# Transcript Exhibit(s)

Docket #(s): E-01345A-11-0224

Exhibit # : APS1-APS4

Part 1 of 5

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To: Docket Control

Date: February 6, 2012

Re: APS - Rates
E-01345A-11-0224
Volumes I through VII, Concluded
January 26 through February 3, 2012

## STATUS OF ORIGINAL EXHIBITS

### *FILED WITH DOCKET CONTROL*

✓ Arizona Public Service (APS Exhibits)

1 through 16

✓ Arizona Association of Realtors (AAR Exhibits)

1 through 2

✓ Arizona Investment Council (AIC Exhibits)

1 through 5

✓ Arizonans for Electric Choice & Competition (AECC Exhibits)

1 through 4
(1A is CONFIDENTIAL – Delivered to CALJ Farmer)

Commissioner Newman (N Exhibits)

1

Department of Defense & Federal Executive Agencies (FEA Exhibits)

1 through 3

Generation Service Provider (GSP Exhibits)

1 and 2

IBEW Locals 387, 640 & 769 (IBEW Exhibits)

1 through 2

Kroger Company (Kroger Exhibits)

1 through 3

Natural Resource Defense Council (NRDC Exhibits)

1 and 2

Residential Utility Consumer Office (RUCO Exhibits)

1 through 7

Southwest Energy Efficiency Project (SWEEP Exhibits)

1 through 3

Staff (S Exhibits)

1 through 16
(Exhibit 2 is CONFIDENTIAL–Delivered to CALJ Farmer

Wal-Mart (WM Exhibits)

1 through 4

Zwick (Zwick Exