost containment. The difficult problem for the regulator is to detect when management is lax. Regulators should concern themselves with this problem; lax management translates into a higher cost of service and, if undetected, higher rates to the utility's customers. Regulators should closely monitor and scrutinize costs, such as those subject to cost trackers, that utilities have little incentive to control.

When mechanisms for cost recovery differ across functional areas, perverse incentives can arise that would make it profitable for the utility not to pursue cost-minimizing activities.[13] The result is higher rates to utility customers. A utility with a FAC might postpone maintenance of a power plant even when it would cost less than the savings in fuel costs. The utility could not immediately (or even at any time) recover additional maintenance costs, while it could pass the higher fuel costs through the FAC.

Cost trackers, in the long run, can bias a utility's technological and investment decisions. A utility recovering fuel costs through a FAC, for example, might want to adopt fuel-intensive generation technologies even if they are more expensive from a life-cycle perspective.[14] The result, again, is higher rates to utility customers.

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[11] Alfred E. Kahn, *Economics of Regulation, Vol. 2* (New York: John Wiley & Sons, 1971), 48.

[12] I assume here that reducing cost has no effect on the quality or quantity of utility service. Controlling costs, therefore, refers to eliminating or reducing "wasteful" expenses that would result in no decline in the value of utility service. The author imagines a situation in which utilities would attempt to defer maintenance costs until the commission sets new base rates that account for those costs.

[13] In the example above, regulators could eliminate any perverse incentive by simply allowing a cost tracker for maintenance expenses.

[14] *See*, for example, the Baron and DeBondt studies cited in footnote 9.

Cost trackers also could motivate utilities to shift more of their costs to functions subject to trackers.[15] They might, for example, want to classify routine maintenance costs as a capital expense that receives tracker cost recovery. Such shifts could lead to earning an excessive rate of return. Regulators implementing trackers should carefully define applicable costs. They should also examine costs claimed under trackers to ensure that the utility recovers only appropriate costs through the tracker.[16]

An important incentive for cost control by regulated utilities is the threat of cost disallowance from retrospective review.[17] To the extent that cost trackers dilute the frequency and quality of these reviews, further erosion of incentives for cost control occurs. With less regulatory oversight and auditing, which often accompany rate cases, a utility might have less concern over the costs it incurs. Regulators have long recognized the importance of retrospective reviews in motivating a utility to avoid cost disallowances from grossly subpar performance.

If a utility has a number of cost trackers, the regulator might want to consider staggering the timing of retrospective reviews to avoid having inadequate staff resources to review the adjustments for individual cost trackers. Some utilities have comprehensive trackers that recover a wide array of costs (e.g., purchased gas, bad debt, energy-efficiency activities, and environmental activities). For these trackers, it would be especially challenging for a regulator to conduct an adequate retrospective review of each item simultaneously.[18]

A contradiction seemingly exists between the criterion that trackers should apply only to those costs beyond the control of a utility and the assertion that the modified incentives caused by trackers can lead to inflated costs. One response is that a utility has at least some control over most of its costs. Except for certain taxes and some other cost items, the actions of utility

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[15] One example is when a tracker for new capital expenditures creates an incentive for a utility to shift labor costs from maintenance to capital projects. In this instance, the utility can schedule employees to work on the capital projects, and maintenance is delayed. The utility consequently reduces its maintenance costs and thereby keep the savings, and increase its capital expenditures, which it recovers through the tracker. I thank Michael McFadden for this example.

[16] I thank Adam Pollock for this insight.

[17] Many regulatory experts view retrospective reviews as dissuading a utility from poor decisions with the threat of a penalty—for example, making the utility more diligent and careful in its planning and procurement. Given asymmetric information, where a utility knows more about its operations and market supply/demand conditions than the commission, some analysts characterize retrospective views as a second-best mechanism to market-like incentives. For most gas utilities, the strong incentives for controlling purchased gas costs derive mainly from the time lag between the incurrence of a cost and its recovery from retail customers, and regulatory prudence reviews where, for example, abnormal costs attract special attention and a review.

[18] I thank Joseph Rogers for this insight.

management can affect costs. Even for fuel or purchased gas, utility management's actions can affect their total costs. Although for the most part the marketplace determines the price paid for these items, utilities can negotiate prices under long-term contracts and decide on the mix and sources of different fuels and purchased gas.[19]

Commissions also tend to avoid cost recovery that results in radical price volatility to utility customers. Such a policy could preclude monthly price adjustments from changes in fuel costs or purchased gas costs. It also might result in a phase-in of the construction costs of a new base-load-generating facility.

III. Utilities' Perspective on Cost Trackers

Under traditional ratemaking, the utility recovers all costs after a rate case review. It requires no commission activity between rate cases. Traditional ratemaking provides base rates based on the test year. A commission relies heavily on cost-of-service studies to determine base rates. Base rates have two characteristics: (1) a commission sets them in a formal rate case, and (2) they remain fixed until the utility files a new rate case and the commission makes a subsequent decision. The costs represent those calculated for a designated test year and exclude those costs recovered in trackers and other mechanisms. No matter how much the actual utility's costs and revenues deviate from their test-year levels, rates remain fixed until the commission approves new ones in a subsequent rate case. The exception is when a commission allows for interim rate relief under highly abnormal conditions that jeopardize a utility's financial condition.

Utilities have argued that a more dynamic market environment, characterized by the increased unpredictability and volatility of certain costs, justifies the recovery of certain costs through a tracker rather than in base rates.[20] Utilities have also asserted that the static nature of the "test year" sometimes denies them a reasonable opportunity to earn their authorized rate of return. They contend that cost trackers advance the ratemaking goals by matching revenues to actual costs.

In contrast to base rates, cost trackers offer a utility the advantages of: (1) shortening the time lag between the incurrence of a cost and its recovery in rates (i.e., curtailing regulatory lag),

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[19] A utility, for example, might be lax in finding the best deals for gas supplies, in applying more resources by employing more highly qualified staff, or in acquiring superior market intelligence. *See,* for example, Ken Costello, *Gas Supply Planning and Procurement: A Comprehensive Regulatory Approach*, NRRI 08-07, June 2008, at http://nrri.org/pubs/gas/Gas_Supply_Planning_and_Procurement_jun08-07.pdf.

[20] *See*, for example, Russell A. Feingold, "Rethinking Natural Gas Utility Rate Design: A Framework for Change," presented at the American Gas Foundation Executive Forum, held at The Ohio State University, May 23, 2006.

(2) increasing cost-recovery certainty,[21] and (3) lessening the regulatory scrutiny of its costs. Normally, in a rate case a regulator closely reviews the utility's costs before approving them for recovery from customers. Regulators often less rigorously scrutinize a utility's costs when recovered through a tracker.[22] Overall, cost trackers lower a utility's financial risk by stabilizing its earnings and cash flow.

Utilities increasingly have asked their state public utility commissions to depart from traditional regulation by approving new cost-recovery mechanisms for different business activities. Some gas utilities want to expand the scope of their PGA clauses to include a wider array of costs. Current cost trackers in the natural gas sector, other than those for purchased gas costs, apply to functions including pipeline integrity management, pipeline replacement costs (e.g., accelerated cast iron main replacement program), bad debt, energy-efficiency costs, general infrastructure costs, manufactured gas plant remediation, stranded restructuring costs, property taxes, post-retirement employee benefits, and environmental costs.

IV. Regulatory Rationales for Cost Trackers

A. "Extraordinary circumstances"

State commissions have traditionally approved cost trackers only under "extraordinary circumstances." Commissions recognize the special treatment given to costs recovered by a tracker; they consider cost trackers an exception to the general rule for cost recovery. This view places the burden on a utility to demonstrate why certain costs require special treatment.

The "extraordinary circumstances" justifying most of the cost trackers that commissions have historically approved have been for costs that are: (1) largely outside the control of a utility, (2) unpredictable and volatile,[23] and (3) substantial and recurring. Historically, commissions required that all three conditions exist if a utility wanted to have costs recovered through a tracker. Fuel costs were a good candidate because of their influence by factors beyond

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[21] Between rate cases, for example, a utility might incur costs unanticipated by the test-year calculation and thus not recovered from its customers.

[22] The regulator, for example, might have less time to review these costs or just might consider them too unimportant to warrant a separate review. Another explanation might be that rate cases are transparent and well-publicized, putting pressure on regulators to closely review all aspects of a rate case filing. These reasons are just the author's speculations. A pertinent research question is whether this hypothesis has validity.

[23] Even if the forecast of a cost item is highly accurate in the long run, it can fluctuate widely in the short run, causing possible serious cash-flow problems for the utility. The utility might then have to purchase short-term debt and other financing. The author thanks Carl Peterson for this insight.

the control of a utility, their volatility, and their large size. Commissions recently have approved cost trackers when not meeting all three conditions, especially the third (substantial and recurring costs).[24]

The last "extraordinary circumstance," substantial and recurring costs, greatly restricts the costs eligible for cost tracker recovery. Differences between their test year and actual cost can have a material effect on a utility's rate of return. Legal precedent dictates that regulators must set reasonable rates that allow a prudent utility to operate successfully, maintain its financial integrity, attract capital, and compensate its investors commensurate with the risks involved.[25] A utility should recover revenues in excess of its operating expenses to provide a "fair return" to investors. Businesses including utilities need to earn a profit to compensate investors for business, financial, and other risks.[26]

Some state commissions have softened or ignored the "substantial and recurring" component of the "extraordinary circumstances" standard. Bad debt, the subject of recent cost trackers, features financial effects that are typically not substantial. Utilities have contended that the unpredictability of this cost makes it difficult to incorporate it accurately into the base rate. Yet, even if this assertion is true, it is questionable whether any bad-debt cost unaccounted for in the test year would inflict substantial financial harm on a typical utility.[27]

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[24] Commissions' rulings seem to reflect the view that regulators have much discretion in approving cost trackers as long as these actions reflect reasonable ratemaking given the facts and circumstances.

[25] The U.S. Supreme Court outlined these conditions in its 1944 order for *FPC v. Hope Natural Gas Co.*, 320 U.S. 591, 605 (1944).

[26] The return on equity for a utility corresponds to the term "normal profits." Both terms involve the cost a utility incurs to attract funds from investors.[26] Let us assume that utility performance should replicate the performance of competitive firms where firms receive normal profits in the long run. A utility would, therefore, earn a return that is reasonable but not excessive. A reasonable return should allow the utility to maintain its credit quality and attract needed capital on reasonable terms, but do no more. Commissions usually consider a rate of return within a "zone of reasonableness" as sufficient but not excessive. They do not guarantee that the utility will earn within this zone; they merely give the utility the opportunity if it performs efficiently and economically.

[27] The outcome would vary across utilities and by period. Especially in bad economic times in conjunction with high energy prices, bad debt can quickly soar, making test-year estimates grossly inaccurate. "Substantial financial harm" has no definitive meaning. It can refer to a situation where a utility has difficulties in raising funds for new investments or faces severe cash flow problems. Such situations can harm customers in the long run, for example, by reducing service reliability and diminishing the utility's credit quality, which in turn can lead to the utility having a higher cost of capital. A tracker for bad debt can also affect how the utility responds to customers who are behind in their payments. It can, for example, make the utility

B. "Severe financial consequences"

Historically, commissions have approved cost trackers to avoid the possibility of a utility suffering a serious financial problem because of cost increases unforeseen at the time of the last rate case.[28] Justification for cost trackers is, therefore, greater when a commission relies on a historical test year that does not recognize the volatility of certain costs or their upward trend over time. Let us assume that a certain operating cost has trended upward (e.g., 2 percent per year) over the past several years. Let us also assume that the commission allows only a historical test year. In this example the utility is likely to under-recover this particular cost. What effect this outcome would have on the utility's overall rate of return depends on the magnitude of any cost increase relative to the utility's earnings and whether other costs fell while rates were in effect.

Commissions do not expect utilities to earn the authorized rate of return during each future period over which new prices are in effect.[29] Commissions implicitly impute a risk premium in the authorized rate of return, partially to account for the earnings volatility from fluctuations in costs or revenues from the test year. Trackers affect what is called "business risk." Business risk refers to the uncertainty linked to the operating cash flows of a business. Business risk is multi-dimensional, inclusive of sales, cost, and operating risks. In the Capital Asset Pricing Model (CAPM), for example, the lower the utility's expected earnings volatility, the lower the measure of the utility's risk relative to the market portfolio (i.e., "beta"). Because

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more lax in its credit policies, which could result in fewer service disconnections, especially for low-income households. In the absence of a tracker, the utility presumably would intensify its efforts to collect money owed by delinquent customers. I thank Michael McFadden for this insight.

[28] *See,* for example, Paul L. Joskow, "Inflation and Environmental Concern: Structural Changes in the Process of Public Utility Regulation," *Journal of Law and Economics*, Vol. 17 (1974): 291-327. A premise behind the wide acceptance of fuel adjustment clauses was that because electric utilities were not responsible for the escalation of fuel costs, commissions should not hold them accountable. Virtually all electric utilities in the 1970s experienced an unprecedented rise in fuel costs, for example, inferring an exogenous event beyond the control of any single utility. Prior to this time, even though FACs were common but fuel prices were much more stable, commissions generally associated changes in the utility's rate of return between rate cases with utility-management performance. A lower rate of return reflected poor performance and a higher rate of return superior performance. (A 1974 study found that 42 out of 51 jurisdictions had some form of fuel adjustment clause. *See* National Economic Research Associates, "The Fuel Adjustment Clause: A Survey of Criticism, Justifications, and Its Applications in the Various Jurisdictions," 1974.)

[29] This statement supports the contention that commissions do not intend the prices they set in a rate case to reflect the utility's actual cost of service for each future year. Commissions, however, judge that the prices they set will allow the utility an opportunity (i.e., a reasonable chance) to earn its authorized rate of return or some return close to the authorized level.

trackers reduce a utility's business risk, a regulator might want to consider revising downward the risk premium of a utility with additional cost trackers or a revenue-decoupling tracker, resulting in a lower return on equity.

If a commission wants to guarantee that the utility will recover its authorized earnings, it would favor a rate design that allows the utility to recover all of its fixed costs in a monthly service charge or a customer charge.[30] Since generally commissions do not, they implicitly recognize the positive incentive effect from allowing a utility's actual rate of return to deviate from the authorized level. Commissions also know that if a utility is continuously earning below its authorized rate of return, the utility has the right to file a general rate increase.

The previous discussion explains why most regulators have favored adjusting rates between rate cases only when such adjustments avoid serious financial situations for utilities. If a commission wanted to assure the utility that it will always earn its authorized rate of return, it would allow the utility to recover all of its actual costs through trackers.[31] Commissions generally do not allow the tracking of all costs because of incentive and other problems, which this paper discusses in Section II.B.

C. An illustration: FACs and PGAs

The wide popularity of FACs and PGAs among utilities and most commissions reflects the perception that these mechanisms are necessary to prevent a utility from earning a rate of return substantially below what was authorized. This perception stems from the magnitude of fuel and purchased gas costs relative to a utility's earnings. Other categories of costs, such as bad debt, are much smaller in size and therefore have smaller earnings consequences.

Until fuel costs started to fluctuate sharply in the 1970s, some energy utilities had to operate without the ability to adjust prices outside a rate case.[32] These utilities shouldered the risks of events between rate cases, but they also retained any high returns from favorable happenings. Prior to around 1970, for example, many electric utilities earned rates of return that were much higher than the authorized levels because of technological improvements, high sales growth, and economies of scale, in addition to the acquiescence of commissions.[33]

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[30] Such a rate design would not guarantee the utility earning its authorized rate of return, as unexpected variable costs would cause the utility's earnings to decline.

[31] This recovery would include fixed costs the commission found prudent in the last rate case. Guarantee of full recovery of all costs would also require a revenue tracker such as revenue decoupling, assuming that the utility recovers some of its fixed costs in the volumetric or commodity charge.

[32] The genesis for these dramatic fuel-cost increases was the Oil Embargo by OPEC and the other Persian Gulf troubles of the 1970s.

[33] Although most state commissions had authority to initiate proceedings to reduce rates, few chose to exercise it.

Not surprisingly, virtually all state commissions believed that trackers for large items such as fuel costs and purchased gas costs were necessary to prevent inordinate rate-of-return fluctuations. Implicit in this belief is the view that the burden on utility shareholders would otherwise be onerous. This factor overwhelmed the arguments against trackers. The major objective of FACs and PGAs, implanted during that era, was to shield the utility's earnings from commodity price volatility. Both debt and equity investors favor these mechanisms in reducing the riskiness of a utility's earnings and cash flow.

V. Two Extreme States of the World: Several and No Cost Trackers

A. A hodgepodge of cost trackers, or a single rate-of-return tracker

If a commission wants a utility always to earn close to its authorized rate of return, it would favor rate adjustments between rate cases for both: (1) actual costs deviating from test-year costs, and (2) actual revenues deviating from test-year revenues. This outcome would require cost trackers covering all of the utility's costs in addition to a revenue decoupling mechanism. (The revenue decoupling mechanism would allow the utility to recover all fixed costs that the commission approved for recovery in the last rate case.)

Putting the utility's future on "autopilot" seems like a reasonable course of action if financial stability is the prime regulatory objective. Considering incentive problems and excessive risk-shifting to customers, this option comes across as much less appealing.

An earnings-sharing mechanism (ESM), which consolidates different cost and revenue trackers, is one ratemaking procedure for stabilizing a utility's rate of return between rate cases. Under this mechanism, the utility adjusts its rates periodically (e.g., annually) when its actual return on equity falls outside some specified band. As an illustration, if the band encompasses a 10 to 14 percent rate of return on equity (with 12 percent as the utility's authorized rate of return established in the last rate case) when the actual return is 9 percent, the utility could adjust its rates upward to increase its return to, or bring it closer to, 10 percent.[34]

An ESM helps to stabilize a utility's rate of return without a full-scale rate case review. Earnings sharing should reduce the frequency of future rate cases and allow adjusted rates to reflect recent market developments, including those affecting a utility's costs.[35] Compared to

[34] The band implicitly reflects the range for the return on equity that the regulator deems both adequate to keep the utility from financial jeopardy and not so excessive as to be exorbitant. The interpretation of these financial conditions is subjective and open to debate.

[35] Under traditional ratemaking, reducing the frequency of rate cases might allow the utility to over-earn by a substantial amount because of the multi-year accumulation of higher-than-expected sales or lower-than-expected costs, or both. Commissions probably are not so concerned when the utility over-earns for a one- or two-year period, but would be when it over-earns by a "significant" amount over several consecutive years. This reaction would be more

traditional ratemaking, where rates remain fixed between rate cases, ESM weakens regulatory lag and thereby reduces the incentive of a utility to control its costs between rate cases.[36] A commission can lessen this problem by requiring the utility to demonstrate its prudence and offer reasons why specific cost items were higher than their test-year levels.[37]

In sum, an ESM would trigger a price adjustment between rate cases only when the aggregation of revenue and cost departures from test-year levels cause the utility's rate of return to fall outside a specified "band" region. An ESM takes into account the overall profitability of a utility. It assumes the role of a rate-of-return tracker that, in effect, amalgamates different cost trackers into a single cost-recovery mechanism.

The ESM differs from conventional trackers, which account for specific costs or functions in isolation from the utility's overall financial position. Trackers' focus on an individual cost categories can cause utilities to delay coming in for rate cases, with the utility earning an "excessively" high rate of return in the interim. Let us assume that the commission has approved a tracker for new infrastructure expenditures. The new infrastructure expects to lower the utility's maintenance and other operating costs. If the last rate case did not recognize these lower operating costs, the utility's rate of return would be higher, yet because of the tracker, the utility suffers no interim financial losses from incurring infrastructure expenditures.

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acute if the commission believes that fortuitous cirscumstances, rather than superior utility management, caused the high earnings.

[36] This incentive problem exists only when the utility is outside the "band" region and the mechanism requires sharing of "excessive "or "deficient" earnings with customers. This fact suggests a wide "band," as the utility operating within the "band" would have "high-powered" incentives to manage costs because it retains all the economic gains.

[37] The incentive problem would be less pronounced compared to a conventional cost tracker. As long as the utility's rate of return is within the "band" region, it has a similar incentive for cost control as it would between rate cases with fixed prices. (The word "similar" is used because if the "band region" is wide enough, it could defer the next rate case to either increase or decrease rates. This deferral would further strengthen the incentive of the utility to control costs.) Outside the "band" region, the utility's incentive depends upon whether ESM requires the sharing of high or low rates of return between the utility and its customers. Assume, for example, that the "band" region is a 10 to 14 percent rate of return on equity. During the year, the utility earns 15 percent; if the utility has to split the difference between the higher boundary of the "band" region and the actual rate of return by adjusting its prices down, in the example the utility would realize a 14.5 percent rate of return. We assume that the mechanism is symmetrical, so if the utility earns below the lower boundary of the "band" region, say, a 9 percent rate of return, it can adjust prices up to realize a rate of return closer to the lower boundary. This sharing arrangement means that if the utility allows its costs to rise, it either suffers the full consequence (when it operates within the 'band" region) or the partial consequence (when it operates outside). The latter condition creates an incentive problem relative to traditional ratemaking with regulatory lag and fixed prices between rate cases.

On net, the utility benefits and its customers immediately pay for the infrastructure costs without benefiting from the lower operating costs (at least until new rates reflect the lower costs). Such an outcome would violate any common meaning of "fairness" and seriously calls into question the merits of using a single-function tracker without readjusting rates for the effect on a utility's other functional areas.[38] This dynamic suggests that commissions implementing trackers should require their utilities to file rate cases on predetermined intervals.

B. No cost trackers

Under the traditional approach to ratemaking, a utility cannot adjust its rates outside a rate case. No matter what happens to a utility's costs or revenues between rate cases, rates remain fixed. Let us assume that a utility's costs and revenues are volatile and difficult to predict. The utility's rate of return can then deviate substantially (on the upside or downside) from the authorized level.

It is one thing to prohibit trackers for costs that are substantial, volatile and unpredictable, and generally beyond the control of a utility; it is another to reject trackers for costs that lack one or more of these features. *Good regulatory policy rejects cost trackers that are not essential for protecting a utility from a dire financial situation.* The utility, in justifying a cost tracker, should present the regulator with credible information showing that a nontrivial probability exists that the cost item under review will rise sufficiently above the test-year level to place the utility in financial jeopardy.[39] This showing is more likely when the regulator uses a historical test year and the cost item recently has exhibited an upward trend or substantial volatility.[40]

Another conceivable justification for a cost tracker is that it transmits better price signals to a utility's customers. Prices would correspond closer to a utility's actual costs and thus improve economic efficiency. For economic efficiency, customers should see costs reflected in their rates, such that they consume less when costs are higher. The validity of this argument for

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[38] Such a non-uniform treatment of costs could also cause perverse incentives. A utility, for example, might overspend on infrastructure structures to receive the gains from lower operating or other costs that the utility retains for itself until the next rate case.

[39] The term "financial jeopardy" has different interpretations. This state, no matter how it is defined, has the potential to harm customers as well as the utility shareholders. It could cause the deferment of needed capital investments to maintain reliable service, lowering of the utility's credit rating, and an increase in the utility's cost of capital. The time period over which these effects would cause injury to utility shareholders generally would be more immediate than the injury to customers.

[40] A future test year might not improve matters much if the cost item is inherently difficult to predict with any forecast and therefore susceptible to large error.

a cost tracker also depends upon the magnitude and nature of the costs involved.[41] This outcome assumes that a tracker involves a variable cost such as fuel or purchased gas costs. When a tracker relates to a fixed cost (e.g., infrastructure costs), the argument turns more to the "fairness" of a cost-recovery mechanism to the utility. Is a tracker justified because test-year cost calculations expose the utility to potentially high financial risk from unanticipated costs that fall primarily outside the control of a utility?

VI. Putting It All Together

Cost trackers have both positive and negative features that regulators must evaluate.[42] In reaching a decision, the regulator needs to weigh these features to determine what is in the public interest based on how they shift risks, ensure cost recovery, and affect incentives. The main challenge for regulators is to evaluate whether the positives outweigh the negatives to justify a cost tracker.[43]

A. The positive side of cost trackers

The primary benefit of cost trackers, as discussed earlier in this paper, is that they reduce the likelihood that a utility will encounter serious financial problems. If test-year costs fail to reflect accurate projections of a utility's actual cost for future periods, then the utility's earnings can deviate substantially from what a commission approved in the last rate case. Some cost items are difficult to project, as they exhibit high volatility and depend on different variables that by themselves are uncertain.

By reducing regulatory lag and the likelihood of prudence reviews, cost trackers can lower a utility's risk and thus increase its access to capital. The utility could then have a higher credit rating that, in turn, could lower the cost of financing capital projects.[44]

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[41] Distortive price signals can relate to the difference between the utility's short-run marginal cost and the marginal price charge to customers in consuming more electricity or natural gas.

[42] For a thorough and excellent discussion of the advantages and disadvantages of cost trackers, with a focus on fuel adjustment clauses, *see* Michael Schmidt, *Automatic Adjustment Clauses: Theory and Applications* (East Lansing, MI: Michigan State University Press, 1981).

[43] For an analysis of similar issues faced by regulators in evaluating different ratemaking mechanisms in general, *see* Ken Costello, *Decision-Making Strategies for Assessing Ratemaking Methods: The Case of Natural Gas*, NRRI 07-10, September 2007, at http://nrri.org/pubs/gas/07-01.pdf.

[44] This argument is similar to the one used to support including construction work in progress (CWIP) in rate base for electricity transmission.

Cost trackers also coincide with the regulatory objective of setting prices based on the actual cost of service. This condition transmits the right price signal to customers deciding how much of the utility's services to consume.[45]

The development of infrastructure such as the smart grid or other new technology costs might warrant that commissions consider cost-recovery mechanisms such as a cost tracker to guarantee minimum cash flow for a utility. Investors might otherwise perceive excessive regulatory risks that preclude committing funding to a utility.[46] A cost tracker in this instance also might cut down on the frequency of future rate cases. Regulators in the future might want to explore less traditional ways for utilities to recover their costs for new technologies with inherently high operational and financial uncertainties.

As a final benefit, cost trackers can reduce regulatory and utility costs by reducing the number of future rate cases. Rate cases absorb substantial staff resources and time, diverting those scarce resources from other commission activities. Yet it is doubtful that many of the recently proposed trackers involving non-major cost items would have any effect on the timing of future rate cases. Another comment is that the costs associated with serious and continuing audits and the monitoring of costs recovered through a tracker could require substantial resources, either in the form of commission staff or outside consultants.

B. The negative side of cost trackers: the case for traditional ratemaking as a default policy or earnings sharing as a preferred alternative

Cost trackers can reduce utility efficiency, as described above. "Just and reasonable" rates require that customers do not pay for costs the utility could have avoided with efficient or prudent management. Regulation attempts to protect customers from excessive utility costs by scrutinizing a utility's costs in a rate case, conducting a retrospective review of costs, applying performance-based incentives, and instituting regulatory lag. Cost trackers diminish one or more of these regulatory activities. In some instances, they diminish all of them. The consequence is the increased likelihood that customers will pay for excessive utility costs.

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[45] One issue that has emerged in states where trackers have become a major method for cost recovery relates to the allocation of those costs across customer classes. Cost allocation determines the actual prices that different customers pay for utility service.

[46] One alternative to reducing regulatory risk through trackers would be for a commission to articulate in a policy statement or other document that it would not apply 20-20 hindsight to determine the cost recovery of new investments. A commission can express, for example, that it will not subject specific utility decisions to prudence reviews. One method of doing so is providing pre-approval for projects before they enter service. For a more detailed discussion of pre-approval mechanisms, *see* Scott Hempling and Scott Strauss, *Pre-Approval Commitments: When And Under What Conditions Should Regulators Commit Ratepayer Dollars to Utility-Proposed Capital Projects?* NRRI 08-12, November 2008, at http://nrri.org/pubs/electricity/nrri_preapproval_commitments_08-12.pdf.

This paper recommends that regulators approve cost trackers only in special situations where the utility would have to show that alternate cost-recovery mechanisms could cause extreme financial problems. This showing requires utilities to provide a distribution of possible cost futures and an assessment of their likelihood. If a certain cost item has high volatility and unpredictability, represents a large component of the utility's revenue requirement and is recurring, and is generally beyond a utility's costs, it becomes a candidate for "tracker" recovery.

Even then, the regulator should consider the adverse incentive effects and how he or she can compensate for this problem.[47] Regulators should condition any approval of a cost tracker on the utility's filing information on its performance for those functional areas directly or indirectly affected by the tracker. For example, has the FAC caused a utility to spend less money on plant maintenance costs, jeopardizing reliability and inflating total utility costs because of higher avoidable fuel costs? These conditions can harm the utility's customers in the long run.

No other rationale merits departing from cost recovery through rate cases. This limited application of cost trackers provides the benefits of:

1. using the same cost-recovery mechanisms for all utility functions to prevent perverse incentives (perverse incentives can lead to a higher cost of service and utility rates);

2. balancing a utility's total costs and total revenues (without this balancing, it is conceivable that the utility could recover one cost item through a tracker and over-recover other costs set in the last rate case to result in the utility earning above its authorized rate of return); a rate case has the attractive feature of matching revenue with costs on an aggregate basis;

3. retaining sufficient regulatory lag to provide the utility with more motivation to control costs (regulatory lag is an important feature of traditional ratemaking in forcing the utility to shoulder the risk of higher costs between rate cases); and

4. scrutinizing a utility's costs and performance in different areas of operation (commissions review costs more rigorously in a rate case setting, decreasing the likelihood that customers will recover a utility's imprudent costs).[48]

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[47] The commission can monitor the utility's performance or include a performance-based incentive component in the tracker mechanism. *See* the NRRI study cited in footnote 8 for a description and analysis of incentive-based gas procurement mechanisms.

[48] In theory, a commission can expend the same resources and effort toward inspecting a utility's costs recovered through a tracker as it does for costs determined in a rate case. In practice, however, the author shares the widely held view that commissions and non-utility parties devote fewer resources to this task for costs recovered through a tracker. Confirmation of this view would require a systematic study that would compare, among other things, the resources expended by the commission and non-utility stakeholders per dollar recovered under trackers and in a rate case.

The earlier discussion points to the advantages of replacing cost trackers (excluding fuel and purchased gas cost trackers) with a single rate-of-return tracker in the form of an earnings-sharing mechanism. This alternative overcomes some of the problems with cost trackers, namely perverse incentives and weak incentives for cost control, the mismatching of a utility's *total* costs and revenues, and inadequate regulatory oversight of costs.[49] An earnings-sharing mechanism is also able to achieve the major objective of cost trackers, namely preventing utilities from suffering serious financial problems between rate cases.

A single rate-of-return tracker can also address the "fairness" issue of why a utility should not recover from customers a cost increase (e.g., property taxes) between rate cases that is completely beyond its control. This mechanism would, in effect, allow the utility to recover the increased costs, but only if it was already earning a "low" rate of return (i.e., a return below the "band" region discussed above). One major problem with cost trackers is that they allow a utility to increase its prices even if the utility is already earning a higher-than-authorized rate of return (or beyond the "zone of reasonableness" set in the last rate case). A commission would not allow this outcome under traditional regulation.

VII. Questions Regulators Should Ask

This paper discusses the major issues regulators face in evaluating cost trackers. Well-informed decisions require regulators to ask certain questions, for which this paper provides some introductory responses. The following is a list of the most pertinent questions:

1. Does a cost-tracker proposal meet the regulatory test of acceptability? What minimum threshold should a regulator set for consideration of a cost tracker?

2. What special circumstances exist to warrant cost recovery outside of a rate case?

3. What evidence does a utility present showing that the absence of a tracker for a particular cost could place it in financial jeopardy?

4. In addition to cost trackers, what other cost-recovery mechanisms can regulators rely on to allow a utility to recover substantial unexpected costs between rate cases? What are the public-interest effects of these mechanisms relative to cost trackers?

5. What advantages does a cost tracker offer? What are its disadvantages?

[49] Regulators can overcome some of these problems. They can, for example, require that a utility with cost trackers file a rate case no less often than every three years or however often frequency regulators consider appropriate. Regulators can also require prudence reviews of utility activities associated with trackers on a regular basis. I thank Michael McFadden for these insights.

6. How should regulators weigh the downsides of cost trackers relative to the upsides? How important are adverse incentive effects relative to the value of stabilizing a utility's rate of return?

7. How should a regulator account for the net-cost effects of a new investment (e.g., capital costs less savings in operating costs) for which the utility wants cost recovery through a tracker?

8. How would the accumulation of cost trackers for a utility motivate the utility to take risks and improve its overall cost performance?

9. If a cost tracker is justified, how can regulators structure it to mitigate potential problems such as weakened incentives for cost control?

10. What conditions should a regulator attach to the approval of a cost tracker?

    a. Should it require the utility to report on its cost performance in functional areas directly and indirectly affected by the tracker?

    b. Should the regulator also require that all costs recovered through trackers be subject to a thorough prudence review?

    c. Should the regulator reduce the utility's return on equity to account for the lower risk resulting from the tracker?

Arizona Corporation Commission
Docket No. E-01345A-11-0224
Exhibit: MJM-9

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January 30, 2009

Mr. Ernest Johnson
Director, Utilities Division
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

RECEIVED
JAN 30 2009
AZ CORP COMM
Director Utilities

RE: DECEMBER 2008 POWER SUPPLY ADJUSTOR REPORT

Dear Mr. Johnson:

Section 8 of the Power Supply Adjustor ("PSA") Plan of Administration ("POA") approved in Decision No. 69663 states that:

> "APS shall provide monthly reports to Staff's Compliance Section and to the Residential Utility Consumer Office detailing all calculations related to the PSA. An APS Principal Officer, as listed in the Company's annual report filed with the Commission's Corporation Division, shall certify under oath that all information provided in the reports itemized below is true and accurate to the best of his or her information and belief. These monthly reports shall be due within 30 days of the end of the reporting period."

Arizona Public Service Company ("APS") is submitting the December 2008 Power Supply Adjustor report. Additionally, APS is submitting the signed officer certification from Mr. James R. Hatfield, APS's Senior Vice-President and Chief Financial Officer.

The Company has also included Schedule 11 as a summary of the monthly calculations, submitted to date, to help summarize all of the accounts.

If you should have any questions regarding the information contained herein, please call Mr. David Rumolo at 602-250-3933.

Sincerely,

Leland R. Snook

LS/jp

Attachments

Cc: Brian Bozzo
Stephen Ahearn
Barbara Keene

ARIZONA PUBLIC SERVICE COMPANY
Schedule 1
Power Supply Adjustment (PSA) Rate Calculation Effective February 1, 2009
($/kWh)

Line No.	PSA Rate Calculation	Current February 1, 2008 [1]	Proposed February 1, 2009 [2]	Increase/(Decrease) $/kWh	Increase/(Decrease) %
1	Forward Component Rate - FC (Schedule 2, L8)	$ 0.002952	$ 0.005080	$ 0.002128	72%
2	Historical Component Rate - HC (Schedule 4, L5) [3]	$ 0.001048	$ 0.000258	$ (0.000790)	-75%
3	PSA Transition Component Rate (Schedule 6, L3) [4]	$ -	$ -	$ -	N/A
4	**PSA Rate (L1+ L2 + L3)**	$ 0.004000	$ 0.005338	$ 0.001338	33%
	Old PSA Rates				
5	2007 Annual Adjustor Rate (Schedule 8, L4) [5]	$ -	$ -	$ -	N/A
6	PV Step 2 Surcharge Component Rate (Sch.9 ,L4) [5]	$ -	$ -	$ -	N/A
7	**Total (L5 + L6)**	$ -	$ -	$ -	N/A

Notes:

[1] See Decision No. 69663.

[2] Proposed levels of the PSA rate components are provided in the September 30 filing and updated in the December 31 filing of each year.

[3] A Historical Component is a true up related to respective prior period PSA activity.

[4] Provides for Mid-Period Corrections when necessary.

[5] The PV Step 2 Surcharge Component Rate and the 2007 Annual Adjustor Rate ended on June 30th, 2008 and July 31st, 2008 respectively.

Arizona Corporation Commission
Docket No. E-01345A-11-0224
Exhibit: MJM-9

ARIZONA PUBLIC SERVICE COMPANY
Schedule 3
2008 PSA Year Forward Component Tracking Account - In Effect from February 1, 2008 to Jan 31, 2009
($ in thousands; Forward Component Rate and Base Rate in $/kWh)

			Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Jan-09
1	Prior Month's Balance	From L27	$ 40,010	$ -	$ (9,663)	$ (25,095)	$ (33,695)	$ (33,983)	$ (9,300)	$ 19,928	$ 38,499	$ 41,535	$ 31,773	$ 14,304	$ -
	Energy Sales														
2	PSA Retail Energy Sales [1]		2,152,680	1,984,493	1,963,596	1,944,346	2,228,211	2,906,001	3,257,410	3,259,836	2,789,656	2,279,113	1,853,772	2,109,394	-
3	Wholesale Native Load Energy Sales [2]		48,609	73,247	83,593	82,539	65,067	50,563	68,985	57,346	47,333	46,617	41,224	28,682	-
4	Total Native Load Energy Sales	L2 + L3	2,201,289	2,057,740	2,047,189	2,026,885	2,293,278	2,956,564	3,326,394	3,317,182	2,836,989	2,325,730	1,894,996	2,138,075	-
5	Retail Energy Sales as a % of Total	L2 / L4	98%	96%	96%	96%	97%	98%	98%	98%	98%	98%	98%	99%	
6	Retail Billed Sales Excluding E-3, E-4, E-36 Sales (MWh) [3]		-	2,046,321	1,892,974	1,927,538	2,065,560	2,434,902	3,041,660	3,104,683	2,987,294	2,503,300	2,104,092	2,018,721	
	System Book Fuel and Purchased Power Costs														
7	Renewables Costs [4]		$ 3,051	$ 2,794	$ 2,923	$ 3,000	$ 2,996	$ 3,074	$ 2,737	$ 2,467	$ 2,599	$ 2,019	$ 2,760	$ 3,237	$ -
8	PPA Fixed Costs		$ 3,561	$ 3,453	$ 3,470	$ 3,578	$ 3,471	$ 5,826	5,768	5,768	$ 4,630	$ 3,567	$ 3,653	$ 3,526	$ -
9	Other Fuel and Purchased Power Costs [5]		$ 75,351	$ 63,628	$ 58,905	$ 68,448	$ 84,040	$ 129,391	$ 146,570	$ 135,550	$ 102,888	$ 76,101	$ 48,860	$ 53,536	$ -
10	Off System Revenue (Credit) [6]		$ (7,468)	$ (7,564)	$ (10,438)	$ (12,771)	$ (9,642)	$ (6,301)	$ (3,835)	$ (4,886)	$ (4,951)	$ (8,063)	$ (6,900)	$ (3,334)	$ -
11	Net Native Load Power Supply Costs	sum(L7 to L10)	$ 74,496	$ 62,306	$ 54,860	$ 62,255	$ 80,865	$ 131,990	$ 151,240	$ 138,898	$ 105,166	$ 72,624	$ 48,373	$ 56,966	$ -
	PSA Retail Fuel and Purchased Power Costs														
12	Renewables Costs	L5 * L7	$ 2,984	$ 2,694	$ 2,804	$ 2,878	$ 2,911	$ 3,021	$ 2,680	$ 2,424	$ 2,555	$ 1,978	$ 2,700	$ 3,194	$ -
13	PPA Fixed Costs	L5 * L8	$ 3,482	$ 3,330	$ 3,328	$ 3,433	$ 3,373	$ 5,726	$ 5,648	$ 5,668	$ 4,553	$ 3,496	$ 3,574	$ 3,479	$ -
14	Other Fuel and Purchased Power Costs	L5 * L9	$ 73,688	$ 61,381	$ 56,500	$ 65,660	$ 81,656	$ 127,178	$ 143,531	$ 133,208	$ 101,172	$ 73,596	$ 47,797	$ 52,818	$ -
15	Off System Revenue (Credit)	L5 * L10	$ (7,303)	$ (7,295)	$ (10,012)	$ (12,251)	$ (9,369)	$ (6,193)	$ (3,756)	$ (4,802)	$ (4,868)	$ (7,801)	$ (6,750)	$ (3,289)	$ -
16	Net PSA Retail Power Supply Costs	sum(L12 to L15)	$ 72,851	$ 60,090	$ 52,620	$ 59,720	$ 78,571	$ 129,732	$ 148,103	$ 136,497	$ 103,412	$ 71,168	$ 47,321	$ 56,201	$ -
	Base Fuel Rate Power Supply Recovery														
17	Renewables Recovery	L28 * L2	$ 1,447	$ 1,334	$ 1,320	$ 1,307	$ 1,497	$ 1,953	$ 2,189	$ 2,191	$ 1,875	$ 1,532	$ 1,246	$ 1,418	$ -
18	PPA Fixed Recovery	L29 * L2	$ 2,609	$ 2,405	$ 2,380	$ 2,357	$ 2,701	$ 3,522	$ 3,948	$ 3,951	$ 3,381	$ 2,762	$ 2,247	$ 2,557	$ -
19	Other Fuel and Purchased Power Recovery	L30 * L2	$ 65,887	$ 60,739	$ 60,100	$ 59,511	$ 68,199	$ 88,944	$ 99,700	$ 99,774	$ 85,383	$ 69,757	$ 56,738	$ 64,562	$ -
	(Over) Under Recovery From Base Fuel Rate														
20	Renewables (Over) Under Recovery	L12 - L17	$ 1,537	$ 1,361	$ 1,484	$ 1,571	$ 1,414	$ 1,068	$ 491	$ 234	$ 681	$ 447	$ 1,455	$ 1,776	$ -
21	PPA Fixed (Over) Under Recovery	L13 - L18	$ 873	$ 925	$ 948	$ 1,076	$ 672	$ 2,204	$ 1,700	$ 1,717	$ 1,172	$ 733	$ 1,327	$ 922	$ -
22	Other Fuel and Purchased Power (Over) Under Recovery	(L14 + L19) - L16	$ 497	$ (6,674)	$ (13,612)	$ (6,101)	$ 4,088	$ 32,041	$ 40,076	$ 28,631	$ 10,920	$ (4,062)	$ (15,691)	$ (15,033)	$ -
23	Less 10% Sharing On Other (Over) Under Recovery	- 0.10 * L22	$ (50)	$ 667	$ 1,361	$ 610	$ (409)	$ (3,204)	$ (4,008)	$ (2,863)	$ (1,092)	$ 406	$ 1,569	$ 1,503	$ -
24	Total (Over) Under Recovery	sum(L20 to L23)	2,858	(3,720)	(9,816)	(2,844)	5,765	32,109	38,259	27,719	11,681	(2,476)	(11,341)	(10,832)	-
25	Interest Accrued on Prior Month's Balance [7]	L27 * L33	$ 154	$ -	$ (26)	$ (66)	$ (89)	$ (90)	$ (25)	$ 53	$ 102	$ 110	$ 84	$ 38	$ -
26	Forward Component Collections [8, 9]	- L32 * L6	$ -	$ 5,942	$ 5,588	$ 5,690	$ 5,964	$ 7,337	$ 9,008	$ 9,200	$ 8,746	$ 7,396	$ 6,212	$ 5,958	$ -
27	Tracking Account Balance	L1 + L24 + L25 - L26	$ 43,023	$ (9,663)	$ (25,095)	$ (33,695)	$ (33,983)	$ (9,300)	$ 19,928	$ 38,499	$ 41,535	$ 31,773	$ 14,304	$ (2,448)	$ -

28	Renewable Costs in Base Fuel Rate - ¢ per kWh	0.0872
29	PPA Fixed Costs in Base Fuel Rate - ¢ per kWh	0.1212
30	Other Costs in Base Fuel Rate - ¢ per kWh	3.0607
31	Total Base Fuel Rate - ¢ per kWh	3.2491
32	Forward Component Rate - ¢ per kWh	0.2952
33	Interest Rate	3.17%

Notes:

[1] PSA Retail Energy Sales are the calendar month's MWh sales. 2008 PSA Year Cumulative Retail Energy Sales of 26,161 MWhs under rate schedule E-36 were excluded from the PSA Calculations.

[2] Includes traditional sales for resale, PacifiCorp supplemental sales, and other non-ACC jurisdictional sales. ED 3 and City of Williams energy sales are excluded from the PSA Calculation.

[3] Retail Billed Sales on Line 6 relate specifically to the Forward Component Collections. Due to billing adjustments and timing, this amount will differ from other components' Retail Billed Sales.

[4] Renewables costs exclude $5,307,782 of 2008 PSA Year year-to-date costs that are currently being recovered through the RES tariff.

[5] Includes native load and off-system fuel and purchased power costs less those costs associated with E-36 and other direct assignment customers, amortization of previously deferred ISFSI, Four Corners Coal Reclamation, and mark-to-market accounting adjustments.

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

[7] In June of 2008, the interest rate was revised to reflect the intended rate pursuant to the PSA Plan of Administration. Balances for February through May of 2008 have been re-stated using the updated interest rate of 3.17%.

[8] Generally, Line 32 * Line 6 = Line 26; however, differences may occur due to billing adjustments.

[9] Line 26 includes revenues associated with billing adjustments from the Old PSA Interim Adjustor.

Schedule presentation will appear to round up to $s and MWh; however, calculations are performed on an actual $ and MWh basis with resultant Rates/kWh rounded up to $0.000000/kWh

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Exhibit: MJM-9

ARIZONA PUBLIC SERVICE COMPANY
Schedule 4
PSA Historical Component Rate Calculation Effective February 1, 2009
($ in thousands; Historical Component Rate in $/kWh)

Line No.	PSA Historical Component Rate Calculation	Current February 1, 2008	Proposed February 1, 2009 [1]	Increase/(Decrease) $ Values	Increase/(Decrease) %
1	Forward Component Tracking Account Balance	$ 30,336	$ (5,312)	$ (35,648)	-118%
2	Historical Component Tracking Account Balance[2]	$ -	12,725	$ 12,725	N/A
3	Total Historical Amount to be (Refunded)/Collected Balance (L1+L2)	$ 30,336	$ 7,413	$ (22,923)	-76%
4	Projected Billed Retail Energy Sales without E-3, E-4 and E-36 (MWh)	28,941,128	28,748,316	$ (192,812)	-1%
5	Applicable Historical Component Rate [L3 / L4]	$ 0.001048	$ 0.000258	$ (0.000790)	-75%

Notes:
[1] Proposed levels are provided in the September 30 filing and updated in the December 31 filing of each year.
[2] Includes projected remaining balances from the Old PSA Annual Adjustor Account ($(4.3) million) and July 2007 Surcharge Account ($+2.7 million).

Arizona Corporation Commission
Docket No. E-01345A-11-0224
Exhibit: MJM-9

ARIZONA PUBLIC SERVICE COMPANY
Schedule 5
Historical Component Tracking Account in Effect Feb 1, 2008 through Jan. 31, 2009
($ in thousands Historical Component Rate in $/kWh)

Line No.		January	February	March	April	May	June	July	August	September	October	November	December	2009 January
								2008 Data						
1	Projected HC Tracking Account Balance at Dec. 31, 2007		-	-	-	-	-	-	-	-	-	-	-	
2	Projected FC Tracking Account Balance at Dec. 31, 2007		30,336	-	-	-	-	-	-	-	-	-	-	
3	True-up from December - January Estimate [1]		12,686	-	-	-	-	-	-	-	-	-	-	
4	Old PSA Step 1 Surcharge Tracking Account Balance at Jan. 31, 2008		124	-	-	-	-	-	-	-	-	-	-	
5	Prior Month's Ending Balance		$ -	$ 41,066	$ 39,191	$ 37,271	$ 35,253	$ 32,741	$ 29,630	$ 26,442	$ 23,406	$ 20,844	$ 18,702	
6	HC Adjusted Beginning Balance (L1+ L2 + L3 + L4 + L5)		$ 43,146	$ 41,066	$ 39,191	$ 37,271	$ 35,253	$ 32,741	$ 29,630	$ 26,442	$ 23,406	$ 20,844	$ 18,702	
7	Applicable Historical Component Rate ($/kWh) [2]		$ 0.001048	$0.001048	$0.001048	$0.001048	$0.001048	$0.001048	$0.001048	$0.001048	$0.001048	$0.001048	$0.001048	
8	Retail Billed Sales Excluding E-3, E-4, E-36 Sales (MWhs) [3]		2,046,321	1,892,974	1,927,538	2,065,560	2,434,902	3,041,660	3,104,883	2,987,294	2,503,300	2,104,092	2,018,721	
9	Less Revenue from Applicable HC (L7 x L8) [4, 5]		$ 2,146	$ 1,984	$ 2,023	$ 2,117	$ 2,605	$ 3,198	$ 3,266	$ 3,105	$ 2,624	$ 2,186	$ 2,125	
10	Monthly Interest ([L5 * L12 / 12])		$ 65	$ 108	$ 104	$ 98	$ 93	$ 86	$ 78	$ 70	$ 62	$ 55	$ 49	
11	HC Ending Balance ; (L6 - L9 + L10)	$ -	$ 41,066	$ 39,191	$ 37,271	$ 35,253	$ 32,741	$ 29,630	$ 26,442	$ 23,406	$ 20,844	$ 18,702	$ 16,627	
12	Interest Rate [6, 7]	3.17%												

Notes:

[1] True-up is the result of using estimated revenue and deferral for December and January since the actual amount was not available at the time of prior period PSA filing.

[2] Historical Component, Schedule 4, Line 5

[3] Sales amounts are for energy billed each period.

[4] Generally, Line 7 x Line 8 = Line 9; however, differences may occur due to billing adjustments.

[5] Line 9 includes revenues associated with billing adjustments from the Old PSA Step 1 Surcharge.

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

[7] In June and August of 2008, the interest rate was revised to reflect the intended rate pursuant to the PSA Plan of Administration. Balances for February through May of 2008 have been re-stated using the updated interest rate of 3.17%.

Arizona Corporation Commission
Docket No. E-01345A-11-0224
Exhibit: MJM-9

ARIZONA PUBLIC SERVICE COMPANY
Schedule 6
PSA Transition Component Rate Calculation
($ in thousands; Transition Component Rate(s) in $/kWh)

Line No.		Current February 1, 2008 [1]	Proposed February 1, 2009 [1]	Increase/(Decrease) $ Values	Increase/(Decrease) %
1	PSA Transition - Approved (Refundable)/Collection Amount [1]	N/A	N/A	N/A	0.00%
2	Projected Energy Sales without E-3, E-4 and E-36 (MWh) XXX. X, XX to XXX. X,XX	N/A	N/A	N/A	0.00%
3	PSA Transition Component (Refundable)/Collection Rate (L1 / L2)	N/A	N/A	N/A	0.00%

Notes:
[1] Commission Decision No. XXXXXXXXXX

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Exhibit: MJM-9

ARIZONA PUBLIC SERVICE COMPANY
Schedule 7
PSA Transition Tracking Account in Effect XX 1, 20XX through XX 31, 20XX
($ in thousands; Transition Component Rate in $/kWh)

Line No.		January	February	March	April	May	June	July	August	September	October	November	December	January
								20XX Data						20XX
1	Transferred balance from FC Tracking Acct Per Decision No. XXXXX		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	Prior Month's Ending Balance		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	Transition Component TA Adjusted Beginning Balance (L1+ L2)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Applicable Transition TA Component Rate ($/kWh) [1]		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Retail Billed Sales Excluding E-3, E-4, E-36 Sales (MWhs) [2]		-	-	-	-	-	-	-	-	-	-	-	-
6	Less Revenue from Applicable Transition Component (L4 x L5) [3]		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	Monthly Interest ([L2 * L9 / 12])		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	Ending Balance; (L3 - L6 + L7)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9	Interest Rate [4]	x.xx%												

Notes:

[1] Transition Component, Schedule 6, Line 3

[2] Sales amounts are for energy billed each period.

[3] Generally, Line 4 x Line 5 = Line 6; however, differences may occur due to billing adjustments.

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

ARIZONA PUBLIC SERVICE COMPANY
Schedule 8
Old PSA Annual Adjustor Account
($ in thousands; Annual Adjustor Rate in $/kWh)

Line No.		2008 Data January	February	March	April	May	June	July	August	September	October	November	December	2009 January
1	Prior Month's Ending Balance	$ 58,027	$ 49,663	$ 41,220	$ 33,795	$ 26,198	$ 18,246	$ 8,350	$ (3,760)	$ (4,260)	$ (4,257)	$ (4,277)	$ (4,261)	
2	Annual Adjustor Rate ($/kWh)	$0.003987	$0.003987	$0.003987	$0.003987	$0.003987	$ 0.003987	$0.003987	$0.003987	$0.003987	$ 0.003987	$0.003987	$0.003987	
3	Retail Billed Sales Excluding E-3, E-4, E-36 Sales (MWhs) [1]	2,147,063	2,125,095	1,889,572	1,927,724	2,057,090	2,443,544	3,040,673	-	-	-	-	-	
4	Less Revenue from Applicable Adjustor Rate (L2 * L3) [2]	$ 8,517	$ 8,574	$ 7,533	$ 7,687	$ 8,021	$ 9,944	$ 12,132	$ 491	$ (14)	$ 8	$ (28)	$ 28	
5	Monthly Interest (L1 * L7 / 12)	$ 153	$ 131	$ 109	$ 89	$ 69	$ 48	$ 22	$ (10)	$ (11)	$ (11)	$ (11)	$ (11)	
6	Ending Balance; (L1 - L4 + L5)	$ 49,663	$ 41,220	$ 33,795	$ 26,198	$ 18,246	$ 8,350	$ (3,760)	$ (4,260)	$ (4,257)	$ (4,277)	$ (4,261)	$ (4,300)	
7	Interest Rate [3, 4]	3.17%												

Notes:

[1] Sales amounts are for energy billed each period.

[2] Generally, Line 2 * Line 3 = Line 4; however, differences may occur due to billing adjustments.

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

[4] In June and August of 2008, the interest rate was revised to reflect the intended rate pursuant to the PSA Plan of Administration. Balances for February through May of 2008 have been re-stated using the updated interest rate of 3.17%.

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Exhibit: MJM-9

ARIZONA PUBLIC SERVICE COMPANY
Schedule 9
Old PSA Step 2 Surcharge Tracking Account
($ in thousands; Transition Component Rate in $/kWh)

Line No.		2008 Data January	February	March	April	May	June	July	August	September	October	November	December	2009 January
1	Prior Month's Ending Balance	$ 17,331	$ 14,860	$ 12,399	$ 10,209	$ 7,971	$ 5,626	$ 2,714	$ 2,661	$ 2,669	$ 2,674	$ 2,679	$ 2,693	
2	Applicable Step 2 Surcharge Rate ($/kWh)	$0.001176	$0.001176	$0.001176	$0.001176	$0.001176	$0.001176	$ 0.001176	$ 0.001176	$ 0.001176	$ 0.001176	$ 0.001176	$ 0.001176	
3	Retail Billed Sales Excluding E-3, E-4, E-38 Sales (MWhs) [1]	2,139,751	2,125,069	1,889,588	1,927,752	2,057,076	2,443,584	-	-	-	-	-	-	
4	Less Revenue from Collections (L2 x L3) [2]	$ 2,517	$ 2,500	$ 2,223	$ 2,265	$ 2,366	$ 2,927	$ 60	$ (1)	$ 2	$ 2	$ (6)	$ 7	
5	Monthly Interest (L1 * L7 / 12)	$ 46	$ 39	$ 33	$ 27	$ 21	$ 15	$ 7	$ 7	7	7	7	7	
6	Ending Balance; (L1 -L4 + L5)	$ 14,860	$ 12,399	$ 10,209	$ 7,971	$ 5,626	$ 2,714	$ 2,661	$ 2,669	$ 2,674	$ 2,679	$ 2,693	$ 2,693	
7	Interest Rate [3,4]	3.17%												

Notes:

[1] Sales amounts are for energy billed each period.

[2] Generally, Line 2 x Line 3 = Line 4; however, differences may occur due to billing adjustments.

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

[4] In June and August of 2008, the interest rate was revised to reflect the intended rate pursuant to the PSA Plan of Administration. Balances for February through May of 2008 have been re-stated using the updated interest rate of 3.17%.

ARIZONA PUBLIC SERVICE COMPANY
Schedule 10
Old PSA Step 1 Surcharge Tracking Account
($ in thousands; Surcharge Rate in $/kWh)

Line No.		2008 Data January	February	March	April	May	June	July	August	September	October	November	December	2009 January
1	Surcharge Rate ($/kWh)	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000						
2	Retail Billed Sales Excluding E-3, E-4, E-36 Sales (MWhs)	-	-	-	-	-	-	-						
3	Beginning Balance	$ 123	$ 124	$ -	$ -	$ -	$ -	$ -						
4	Less: Revenue from Surcharge Rate (Line 1 * Line 2) [1]	$ 0	$ -	$ -	$ -	$ -	$ -	$ -						
5	Monthly Interest (Line 3 * [4.63% / 12]) [2]	$ 0	$ -	$ -	$ -	$ -	$ -	$ -						
6	Transfer to the 2008 Historical Tracking Account	$ 0	$ (124)	$ -	$ -	$ -	$ -	$ -						
7	Ending Balance with Interest (Line 3 - Line 4 + Line 5 + Line 6) [3]	$ 124	$ -	$ -	$ -	$ -	$ -	$ -						

[1] Difference between Line 1 times Line 2 and Line 4 are due to billing adjustments. Revenues after April 2007 are related to adjustments to prior periods.
[2] Based on one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release, H-15. Beginning in January 2008, the interest rate is 3.17%.
[3] On January 31, 2008, the Step 1 Surcharge balance was transferred to the 2008 Historical Component Account.

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Exhibit: MJM-9

ARIZONA PUBLIC SERVICE COMPANY
Schedule 11
Summary of Monthly Calculations
December 2008
($ in thousands)

Line No.		2008 Data January	February	March	April	May	June	July	August	September	October	November	December	2009 January
	2008 Forward Component Tracking Account													
1	Beginning Balance	$ 40,010	$ 43,023	$ (9,663)	$ (25,095)	$ (33,695)	$ (33,983)	$ (9,300)	$ 19,928	$ 38,499	$ 41,535	$ 31,773	$ 14,304	$ -
2	Transfers to 2008 Historical Component Tracking Account	$ -	$ (43,023)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	Monthly Interest [1]	$ 154	$ -	$ (26)	$ (66)	$ (89)	$ (90)	$ (25)	$ 53	$ 102	$ 110	$ 84	$ 38	$ -
4	Post-Sharing (Over)/Under Collection	$ 2,858	$ (3,720)	$ (9,818)	$ (2,844)	$ 5,765	$ 32,109	$ 38,259	$ 27,719	$ 11,681	$ (2,476)	$ (11,341)	$ (10,832)	$ -
5	Less Revenue from Applicable Forward Component Rate	$ -	$ 5,942	$ 5,588	$ 5,690	$ 5,964	$ 7,337	$ 9,008	$ 9,200	$ 8,746	$ 7,396	$ 6,212	$ 5,958	$ -
6	Ending Balance with Interest (Ln. 1, 2, 3, 4 - Ln. 5)	$ 43,023	$ (9,663)	$ (25,095)	$ (33,695)	$ (33,983)	$ (9,300)	$ 19,928	$ 38,499	$ 41,535	$ 31,773	$ 14,304	$ (2,448)	$ -
	2008 Historical Component Tracking Account													
7	Beginning Balance	$ -	$ -	$ 41,066	$ 39,191	$ 37,271	$ 35,253	$ 32,741	$ 29,630	$ 26,442	$ 23,406	$ 20,844	$ 18,702	$ -
8	Transfers from 2008 Forward Component Tracking Account	$ -	$ 43,023	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9	Transfers from the Old PSA Step 1 Surcharge Account	$ -	$ 124	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	Monthly Interest [1]	$ -	$ 65	$ 108	$ 104	$ 98	$ 93	$ 86	$ 78	$ 70	$ 62	$ 55	$ 49	$ -
11	Less Revenue from Applicable Historical Component Rate	$ -	$ 2,146	$ 1,984	$ 2,023	$ 2,117	$ 2,605	$ 3,198	$ 3,266	$ 3,105	$ 2,624	$ 2,196	$ 2,125	$ -
12	Ending Balance with Interest (Ln. 7, 8, 9, 10 - Ln. 11)	$ -	$ 41,066	$ 39,191	$ 37,271	$ 35,253	$ 32,741	$ 29,630	$ 26,442	$ 23,406	$ 20,844	$ 18,702	$ 16,627	$ -
	Annual Adjustor Account													
13	Beginning Balance	$ 58,027	$ 49,663	$ 41,220	$ 33,795	$ 26,198	$ 18,246	$ 8,350	$ (3,760)	$ (4,260)	$ (4,257)	$ (4,277)	$ (4,261)	$ -
14	Monthly Interest [1]	$ 153	$ 131	$ 109	$ 89	$ 69	$ 48	$ 22	$ (10)	$ (11)	$ (11)	$ (11)	$ (11)	$ -
15	Less Revenue from Applicable Adjustor Rate	$ 8,517	$ 8,574	$ 7,533	$ 7,687	$ 8,021	$ 9,944	$ 12,132	$ 491	$ (14)	$ 8	$ (28)	$ 28	$ -
16	Ending Balance with Interest (Ln. 13, 14 - Ln. 15)	$ 49,663	$ 41,220	$ 33,795	$ 26,198	$ 18,246	$ 8,350	$ (3,760)	$ (4,260)	$ (4,257)	$ (4,277)	$ (4,261)	$ (4,300)	$ -
	July 2007 Surcharge Account													
17	Beginning Balance	$ 17,331	$ 14,860	$ 12,399	$ 10,209	$ 7,971	$ 5,626	$ 2,714	$ 2,661	$ 2,669	$ 2,674	$ 2,679	$ 2,693	$ -
18	Monthly Interest [1]	$ 46	$ 39	$ 33	$ 27	$ 21	$ 15	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ -
19	Less Revenue from Applicable Surcharge Rate	$ 2,517	$ 2,500	$ 2,223	$ 2,265	$ 2,366	$ 2,927	$ 60	$ (1)	$ 2	$ 2	$ (6)	$ 7	$ -
20	Ending Balance with Interest (Ln. 17, 18 - Ln. 19)	$ 14,860	$ 12,399	$ 10,209	$ 7,971	$ 5,626	$ 2,714	$ 2,661	$ 2,669	$ 2,674	$ 2,679	$ 2,693	$ 2,693	$ -
	May 2006 Surcharge Account													
21	Beginning Balance	$ 123	$ 124	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
22	Transfers to 2008 Historical Component Tracking Account	$ -	$ (124)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
23	Monthly Interest [1]	$ 0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
24	Less Revenue from Applicable Surcharge Rate	$ 0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25	Ending Balance with Interest (Ln. 21, 22, 23 - Ln. 24)	$ 124	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26	**Combined Balance** (Ln. 6, 12, 16, 20, 25)	$ 107,669	$ 85,022	$ 58,100	$ 37,745	$ 25,142	$ 34,506	$ 48,459	$ 63,349	$ 63,358	$ 51,019	$ 31,439	$ 12,573	$ -
27	Combined Monthly Interest (Ln. 3, 10, 14, 18, 23) [1]	$ 354	$ 236	$ 225	$ 153	$ 100	$ 66	$ 91	$ 128	$ 167	$ 167	$ 135	$ 83	$ -

[1] In June and August of 2008, the interest rate was revised to reflect the intended rate pursuant to the PSA Plan of Administration. Balances for February through May of 2008 have been re-stated using the updated interest rate of 3.17%.

Arizona Corporation Commission
Docket No. E-01345A-11-0224
Exhibit: MJM-9,

ARIZONA PUBLIC SERVICE COMPANY
Schedule 12
2008 Native Load Customer Counts, Sales and Revenue
December 2008

Line No.	Class	January	February	March	April	May	June	July	August	September	October	November	December	Total[1]
	Customers													
1	Residential	983,309	981,948	982,119	978,785	974,737	973,259	974,295	972,054	974,017	975,181	979,259	986,363	977,944
2	Commercial	117,528	117,765	118,156	118,459	118,799	119,069	119,150	119,264	119,488	119,712	119,776	120,122	118,941
3	Industrial	3,612	3,614	3,626	3,607	3,623	3,611	3,617	3,609	3,604	3,593	3,582	3,588	3,607
4	Irrigation	325	327	323	327	327	327	327	328	327	326	325	325	326
5	Sales for Resale[2]	18	18	18	18	18	18	18	18	18	18	18	18	18
6	Streetlights & OPA	1,070	1,072	1,071	1,080	1,083	1,082	1,083	1,090	1,090	1,091	1,090	1,092	1,083
7	Less E-36 and ED 3 (includes adj. to prior mth)	(4)	(4)	(5)	(5)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)
8	Total	1,105,858	1,104,740	1,105,308	1,102,271	1,098,581	1,097,360	1,098,464	1,096,355	1,098,538	1,099,915	1,104,044	1,111,502	1,101,913
	Sales (MWh)													
9	Residential	1,082,505	883,603	808,031	751,684	942,770	1,417,361	1,763,500	1,720,447	1,391,999	979,560	710,827	915,728	13,368,015
10	Commercial	903,391	885,226	947,382	985,167	1,082,572	1,239,857	1,278,565	1,312,202	1,181,835	1,079,811	953,540	970,515	12,820,063
11	Industrial	159,566	202,458	198,269	199,318	192,203	239,239	204,572	213,663	205,453	206,565	180,416	196,616	2,398,338
12	Irrigation	618	865	1,240	2,345	2,927	3,256	2,430	2,509	2,202	2,608	1,599	1,118	23,717
13	Sales for Resale[2]	48,609	73,247	108,878	128,032	95,083	105,243	131,554	121,598	93,920	83,152	68,720	69,075	1,125,108
14	Streetlights & OPA	10,453	10,052	11,817	11,251	11,643	11,149	10,645	11,427	10,217	11,227	11,186	11,982	133,049
15	Less E-36 and ED 3 (includes adj. to prior mth)	(3,853)	2,289	(26,428)	(50,912)	(33,920)	(59,542)	(64,871)	(64,662)	(48,637)	(37,193)	(31,292)	(26,958)	(445,979)
16	Total	2,201,289	2,057,740	2,047,189	2,026,885	2,293,278	2,956,563	3,326,395	3,317,182	2,836,989	2,325,730	1,894,996	2,138,075	29,422,311
	Revenue ($000)													
17	Residential	$ 102,798	$ 86,093	$ 81,795	$ 83,749	$ 112,586	$ 168,545	$ 203,183	$ 194,506	$ 157,780	$ 102,154	$ 69,894	$ 90,931	$ 1,454,016
18	Commercial	$ 81,715	$ 80,382	$ 87,672	$ 95,093	$ 113,497	$ 127,694	$ 127,659	$ 127,462	$ 115,728	$ 100,916	$ 83,886	$ 87,074	$ 1,228,780
19	Industrial	$ 12,355	$ 15,512	$ 16,066	$ 16,124	$ 16,163	$ 20,918	$ 18,895	$ 17,870	$ 15,299	$ 15,119	$ 13,161	$ 14,389	$ 189,672
20	Irrigation	$ 69	$ 91	$ 123	$ 220	$ 280	$ 313	$ 230	$ 231	$ 205	$ 238	$ 144	$ 120	$ 2,264
21	Sales for Resale[2]	$ 3,150	$ 2,902	$ 6,925	$ 7,186	$ 7,238	$ 8,473	$ 9,629	$ 8,397	$ 6,463	$ 5,571	$ 4,844	$ 3,764	$ 74,344
22	Streetlights & OPA	$ 1,471	$ 1,457	$ 1,687	$ 1,648	$ 1,659	$ 1,625	$ 1,545	$ 1,635	$ 1,447	$ 1,582	$ 1,588	$ 1,637	$ 18,981
23	Less E-36 and ED 3 (includes adj. to prior mth)	$ (586)	$ 222	$ (3,140)	$ (3,245)	$ (3,259)	$ (5,074)	$ (5,311)	$ (5,524)	$ (3,629)	$ (3,048)	$ (2,403)	$ (2,218)	$ (37,214)
24	Total	$ 200,973	$ 186,659	$ 191,129	$ 200,776	$ 248,164	$ 322,495	$ 353,831	$ 344,377	$ 293,293	$ 222,532	$ 170,917	$ 195,698	$ 2,930,843
	Est. System Losses and Peak												Preliminary	
25	Est. Native Load Sys. Losses (MWh)	154,528	130,193	151,185	156,278	170,031	222,254	265,288	235,779	216,537	154,561	141,932	174,108	
26	Est. Native Load Sys. Losses (MW)	461	457	349	453	718	869	896	910	798	711	532	521	
27	Est. Native Load Sys. Peak (MW)[3]	4,404	4,376	3,610	4,352	5,972	6,778	6,915	7,026	6,156	5,489	4,103	4,018	

[1] The Customers total is the average of the customer class' monthly totals.

[2] Includes traditional sales for resale, PacifiCorp supplemental sales, ED 3, City of Williams, and other non-ACC jurisdictional sales. Off-System Interchange customers, sales and revenue are excluded from Sales for Resale.

[3] The Preliminary Native Load System Peak totals will be updated each month.

Arizona Corporation Commission
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Exhibit: MJM-9

CERTIFICATION BY APS
OF
MONTHLY PSA REPORTS

Pursuant to Decision No. 69663 (June 28, 2007) and the Power Supply Adjustor Plan of Administration (July 30, 2007), I certify that to the best of my knowledge and based on the information made available to me, the attached Monthly PSA Report is complete and accurate in all material respects.

Date: January 30, 2009

James R. Hatfield

James R. Hatfield
Senior Vice President and Chief Financial Officer

Arizona Corporation Commission
Docket No. E-01345A-11-0224
Exhibit: MJM-9

APS

Leland R. Snook
Director
State Regulation & Pricing

Tel. 602-250-3730
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Mail Station 9708
PO Box 53999
Phoenix, Arizona 85072-3999

January 29, 2010

RECEIVED
JAN 29 2010
AZ CORP COMM
Director Utilities

Mr. Steve Olea
Utilities Division
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

RE: DECEMBER 2009 POWER SUPPLY ADJUSTOR REPORT

Dear Mr. Olea:

Section 8 of the Power Supply Adjustor ("PSA") Plan of Administration ("POA") approved in Decision No. 69663 states that:

> "APS shall provide monthly reports to Staff's Compliance Section and to the Residential Utility Consumer Office detailing all calculations related to the PSA. An APS Principal Officer, as listed in the Company's annual report filed with the Commission's Corporation Division, shall certify under oath that all information provided in the reports itemized below is true and accurate to the best of his or her information and belief. These monthly reports shall be due within 30 days of the end of the reporting period."

Arizona Public Service Company ("APS") is submitting the December 2009 Power Supply Adjustor report. The January 1, 2010 PSA rates included in the Schedules correspond to the PSA rates adopted by the Commission with the Rate Settlement approved in Decision 71448. Additionally, APS is submitting the signed officer certification from Mr. James R. Hatfield, APS's Senior Vice-President and Chief Financial Officer.

The Company has also included Schedule 11 as a summary of the monthly calculations, submitted to date, to help summarize all of the accounts.

If you should have any questions regarding the information contained herein, please contact David Rumolo at (602)250-3933.

Sincerely,

Leland R. Snook

LS/sl

Attachments

cc: Brian Bozzo
Jodi Jerich
Barbara Keene

ARIZONA PUBLIC SERVICE COMPANY
Schedule 1
Power Supply Adjustment (PSA) Rate Calculation Effective January 1, 2010
($/kWh)

Line No.	PSA Rate Calculation	Current February 1, 2009	Proposed January 1, 2010 [1]	Increase/(Decrease) $/kWh	Increase/(Decrease) %
1	Forward Component Rate - FC (Schedule 2, L9)	$ 0.005080	$ (0.001816)	$(0.006896)	-136%
2	Historical Component Rate - HC (Schedule 4, L5) [2]	$ 0.000258	$ (0.002674)	$(0.002932)	-1137%
3	PSA Transition Component Rate (Schedule 6, L3) [3]	$ -	$ -	$ -	N/A
4	**PSA Rate (L1+ L2 + L3)** [4]	$ 0.005338	$ (0.004490)	$(0.009828)	-184%
5	**Base Fuel Rate**	$ 0.032491	$ 0.037571	$ 0.005080	16%
6	**Total Fuel Recovery (L4 + L5)** [5]	$ 0.037829	$ 0.033081	$(0.004748)	-13%

Notes:

[1] *Proposed levels of the PSA rate components are provided in the September 30 filing and updated in the December 31 filing of each year.* The January 1, 2010 PSA rates correspond to the PSA rates adopted by the Commission with the Rate Settlement approved in Decision 71448.

[2] A Historical Component is a true up related to respective prior period PSA activity.

[3] Provides for Mid-Period Corrections when necessary.

[4] Decision No. 69663 limits the sum of the Forward and Historical Component annual increase/(decrease) to no more than $0.004000/kWh. However, APS does not believe that the annual $0.004000/kWh cap applies in a year that the base fuel rate has been reset.

[5] The Total Fuel Recovery for the PSA year beginning January 1, 2010 includes the impact of the margins from the sale of excess emission allowances not recorded in fuel.

Arizona Corporation Commission
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Exhibit: MJM-9

ARIZONA PUBLIC SERVICE COMPANY
Schedule 2
PSA Forward Component Rate Calculation Effective January 1, 2010
($ in thousands; Forward Component Rate in $/kWh)

Line No.	PSA Forward Component Rate - Calculation	Current February 1, 2009	Proposed January 1, 2010 [1]	Increase/(Decrease) $ Values	Increase/(Decrease) %
1	Projected Fuel and Purchased Power Costs	$ 1,162,540	$ 1,083,459	$ (79,081)	-7%
2	Projected Off-System Sales Revenue	$ (63,442)	(55,591)	$ 7,851	-12%
3	PSA Adjustments to Fuel and Purchased Power Costs [2]	$ 3,733	(21,629)	$ (25,362)	-679%
4	Net Fuel and Purchased Power Cost (L1 through L3)	$ 1,102,831	$ 1,006,239	$ (96,592)	-9%
5	Projected Net Margins on the Sale of Emission Allowances	-	-	-	-
6	Projected Billed Native Load Sales, excluding E-3, E-4, E-36 (MWhs) [3]	$ 29,353,008	28,334,369	(1,018,639)	-3%
7	Projected Average Net Fuel Cost $/kWh (L4 / L6)	$ 0.037571	$ 0.035513	(0.002058)	-5%
8	Projected Average Margin on Emission Allowances $/kWh (L5 / L6)	$ -	$ -	-	-
9	Total Projected Average PSA Cost $/kWh (L7+L8)	$ 0.037571	$ 0.035513	(0.002058)	-5%
10	Authorized Base Cost of Fuel and Purchased Power Rate $/kWh [4]	$ 0.032491	$ 0.037571	0.005080	16%
11	Authorized Base Net Margins on the Sale of Emission Allowances Rate $/kWh *	$ -	$ (0.000242)	(0.000242)	-
12	Total Authorized Base Cost $/kWh	$ 0.032491	$ 0.037329	0.004838	15%
13	Forward Component Rate $/kWh (L9 - L12)	$ 0.005080	$ (0.001816)	$ (0.006896)	-136%

Notes:

[1] Proposed levels of the PSA rate components are provided in the September 30 filing and updated in the December 31 filing of each year. The January 1, 2010 PSA rates correspond to the PSA rates adopted by the Commission with the Rate Settlement approved in Decision 71448.

[2] Includes costs associated with E-36 and other direct assignment customers, ISFSI, and mark-to-market accounting adjustments.

[3] The Projected Billed Native Load Sales of 28,334,369 MWhs for the Current Rate represent forecast sales for 2010 as of November 30th, 2009. They exclude ED 3 and City of Williams wholesale contracts that are excluded from the Proposed sales and fuel costs

[4] Base Cost of Fuel and Purchased Power established in the Commision approved settlement agreement.

Schedule presentation will appear to round up to $s and MWh; however, calculations are performed on an actual $ and MWh basis with resultant Rates/kWh rounded up to $0.000000/kWh.

Arizona Corporation Commission
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Exhibit: MJM-9

ARIZONA PUBLIC SERVICE COMPANY

Schedule 3

2009 PSA Year Forward Component Tracking Account - In Effect from February 1, 2009 to Dec 31, 2009

($ in thousands; Forward Component Rate and Base Rate in $/kWh)

		Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09
1 Prior Month's Balance	*From L27*	$ (2,448)	$ -	$ (19,411)	$ (35,723)	$ (45,937)	$ (49,263)	$ (53,552)	$ (42,253)	$ (35,333)	$ (40,163)	$ (44,414)	$ (51,204)
Energy Sales													
2 PSA Retail Energy Sales [1]		2,029,549	1,788,880	1,924,963	1,903,347	2,533,870	2,566,763	3,369,540	3,206,817	2,732,495	2,091,087	1,853,027	2,107,187
3 Wholesale Native Load Energy Sales [2]		21,620	34,204	23,790	40,700	23,645	33,448	50,839	33,917	59,210	25,463	18,211	13,000
4 Total Native Load Energy Sales	*L2 + L3*	2,051,169	1,823,084	1,948,754	1,944,048	2,557,515	2,600,211	3,420,379	3,240,734	2,791,705	2,116,550	1,871,239	2,120,187
5 Retail Energy Sales as a % of Total	*L2 / L4*	99%	98%	99%	98%	99%	99%	99%	99%	98%	99%	99%	99%
6 Retail Billed Sales Excluding E-3, E-4, E-36 Sales (MWh) [3]		2,076,910	1,903,244	1,841,755	1,790,644	1,985,762	2,595,475	2,976,745	3,068,916	2,938,095	2,326,355	1,926,701	1,990,541
System Book Fuel and Purchased Power Costs													
7 Renewables Costs [4]		$ 2,151	$ 2,287	$ 2,919	$ 2,029	$ 2,290	$ 1,540	$ 2,092	$ 2,789	$ 2,267	$ 3,586	$ 2,635	$ 2,754
8 PPA Fixed Costs		$ 3,479	$ 3,261	$ 3,408	$ 3,404	$ 4,933	$ 6,399	$ 6,262	$ 6,279	$ 6,279	$ 4,557	$ 3,651	$ 3,464
9 Other Fuel and Purchased Power Costs [5]		$ 53,104	$ 48,729	$ 58,184	$ 60,330	$ 87,007	$ 92,006	$ 134,782	$ 124,349	$ 98,951	$ 73,380	$ 82,900	$ 60,096
10 Off System Revenue (Credit) [6]		$ (4,983)	$ (6,260)	$ (9,348)	$ (4,019)	$ (2,783)	$ (6,374)	$ (2,416)	$ (3,065)	$ (5,716)	$ (4,741)	$ (5,620)	$ (3,583)
11 Net Native Load Power Supply Costs	*sum(L7 to L10)*	$ 53,752	$ 48,017	$ 55,163	$ 61,745	$ 91,447	$ 93,571	$ 140,719	$ 130,352	$ 101,780	$ 76,783	$ 63,566	$ 62,731
PSA Retail Fuel and Purchased Power Costs													
12 Renewables Costs	*L5 * L7*	$ 2,129	$ 2,244	$ 2,883	$ 1,987	$ 2,269	$ 1,520	$ 2,061	$ 2,760	$ 2,219	$ 3,543	$ 2,609	$ 2,737
13 PPA Fixed Costs	*L5 * L8*	$ 3,443	$ 3,200	$ 3,366	$ 3,333	$ 4,888	$ 6,317	$ 6,169	$ 6,213	$ 6,146	$ 4,502	$ 3,615	$ 3,443
14 Other Fuel and Purchased Power Costs	*L5 * L9*	$ 52,545	$ 47,815	$ 57,474	$ 59,067	$ 86,203	$ 90,822	$ 132,778	$ 123,048	$ 98,852	$ 72,497	$ 62,288	$ 59,728
15 Off System Revenue (Credit)	*L5 * L10*	$ (4,930)	$ (6,143)	$ (9,234)	$ (3,934)	$ (2,758)	$ (6,292)	$ (2,380)	$ (3,033)	$ (5,595)	$ (4,683)	$ (5,565)	$ (3,561)
16 Net PSA Retail Power Supply Costs	*sum(L12 to L15)*	$ 53,186	$ 47,116	$ 54,489	$ 60,452	$ 90,602	$ 92,367	$ 138,628	$ 128,988	$ 99,622	$ 75,859	$ 62,947	$ 62,347
Base Fuel Rate Power Supply Recovery													
17 Renewables Recovery	*L28 * L2*	$ 1,364	$ 1,202	$ 1,294	$ 1,279	$ 1,703	$ 1,725	$ 2,264	$ 2,155	$ 1,836	$ 1,405	$ 1,245	$ 1,416
18 PPA Fixed Recovery	*L29 * L2*	$ 2,460	$ 2,168	$ 2,333	$ 2,307	$ 3,071	$ 3,111	$ 4,084	$ 3,887	$ 3,312	$ 2,534	$ 2,246	$ 2,554
19 Other Fuel and Purchased Power Recovery	*L30 * L2*	$ 62,118	$ 54,752	$ 58,917	$ 58,256	$ 77,554	$ 78,561	$ 103,132	$ 98,151	$ 83,633	$ 64,002	$ 56,716	$ 64,495
(Over) Under Recovery From Base Fuel Rate													
20 Renewables (Over) Under Recovery	*L12 - L17*	$ 765	$ 1,042	$ 1,589	$ 708	$ 567	$ (205)	$ (204)	$ 605	$ 382	$ 2,138	$ 1,364	$ 1,321
21 PPA Fixed (Over) Under Recovery	*L13 - L18*	$ 983	$ 1,032	$ 1,033	$ 1,026	$ 1,816	$ 3,206	$ 2,085	$ 2,327	$ 2,834	$ 1,968	$ 1,370	$ 889
22 Other Fuel and Purchased Power (Over) Under Recovery	*(L14 + L15) - L19*	$ (14,504)	$ (13,080)	$ (10,677)	$ (3,123)	$ 5,891	$ 5,969	$ 27,266	$ 21,863	$ 7,624	$ 3,812	$ 7	$ (8,328)
23 Less 10% Sharing On Other (Over) Under Recovery	*- 0.10 * L22*	$ 1,450	$ 1,308	$ 1,068	$ 312	$ (589)	$ (597)	$ (2,727)	$ (2,186)	$ (762)	$ (381)	$ (1)	$ 833
24 Total (Over) Under Recovery	*sum(L20 to L23)*	(11,306)	(9,699)	(6,987)	(1,077)	7,685	8,373	26,421	22,609	10,078	7,537	2,740	(5,285)
25 Interest Accrued on Prior Month's Balance	*L27 * L33*	$ (1)	$ -	$ (6)	$ (12)	$ (15)	$ (16)	$ (18)	$ (14)	$ (12)	$ (13)	$ (15)	$ (17)
26 Forward Component Collections [7,8]	*- L32 * L6*	$ 6,133	$ 9,712	$ 9,319	$ 9,126	$ 10,995	$ 12,646	$ 15,105	$ 15,674	$ 14,896	$ 11,774	$ 9,516	$ 10,079
27 Tracking Account Balance	*L1 + L24 + L25 - L26*	$ (19,888)	$ (19,411)	$ (35,723)	$ (45,937)	$ (49,263)	$ (53,552)	$ (42,253)	$ (35,333)	$ (40,163)	$ (44,414)	$ (51,204)	$ (66,586)

28 Renewable Costs In Base Fuel Rate - ¢ per kWh	0.067200	
29 PPA Fixed Costs In Base Fuel Rate - ¢ per kWh	0.121200	
30 Other Costs In Base Fuel Rate - ¢ per kWh	3.060700	
31 Total Base Fuel Rate - ¢ per kWh	3.249100	
32 Forward Component Rate - ¢ per kWh	0.508030	
33 Interest Rate -- 2009	0.40%	
34 Interest Rate -- 2010	0.50%	

Notes:

[1] *PSA Retail Energy Sales are the calendar month's MWh sales. 2009 PSA Year Cumulative Retail Energy Sales of 36,291 MWhs under* rate schedule E-36 were excluded from the PSA Calculations.

[2] Includes traditional sales for resale, PacifiCorp supplemental sales, and other non-ACC jurisdictional sales. ED 3 and City of Williams energy sales are excluded from the PSA Calculation.

[3] Retail Billed Sales on Line 6 relate specifically to the Forward Component Collections. Due to billing adjustments and timing, this amount will differ from other components' Retail Billed Sales.

[4] Renewables costs exclude 6,483,595 of 2009 PSA Year year-to-date costs that are currently being recovered through the RES tariff.

[5] Includes native load and off-system fuel and purchased power costs less those costs associated with E-36 and other direct assignment customers, amortization of previously deferred ISFSI, Four Corners Coal Reclamation, and mark-to-market accounting adjustments.

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

[7] Generally, Line 32 * Line 6 = Line 26; however, differences may occur due to billing adjustments.

[8] Line 26 includes revenues associated with billing adjustments from the Old PSA Interim Adjustor.

Schedule presentation will appear to round up to $s and MWh; however, calculations are performed on an actual $ and MWh basis with resultant Rates/kWh rounded up to $0.000000/kWh

Arizona Corporation Commission
Docket No. E-01345A-11-0224
Exhibit MJM-9

ARIZONA PUBLIC SERVICE COMPANY
Schedule 4
PSA Historical Component Rate Calculation Effective January 1, 2010
($ in thousands; Historical Component Rate in $/kWh)

Line No.	PSA Historical Component Rate Calculation	Current February 1, 2009	Proposed January 1, 2010 [1]	Increase/(Decrease) $ Values	Increase/(Decrease) %
1	Forward Component Tracking Account Balance	$ (5,312)	$ (65,639)	$ (60,327)	1136%
2	Historical Component Tracking Account Balance	12,725	(13,730)	(26,455)	-208%
3	Total Historical Amount to be (Refunded)/Collected Balance (L1+L2)	$ 7,413	$ (79,369)	$ (86,782)	-1171%
4	Projected Billed Retail Energy Sales without E-3, E-4 and E-36 (MWh) [2]	28,748,316	29,676,884	928,568	3%
5	Applicable Historical Component Rate [L3 / L4]	$ 0.000258	$ (0.002674)	$ (0.002932)	-1137%

Notes:

[1] Proposed levels of the PSA rate components are provided in the September 30 filing and updated in the December 31 filing of each year. The January 1, 2010 PSA rates correspond to the PSA rates adopted by the Commission with the Rate Settlement approved in Decision 71448.

[2] The Proposed Projected Billed Retail Energy Sales on Line No. 4 are for January 2010 through January 2011. The Current Rate Projected Billed retail Energy Sales are for February 2009 through January 2010.

Arizona Corporation Commission
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Exhibit: MJM-9

ARIZONA PUBLIC SERVICE COMPANY
Schedule 5
Historical Component Tracking Account in Effect Feb 1, 2009 through Dec 31, 2010
($ in thousands Historical Component Rate in $/kWh)

Line No.		2009 Data January	February	March	April	May	June	July	August	September	October	November	December
1	Projected HC Tracking Account Balance at Dec. 31, 2009		14,332										
2	Projected FC Tracking Account Balance at Dec. 31, 2009		(5,312)										
3	Old PSA Account Balances at Jan. 31, 2009		(1,607)										
4	True-up from December - January Estimate [1]		(14,451)										
5	Prior Month's Ending Balance		$ -	$ (7,545)	$ (7,826)	$ (8,488)	$ (9,053)	$ (9,692)	$ (10,499)	$ (11,294)	$ (12,085)	$ (12,704)	$ (13,217)
6	HC Adjusted Beginning Balance (L1+ L2 + L3 + L4 + L5)		$ (7,038)	$ (7,545)	$ (7,826)	$ (8,488)	$ (9,053)	$ (9,692)	$ (10,499)	$ (11,294)	$ (12,085)	$ (12,704)	$ (13,217)
7	Applicable Historical Component Rate ($/kWh) [2]		$ 0.000258	$ 0.000258	$ 0.000258	$ 0.000258	$ 0.000258	$ 0.000258	$ 0.000258	$ 0.000258	$ 0.000258	$ 0.000258	$ 0.000258
8	Retail Billed Sales Excluding E-3, E-4, E-36 Sales (MWhs) [3]		1,903,244	1,841,755	1,790,644	1,985,762	2,595,475	2,976,745	3,066,916	2,938,095	2,326,355	1,926,701	1,990,541
9	Less Revenue from Applicable HC (L7 x L8) [4,5]		$ 505	$ 278	$ 660	$ 562	$ 636	$ 804	$ 791	$ 788	$ 615	$ 509	$ 507
10	Monthly Interest ([L5 * L12 / 12])		$ (2)	$ (3)	$ (3)	$ (3)	$ (3)	$ (3)	$ (3)	$ (4)	$ (4)	$ (4)	$ (4)
11	HC Ending Balance ; (L6 - L9 + L10)	$ -	$ (7,545)	$ (7,826)	$ (8,488)	$ (9,053)	$ (9,692)	$ (10,499)	$ (11,294)	$ (12,085)	$ (12,704)	$ (13,217)	$ (13,728)
12	Interest Rate -- 2009 [6]	0.40%											

Notes:

[1] True-up is the result of using estimated revenue and deferral for December and January since the actual amount was not available at the time of prior period PSA filing.

[2] Historical Component, Schedule 4, Line 5

[3] Sales amounts are for energy billed each period.

[4] Generally, Line 7 x Line 8 = Line 9; however, differences may occur due to billing adjustments.

[5] Line 9 Includes revenues associated with billing adjustments from the Old PSA Adjustors.

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

Arizona Corporation Commission
Docket No. E-01345A-11-0224
Exhibit: MJM-9

ARIZONA PUBLIC SERVICE COMPANY
Schedule 6
PSA Transition Component Rate Calculation
($ in thousands; Transition Component Rate(s) in $/kWh)

Line No.		Current February 1, 2009 [1]	Proposed February 1, 2010 [1]	Increase/(Decrease) $ Values	Increase/(Decrease) %
1	PSA Transition - Approved (Refundable)/Collection Amount [1]	N/A	N/A	N/A	0.00%
2	Projected Energy Sales without E-3, E-4 and E-36 (MWh) XXX. X, XX to XXX. X,XX	N/A	N/A	N/A	0.00%
3	PSA Transition Component (Refundable)/Collection Rate (L1 / L2)	N/A	N/A	N/A	0.00%

Notes:
[1] Commission Decision No. XXXXXXXXXX

Arizona Corporation Commission
Docket No. E-01345A-11-0224
Exhibit: MJM-9

ARIZONA PUBLIC SERVICE COMPANY

Schedule 7

PSA Transition Tracking Account In Effect XX 1, 20XX through XX 31, 20XX

($ in thousands; Transition Component Rate in $/kWh)

Line No.		20XX Data January	February	March	April	May	June	July	August	September	October	November	December	20XX January
1	Transferred balance from FC Tracking Acct Per Decision No. XXXXX			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	Prior Month's Ending Balance			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	Transition Component TA Adjusted Beginning Balance (L1+ L2)			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Applicable Transition TA Component Rate ($/kWh) [1]			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Retail Billed Sales Excluding E-3, E-4, E-36 Sales (MWhs) [2]			-	-	-	-	-	-	-	-	-	-	-
6	Less Revenue from Applicable Transition Component (L4 x L5) [3]			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	Monthly Interest ([L2 * L9 / 12])			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	Ending Balance; (L3 - L6 + L7)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9	Interest Rate [4]	x.xx%												

Notes:

[1] Transition Component, Schedule 6, Line 3

[2] Sales amounts are for energy billed each period.

[3] Generally, Line 4 x Line 5 = Line 6; however, differences may occur due to billing adjustments.

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

Arizona Corporation Commission
Docket No. E-01345A-11-0224
Exhibit: MJM-9

ARIZONA PUBLIC SERVICE COMPANY
Schedule 8
Old PSA Annual Adjustor Account
($ in thousands; Annual Adjustor Rate in $/kWh)

Line No.		2009 Data January	February	March	April	May	June	July	August	September	October	November	December	2010 January
1	Prior Month's Ending Balance	$ (4,300)	$ (4,301)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	Transfer to 2009 Historical Component Tracking Account	$ -	$ 4,301	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	Annual Adjustor Rate ($/kWh)	$0.003987	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Retail Billed Sales Excluding E-3, E-4, E-36 Sales (MWhs) [1]	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Less Revenue from Applicable Adjustor Rate (L3 * L4) [2]	$ 0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Monthly Interest (L1 * L8 / 12)	$ (1)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	Ending Balance; (L1 - L5 + L6)	$ (4,301)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	Interest Rate -- 2009 [3]	0.40%												

Notes:

[1] Sales amounts are for energy billed each period.

[2] Generally, Line 3 * Line 4 = Line 5; however, differences may occur due to billing adjustments.

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

Arizona Corporation Commission
Docket No. E-01345A-11-0224
Exhibit: MJM-9

ARIZONA PUBLIC SERVICE COMPANY
Schedule 9
Old PSA Step 2 Surcharge Tracking Account
($ in thousands; Transition Component Rate in $/kWh)

Line No.		2009 Data January	February	March	April	May	June	July	August	September	October	November	December	2010 January
1	Prior Month's Ending Balance	$ 2,693	$ 2,694	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	Transfer to 2009 Historical Component Tracking Account	$ -	$ (2,694)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	Applicable Step 2 Surcharge Rate ($/kWh)	$0.001176	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Retail Billed Sales Excluding E-3, E-4, E-36 Sales (MWhs) [1]	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Less Revenue from Collections (L3 x L4) [2]	$ (0)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Monthly Interest (L1 * L8 / 12)	1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	Ending Balance; (L1 -L5 + L6)	$ 2,694	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	Interest Rate -- 2009 [3]	0.40%												

Notes:

[1] Sales amounts are for energy billed each period.

[2] Generally, Line 3 x Line 4 = Line 5; however, differences may occur due to billing adjustments.

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

Arizona Corporation Commission
Docket No. E-01345A-11-0224
Exhibit: MJM-9

ARIZONA PUBLIC SERVICE COMPANY
Schedule 10
Summary of Monthly Calculations
December 2009
($ in thousands)

Line No.		2009 Data January	February	March	April	May	June	July	August	September	October	November	December	2010 January
	2009 Forward Component Tracking Account													
1	Beginning Balance	$ (2,448)	$ (19,888)	$ (19,411)	$ (35,723)	$ (45,937)	$ (49,263)	$ (53,552)	$ (42,253)	$ (35,333)	$ (40,163)	$ (44,414)	$ (51,204)	$ -
2	Transfers to 2009 Historical Component Tracking Account	$ -	$ 19,888	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	Monthly Interest	$ (1)	$ -	$ (6)	$ (12)	$ (15)	$ (16)	$ (18)	$ (14)	$ (12)	$ (13)	$ (15)	$ (17)	$ -
4	Post-Sharing (Over)/Under Collection	$ (11,306)	$ (9,699)	$ (6,987)	$ (1,077)	$ 7,685	$ 8,373	$ 26,421	$ 22,609	$ 10,078	$ 7,537	$ 2,740	$ (5,285)	$ -
5	Less Revenue from Applicable Forward Component Rate	$ 6,133	$ 9,712	$ 9,319	$ 9,126	$ 10,995	$ 12,646	$ 15,105	$ 15,674	$ 14,896	$ 11,774	$ 9,516	$ 10,079	$ -
6	Ending Balance with Interest (Ln. 1, 2, 3, 4 - Ln. 5)	$ (19,888)	$ (19,411)	$ (35,723)	$ (45,937)	$ (49,263)	$ (53,552)	$ (42,253)	$ (35,333)	$ (40,163)	$ (44,414)	$ (51,204)	$ (66,586)	$ -
	2009 Historical Component Tracking Account													
7	Beginning Balance	$ 16,627	$ 14,457	$ (7,545)	$ (7,826)	$ (8,488)	$ (9,053)	$ (9,692)	$ (10,499)	$ (11,294)	$ (12,085)	$ (12,704)	$ (13,217)	$ -
8	Transfers from 2008 Forward Component Tracking Account	$ -	$ (19,888)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9	Transfers from the Old PSA Adjustor and Surcharge Accounts	$ -	$ (1,607)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	Monthly Interest	$ 6	$ (2)	$ (3)	$ (3)	$ (3)	$ (3)	$ (3)	$ (3)	$ (4)	$ (4)	$ (4)	$ (4)	$ -
11	Less Revenue from Applicable Historical Component Rate	$ 2,175	$ 505	$ 278	$ 660	$ 562	$ 636	$ 804	$ 791	$ 788	$ 615	$ 509	$ 507	$ -
12	Ending Balance with Interest (Ln. 7, 8, 9, 10 - Ln. 11)	$ 14,457	$ (7,545)	$ (7,826)	$ (8,488)	$ (9,053)	$ (9,692)	$ (10,499)	$ (11,294)	$ (12,085)	$ (12,704)	$ (13,217)	$ (13,728)	$ -
	Annual Adjustor Account													
13	Beginning Balance	$ (4,300)	$ (4,301)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	Transfers to 2009 Historical Component Tracking Account	$ -	$ 4,301											
15	Monthly Interest	$ (1)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
16	Less Revenue from Applicable Adjustor Rate	$ 0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
17	Ending Balance with Interest (Ln. 13, 14, 15 - Ln. 16)	$ (4,301)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	July 2007 Surcharge Account													
18	Beginning Balance	$ 2,693	$ 2,694	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
19	Transfers to 2009 Historical Component Tracking Account		$ (2,694)											
20	Monthly Interest	$ 1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
21	Less Revenue from Applicable Surcharge Rate	$ (0)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
22	Ending Balance with Interest (Ln. 18, 19, 20 - Ln. 21)	$ 2,694	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
23	**Combined Balance (Ln. 6, 12, 17, 22)**	$ (7,038)	$ (26,956)	$ (43,548)	$ (54,426)	$ (58,316)	$ (63,244)	$ (52,752)	$ (46,627)	$ (52,248)	$ (57,118)	$ (64,422)	$ (80,314)	$ -
24	Combined Monthly Interest (Ln. 3, 10, 15, 20)	$ 4	$ (2)	$ (9)	$ (15)	$ (18)	$ (19)	$ (21)	$ (18)	$ (16)	$ (17)	$ (19)	$ (21)	$ -

Arizona Corporation Commission
Docket No. E-01345A-11-0224
Exhibit: MJM-9

ARIZONA PUBLIC SERVICE COMPANY
Schedule 11
2009 Native Load Customer Counts, Sales and Revenue
December 2009

Line No.	Class	January	February	March	April	May	June	July	August	September	October	November	December	Total[1]
	Customers													
1	Residential	988,831	988,356	988,838	985,349	981,116	978,782	979,570	977,583	978,818	979,626	983,527	992,077	983,539
2	Commercial	120,130	120,138	120,165	120,328	120,269	120,194	120,299	120,300	120,403	120,435	120,526	120,428	120,301
3	Industrial	3,557	3,554	3,534	3,551	3,566	3,564	3,545	3,529	3,530	3,518	3,520	3,491	3,538
4	Irrigation	324	323	321	323	321	319	318	318	315	316	314	315	319
5	Sales for Resale[2]	18	18	18	18	18	18	18	18	18	18	18	18	18
6	Streetlights & OPA	1,091	1,092	1,092	1,095	1,095	1,099	1,100	1,099	1,104	1,100	1,102	886	1,080
7	Less E-36, ED 3 and CoW (includes adj. to prior mth)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)
8	Total	1,113,945	1,113,475	1,113,962	1,110,658	1,106,379	1,103,970	1,104,844	1,102,841	1,104,182	1,105,007	1,109,001	1,117,207	1,108,789
	Sales (MWh)													
9	Residential	978,977	751,579	768,310	744,027	1,132,853	1,302,661	1,825,928	1,727,522	1,394,756	909,858	717,357	960,269	13,214,097
10	Commercial	883,018	852,455	947,889	954,130	1,189,784	1,098,849	1,341,667	1,268,421	1,140,654	994,903	944,268	972,551	12,588,588
11	Industrial	161,338	176,356	198,570	195,251	197,673	157,628	192,486	192,862	187,133	175,794	180,706	173,851	2,189,648
12	Irrigation	518	926	1,583	2,137	3,049	2,715	3,190	2,563	2,181	2,224	1,528	1,171	23,785
13	Sales for Resale[2]	48,795	62,882	57,747	74,140	77,575	86,428	111,667	91,118	100,501	58,075	48,548	38,560	856,036
14	Streetlights & OPA	10,689	10,193	11,965	11,640	12,885	10,191	11,879	11,280	10,291	11,153	12,346	5,429	129,941
15	Less E-36, ED 3 and CoW (includes adj. to prior mth)	(32,166)	(31,307)	(37,310)	(37,277)	(56,304)	(58,261)	(66,438)	(53,032)	(43,811)	(35,457)	(33,514)	(31,643)	(516,520)
16	Total	2,051,169	1,823,084	1,948,754	1,944,048	2,557,515	2,600,211	3,420,379	3,240,734	2,791,705	2,116,550	1,871,239	2,120,187	28,485,575
	Revenue ($000)													
17	Residential	$ 97,503	$ 77,598	$ 80,718	$ 85,339	$ 136,055	$ 155,369	$ 215,314	$ 204,670	$ 167,581	$ 101,449	$ 74,804	$ 99,227	$ 1,495,629
18	Commercial	$ 82,246	$ 80,340	$ 89,529	$ 96,211	$ 125,921	$ 113,830	$ 139,497	$ 131,554	$ 120,272	$ 101,814	$ 91,605	$ 92,560	$ 1,265,379
19	Industrial	$ 11,922	$ 13,673	$ 14,770	$ 15,739	$ 16,477	$ 14,776	$ 16,274	$ 16,415	$ 15,223	$ 13,887	$ 14,754	$ 13,657	$ 177,567
20	Irrigation	$ 67	$ 110	$ 149	$ 207	$ 297	$ 268	$ 304	$ 249	$ 213	$ 225	$ 153	$ 129	$ 2,371
21	Sales for Resale[2]	$ 3,754	$ 4,108	$ 4,181	$ 5,217	$ 5,565	$ 6,487	$ 7,822	$ 6,903	$ 7,071	$ 4,440	$ 3,469	$ 2,987	$ 62,005
22	Streetlights & OPA	$ 1,543	$ 1,486	$ 1,741	$ 1,717	$ 1,825	$ 1,465	$ 1,761	$ 1,662	$ 1,504	$ 1,635	$ 1,807	$ 1,048	$ 19,193
23	Less E-36, ED 3 and CoW (includes adj. to prior mth)	$ (2,212)	$ (2,302)	$ (2,983)	$ (3,026)	$ (4,108)	$ (4,741)	$ (432)	$ 63	$ (275)	$ (310)	$ (284)	$ (364)	$ (20,975)
24	Total	$ 194,824	$ 175,013	$ 188,106	$ 201,404	$ 282,032	$ 287,454	$ 380,539	$ 361,514	$ 311,589	$ 223,141	$ 186,308	$ 209,245	$ 3,001,169
	Est. System Losses and Peak													
25	Est. Native Load Sys. Losses (MWh)	179,287	134,749	143,211	151,573	209,749	205,690	259,786	232,610	175,408	129,774	157,637	181,446	
26	Est. Native Load Sys. Losses (MW)	355	301	262	366	484	516	556	511	401	301	319	351	
27	Est. Native Load Sys. Peak (MW)[3]	4,023	3,997	3,530	4,608	5,856	6,452	7,218	7,031	6,247	4,862	3,752	4,093	

[1] The Customers total is the average of the customer class' monthly totals.

[2] Includes traditional sales for resale, PacifiCorp supplemental sales, ED 3, City of Williams, and other non-ACC jurisdictional sales. Off-System Interchange customers, sales and revenue are excluded from Sales for Resale.

[3] The Preliminary Native Load System Peak totals will be updated each month.

Arizona Corporation Commission
Docket No. E-01345A-11-0224
Exhibit: MJM-9

CERTIFICATION BY APS
OF
MONTHLY PSA REPORTS

Pursuant to Decision No. 69663 (June 28, 2007) and the Power Supply Adjustor Plan of Administration (July 30, 2007), I certify that to the best of my knowledge and based on the information made available to me, the attached Monthly PSA Report is complete and accurate in all material respects.

Date: January 29, 2010

James R. Hatfield

James R. Hatfield
Senior Vice-President and Chief Financial Officer

APS

Susan Casady
Regulatory Programs Leader
State Regulation

Tel. 602-250-2709
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Mail Station 9708
PO Box 53999
Phoenix, Arizona 85072-3999

January 28, 2011

Mr. Steve Olea
Utilities Division
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

RE: Arizona Public Service Company December 2010 Power Supply Adjustor Report
Docket No. E-01345A-05-0816, E-01345A-05-0826, & E-01345A-05-0827
Decision No. 69663

Section 8 of the Power Supply Adjustor ("PSA") Plan of Administration ("POA") approved in Decision No. 69663 states that:

"APS shall provide monthly reports to Staff's Compliance Section and to the Residential Utility Consumer Office detailing all calculations related to the PSA. An APS Principal Officer, as listed in the Company's annual report filed with the Commission's Corporation Division, shall certify under oath that all information provided in the reports itemized below is true and accurate to the best of his or her information and belief. These monthly reports shall be due within 30 days of the end of the reporting period."

Arizona Public Service Company ("APS") is submitting the December 2010 Power Supply Adjustor report. Additionally, APS is submitting the signed officer certification from Mr. Mark A. Schiavoni, APS's Senior Vice-President, Fossil Generation. The Company has also included Schedule 7 (formerly Schedule 11) as a summary of the monthly calculations, submitted to date, to help summarize all of the accounts.

If you should have any questions regarding the information contained herein, please contact David Rumolo at (602)250-3933.

Sincerely,

Susan Casady

SC/sl
Attachments

cc: Brian Bozzo
Jodi Jerich
Barbara Keene

ARIZONA PUBLIC SERVICE COMPANY
Schedule 1
Power Supply Adjustment (PSA) Rate Calculation Effective January 1, 2010
($/kWh)

Line No.	PSA Rate Calculation	Current January 1, 2010	Proposed February 1, 2011 [1]	Increase/(Decrease) $/kWh	Increase/(Decrease) %
1	Forward Component Rate - FC (Schedule 2, L13)	$ (0.001816)	$ (0.003016)	$(0.001200)	-66%
2	Historical Component Rate - HC (Schedule 4, L5) [2]	$ (0.002674)	$ (0.002642)	$ 0.000032	1%
3	PSA Transition Component Rate	$ -	$ -	$ -	N/A
4	**PSA Rate (L1+ L2 + L3)**	$ (0.004490)	$ (0.005658)	$(0.001168)	-26%
5	**Base Fuel Rate**	$ 0.037571	$ 0.037571	$ -	N/A
6	**Total Fuel Recovery (L4 + L5)** [4]	$ 0.033081	$ 0.031913	$(0.001168)	-4%

Notes:

[1] Proposed levels of the PSA rate components are provided in the September 30 filing and updated in the December 31 filing of each year.

[2] A Historical Component is a true up related to respective prior period PSA activity.

[3] Provides for Mid-Period Corrections when necessary.

[4] The Total Fuel Recovery beginning January 1, 2010 includes the impact of the margins from the sale of excess emission allowances not recorded in fuel.

ARIZONA PUBLIC SERVICE COMPANY
Schedule 2
PSA Forward Component Rate Calculation Effective January 1, 2010
($ in thousands; Forward Component Rate in $/kWh)

Line No.	PSA Forward Component Rate - Calculation	Current January 1, 2010	Proposed February 1, 2011 [1]	Increase/(Decrease) $ Values	Increase/(Decrease) %
1	Projected Fuel and Purchased Power Costs	$ 1,083,459	$ 1,006,577	$ (76,882)	-7%
2	Projected Off-System Sales Revenue	(55,591)	(31,286)	24,305	-44%
3	PSA Adjustments to Fuel and Purchased Power Costs [2]	(21,629)	(14,066)	7,562	35%
4	Net Fuel and Purchased Power Cost (L1 through L3)	$ 1,006,239	$ 961,225	$ (45,014)	-4%
5	Projected Net Margins on the Sale of Emission Allowances	-	-	N/A	N/A
6	Projected Billed Native Load Sales, excluding E-3, E-4, E-36 (MWhs) [3]	28,334,369	28,012,931	(321,438)	-1%
7	Projected Average Net Fuel Cost $/kWh (L4 / L6)	$ 0.035513	$ 0.034314	$ (0.001200)	-3%
8	Projected Average Margin on Emission Allowances $/kWh (L5 / L6)	$ -	$ -	N/A	N/A
9	Total Projected Average PSA Cost $/kWh (L7+L8)	$ 0.035513	$ 0.034314	$ (0.001200)	-3%
10	Authorized Base Cost of Fuel and Purchased Power Rate $/kWh [4]	$ 0.037571	$ 0.037571	N/A	N/A
11	Authorized Base Net Margins on the Sale of Emission Allowances Rate $/kWh [4]	$ (0.000242)	$ (0.000242)	N/A	N/A
12	Total Authorized Base Cost $/kWh	$ 0.037329	$ 0.037329	N/A	N/A
13	Forward Component Rate $/kWh (L9 - L12)	$ (0.001816)	$ (0.003016)	$ 0.001200	-66%

Notes:

[1] Proposed levels of the PSA rate components are provided in the September 30 filing and updated in the December 31 filing of each year.

[2] Includes costs associated with E-36 and other direct assignment customers, ISFSI, and mark-to-market accounting adjustments.

[3] The proposed Billed Native Load Sales of 28,012,931 MWhs for the Current Rate represent forecast sales for 2011 as of November 30th, 2010. They exclude ED 3 and City of Williams wholesale contracts that are excluded from the proposed sales and fuel costs.

[4] Base Cost of Fuel and Purchased Power established in the Commision approved settlement agreement.

JBLIC SERVICE COMPANY
Schedule 3
2010 PSA Year Forward Component Tracking Account - in Effect from January 1, 2010 to Dec 31, 2010

($ in thousands; Forward Component Rate and Base Rate in $/kWh)

		Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10
1 Prior Month's Balance	From L31	$ -	$ (18,579)	$ (29,171)	$ (39,540)	$ (49,699)	$ (53,222)	$ (49,995)	$ (42,041)	$ (28,828)	$ (18,907)	$ (23,131)	$ (33,752)
Energy Sales													
2 PSA Retail Energy Sales [1]		2,033,708	1,768,419	1,906,383	1,836,615	2,129,135	2,685,321	3,249,577	3,148,099	2,794,192	2,191,430	1,861,882	1,996,557
3 Wholesale Native Load Energy Sales [2]		24,201	33,241	26,034	30,393	21,756	31,654	32,367	41,486	45,800	14,142	20,427	5,773
4 Total Native Load Energy Sales	L2 + L3	2,057,909	1,801,660	1,932,416	1,867,008	2,150,891	2,716,975	3,281,944	3,189,585	2,839,991	2,205,571	1,882,309	2,002,331
5 Retail Energy Sales as a % of Total	L2 / L4	99%	98%	99%	98%	99%	99%	99%	99%	98%	99%	99%	100%
6 Retail Billed Sales Excluding E-3, E-4, E-36 Sales (MWh) [3]		976,488	1,961,027	1,799,468	1,749,133	1,884,182	2,275,822	2,927,659	2,962,139	2,902,584	2,503,986	1,993,077	1,915,478
PSA Costs													
7 Renewables Costs [4]		$ 3,024	$ 2,092	$ 3,251	$ 3,626	$ 3,762	$ 2,838	$ 2,091	$ 1,782	$ 3,027	$ 3,448	$ 3,956	$ 4,524
8 PPA Fixed Costs		$ 3,503	$ 3,503	$ 3,186	$ 3,393	$ 3,904	$ 13,657	$ 13,441	$ 13,620	$ 13,287	$ 3,524	$ 3,648	$ 3,648
9 Other Fuel and Purchased Power Costs [5]		$ 56,527	$ 53,103	$ 55,353	$ 51,389	$ 68,163	$ 94,065	$ 118,868	$ 123,569	$ 103,119	$ 68,695	$ 52,157	$ 54,480
10 Off System Revenue (Credit) [6]		$ (3,631)	$ (7,277)	$ (5,346)	$ (3,943)	$ (3,271)	$ (11,329)	$ (9,579)	$ (11,720)	$ (9,056)	$ (3,208)	$ (5,410)	$ (11,076)
11 Net Margins on Sale of Emission Allowances (Credit)		$ -	$ -	$ -	$ (13)	$ -	$ -	$ -	$ -	$ -	$ (8)	$ -	$ -
12 Net PSA Costs	sum(L7 to L11)	$ 59,423	$ 51,421	$ 56,443	$ 54,452	$ 72,558	$ 99,231	$ 124,821	$ 127,252	$ 110,377	$ 72,450	$ 54,351	$ 51,576
Retail PSA Costs													
13 Renewables Costs	L5 * L7	$ 2,988	$ 2,053	$ 3,207	$ 3,567	$ 3,724	$ 2,805	$ 2,070	$ 1,759	$ 2,978	$ 3,426	$ 3,913	$ 4,511
14 PPA Fixed Costs	L5 * L8	$ 3,462	$ 3,438	$ 3,143	$ 3,337	$ 3,864	$ 13,498	$ 13,309	$ 13,443	$ 13,073	$ 3,501	$ 3,608	$ 3,637
15 Other Fuel and Purchased Power Costs	L5 * L9	$ 55,862	$ 52,123	$ 54,607	$ 50,553	$ 67,474	$ 92,970	$ 117,696	$ 121,962	$ 101,456	$ 68,255	$ 51,591	$ 54,323
16 Off System Revenue (Credit)	L5 * L10	$ (3,588)	$ (7,142)	$ (5,274)	$ (3,879)	$ (3,238)	$ (11,197)	$ (9,484)	$ (11,567)	$ (8,910)	$ (3,188)	$ (5,351)	$ (11,044)
17 Net Margins on Sale of Emission Allowances (Credit)	L5 * L11	$ -	$ -	$ -	$ (13)	$ -	$ -	$ -	$ -	$ -	$ (8)	$ -	$ -
18 Net Retail PSA Costs	sum(L13 to L17)	$ 58,724	$ 50,472	$ 55,683	$ 53,565	$ 71,824	$ 98,075	$ 123,590	$ 125,597	$ 108,597	$ 71,986	$ 53,761	$ 51,427
Base Rate Power Supply Recovery													
19 Renewables Recovery	L32 * L2	$ 2,440	$ 2,122	$ 2,288	$ 2,204	$ 2,555	$ 3,222	$ 3,899	$ 3,778	$ 3,353	$ 2,630	$ 2,234	$ 2,396
20 PPA Fixed Recovery	L33 * L2	$ 3,976	$ 3,457	$ 3,727	$ 3,591	$ 4,162	$ 5,250	$ 6,353	$ 6,155	$ 5,463	$ 4,284	$ 3,640	$ 3,903
21 Other Fuel and Purchased Power Recovery	L34 * L2	$ 69,992	$ 60,862	$ 65,610	$ 63,209	$ 73,276	$ 92,418	$ 111,837	$ 108,345	$ 96,165	$ 75,420	$ 64,079	$ 68,714
22 Net Margins on Sale of Emission Allowances	L36 * L2	$ (492)	$ (428)	$ (461)	$ (444)	$ (515)	$ (649)	$ (786)	$ (761)	$ (676)	$ (530)	$ (450)	$ (483)
(Over) Under Recovery From Base Rate													
23 Renewables (Over) Under Recovery	L13 - L19	$ 548	$ (69)	$ 920	$ 1,363	$ 1,169	$ (417)	$ (1,829)	$ (2,019)	$ (375)	$ 796	$ 1,679	$ 2,115
24 PPA Fixed (Over) Under Recovery	L14 - L20	$ (514)	$ (19)	$ (584)	$ (253)	$ (298)	$ 8,248	$ 6,956	$ 7,289	$ 7,610	$ (783)	$ (32)	$ (266)
25 Other Fuel and Purchased Power (Over) Under Recovery	(L15 + L16) - L21	$ (17,718)	$ (15,881)	$ (16,277)	$ (16,535)	$ (9,041)	$ (10,646)	$ (3,626)	$ 2,050	$ (3,619)	$ (10,353)	$ (17,839)	$ (25,435)
26 Net Margins on Sale of Emission Allowances (Over) Under Recovery	L17 - L22	$ 492	$ 428	$ 461	$ 431	$ 515	$ 649	$ 786	$ 761	$ 676	$ 522	$ 450	$ 483
27 Less 10% Sharing On Other (Over) Under Recovery	- 0.10 * L25	$ 1,772	$ 1,588	$ 1,628	$ 1,654	$ 904	$ 1,065	$ 363	$ (205)	$ 362	$ 1,035	$ 1,784	$ 2,543
28 Total (Over) Under Recovery	sum(L23 to L27)	(15,420)	(13,954)	(13,853)	(13,340)	(6,751)	(1,101)	2,649	7,876	4,654	(8,783)	(13,958)	(20,560)
29 Interest Accrued on Prior Month's Balance	L38 * L1	$ -	$ (7)	$ (11)	$ (15)	$ (19)	$ (20)	$ (19)	$ (16)	$ (11)	$ (7)	$ (9)	$ (13)
30 Forward Component Collections/(Refund) [7]	- L37 * L6	$ 3,159	$ (3,369)	$ (3,494)	$ (3,196)	$ (3,247)	$ (4,348)	$ (5,324)	$ (5,353)	$ (5,278)	$ (4,566)	$ (3,345)	$ (3,692)
31 Tracking Account Balance	L1 + L28 + L29 - L30	$ (18,579)	$ (29,171)	$ (39,540)	$ (49,699)	$ (53,222)	$ (49,995)	$ (42,041)	$ (28,828)	$ (18,907)	$ (23,131)	$ (33,752)	$ (50,632)

32 Renewable Costs In Base Fuel Rate - ¢ per kWh	0.1200
33 PPA Fixed Costs In Base Fuel Rate - ¢ per kWh	0.1955
34 Other Costs In Base Fuel Rate - ¢ per kWh	3.4416
35 Total Base Fuel Rate - ¢ per kWh	3.7571
36 Base Net Margin on the Sale of Emission Allowances - ¢ per kWh	-0.0242
37 Forward Component Rate - ¢ per kWh	-0.1816
38 Interest Rate -- 2010 [8]	0.45%

Notes:

[1] PSA Retail Energy Sales are the calendar month's MWh sales. 2010 PSA Year Cumulative Retail Energy Sales of 72,069 MWhs under rate schedule E-36 were excluded from the PSA Calculations.

[2] Includes traditional sales for resale, PacifiCorp supplemental sales, and other non-ACC jurisdictional sales. ED 3 and City of Williams energy sales are excluded from the PSA Calculation.

[3] Retail Billed Sales on Line 6 relate specifically to the Forward Component Collections. Due to billing adjustments and timing, this amount will differ from other components' Retail Billed Sales.

[4] Renewables costs exclude $8,219,601 of 2010 PSA Year year-to-date costs that are currently being recovered through the RES rate schedule.

[5] Includes native load and off-system fuel and purchased power costs less those costs associated with E-36 and other direct assignment customers, amortization of previously deferred ISFSI, Four Corners Coal Reclamation, and mark-to-market accounting adjustments.

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

[7] Generally, Line 37 * Line 6 = Line 26; however, differences may occur due to billing adjustments.

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

ARIZONA PUBLIC SERVICE COMPANY
Schedule 4
PSA Historical Component Rate Calculation Effective January 1, 2010
($ in thousands; Historical Component Rate in $/kWh)

Line No.	PSA Historical Component Rate Calculation	Current January 1, 2010	Proposed February 1, 2011 [1]	Increase/(Decrease) $ Values	Increase/(Decrease) %
1	Forward Component Tracking Account Balance	$ (65,639)	(66,871)	$ (1,232)	-2%
2	Historical Component Tracking Account Balance	(13,730)	(5,908)	7,822	57%
3	Total Historical Amount to be (Refunded)/Collected Balance (L1+L2)	$ (79,369)	$ (72,779)	$ 6,590	8%
4	Projected Billed Retail Energy Sales without E-3, E-4 and E-36 (MWh) [2]	29,676,884	27,547,880	(2,129,004)	-7%
5	Applicable Historical Component Rate [L3 / L4]	$ (0.002674)	$ (0.002642)	$ 0.000032	1%

Notes:
[1] Proposed levels of the PSA rate components are provided in the September 30 filing and updated in the December 31 filing of each year.
[2] The Current Rate Projected Billed Retail Energy Sales are for January 2010 through January 2011. The Proposed Rate Projected Billed Retail Energy Sales are for February 2011 through January 2012.

ARIZONA PUBLIC SERVICE COMPANY
Schedule 5
Historical Component Tracking Account in Effect Jan 1, 2010 through Jan. 31, 2011
($ in thousands Historical Component Rate in $/kWh)

Line No.		2010 Data January	February	March	April	May	June	July	August	September	October	November	December	2011 January
1	Projected HC Tracking Account Balance at Dec. 31, 2009	(13,730)												
2	Projected FC Tracking Account Balance at Dec. 31, 2009	(65,639)												
3	Old PSA Account Balances at Jan. 31, 2010	-												
4	True-up from December - January Estimate [1]	(945)												
5	Prior Month's Ending Balance	$ -	$ (78,090)	$ (72,871)	$ (68,087)	$ (63,437)	$ (58,426)	$ (52,364)	$ (44,557)	$ (36,649)	$ (28,910)	$ (22,226)	$ (16,907)	
6	HC Adjusted Beginning Balance (L1+ L2 + L3 + L4 + L5)	(80,314)	(78,090)	(72,871)	(68,087)	(63,437)	(58,426)	(52,364)	(44,557)	(36,649)	(28,910)	(22,226)	(16,907)	
7	Applicable Historical Component Rate ($/kWh) [2]	$ (0.002674)	$ (0.002674)	$ (0.002674)	$ (0.002674)	$ (0.002674)	$ (0.002674)	$ (0.002674)	$ (0.002674)	$ (0.002674)	$ (0.002674)	$ (0.002674)	$ (0.002674)	
8	Retail Billed Sales Excluding E-3, E-4, E-36 Sales (MWhs) [3]	976,488	1,961,027	1,799,468	1,749,133	1,884,182	2,275,822	2,927,659	2,962,139	2,902,584	2,503,986	1,993,077	1,915,478	
9	Less Revenue from Applicable HC (L7 x L8) [4,5]	$ (2,254)	$ (5,249)	$ (4,811)	$ (4,675)	$ (5,035)	$ (6,084)	$ (7,827)	$ (7,924)	$ (7,753)	$ (6,694)	$ (5,328)	$ (5,121)	
10	Monthly Interest ([L5 * L12 / 12])	$ (30)	$ (29)	$ (27)	$ (26)	$ (24)	$ (22)	$ (20)	$ (17)	$ (14)	$ (11)	$ (8)	$ (6)	
11	HC Ending Balance ; (L6 - L9 + L10)	$ (78,090)	$ (72,871)	$ (68,087)	$ (63,437)	$ (58,426)	$ (52,364)	$ (44,557)	$ (36,649)	$ (28,910)	$ (22,226)	$ (16,907)	$ (11,792)	
12	Interest Rate -- 2010 [6]	0.45%												

Notes:

[1] True-up is the result of using estimated revenue and deferral for December and January since the actual amount was not available at the time of prior period PSA filing.

[2] Historical Component, Schedule 4, Line 5

[3] Sales amounts are for energy billed each period.

[4] Generally, Line 7 x Line 8 = Line 9; however, differences may occur due to billing adjustments.

[5] Line 9 includes revenues associated with billing adjustments from the Old PSA Adjustors.

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

ARIZONA PUBLIC SERVICE COMPANY
Schedule 6
(formerly Schedule 10)[1]
Summary of Monthly Calculations
December 2010
($ in thousands)

Line No.		2010 Data January	February	March	April	May	June	July	August	September	October	November	December	2011 January
	2010 Forward Component Tracking Account													
1	Beginning Balance	$ (66,586)	$ (18,579)	$ (29,171)	$ (39,540)	$ (49,699)	$ (53,222)	$ (49,995)	$ (42,041)	$ (28,828)	$ (18,907)	$ (23,131)	$ (33,752)	$ -
2	Transfers to 2009 Historical Component Tracking Account	$ 66,586	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	Monthly Interest	$ -	$ (7)	$ (11)	$ (15)	$ (19)	$ (20)	$ (19)	$ (16)	$ (11)	$ (7)	$ (9)	$ (13)	$ -
4	Post-Sharing (Over)/Under Collection	$ (15,420)	$ (13,954)	$ (13,853)	$ (13,340)	$ (6,751)	$ (1,101)	$ 2,649	$ 7,876	$ 4,654	$ (8,783)	$ (13,958)	$ (20,569)	$ -
5	Less Revenue from Applicable Forward Component Rate	$ 3,159	$ (3,369)	$ (3,494)	$ (3,196)	$ (3,247)	$ (4,348)	$ (5,324)	$ (5,353)	$ (5,278)	$ (4,566)	$ (3,345)	$ (3,692)	$ -
6	Ending Balance with Interest (Ln. 1, 2, 3, 4 - Ln. 5)	$ (18,579)	$ (29,171)	$ (39,540)	$ (49,699)	$ (53,222)	$ (49,995)	$ (42,041)	$ (28,828)	$ (18,907)	$ (23,131)	$ (33,752)	$ (50,632)	$ -
	2010 Historical Component Tracking Account													
7	Beginning Balance	$ (13,728)	$ (78,090)	$ (72,871)	$ (68,087)	$ (63,437)	$ (58,426)	$ (52,364)	$ (44,557)	$ (36,649)	$ (28,910)	$ (22,226)	$ (16,907)	$ -
8	Transfers from 2009 Forward Component Tracking Account	$ (66,586)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9	Transfers from the Old PSA Adjustor and Surcharge Accounts	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	Monthly Interest	$ (30)	$ (29)	$ (27)	$ (26)	$ (24)	$ (22)	$ (20)	$ (17)	$ (14)	$ (11)	$ (8)	$ (6)	$ -
11	Less Revenue from Applicable Historical Component Rate	$ (2,254)	$ (5,249)	$ (4,811)	$ (4,675)	$ (5,035)	$ (6,084)	$ (7,827)	$ (7,924)	$ (7,753)	$ (6,694)	$ (5,328)	$ (5,121)	$ -
12	Ending Balance with Interest (Ln. 7, 8, 9, 10 - Ln. 11)	$ (78,090)	$ (72,871)	$ (68,087)	$ (63,437)	$ (58,426)	$ (52,364)	$ (44,557)	$ (36,649)	$ (28,910)	$ (22,226)	$ (16,907)	$ (11,792)	$ -
13	**Combined Balance (Ln. 6 + Ln. 12)**	$ (96,669)	$ (102,041)	$ (107,627)	$ (113,136)	$ (111,648)	$ (102,359)	$ (86,598)	$ (65,477)	$ (47,817)	$ (45,358)	$ (50,659)	$ (62,425)	$ -
14	Combined Monthly Interest (Ln. 3 + Ln. 10)	$ (30)	$ (36)	$ (38)	$ (40)	$ (42)	$ (42)	$ (38)	$ (32)	$ (25)	$ (18)	$ (17)	$ (19)	$ -

[1] Schedule number has changed due to the exclusion of previously expired surcharge account schedules.

ARIZONA PUBLIC SERVICE COMPANY
Schedule 7
(formerly Schedule 11)[4]
2010 Native Load Customer Counts, Sales and Revenue
December 2010

Line No.	Class	January	February	March	April	May	June	July	August	September	October	November	December	Total[1]
	Customers													
1	Residential	993,081	995,062	997,016	992,932	988,047	986,388	986,922	985,128	984,331	985,628	988,907	996,422	989,989
2	Commercial	120,031	120,434	120,478	120,646	120,530	120,622	120,357	120,231	120,049	120,095	120,329	120,615	120,368
3	Industrial	3,464	3,487	3,490	3,496	3,492	3,484	3,478	3,475	3,462	3,429	3,458	3,471	3,474
4	Irrigation	311	313	314	313	310	311	310	309	309	308	307	306	310
5	Sales for Resale[2]	18	18	18	18	18	18	18	18	18	18	18	18	18
6	Streetlights & OPA	1,091	1,092	1,092	1,095	1,095	1,099	1,100	1,099	1,104	1,100	1,102	886	1,080
7	Less E-36, ED 3 and CoW (includes adj. to prior mth)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)
8	Total	1,117,990	1,120,400	1,122,402	1,118,494	1,113,486	1,111,916	1,112,179	1,110,254	1,109,267	1,110,572	1,114,115	1,121,712	1,115,232
	Sales (MWh)													
9	Residential	1,001,980	761,404	811,501	725,836	900,819	1,329,986	1,778,117	1,673,593	1,438,918	993,296	712,162	907,888	13,035,500
10	Commercial	869,343	830,283	906,675	927,583	1,036,568	1,148,407	1,280,591	1,278,811	1,161,175	1,013,032	957,257	915,648	12,325,372
11	Industrial	160,327	174,664	177,980	172,401	181,540	197,867	181,282	184,534	188,103	177,389	186,356	166,685	2,149,128
12	Irrigation	717	681	942	1,896	2,738	2,918	2,767	1,905	1,999	2,100	1,452	840	20,955
13	Sales for Resale[2]	48,392	55,388	57,779	66,167	64,232	86,768	87,784	97,837	86,233	53,717	47,262	34,701	786,260
14	Streetlights & OPA	17,346	10,093	11,966	12,144	11,817	12,093	11,154	12,033	10,123	10,824	12,039	10,884	142,516
15	Less E-36, ED 3 and CoW (includes adj. to prior mth)	(40,196)	(30,853)	(34,426)	(39,019)	(46,823)	(61,064)	(59,751)	(59,128)	(46,560)	(44,787)	(40,188)	(37,057)	(539,852)
16	Total	2,057,909	1,801,660	1,932,416	1,867,008	2,150,891	2,716,975	3,281,944	3,189,585	2,839,991	2,205,571	1,876,340	1,999,589	27,919,879
	Revenue ($000)													
17	Residential	$ 101,336	$ 79,657	$ 86,098	$ 84,806	$ 111,413	$ 163,995	$ 216,958	$ 202,722	$ 176,726	$ 112,068	$ 74,603	$ 93,907	$ 1,504,288
18	Commercial	$ 79,860	$ 78,294	$ 86,877	$ 94,504	$ 112,985	$ 122,768	$ 134,351	$ 133,275	$ 123,986	$ 103,074	$ 91,164	$ 85,177	$ 1,246,314
19	Industrial	$ 11,189	$ 13,154	$ 13,491	$ 14,409	$ 14,847	$ 15,909	$ 14,940	$ 15,447	$ 15,371	$ 13,196	$ 13,921	$ 12,342	$ 168,215
20	Irrigation	$ 78	$ 87	$ 109	$ 188	$ 274	$ 286	$ 266	$ 194	$ 190	$ 201	$ 128	$ 104	$ 2,106
21	Sales for Resale[2]	$ 3,509	$ 3,872	$ 11,106	$ 4,886	$ 5,590	$ 6,513	$ 6,621	$ 7,593	$ 6,337	$ 4,763	$ 3,851	$ 3,018	$ 67,660
22	Streetlights & OPA	$ 2,331	$ 1,536	$ 1,839	$ 1,886	$ 1,775	$ 1,924	$ 1,649	$ 1,698	$ 1,638	$ 1,661	$ 1,857	$ 1,610	$ 21,403
23	Less E-36, ED 3 and CoW (includes adj. to prior mth)	$ (2,997)	$ (2,691)	$ (2,866)	$ (3,217)	$ (4,150)	$ (5,222)	$ (5,139)	$ (5,389)	$ (3,994)	$ (3,662)	$ (3,289)	$ (2,931)	$ (45,548)
24	Total	$ 195,306	$ 173,908	$ 196,654	$ 197,461	$ 242,735	$ 306,173	$ 369,646	$ 355,540	$ 320,254	$ 231,301	$ 182,234	$ 193,227	$ 2,964,438
	Est. System Losses and Peak	**1,901,517**												
25	Est. Native Load Sys. Losses (MWh)	156,392	141,283	133,303	116,069	147,852	196,495	230,140	210,885	192,859	167,281	161,032	162,473	
26	Est. Native Load Sys. Losses (MW)	299	302	256	236	324	470	491	463	432	439	346	328	
27	Est. Native Load Sys. Peak (MW)[3]	3,925	3,796	3,672	3,746	4,669	6,440	6,936	6,912	6,279	5,758	4,019	4,036	

[1] The Customers total is the average of the customer class' monthly totals.
[2] Includes traditional sales for resale, PacifiCorp supplemental sales, ED 3, City of Williams, and other non-ACC jurisdictional sales. Off-System Interchange customers, sales and revenue are excluded from Sales for Resale.
[3] The Preliminary Native Load System Losses and Peak totals may be updated periodically.
[4] Schedule number has changed due to the exclusion of previously expired surcharge account schedules.

CERTIFICATION BY APS
OF
MONTHLY PSA REPORTS

Pursuant to Decision No. 69663 (June 28, 2007) and the Power Supply Adjustor Plan of Administration (July 30, 2007), I certify that to the best of my knowledge and based on the information made available to me, the attached Monthly PSA Report is complete and accurate in all material respects.

Date: January 28, 2011

Mark A. Schiavoni
Senior Vice-President, Fossil Generation

Reconciliation of Gross Fuel and Purchased Power Expense to Net Base Fuel Cost
($000)

	Nuclear	Coal	Natural Gas/Oil	Purchased Power	Purchased Renewables	Gas Transport/ Fuel Handling	Subtotal	Off-System Revenues/ Margin	Total System
Total (from Monthly Detail, Recorded Gross)	74,428	223,454	495,478	377,652	-	-	1,171,012	(145,483)	1,025,528
less Adjustments:									
Nuclear ISFSI Amortization	5,233	-	-	-	-	-	5,233	-	5,233
Coal Reclamation Amortization	-	1,305	-	-	-	-	1,305	-	1,305
Gas/Oil Used at Coal Plants	-	1,477	(1,477)	-	-	-	-	-	-
FAS 133 Mark-to-Market	-	-	22,907	16,608	-	-	39,515	(1,089)	38,426
Off-System Sales	-	20,494	28,793	21,960	-	-	71,247	(71,247)	-
ED 3/CoW Sales	-	-	-	32,217	-	-	32,217	-	32,217
Hedge Sales Recorded as Revenue Credit	-	-	-	39,283	-	-	39,283	(39,283)	-
Firm Gas Transportation	-	-	55,455	-	-	(55,455)	-	-	-
Fuel Handling	-	4,504	3,123	-	-	(7,627)	-	-	-
Renewables in Purchased Power	-	-	-	37,421	(37,421)	-	-	-	-
Renewables Above Market	-	-	-	8,220	-	-	8,220	-	8,220
Total Adjustments	5,233	27,780	108,801	155,708	(37,421)	(63,082)	197,020	(111,619)	85,401
Net Base Fuel Cost	69,195	195,674	386,677	221,944	37,421	63,082	973,991	(33,864)	940,127

Arizona Corporation Commission
Docket No. E-01345A-11-0224
Exhibit: MJM-10

ARIZONA CORPORATION COMMISSION
STAFF'S TWENTY SECOND SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
OCTOBER 14, 2011

Staff 22.9: Base cost of fuel.

a) Please update Attachment PME-3 and PME-4 using current information on fuel costs projected for 2012. Please provide the updated results in Excel.

b) Please provide quantifications and workpapers for the items in footnotes 1 through 7 on Attachment PME-3:

1) ISFSI expense
2) Coal reclamation costs
3) Fuel costs associated with long-term tolling arrangements
4) Native load head liquidation costs
5) Fixed capacity contract costs
6) Above market purchases of renewable that are recovered through RES
7) Generation associated with Company owned facilities

Response:

a) APS is in the process of updating the base fuel and purchased power pro forma adjustment and will provide it upon its completion. We anticipate having this update available at the Rate Case Technical Conference on October 27, 2011.

b)

1) Please see PME_WP2, page 1 of 3, for the test year amounts of nuclear ISFSI amortization excluded from the base fuel rate.

2) Please see PME_WP2, page 1 of 3, for the test year amounts of coal reclamation costs excluded from the base fuel rate.

3) Please see PME_WP5, page 2 of 7, for the amount of gas fuel expense associated with long-term tolling arrangements included in the base fuel rate.

4) Please see PME_WP5, page 2 of 7, for the current contract cost vs. market value of the native load power hedges (labeled "SE06 Hedge MTM") included in the base fuel rate.

Witness: Pete Ewen

ARIZONA CORPORATION COMMISSION
STAFF'S TWENTY SECOND SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
OCTOBER 14, 2011

Response to Staff 22.9 continued:

5) Please see PME_WP5, page 2 of 7, for the amount of fixed capacity contract costs (labeled "Demand Cost" or "Demand") included in the base fuel rate.

6) Please see PME_WP5, page 2 of 7, for the amount of above market purchases of renewable energy that are recovered through RES (labeled "Above-Market Premiums") included in the base fuel rate.

7) Please see APS14923, attached.

Renewable MWH
Additional Detail from PME_WP5 page 1

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2012
ARAGONNE WIND	26,655	19,714	25,153	25,376	25,825	17,795	15,731	13,583	18,120	20,955	23,457	29,622	261,986
Perrin Ranch Wind	26,000	22,256	28,689	31,070	28,221	23,986	16,400	16,999	19,896	21,865	25,603	21,946	282,931
HIGH LONESOME WIND	30,453	25,388	35,367	32,202	22,207	20,409	12,528	13,774	20,498	23,437	25,186	30,030	291,480
Subtotal Wind (PPA)	83,108	67,358	89,209	88,648	76,253	62,191	44,659	44,356	58,513	66,257	74,246	81,598	836,396
Saguaro Solar	131	116	117	183	177	248	242	233	213	164	129	67	2,020
APS Solar	689	673	840	848	864	809	752	752	753	771	695	684	9,130
AZ Sun Gila Bend	2,608	2,907	4,063	4,742	5,295	5,353	4,647	4,204	3,907	3,429	2,753	2,541	46,448
AZ Sun Chino	2,741	2,859	4,337	5,041	5,985	5,988	4,761	4,224	4,237	3,676	2,902	2,494	49,246
AZ Sun Hyder	2,545	2,786	3,995	4,457	5,047	5,068	4,527	4,124	3,807	3,347	2,677	2,378	44,759
AZ Sun Paloma	3,033	3,029	3,723	3,875	4,116	3,960	3,657	3,544	3,472	3,420	3,010	2,858	41,697
Subtotal Company Owned Solar	11,748	12,369	17,075	19,146	21,484	21,426	18,586	17,082	16,390	14,807	12,165	11,023	193,300
Solar PV Ajo	833	813	1,014	1,025	1,045	978	908	909	910	931	840	826	11,031
Solar PV Prescott	2,062	2,013	2,512	2,537	2,587	2,421	2,250	2,251	2,253	2,307	2,079	2,047	27,318
SolPV Fut RFP 1	4,151	4,053	5,057	5,108	5,207	4,873	4,529	4,531	4,535	4,643	4,185	4,120	54,994
SolPV Fut Small 1	4,981	4,863	6,069	6,130	6,249	5,848	5,435	5,437	5,442	5,572	5,023	4,945	65,993
SolPV Fut Small 2	4,981	4,863	6,069	6,130	6,249	5,848	5,435	5,437	5,442	5,572	5,023	4,945	65,993
Subtotal Solar (PPA)	17,009	16,606	20,721	20,930	21,335	19,968	18,556	18,565	18,583	19,026	17,149	16,883	225,331
Geothrml CE-Turbo (PPA)	6,636	6,208	6,637	6,422	6,636	6,423	6,636	6,636	6,423	6,636	6,422	6,636	78,354
Biomass Snowflake	7,336	6,863	7,337	7,099	7,336	7,100	7,336	7,336	7,100	7,336	7,099	7,336	86,613
Landfill Surprise	1,921	1,602	1,879	1,790	1,927	1,743	1,898	1,926	1,765	1,895	1,801	1,906	22,054
Landfill Glendale	1,771	1,656	1,771	1,714	1,771	1,714	1,771	1,771	1,714	1,771	1,714	1,771	20,906
Subtotal Biomass (PPA)	11,027	10,121	10,987	10,603	11,033	10,557	11,005	11,033	10,579	11,002	10,614	11,013	129,573
Renewables Total	**129,528**	**112,662**	**144,629**	**145,749**	**136,742**	**120,563**	**99,443**	**97,672**	**110,488**	**117,728**	**120,597**	**127,152**	**1,462,954**

ARIZONA CORPORATION COMMISSION
STAFF'S THIRTY FIRST SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
NOVEMBER 4, 2011

Staff 31.1: Transmission Cost Adjustment (TCA).

a) Please confirm that APS has included all costs associated with transmission in the ACC jurisdictional cost of service in the current base rate revenue requirement determination. If this cannot be confirmed, explain fully why not, and identify the amounts of the transmission cost of service that would need to be reflected in the base rate revenue requirement.

b) Please confirm that APS has treated its proposed modification to the TCA mechanism solely as a rate design issue in the current case, such that (1) if APS' proposed TCA is adopted, the remaining ACC jurisdictional base rate revenue requirement would be the $2.835 billion shown on Schedule H-2, column G; and (2) if the currently existing TCA remains in place, the ACC jurisdictional base rate revenue requirement would be the $2,964,351,000 amount shown on Schedule H-2, column I. If this cannot be confirmed, explain fully why not and provided the related dollar amounts.

c) Please confirm that, as reflected in APS' filing, if the existing TCA is continued, the ACC jurisdictional base rate revenue increase being proposed by APS is the sum of the $95.493 million on Schedule H-2, column J, line 42, and the $129.301 million on Schedule H-2, column H, line 42. If this cannot be confirmed, explain fully why not and provide the amount of base rate revenue increase sought by APS if the existing TCA remains in place (rather than the revised TCA APS has requested).

d) To the extent that any portions of parts a, b and c, are not confirmed by APS, and alternative amounts or results are identified in APS' explanations to those requests, please include all related workpapers and Excel files related to such alternative amounts and results.

Response:

a) The Cost of Service Study assigns all transmission cost components to the "All Other" Column (non-ACC Jurisdiction) and equates retail OATT charges to revenues. The ACC jurisdictional OATT charges are identified in Attachment APS14993.

b) APS confirms both positions. See Attachment APS14993.

Witness: Zachary J. Fryer

ARIZONA CORPORATION COMMISSION
STAFF'S THIRTY FIRST SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
NOVEMBER 4, 2011

Response to Staff 31.1 Continued:

c) The ACC jurisdictional base rate revenue increase is $95.493 million. The $129.301 million represents the OATT charges/revenues that are embedded in present base revenues. The inclusion of $129.301 million in base revenues results in total revenue of $2,964,351,000. Total revenue of $2,964,351,000 results in a base rate revenue increase of $95.493 million, not the sum of $95.493 million and $129.301 million. See Attachment APS14993.

d) See Attachment APS14993.

ARIZONA PUBLIC SERVICE COMPANY
Transmission Cost Adjustment
ACC Jurisdiction
STF 31.1

Test Year Ending 12/31/2010
(Thousands of Dollars)

Line No.	Description			Source Reference			
	A. Cost of Service Study Detail						
1.	Ancillary Services	$	22,674	ZJF_WP1	Page 61 of 92	Line 7	Column (2)
2.	Plus: Network Integrated Transmission Service & Scheduling	$	163,470	ZJF_WP1	Page 61 of 92	Line 29	Column (2)
3.	Total OATT Charges (L1 + L2)	$	186,144				
4.	TCA Surcharge Proforma	$	(56,843)	ZJF_WP1	Page 49 of 92	Line 24	Column (2)
5.	Total OATT Charges in Base Revenues (L3 + L4)	$	129,301	ZJF_WP3	Page 4 of 60	Line 24	Column (Transmission and Ancillary Services)
				Schedule H-2	Page 1 of 1	Line 42	Column (H)
	B. Revenue Requirement Reconciliation						
6.	Present Base Revenues	$	2,868,858	Schedule A-1	Page 1 of 1	Line 18	
				Schedule H-2	Page 1 of 1	Line 42	Column (E)
7.	Proposed Rate Increase	$	95,493	Schedule A-1	Page 1 of 1	Line 10	
				Schedule H-2	Page 1 of 1	Line 42	Column (J)
8.	Total Proposed Base Revenues (L6 + L7)	$	2,964,351	Schedule H-2	Page 1 of 1	Line 42	Column (I)
				ZJF_WP3	Page 5 of 60	Line 24	Column (Total)
9.	Total OATT Charges in Base Revenues (L5)	$	129,301	ZJF_WP3	Page 4 of 60	Line 24	Column (Transmission and Ancillary Services)
				Schedule H-2	Page 1 of 1	Line 42	Column (H)
10.	Total Proposed Base Revenues Excluding OATT Base Revenues (L8 - L9)	$	2,835,050	Schedule H-2	Page 1 of 1	Line 42	Column (G)
11.	Total Proposed Base Revenues With Total OATT Charges (Base and TCA Surcharge) (L10 + L3)	$	3,021,194				

ARIZONA CORPORATION COMMISSION
STAFF'S TWENTY EIGHTH SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
OCTOBER 27, 2011

Staff 28.1: Service Schedule 1: Referring to Service Schedule - 1 (see Attachment CAM-12 Page 2 of 19), please fully explain and provide supporting documentation to show that the items listed have been evaluated in light of the Company's implementation of AMI. For example, Overhead Reconnection Charge is proposed to be $96.50 per reconnection. Please explain and provide documentation that shows that all charges are still appropriate after implementing AMI. Please provide an explanation and support for the charges listed for all items listed on Service Schedule 1.

Response: The supporting documentation for the Schedule 1 charges is provided as APS14992. This information is the historical 2002 Test Year cost information, which supports the current charges, with the exception of 'after hours trip charge' that was approved based on a September 30, 2005 Test Year.

The cost reductions associated with AMI and other cost impacts related to Schedule 1 are included in the test year revenue requirements, which are in turn reflected in the Company's proposed base rates.

Because Schedule 1 revenue is credited against revenue requirements in the rate making process, any reductions in Schedule 1 charges (and revenue) to reflect AMI or other cost impacts would require an increase in base rates by a like amount, in order to recover the test year revenue requirements.

The supporting documentation for the Schedule 1 charges in the 2010 Test Year is provided as APS14994. APS is not proposing to change any of the Schedule 1 charges in this proceeding. Instead, the Company proposes to revise them in a future rate case when AMI is fully deployed.

Witness: Charles A. Miessner

Service Schedule 1, Costs and Charges
Historic Cost and Charge Information
(Hourly Wage Rates are for 2002)

Type of Service				Section	Job Code Performing Task	Number of Employees	Avg. Time (Straight Time Hrs)	Avg. Time (Overtime Time Hrs)	Overtime Rate	Hourly Wage Rate	Direct Payroll Expense	Allowed Time Load	Benefits & PR Tax Load	Transportation Load	Call Center	Other Expenses	Total Expense		Current Charge
Service establishment charge	Residential		Regular Hours	2.2	009242	1	0.25			$23.50	$5.88	$1.18	$2.65	$1.16	$4.33		$15.19		$25.00
			After Hours	2.2.1	009241 / 009242	1		2.00	1.5	$23.44	$70.33	$0.00	$4.92	$11.55	$4.33		$91.13		$75.00
	Non-residential	Single phase	Regular Hours	2.2	009241 / 009242	1	0.25			$23.44	$5.86	$1.17	$2.64	$1.15	$4.33		$15.16		$25.00
			After Hours	2.2.1	009241 / 009242	1		2.00	1.5	$23.44	$70.33	$0.00	$4.92	$11.55	$4.33		$91.13		$75.00
		Three phase	Regular Hours	2.2	009560	1	0.25			$28.66	$7.16	$1.43	$3.23	$1.41	$4.33		$17.57		$35.00
			After Hours	2.2.1	009560	1		2.00	1.5	$28.66	$85.97	$0.00	$6.02	$14.12	$4.33		$110.43		$75.00
Direct Access Service Request				2.3	044681	1	0.32			$28.06	$8.89	$1.78	$4.01				$14.67		$10.00
Dishonored payment fee				4.4.1	034401 / 034402	1	0.02			$15.77	$0.32	$0.06	$0.14		$1.70	$3.00	$7.15		$15.00
					034402	1	0.07			$16.71	$1.17	$0.23	$0.53						
Field Call Charge to: accept payment, notify of service termination, make payment arrangement, terminate service				4.5	034401 / 034402	1	0.33			$15.77	$5.21	$1.04	$2.35	$1.03	$1.70		$11.32		$16.00
Reconnection charge	Overhead		Regular Hours	4.5.1	009263	1	2.00			$24.81	$49.62	$9.92	$22.38	$9.78	$4.33		$96.03		$96.50
			After Hours	2.2.1	009263	1		2.00	1.5	$24.81	$74.43	$0.00	$5.21	$12.22	$4.33		$96.19		$96.50
	Underground		Regular Hours	4.5.1	009835	1	2.00			$29.82	$59.63	$11.93	$26.90	$11.75	$4.33		$114.54		$115.00
			After Hours	2.2.1	009241 / 009242	1		2.00	1.5	$23.44	$70.33	$0.00	$4.92	$11.55	$4.33		$91.13		$115.00
	Normal (At Meter)		Regular Hours	4.5	009835	1	0.25			$29.82	$7.45	$1.49	$3.36	$1.47	$4.33		$18.11		N/A
			After Hours	2.2.1	009241 / 009242	1		2.00	1.5	$23.44	$70.33	$0.00	$4.92	$11.55	$4.33		$91.13		N/A
On site evaluation - reduce energy use				4.6	031763	1	1.50			$27.28	$40.91	$8.18	$18.45	$8.06	$6.37		$81.98		N/A
Lease of meter lock ring key				6.2.2		1					$0.00	$0.00	$0.00	$0.00		$70.00	$70.00		$70.00
Joint site meeting to: remove APS metering equipment / lock ring	Metro area, per visit base fee			6.2.3	009560	1	0.58			$28.66	$16.62	$3.32	$7.50	$3.27			$30.72		$62.00
	Other areas, per visit base fee			6.2.3	009560	1	1.75			$28.66	$50.15	$10.03	$22.62	$9.88			$92.68		$62.00
	Additional fee for visits that exceed 30 minutes, change to hourly rate			6.2.3	009560	1	1.00			$28.66	$28.66	$5.73	$12.93	$5.65			$52.96		$53.00
Meter rereads				6.4.4	009517	1	0.25			$21.93	$5.48	$1.10	$2.47	$1.08	$6.37		$16.50		$16.50
Meter testing - if meter is found w/in +/- 3%	1 Phase	Field Tested	Kwh	6.5	009561	1	1.70			$24.71	$42.00	$8.40	$18.95	$8.28	$6.37		$83.99		$50.00
			Kw (& Kwh)		009561	1	3.20			$24.71	$79.06	$15.81	$35.66	$15.58	$6.37		$152.48		$50.00
		Shop Tested	Kwh		009241 / 009242	1	0.25			$23.44	$5.94	$1.19	$2.68	$1.17	$6.37		$21.15		$30.00
					009561	1	0.08			$24.71	$2.06	$0.41	$0.93	$0.41					
			Kw (& Kwh)		009241 / 009242	1	0.25			$23.44	$5.94	$1.19	$2.68	$1.17	$6.37		$29.52		$30.00
					009561	1	0.27			$24.71	$6.59	$1.32	$2.97	$1.30					
	3 Phase or CT	Field Tested	Kwh		009560	1	1.70			$28.66	$48.71	$9.74	$21.97	$9.60	$6.37		$96.40		New
			Kw (& Kwh)		009560	1	2.20			$28.66	$63.04	$12.61	$28.44	$12.42	$6.37		$122.87		New
		Shop Tested	Kwh		009560	1	0.57			$28.66	$16.24	$3.25	$7.32	$3.20	$6.37		$46.97		New
					009560	1	0.20			$28.66	$5.73	$1.15	$2.59	$1.13					
			Kw (& Kwh)		009560	1	0.57			$28.66	$16.24	$3.25	$7.32	$3.20	$6.37		$56.68		New
					009560	1	0.38			$28.66	$10.98	$2.20	$4.95	$2.16					
Fee for duplicate bills, statement of accounts, screen prints, etc.				4.7	034401	1	0.02			$13.70	$0.27	$0.05	$0.12			$0.37	$0.82		N/A
Trip Charge				2.2	009242	1	0.25			$23.50	$5.88	$1.18	$2.65	$1.16	$4.33	$0.37	$15.56		$16.00

Service Schedule 1, Costs and Charges
Test Year 2010

Type of Service			Service Schedule 1 Section	Job Title	Non-AMI Avg. Time (Straight Time Hrs)	Non-AMI Avg. Time (Overtime Time Hrs)	AMI Avg. Time (Straight Time Hrs)	AMI Avg. Time (Overtime Time Hrs)	Hourly Wage Rate	Total Hourly Cost	Non-AMI Unit Cost	AMI Unit Cost	Non-AMI Unit Cost	AMI Unit Cost	Average Unit Cost		Current Charge
													57%	43%			
Service Establishment Charge	Residential	Regular Hours	2.2	Customer Svmn B 2-6	0.25		0.00		$30.84	$57.65	$14.41	$0.00	$17.61	$4.80	$12.10		$25.00
				Cust Assoc I-III avg.	0.10		0.15		$17.13	$32.03	$3.20	$4.80					
		Trip Charge	2.2.1	Customer Svmn B 2-6	0.25				$30.84	$57.65	$14.41	$0.00	$14.41	$0.00	$8.21		$16.00
		Same Day	2.2.3	Customer Svmn B 2-6		2.00			$30.84	$55.10	$110.20	$0.00	$115.65	$5.45	$68.26		$75.00
				Cust Assoc I-III avg.	0.17		0.17		$17.13	$32.03	$5.45	$5.45					
		After Hours	2.2.2	Customer Svmn B 2-6		2.00			$30.84	$55.10	$110.20	$0.00	$115.65	$5.45	$68.26		$75.00
				Cust Assoc I-III avg.	0.17		0.17		$17.13	$32.03	$5.45	$5.45					
		Waived Svc Est Charge	2.2.5	N/A													
		Re-Establishment	2.2	Customer Svmn B 2-6	0.25				$30.84	$57.65	$14.41	$0.00	$19.86	$5.45	$13.66		$25.00
				Cust Assoc I-III avg.	0.17		0.17		$17.13	$32.03	$5.45	$5.45					
	Non-residential - Self Contained and Three Phase	Regular Hours	2.2	Mtrmn Elec Polyphase	0.33		0.33		$37.61	$70.31	$23.20	$23.20	$29.82	$29.82	$29.82		$35.00
				Business Associate	0.17		0.17		$20.83	$38.93	$6.62	$6.62					
		Trip Charge	2.2.1	Mtrmn Elec Polyphase	0.33		0.33		$37.61	$70.31	$23.20	$23.20	$23.20	$23.20	$23.20		$16.00
		Same Day	2.2.3	Customer Svmn B 2-6		2.00			$30.84	$55.10							$75.00
		Meter Crew Service Charge	2.2.4	N/A													$0.00
		After Hours	2.2.2	Mtrmn Elec Polyphase		2.00		2.00	$37.61	$67.19	$134.38	$134.38	$141.00	$141.00	$141.00		$75.00
				Business Associate	0.17		0.17		$20.83	$38.93	$6.62	$6.62					
		Re-Establishment	2.2	Mtrmn Elec Polyphase	0.33		0.33		$37.61	$70.31	$23.20	$23.20	$29.82	$29.82	$29.82		$35.00
				Business Associate	0.17		0.17		$20.83	$38.93	$6.62	$6.62					
	Direct Access Service Charge		2.3	N/A													$10.00
Billing & Collection	Electronic Bill Pay		4.3.3	N/A									($0.40)	($0.40)	($0.40)		($0.48)
	Late Charge		4.2.1	N/A													18%
	Dishonored Payments		4.4.1	Cust Assoc I	0.07		0.07		$14.68	$27.44	$1.92	$1.92	$5.19	$5.19	$5.19		$15.00
				Cust Assoc II	0.02		0.02		$16.51	$30.86	$0.62	$0.62					
				Cust Assoc III	0.07		0.07		$20.22	$37.80	$2.65	$2.65					
	Field Call		4.5.1	Cust Assoc I	0.07		0.07		$14.68	$27.44	$1.92	$1.92	$14.39	$14.39	$14.39		$15.00
				Cust Assoc III	0.33		0.33		$20.22	$37.80	$12.47	$12.47					
	Reconnection	At the pole	4.5.2	Elec Svmn Metro Th	1.00		1.00		$32.56	$60.87	$60.87	$60.87	$66.32	$66.32	$66.32		$96.50
				Cust Assoc I-III avg.	0.17		0.17		$17.13	$32.03	$5.45	$5.45					
	Reconnection	Underground	4.5.2	Troublemn Mtro	1.50		1.50		$40.99	$76.63	$114.95	$114.95	$120.40	$120.40	$120.40		$115.00
				Cust Assoc I-III avg.	0.17		0.17		$17.13	$32.03	$5.45	$5.45					
Metering & Metering Equipment	Lease of meter lock ring key		6.2.2	N/A													$70.00
	Joint site meeting for removal of metering & associated equipment and/or lock ring		6.2.3	Mtrmn Elec Polyphase	1.11		1.11		$37.61	$70.31	$78.04	$78.04	$78.04	$78.04	$78.04		$62.00
	Additional fee for visits that exceed 30 minutes		6.2.3						$0.00								$53.00
	Meter Rereads	Company is the MRSP	6.4.4	Cust Assoc I-III avg.	0.25		0.25		$17.13	$32.03	$8.01	$8.01	$8.01	$8.01	$8.01		$16.50
	Meter Rereads	*ESP is the MSP or MRSP*	6.4.5	Cust Assoc I-III avg.	0.25		0.25		$17.13	$32.03	$8.01	$8.01	$8.01	$8.01	$8.01		$0.00
	Meter testing if meter is found w/in +/- 3%	Field Tested - single phase	6.5	Mtrmn Elec Sl Ph	1.00		1.00		$32.42	$60.61	$60.61	$60.61	$68.62	$68.62	$68.62		$50.00
				Cust Assoc I-III avg.	0.25		0.25		$17.13	$32.03	$8.01	$8.01					
		Shop Tested - single phase	6.5	Mtrmn Elec Sl Ph	0.45		0.45		$32.42	$60.61	$27.27	$27.27	$35.28	$35.28	$35.28		$30.00
				Cust Assoc I-III avg.	0.25		0.25		$17.13	$32.03	$8.01	$8.01					
		Field Tested - three phase	New	Mtrmn Elec Polyphase	2.00		2.00		$37.61	$70.31	$140.62	$140.62	$150.35	$150.35	$150.35		N/A
				Business Associate	0.25		0.25		$20.83	$38.93	$9.73	$9.73					
		Shop Tested - three phase	New	Mtrmn Elec Polyphase	0.45		0.45		$37.61	$70.31	$31.64	$31.64	$41.37	$41.37	$41.37		N/A
				Business Associate	0.25		0.25		$20.83	$38.93	$9.73	$9.73					

BEFORE THE ARIZONA CORPORATION COMMISSION

GARY PIERCE
Chairman
BOB STUMP
Commissioner
SANDRA D. KENNEDY
Commissioner
PAUL NEWMAN
Commissioner
BRENDA BURNS
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	)	DOCKET NO. E-01345A-11-0224

DIRECT

TESTIMONY

OF

W. MICHAEL LEWIS, P.E.

ON BEHALF OF THE

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

NOVEMBER 18, 2011

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EXECUTIVE SUMMARY
ARIZONA PUBLIC SERVICE COMPANY
DOCKET NO. E-01345A-11-0224

The Direct Testimony of W. Michael Lewis of W. M. Lewis and Associates, Inc. provides the results of engineering investigations of Arizona Public Service Company ("APS" or "Company") as authorized by the Arizona Corporation Commission ("Commission") pursuant to requests and direction from the Commission's Utility Division Staff ("Staff"). The engineering investigations were undertaken by Mr. Lewis and Mr. Strobl of Technical Associates, Inc. Field inspections of selected facilities and technical projects under the direction and operation of the Company in Arizona, as well as reviews and analyses of the APS Application and other APS documentation comprised the engineering investigations for this case.

The inspections and reviews were performed by Messrs. Lewis and Strobl on September 26 through September 29, along with Mr. Prem Bahl of Staff on September 26, and included discussions with APS technical, management, and systems operations personnel. Data requests to APS regarding performance indices, maintenance practices and design standards, and the in-service status of construction and design projects were also prepared and submitted to APS. Within the construction and design projects requested by APS for inclusion in rate base in this case, the AZ Sun solar projects were of particular interest because of their recent (or eminent) in-service dates, and that they represented significant capital expenditures. The Company's responses to data requests, our face-to-face meetings with APS personnel, and observations during the field investigation, formed the bases for the discussions, conclusions and recommendations set forth in this direct testimony.

The principle elements of the engineering investigations focused on APS' service quality, system reliability indices, and the maintenance and operation of selected generation and distribution facilities currently in-service or as is the case with solar facilities are under construction and expected to be in-service as part of APS' proposed utility plant investment additions being requested for inclusion in rate base. APS proposed many individual plant investment projects within Solar Generation, Fossil Generation, Nuclear Generation, and Distribution/General/Intangible categories. APS supported its request for the inclusion of these plant investments in rate base claiming that these post-test year investments have been or will be placed in-service by June 30, 2012. Our objectives during our field investigations were to observe some of these projects and discuss these, and other aspects of APS operations, with the personnel responsible for the development and/or management of projects and operations.

Quality of Service/System Indices. The information provided by APS in responses to data requests, and in meetings with responsible APS personnel, addressed electric service reliability and quality measures consisting of Customer Average Interruption Duration Index ("CAIDI"), System Average Interruption Duration Index ("SAIDI") and System Average Interruption Frequency Index ("SAIFI"). These are the three (3) indices most commonly reported to express electric system reliability. These electric utility records, determinations and reported information on reliability and outage events when taken together provide the metrics

regarding electric system reliability measured by the duration and frequency of power interruptions to the average customer.

The reported values for CAIDI, SAIDI, and SAIFI provided by APS for the period 2008 through June 2011 indicate improvements in all of the indices. APS needs to continue its current practices of data collection of outage frequencies and the durations and analyses of these parameters. APS personnel with whom we met place a high degree of effort in their monitoring outages, causes and durations, and the customers affected. APS' continued utilization of its Distribution Outage Management System ("DOMS") should enhance these efforts as well.

Facilities Investment/In-Service Operations. The field investigation included observing underground cable installations and discussions with APS personnel regarding APS' underground cable program of replacing older but not necessarily failed cables. While such a program may be laudable, the annual expenditures are significant. Accordingly, there needs to be some triggering guidelines and/or criteria, such as the replacement of the oldest cables first, cables with one or more previous repairs, previous faults, etc. in order to justify the expenditures for this underground cable replacement program.

APS post-test year Fossil Generation category included substantial expenditures at the Redhawk generation station related to equipment replacement and overhaul work. APS' proposed work was essentially completed at the time of our visit on September 28, which consisted of essentially all vendor recommended overhauls and maintenance on a four (4) year schedule. There was a fairly unique vibration problem with the steam-side generator that we were made aware of at our visit. With regard to this vibration problem, the unit should be replaced or the vibration problem rectified in a timely manner.

A significant aspect of our field investigations included visits to the solar generation facilities that are part of the post-test year investment additions requested for rate base inclusion; i.e., utility-scale and customer installed photovoltaic projects. The APS utility-scale AZ Sun projects (Paloma, Cotton Center and Hyder) are in Gila Bend, Arizona. The customer installed photovoltaic projects are in Flagstaff, Arizona associated with the Schools and Government Program ("S&G Prorgram") and the Community Power Project ("CPP").

APS utility-scale photovoltaic generation stations are, or will, be remotely monitored facilities, with routine and fault correction maintenance work being done by APS crews stationed in the vicinity of the projects.

The S&G Program and CPP projects are basically undertakings in the form of a fairly long-term study of the potentials of distributed generation, mainly solar, integrated into a discrete service area. The results of these projects should be portable in that they can develop strategies for future applications in other parts of the APS system; i.e., this experience will be of significant benefit when such features are installed in other areas of the APS service territory.

AMR/Advanced Metering. The new electronic meters being installed by APS have no moving parts and presumably have been suitably selected for the ambient temperatures and weather conditions of the APS service area. Absent any authoritative studies to the contrary,

there is no reason that these meters should have a reduced service life from 26 years to 15 years compared to the older meters as proposed by APS.

Liberty Group Issues. There were three (3) issues identified in the Liberty Consulting Group APS Benchmarking Analysis ("Liberty Study") relating to the operations of APS' Palo Verde nuclear facility, the performance of APS' Four Corners coal-fired generating facility, and the sustainability/emission control problems at the Four Corners facility. APS needs to address the low availability of the Palo Verde units and the above-average refueling outages in its Palo Verde Nuclear Performance Reporting Standard ("NPRS") which was developed in the Commission's Docket No. E-01345A-09-0506 proceeding.

With respect to the issues at the APS Four Corners generation station, APS needs to provide a plan and explain how it intends to address the NOx emissions and forced outages, as well as their intentions related to the purchase of the balance of the ownership in Units 4 and 5.

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is William Michael Lewis. My business address is 934 Valley Street, Wheelersburg, Ohio 45694.

Q. What is your present employment?

A. I am employed by the firm of W. M. Lewis and Associates, Inc. ("WML&A"). I am the President of the firm.

Q. Please describe the nature of the firm.

A. WML&A is a Consulting Engineering firm which provides various engineering services, primarily in areas of electrical power and electric utility operation, to a range of clients including investor-owned electric utilities, municipal utilities, international investment organizations, and regulatory bodies. The firm was established in 1958.

Q. Please describe your background, education, and experience.

A. I have been employed by WML&A since 1979. Prior employment was with Goodyear Atomic Corp. and Westinghouse Electric. Positions that I have held at WML&A include Sr. Engineer, Manager of Engineering, Vice-President, and President. I hold a BSEE degree from Ohio State University and an MBA from Ohio University. For the past 15 years, much of my work has involved foreign assignments on behalf of the Asian Development Bank and World Bank in project post-evaluation, feasibility studies, and reviews of operation and maintenance of various generating stations, urban and rural transmission and distribution systems, and utility management. Additional tasks included the design of facilities and preparation of agreements for the interconnection of utilities, preparing operating agreements between utilities and independent power producers, and

various tasks related to the privatization of electric utilities in the South Asian area. Additional aspects of my experience and education are presented in my resume, which is attached to this testimony as Attachment 1.

Q. Are you filing Direct Testimony on behalf of Arizona Corporation Commission ("Commission") Utilities Division Staff ("Staff")?

A. Yes.

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

A. My testimony describes and presents evaluations, observations and recommendations regarding the above captioned matter. I was to evaluate the service quality and reliability of the distribution system, review some issues that were identified in the December 31, 2010 Liberty Consulting Group APS Benchmarking Analysis ("Liberty Study") of the Company's operational and cost performance, and observe and evaluate the status of some of the major items of investment proposed for post test year inclusion into rate base.

Q. What is the major focus of your evaluations?

A. The major focus of my evaluations was field investigations of Arizona Public Service Company ("APS" or "Company") facilities throughout Arizona. Field investigations were made on September 26 through September 29 by myself and Kenneth C. Strobl of Technical Associates, Inc. and were coordinated and accompanied by APS personnel. Mr. Prem Bahl of the Commission Staff accompanied us as well on September 26.

Schedule 1, consisting of four (4) pages, provides a summary of APS' plant investment facilities and various projects that were observed in our field investigation. In addition to

listing the facilities and projects, Schedule 1 provides APS' estimated costs related to each of the facilities and projects observed and discussed with APS personnel.

The purpose of these field investigations was two-fold. First was to visit and review a number of the major construction projects included in the as-filed $986.8 million of total gross post-test year plant investment additions that the Company is requesting be included in Rate Base in this case. And second was to discuss with APS personnel these projects and the other influences on the current and projected quality of electrical services to APS customers.

Q. Please describe the major elements of your investigations.

A. The major elements of our investigations are directed at APS' service quality, distribution system indices, and the construction and operations of selected generation, distribution, and other plant facilities currently in-service and/or expected to be in-service in the next few months, and thereafter. The field investigations and reviews of project developments included discussions with APS engineering, linemen, electricians, and other technical personnel in charge of, or participating in, the construction, operations, and development of network facilities and network monitoring systems. In addition to these field activities, we reviewed portions of APS' prefiled Application and testimony in this case, as well as public documents such as APS' Federal Energy Regulatory Commission ("FERC") Form No. 1, and Institute of Electrical and Electronics Engineers ("IEEE") service quality reports. We also prepared data requests to the Company that addressed service quality and distribution system indices, and construction work in progress ("CWIP") plant investments that are proposed by APS for inclusion in Rate Base in this case, and reviewed APS' responses to such data requests.

Q. What are the impacts of your efforts on behalf of Staff?

A. The field investigations, the discussions with APS personnel, the reviews and analyses of APS filed testimony and documentation in this case, and public documents provided some perspective and understanding of the Company's installations and operations of its electric network facilities and monitoring systems in APS' five (5) operating districts in Arizona. The remainder of this testimony discusses these observations and evaluations, and provides some recommendations for the Commission's consideration regarding these matters. This testimony also contains comments regarding the capabilities of the APS personnel we met in our field visits that are charged with ensuring that facilities and systems are safe, reliable, and operate in an effective manner to meet the electrical service needs of APS customers.

Q. Please discuss the Company's current CWIP investments and its requests in this case.

A. APS's Schedule B-2 of its Application lists the post-test year gross utility plant investment additions being requested for inclusion in rate base in this case. As shown in Schedule B-2, the gross utility plant additions as filed are separated as follows:

Category	($ Millions) Total Company	ACC Jursidictional
Solar Generation	$277.411	$267.979
Fossil Generation	156.269	150.956
Nuclear Generation	120.103	116.019
Distribution/General/Intangible	432.984	423.910
TOTALS	$986.767	$958.864

There are many individual projects within the above categories. The listing of the individual projects under each of the above categories was provided by APS in response to Staff's Sixth Set of Data Requests (STF 6.55). This is the APS supplemental response on September 22, 2011, providing actual data through July 31, 2011. Based on the supplemental response to Staff 6.55, the gross utility plant additions are revised as follows:

Category	($ Millions) Total Company	ACC Jursidictional
Solar Generation	$260.765	$251.899
Fossil Generation	154.606	149.350
Nuclear Generation	111.397	107.609
Distribution/General/Intangible	422.758	413.898
TOTALS	$949.526	$922.756

Q. What topics and issues are addressed in this testimony?

A. The following general topics and issues are addressed in this testimony:

(1) Quality of Service/Distribution Indices --- reflects the evaluations of the operational quality and electric service performance satisfaction provided to APS customers;

(2) Facility Investment and In-Service Operations --- relates to the Company's requested inclusion of new construction and replacement of generation and distribution system components;

(3) System Monitoring Plans and Project Investments --- addresses such topics as the development and implementation of APS' Distribution Outage Management System ("DOMS") and its "intelligent" network components included in a pilot project;

(4) Solar Systems --- relates to the planning, construction, and implementation of large scale utility-owned and customer specific solar photovoltaic projects; and,

(5) Liberty Issues---relating to some of the issues identified in the Liberty Study.

Although these topics and issues are addressed in this testimony, the collective scope of these topics to great to be addresses comprehensively. To do so would require substantially more time then is allotted by the schedule of this case. Moreover, in contrast to our review of plant investment projects in the last case (Docket No. E-01345A-08-0172), APS is proposing a far greater number of total projects within the requested additions to rate base. Additionally, there are not as many individual projects with large expenditures relative to the totals included in the list of post-test year dollars that APS is requesting to be included in rate base in this case.

Q. What is your general perspective of the operations of APS facilities and APS personnel that you have had an opportunity to witness in your field visit?

A. Generally speaking, the Company's plant facilities, network systems and operations appear to reflect thoughtful planning, and appear to be effectively utilized and maintained. The Company's operating practices, including its preventative maintenance planning and outage response practices, which use newly developed software support; e.g., DOMS, as well as the technical personnel involved, are of an acceptable level and of high quality.

II. WORK EFFORT AND EVALUATIONS

Q. Please describe your evaluations and the role of your field investigations in these evaluations.

A. Our work effort commenced with reviews and analyses of APS' Application and filed testimony in this proceeding. To supplement the information in APS' Application and prefiled testimony, we reviewed the Company's Annual Reports, FERC Form No. 1, as well as other documentation filed in support of its Application.

Additional information was acquired and analyses were made through APS' responses to data requests issued by Staff, most notably Staff Set No. Six (STF 6.1 through 6.59), APS' supplemental responses to STF 6.4, 6.33, and 6.55, and APS' response to Staff's Eleventh Set (Follow-up to Staff 6.30 and 6.48). Responses to Staff data requests (STF 6.46, 6.55 and Supplemental response to STF 6.55) address the Company's plant investment projects being requested for rate base, including a breakdown of the individual construction project investments and corresponding actual and estimated in-service dates for the projects in four (4) categories: Solar Generation; Fossil Generation, Nuclear Generation; and, Distribution, General and Intangibles. Staff data requests (STF 6.1, 6.2, 6.3, 6.10, 6.13, 6.37, 6.38, 6.41, 6.43, and 6.44) addressed the Company's calculations and claims

regarding its electric service reliability and quality, specifically evaluations of Customer Average Interruption Duration Index ("CAIDI"), System Average Interruption Duration Index ("SAIDI"), and System Average Interruption Frequency Index ("SAIFI").

A. Quality of Service/Distribution Indices

Q. What are the characteristics of SAIFI, SAIDI, and CAIDI and what is the basis for using these indices as an indication of system reliability?

A. Electric utilities record and report information on system reliability events using a variety of metrics which, taken together, provide a measure of electric system quality of service, as measured by the duration and frequency of power interruptions to the average customer. These three (3) indices are those most commonly reported to express reliability. The characteristics can be inferred by the descriptions above. SAIFI (on an annual basis) is the sum of the number of customers interrupted divided by the total number of customers served. SAIDI is the total of customer interruption durations (in minutes) divided by the total number of customers served. CAIDI is calculated as SAIDI/SAIFI which is an indication of the interruptions and duration of interruptions to the average customer on the system.

Q. You stated that one of the areas in your evaluation was that of the reliability of APS' distribution system. How is this evaluated?

A. Distribution reliability can be evaluated by the methodology of IEEE 1366, "Guide for Electric Power Distribution Reliability Indices". This method is followed by most of the investor-owned electric utilities in the USA as well as most of the larger Municipal and Federal agency utilities.

Q. Are the results of other utilities published for comparison?

A. Yes. A majority of those utilities submit their results on an annual basis.

Q. How has APS' performance compared to other utilities in recent years?

A. APS has compared well over the past three calendar years in all three of the main indices. APS' performance for 2009-2010 would place them in the top ("best") 20-25 percent of reporting utilities of comparable size.

Q. What are the three indices you mentioned?

A. These are SAIFI, SAIDI, and CAIDI where the final "I" indicates "Index" in each case. The calculation of each is described by the aforementioned IEEE Guide.

Q. What type of system interruption is included in the calculation of these?

A. IEEE recommends that an interruption of more than 5 minutes time be counted as an interruption to be included in the calculation of the indices.

Q. Does APS follow the IEEE criteria?

A. Yes. In response to STF 6.1, APS stated its concurrence with the more than 5 minute threshold and provided the results of these three indices on an annual basis for Calendar Years 2008-2010 and for the initial 6 months of CY 2011.

Q. Are these indices based on all interruptions?

A. No. Common utility practice is to base these on "sustained interruptions" which are defined as those of five (5) minutes or more. APS employs this same time measure for its interruption evaluations, and separates its analyses of the indices among transmission, distribution, and substation initiated interruptions to customers.

Q. What has been the Company's recent performance and how does it compare with comparable electric utilities?

A. In response to a STF 6.1, the Company provided the values of the following indices:

Summary of APS Indice Values 2008-2011

	SAIFI	SAIDI (hr.)	CAIDI (hr.)
2008	0.95	1.47	1.55
2009	0.88	1.21	1.37
2010	0.92	1.33	1.44
2011 (All Data, As of 6/30/11)	0.27	0.40	1.48

The above values are those with major event days ("MEDs") excluded from the calculations of the values. There were no MEDs in 2011 through June 30.

Q. What is a MED?

A. An MED is a day or a portion of a 24 hour time period during which the service area is subjected to extreme or unusual conditions.

Q. Are MEDs then another consideration as to what constitutes an outage to be included in the calculation of these indices?

A. Yes. In addition to the five minute threshold, IEEE-1366 also defines various aspects of weather (storms, temperature variances, etc.) as designated MEDs. The indices are calculated on an annual basis (or for a given time period) with and without the outages occurring during MEDs. APS provided both sets of indices for the periods stated above.

Q. What can be said as to these results?

A. Considering the values of the indices, the comparison to the industry, and the general improvement in the values as indicated, APS has very good reliability in its distribution system. The most recent values provided for the period of January-June of 2011 (there were no MEDs during this period) are a SAIFI of 0.27, SAIDI of 0.4 Hr., and a corresponding CAIDI of 1.48 Hr. I would consider these values to be very acceptable, comparing these to the corresponding values (MEDS excluded) of CY 2008 where SAIFI was 0.95, SAIDI was 1.47 Hr., and a corresponding CAIDI was 1.56 Hr. The improvements in all of the three indices are apparent.

Q. You seem to be consistent in characterizing the CAIDI as "corresponding". Why is that?

A. By definition, CAIDI is equal to SAIDI divided by SAIFI; therefore, CAIDI corresponds to the values of the other two indices in the same time period. By inspection of the above values listed, one can see that numerically there was a comparatively large improvement in SAIFI and SAIDI between 2008 and 2011. These decreased to about 28 percent of the 2008 values. However, the CAIDI improvement was only about 5 percent (1.48/1.56 = 0.949). This is merely indicative of the manner of the calculations involved. It indicates that it can be difficult to significantly improve CAIDI and this is somewhat reflected in actual practice.

Q. Do you consider the relative ranking of a given utility's indices to determine if its distribution reliability performance is adequate?

A. No. On a prima-facie consideration, these determinations may be adequate but there are too many variances that, in my opinion, can make such an evaluation misleading. These include such considerations as the nature of a given utility's service area, the mix of radial versus networked feeders, the proportion of underground services and feeders, relative distances between service centers and fault locations, relative length of feeders, and lightning frequency, which is a minor consideration. The reporting and data collection quality across the reporting utilities can vary greatly.

Q. You have stated that you consider APS' distribution reliability to be "very good". What would you recommend that the Commission consider in future evaluations of this reliability and what actions on the part of APS do you think are appropriate at this point in time?

A. I would recommend that APS continue its present practices of data collection on outage frequency and duration and the analysis of these parameters. Our discussions with APS personnel responsible for these actions and the outage records provided to us indicated that APS does place a high degree of effort in monitoring outages, causes, and durations as well as the number of customers affected. The present incorporation of the DOMS (discussed later) will enhance these efforts.

Furthermore APS personnel responsible for the reliability monitoring should determine a set of (for lack of a more descriptive term or terms) "Target Values" for SAIDI and SAIFI that will be maintained as a (targeted) minimum by APS, irrespective of their ranking in the reported industry results.

Q. What actions by APS can be said to have caused the recent improvements in the indices?

A. The more likely actions are probably the replacement of underground cable and the inspection and restoration of overhead feeders in the distribution system. Mr. Froetscher has alluded to these as well in his Direct Testimony.

Q. Do you agree with his assessment?

A. For the most part, yes. It is certainly clear that improvements to overloaded and/or deteriorated overhead circuits will reduce the number of outages. This is also true for aging underground cables with the added benefit that limiting failures in underground cables, which require longer durations to locate the fault and replace or repair the cable compared to an overhead circuit, reduces the duration of outages. This does improve the SAIDI and CAIDI.

B. Underground Cable Replacement Program

Q. Do you have any concerns about this program?

A. Yes. My concerns are the significant costs involved in the replacement of the underground cables compared to the benefits projected.

Q. Please explain.

A. It is known that the majority of the typical XLPE (8/15 KV class) cable installed for underground services by most electric utilities circa 1970-1985 have not had the expected service life. This is typically attributed primarily to two causes. The initial XLPE insulation was found to be susceptible to "treeing" from moisture and voltage stress, especially if directly buried, which caused tracking and voids in the insulation and corrosion of the bare neutral conductor by various properties of the earth covering. More

recently available cables are of the *TR*XLPE where the "tr" indicates "treeing resistant". This has been shown to have superior service life over that of earlier versions. APS is and has been installing this type of cable in new and replacement services.

Q. Please continue.

A. APS appears to have adopted as a standard the TRXLPE with covered neutral and increased insulation thickness (to a 21 kV rating) and abandoned direct burial in favor of conduit ducts. This should result in a significant reduction in failure rates and extended service life of the underground services.

Q. Based on the above, what is the problem with APS's program?

A. The problem, in my opinion, is that a major justification for APS' underground cable program of replacing older but not necessarily failed cables is to improve the value of the CAIDI. While laudable on the one hand, improvements in CAIDI can be one of diminishing returns in terms of expenditures.

Q. Why do you say that?

A. With the qualification that the replacement should also decrease the number of faults, an outage due to a cable fault still has a certain response time, time to locate the fault, and then the time to repair or replace the cable. So, the justification should be that of reducing the frequency of failures, i.e., SAIFI. This implies that criteria for the replacement of older cables should be determined based on the oldest cables first, cables with one or more previous repairs, previous faults, etc. Also, I would request that APS justify its use of 21 kV rated cables if, in fact, that is now APS' standard. I would like to see APS' response to this concern for criteria in its rebuttal. Established criteria may lead to a means of

reducing APS' projected annual expenditures by extending the underground cable replacement program over a longer period.

Q. Were you able to observe the inspection of overhead circuits and/or their rehabilitation?

A. We did observe a rehabilitation project where an older series of spans of wood pole construction was being replaced with new conductor and steel poles. The circuit had been identified as in need of replacement of the conductor due to previous overloading, and inspection demonstrated that the wood poles were at end-of-life. Using that observation of materials and workmanship, we were very satisfied with the criteria for replacement and the resulting improved circuit. Other observations of rehabilitated and replaced (due to storm damage) overhead circuits indicated to us that APS has high standards of construction and materials. We were not able to observe a survey of an overhead circuit in progress but discussions with APS personnel as to their method and criteria for replacement leads us to believe that this is properly performed.

C. IT Projects

Q. Earlier you mentioned the "DOMS". Please explain this acronym.

A. This is the "Distribution Operation Management System" which we had reviewed during its early phases of development during the previous rate proceedings. The system is currently implemented in most of the service area and should be fully implemented in early 2012 if not sooner with the move to the new building facility at Deer Valley. The system incorporates a computerized model of the distribution system down to individual service level and is presently used to support responses to outages by directing the response personnel to the location efficiently and to provide the respondents with circuit information as to the location of isolating switches, fuses, and probability analysis of the

likely cause of the outage and what customers are affected. It also aids in service restoration by correctly isolating the fault allowing (if possible) routing to other affected customers to be returned to service. In the future, DOMS will support Smart Grid and distribution SCADA systems with switching and other functions.

Q. So you can confirm the functionality of DOMS and find its projected in-service date as indicated by APS to be reasonable?

A. Yes.

Q. What concerns do you have with the function and/or costs of the DOMS?

A. I have no concerns as to the functionality of DOMS. I would expect that the system should produce a reduction in customer outage time but agree with Mr. Froetscher that that may be difficult to confirm. My concern is with the cost of DOMS. APS has expended substantial funds on its development and implementation. I believe that APS should now concentrate on developing its in-house abilities to maintain and update this system so as to minimize its further commitments to outside services, both hardware and software leasing and maintenance expenses.

Q. What other IT systems did you review?

A. I reviewed the conversion of paper "wall" maps to computer projections which is well under way and also should be implemented in early 2012 in the new facility. Given the condition of the existing maps and the reduced needs for storage, this appears to be a worthwhile and needed improvement. I have the same concerns as to this system as stated above for the DOMS, e.g., I recommend that APS reduce dependence on outside vendors for maintenance and modifications to software and hardware.

Q. Have you reviewed any proposed changes in the depreciation schedules as proposed by APS in this proceeding?

A. Our only consideration on this subject is the proposed change in the service life of the AMR and other advanced meters to 15 years as opposed to the 26 year schedule for the current meters. We are opposed to that change and recommend that the meter service life remain at 26 years.

Q. Why do you object to the reduction in service life?

A. There are basically two causes for meter end-of-life: Technological obsolescence and physical failure. The new electronic meters have no moving parts and are assumed to have been selected because they are suitable for the ambient temperature and weather conditions of the APS service area. Thus, absent any authoritative studies to the contrary, we see no reason that these meters should have a reduced life as compared to the older types. Technological advances, changes in parameters, telemetry protocol changes, and withdrawal of software support by the vendor may require some changes of circuit boards or reprogramming but these changes would not require the replacement of the meter body, power supply, or other common features. APS should be required to provide documented studies to support this proposed reduction in service life.

D. APS Call Center

Q. Did you have an opportunity to observe the APS Call Center and discuss its operation with APS personnel?

A. Our discussion focused on the functions that relate to outage notification and APS responses to outage notifications from customers.

Q. How would you assess the Call Center on that basis?

A. We were satisfied that the Call Center efficiently responds to these matters and is on par with other utilities in our experience.

Q. Were there any aspects of your discussions with Call Center personnel that you would like to mention for the benefit of the Commission?

A. Yes. We discussed the possibility of enlisting the local cable companies to make their public service channels available to APS for the purpose of advising customers of planned outages by locations. This could serve to supplement APS' use of "door hanger" notifications.

E. Solar Systems

Q. Please describe the APS solar projects that you observed on your field investigation.

A. A significant portion of APS's requested plant investment additions to Rate Base in this case include the generation of electricity by solar facilities. In particular, APS has two (2) types of solar programs currently under development: utility-scale photovoltaic and customer installed photovoltaic projects. The former are projects of APS-owned renewable generation solar photovoltaic projects ("AZ Sun") in Gila Bend, Arizona. The latter are projects in Flagstaff, Arizona, associated with the Schools and Government Program ("S&G Program") and the Community Power Project ("CPP").

APS' utility scale AZ Sun projects currently consist of three (3) facilities: Paloma, Cotton Center, and Hyder. Paloma and Cotton Center are each 17 megawatt ("MW") generation facilities, and Hyder is a 16 MW facility. Paloma, Cotton Center, and the first phase of Hyder (11 MW) are in service as of Nov. 11, 2011. The second phase (5 MW) of Hyder is projected to be in service in March 2012.

The Paloma, Cotton Center and Hyder stations each consists of 80,000 to 90,000 photovoltaic panels, each panel producing 200 to 220 watts; i.e., with total output of about 85,000 panels times 210 watts = 17.9 MW. In addition to the photovoltaic panels, the stations contain inverter equipment (to convert direct current to alternating current), SCADA systems for monitoring the stations, as well as interconnection gear to tie the stations into the local substation distribution network. After the stations are completed and on line, APS contemplates no permanent personnel on site during operations. Monitoring the station output and photovoltaic panel operations will be done remotely, with routine and fault correction maintenance work being done by APS crews stationed in the vicinity of the projects; e.g., Redhawk station crews for the Paloma and Cotton Center facilities.

Q. Please continue.

A. In Flagstaff, APS has two (2) programs in development --- the S&G and the CPP programs. The S&G and CPP programs represent APS-owned and operated solar photovoltaic equipment installed on schools and individual homes. These photovoltaic generation facilities are connected on APS' side of the meter with the customer receiving the benefits of the production of solar power through a 20-year fixed Solar Rate. APS projects that the full development and roof installations of these sites will be completed by June 30, 2012. Our field investigation observed photovoltaic panels on roofs of homes, with inverters and dual meters installed in several neighborhoods as well as at Cromer Elementary School. APS will also be installing fixed ground mounted panels adjacent to the Cromer School. Inverter and switch gear equipment are currently being installed on the school property to interconnect this facility with the local distribution network.

Q. Please describe briefly the other projects APS is working on in the Flagstaff area.

A. In addition to the photovoltaic installation projects, APS is also conducting a pilot program to implement and monitor "intelligent" equipment and circuitry to evaluate the operations of "smart grid" type systems on selected feeders in the Flagstaff area. These deployments have included the installation of smart meters, special supervisory control equipment, fault anticipation/self isolating feeder equipment and other facilities on two (2) feeders.

APS is also constructing a renewable energy site (Doney Park) that will include photovoltaic panels (about 500 KW of alternating current) and eventually a new 69 kV substation facility. APS is currently doing site preparation and excavating work at this site including the installation of a grounding grid throughout the site. APS expects to complete the installation of the ground mounted fixed orientation photovoltaic panels and associated equipment (e.g., inverters, interconnection gear, etc.) by the end of 2011.

Part of the above project is an electrical energy storage (1.5 MWh capacity lithium-ion battery) demonstration project at Elden Substation. APS is partnering with other companies to test the feasibility of interfacing a battery storage system to regulate energy to levelize local peak loads and to reduce the variability of electricity production from photovoltaic generation. APS expects that the initial operation of this electric energy storage system to be an on-off type operation with the ultimate expectation to be a remote control, load-following operation.

The Solar and Energy Storage projects in the Flagstaff service area are basically in the form of a fairly long-term study of the potentials of distributed generation, mainly solar, integrated into a discrete service area. The results should be portable in that they can

develop strategies for future applications in other parts of the APS system. We think the potential for development strategies is significant. This is also true of the pilot program to implement various "intelligent" devices as a (in effect) mini-Smart Grid system on actual operating feeder circuits. We feel that the experience gained by the operation of these projects in the Flagstaff service area will be of significant benefit when such features are installed in other APS service areas.

F. Fossil Generation – Redhawk Station

Q. What were your observations of the listed replacement and overhaul work at the Redhawk generating facility?

A. We were interested in the Redhawk facility due to the projected costs proposed to be moved to plant-in-service in APS' listing of post-test-year projects and to substantiate that such work would be in-service at the projected times. We were able to determine that the described works were substantially completed as of the time of our visit which was on September 28, 2011.

Q. What was the scope of the post test-year costs proposed?

A. The bulk of the projected cost involved overhaul and related maintenance as recommended by the major equipment vendors on a four (4) year schedule. Several improvements in the gas turbine enclosures had also been completed and the facility management had taken the shut-down opportunity to accomplish other maintenance and improvements. We found the facility to be well maintained and on schedule.

Q. Were there any aspects of the facility that you feel merit attention by APS to increase the reliability of the generation facility?

A. Yes. We were made aware of a fairly unique vibration problem with the steam-side generator. This unit had evidently been converted from a 50 Hz operation to the required 60 Hz for use at Redhawk. That may or may not be the cause of the vibration; that had not been determined. But we feel that the unit should be replaced or the vibration problem rectified in a timely manner.

G. Liberty Group Issues

Q. Do you have any other issues at this time to bring to the attention of the Commission?

A. Yes. I have comments regarding three (3) of the issue areas that were identified in the Liberty Study of the operational and cost performance of APS. The three (3) issue areas relate to the operations of APS' Palo Verde nuclear facility; the performance of APS' Four Corners coal-fired generating facility; and the sustainability/emission control problems at APS' Four Corners facility, which is jointly-owned by APS with other utilities.

Q. Please continue.

A. With regard to APS' Palo Verde nuclear facility, my concerns center on issues of capacity factor and availability. Both of these were discussed in the Liberty Study.

Q. What is the concern with the capacity factor?

A. From the data presented in the Liberty Study, all three generating units regularly lag industry averages. There were safety system issues in prior years, circa 2003-2007, which contributed to this, but those would not account for the below average performance in subsequent years.

Q. Please continue.

A. As regard to availability, the Palo Verde units are averaging about 5-6 percentage points below industry averages. In addition, the average duration of refueling outages for the industry is about 40 days. Recent refueling outages at Palo Verde have been well over that duration.

Q. What can be the effect of lower availability?

A. This can result in an increased need for supplemental power purchases from the grid to meet APS system requirements or a lost opportunity to make off-system sales. Either of these conditions can result in an increase in APS' cost of service.

Q. Does it appear that the lower availability is the result of forced outages?

A. No. Subsequent to 2007, Palo Verde's forced outage rates have been only slightly below industry averages.

Q. What actions would you recommend that APS take to address these concerns in this proceeding?

A. I would recommend that APS address these concerns in their Rebuttal Testimony as to what actions are being considered to improve the capacity factor, the overall availability, and to expedite the refueling outage durations.

Q. Are there other means by which APS can report the performance of Palo Verde?

A. Yes. In a previous proceeding, Docket No. E-01345A-09-0506, the Palo Verde Nuclear Performance Reporting Standard ("NPRS") was developed requiring APS to file annual reports to the Commission on aspects of capacity factor and regulatory performance. This contains a provision that Staff and APS will "...collectively work together to evaluate this Reporting Standard after 3 years of implementation." I would recommend that re-fueling outage duration and unit availability be added as reporting items in the NPRS by APS in its January 2012 report and that these be included as standard topics in subsequent reports. Staff and APS should collectively set the percentages for availability and the number of days for refueling outage durations that would trigger the submission of semi-annual reports.

Q. What is your issue with the performance of the Four Corners Generating Facility?

A. There are two issues: (1) the forced outage rate; and (2) the amount of Nitrous Oxide ("NOx") emissions from the facility. The forced outage rates at all of the Four Corners units are above industry averages and those rates are trending negatively. Units 1-3 NOx emissions on a pounds per year basis are the worst in the peer group considered by the Liberty Study. The elevated levels of emissions are a significant sustainability issue.

Q. Please continue.

A. There is a clear need to resolve the emissions and to address the forced outage rates at the facility. The concerns of emissions and poor forced outage rates as well as the future operation of the Four Corners facility are being addressed in a separate docket, E-01345A-10-0474. A scenario has been advanced where APS would retire Units 1-3 and purchase the portions of Units 4 and 5 capacity that Southern California Edison ("SCE") currently owns. This scenario would allow APS to avoid the cost and technical problems that Units

1-3 present in attempting to apply the required Best Available Removal Technology ("BART") to reduce NOx emissions and acquire new generation in the form of the increased share of Units 4 and 5.

Q. What is your understanding of the technical problems with Units 1-3?

A. I understand that there are severe space limitations at the site which would make it very difficult and costly to retrofit emission controls for these Units.

Q. What do you understand APS' plans to be at present?

A. This is not clear at present. As already discussed, APS has an application pending for Four Corners where it would go forward with the purchase of SCE interest in Units 4 and 5, which APS currently along with other entities has an ownership interest in, retire Units 1-3 which APS owns, and install BART on Units 4 and 5. I'm unaware that has changed.

Q. What actions would you recommend be taken by APS in this proceeding regarding the future of the Four Corners facility?

A. I would recommend that APS provide a plan to address both the emissions and outages. APS should also advise on whether there have been any changes to its planned purchase of SCE's interest in Units 4 and 5 and the simultaneous retirement of Units 1-3.

III. CONCLUSIONS AND RECOMMENDATIONS

A. Conclusions

Q. What are your conclusions based on your observations and APS responses?

A. I can summarize our conclusions as follows: APS operates a reliable distribution system with representative indices well within acceptable ranges. In comparison with similar electric utilities, APS would fall within the top 20 percent in reliability. APS has proposed

an ambitious program of circuit rehabilitation and upgrading, especially toward its underground distribution circuits and services. We have concluded that such a program has merit in substantially improving or maintaining its present levels of reliability, however, we believe that the program may be too ambitious at the present level of usage due to the cost involved. We have concluded that the program of underground cable replacement could be improved by the development of a replacement criteria based upon cable time-in-service, prior repair, or similar aspects. The personnel responsible for the selection of circuits to be upgraded appeared to have very sound criteria for the selection of circuits, however, this was not clearly stated in APS' response to our query for such in our Data Requests.

Q. Please continue.

A. The solar projects of AZ Sun should be in commercial operation at the times indicated by APS in its listing of Post Test-Year projects. The three projects utilize different types of solar cells and tracking arrangements, and one of the three is non-tracking. The outputs of the three projects should provide a valid comparison of which configuration has the best cost-benefit ratio and efficiency of generation. The Community Power Project and The S&G Program (the "Flagstaff" projects) will provide useful data on efficiency and operation of distributed solar generation and potential Smart Grid operation.

Q. Please continue.

A. The observed rehabilitation of overhead circuits and the observed underground cable replacement and new installations observed lead us to conclude that APS uses proper working methods and materials in keeping with prudent utility practice. In conjunction with the move to the new building facility at Deer Valley, the DOMS operations, which is currently working in all of APS' five (5) Divisions, is available as described and projected

at our last visit in 2009. The project to replace the existing paper wall maps is also proceeding as projected.

Q. Please continue.

A. The unit availability issues at Palo Verde and the refueling outage durations need to be addressed by APS. Also, APS needs to finalize its plans as to the purchase of SCE's interest in Units 4 and 5 at the Four Corners facility and the operational problems as to emissions and forced outages.

B. Recommendations

Q. What recommendations do you offer for consideration by the Commission based on the scope of your work in this APS case?

A. We have the following recommendations based on our work in this APS case:

(1) APS should maintain the values of its quality of service indices, in particular SAIDI and SAIFI;

(2) APS' should rectify the vibration problem with the steam-side generator at its Redhawk facility in a timely manner;

(3) APS's underground cable replacement program should reflect certain triggering guidelines; e.g., number of faults, years installed, etc., for replacement, as well as the justification for the size/type of cable replacement; e.g., use of 21 kV rated TrXPLe;

(4) the proposed reduction in the service life of AMR meters and other advanced meters from 26 years to 15 years, should be rejected;

(5) APS should address the low availability of the Palo Verde units and the above-average refueling outages and include these items in the annual NPRS in conjunction with Commission Staff as to the format and triggering values; and,

(6) APS should provide an explanation in this proceeding of how they intend to address the NOx emissions and forced outages at the Four Corners facility and whether its intentions to purchase SCE's interest in Units 4 and 5 has changed.

Q. Does this complete your testimony?

A. Yes, it does.

BACKGROUND & EXPERIENCE PROFILE

W. MICHAEL LEWIS, P.E.

PRESIDENT

W.M. LEWIS & ASSOCIATES, INC.

EDUCATION

1981 - 1988	Master of Business Administration, Ohio University, Athens Office
1971 - 1971	B.S., Electrical Engineering, Ohio State University, Columbus, Ohio
Special Courses:	Power Circuit Breakers, Ohio State University Modern Power System Analysis, University of Wisconsin Digital Electronics for Power Application, IEEE Modern Methods of Analysis and Protection of Electric Power Systems, IEEE Project Management and Planning, University of Wisconsin Construction Contract Administration, University of Wisconsin High Voltage Testimony, Pennsylvania State Lighting Solution and Design, IIT/AEE Cogeneration Theory and Design, University of Wisconsin Planning, Procurement, and Installation of SCADA Systems, University of Wisconsin, 1989

REGISTRATIONS

Registered Professional Engineer in Kentucky and Ohio
Registered Consultant to the Asian Development Bank, Manila, Philippines

POSITIONS

1979 - Present	President and Manager of Engineering of W.M. Lewis & Associates, Inc.
1974 - 1979	Electric Power Engineer, Goodyear Atomic Corporation (now Martin Marietta Energy Systems)

EXPERIENCE

Summary -- Extensive experience in utility practice, including serving as an expert witness on topics of planning, design, construction, operation, and maintenance of high-voltage transmission lines and facilities, (overhead and underground); high-voltage transformer and circuit breaker loading, operation, and maintenance; working and design clearances on facilities at 230 kV and above and other aspects of utility practice before the State Corporation Commission of Virginia; and on aspects of electric utility design and operation before the Federal Energy Regulatory Commission. Also served as an expert witness in numerous electrical accident litigation concerning interpretation of the NESC, OSHA regulations, and the concept of "Prudent Utility Practice." Has performed reviews of rural electric utilities in 14 countries.

In addition to experience and expertise in engineering, operation, and code application, prepared operation manuals for client utilities and industries, prepared training curriculum for power operators, trained power operators and linemen, and prepared PM program criteria for utilities and industry. Experienced in HV and EH V testing techniques of transformers and cables and circuit breakers, including OCB and SF_6 designs.

Graduate level studies include concentrated studies of staffing level theory and the use of statistical techniques in electric rate design and preparation of tariffs for electric utilities. Training in safety audits and compliance plans.

** Confidential Information has been REDACTED**

APS SOLAR PLANT POST
TEST YEAR ADDITIONS
($ MILLIONS)

Plant	Capacity	Cost	Estimated In-Service
Paloma	17 MW	[redacted]	Sept. 2011
Cotton Center	17 MW	[redacted]	Nov. 2011
Hyder I	11 MW	[redacted]	Oct. 2011
Hyder II	5 MW		March 2012
S&G	6.8 MW	[redacted]	As Built (2011/2012)
CPP	1.4 MW	[redacted]	As Built (2011)
		[redacted] 1/	

Source: APS response to Staff 6.55, JBG_WP1, Page 5 of 19

1/ Represents total amount of Solar project plant in service requested by APS for inclusion in rate base. Arizona jurisdictional portion is [redacted]

APS FOSSIL PLANT POST TEST YEAR ADDITIONS 1/ ($MILLION)

Item/WA#	Plant	Cost	Project	Estimated In Service
1./RHC0140	Redhawk Unit 2	$32.086	Gas turbine overhaul	March 2011
11./RHC0104	Redhawk Unit 2	$2.931	Piping replacement	March 2011
12./RHC0088	Redhawk Unit 2	$2.736	IP turbine shims & blade replacement	March 2011
17./ RHC0136	Redhawk Unit 2	$2.072	Compressor row replacement	March 2011
20./ RHC06441	Redhawk Unit 2	$1.917	Turbine rotor & casing seal replacement	May 2011
35./RHC0091	Redhawk Unit 2	$1.094	SCR catalyst replacement	March 2011
38./RHC0100	Redhawk Units 1 & 2	$1.053	Complete the conversion of piping for well water	Aug. 2011
		$43.889		

Source: APS response to Staff 6.55, APS14744, 16 pages

1/ Represents 7 of the 40 fossil generation projects with estimated costs of over $1 Million. Total of 244 fossil projects totaling $154.606 with Arizona jurisdictional amount of $149.350.

APS NUCLEAR PLANT POST TEST YEAR ADITIONS 1/ ($ MILLIONS)

Item/WA #	Cost	Project 2/	Estimated In-Service
1./070005	$26.069	Pond #2 liner replacement	Jan. 2012
9./110020	$2.492	Unit 1/cooling tower structural component replacement	Nov. 2011
10./110021	$2.342	Unite 2 cooling tower structural component replacement	May 2011
11./120016	$2.307	Unit 3 cooling tower structural component replacement	April 2012

Source: APS response to Staff 6.55, APS 14745, 21 Pages

1/ Represents 4 of the 21 nuclear generation projects with estimated costs of over $1 Million. Total of 149 nuclear projects totaling $111.397 with Arizona jurisdictional amount of $107.609.

2/ Observed these types of projects during field investigation in the last APS rate case and discussed with APS personnel that pond liner and cooling tower replacement projects would be on-going at its Palo Verde generating station.

APS DISTRIBUTION/GENERAL/INTANGIBLE
POST TEST YEAR ADDITIONS
($ MILLIONS)

Item/WA #	Cost	Project 1/	Estimated In-Service
IT and Facilities (Total of $92.155)			
1./P138020	$36.697	Building rehabilitation	Dec. 2011
6./T26919H	$2.519	Digital/video wall maps (MDH)	Dec. 2011
10./Budget	$1.533	Concentrator upgrades - Smart Grid expansion	Dec. 2011
Distribution Substation (Total of $18.751)			
New Substations	$12.862	Granite Reef installation represents portion of these projects 2/	In Service
Overhead Conductor Replacement (Total of $6.237)			
Along 15th Av., from Sherman St. to across I-17 Freeway		Reconductoring represents portion of total project replacements 2/	In Service
Underground Cable Replacement/Service Line Extensions (Total of $38.634 plus $21.663)			
Goodyear Community		Reconductoring/line extension to commercial business 2/	Dec. 2011
Smart Grid Demonstration (Total of $20.984)			
Smart Circuit Automation-Flagstaff 2/	$4.873	Testing component capabilities	In-Service
Community Power Project (Total of $2.233)			
Elden Substation Battery Storage 2/	$2.233	Testing storage capabilities	Within Couple of Months

Source: APS response to Staff 6.55, APS 14746, 11 pages (September 2011 Update)

1/ Represents projects of the total of 87 IT projects observed in field investigation including discussion with, and demonstrations by, APS personnel of IT projects; e.g., DOMS digital/ video mapping capabilities.

2/ Represents various projects observed in field investigation including discussions with APS field and management personnel responsible for field and administrative work activities.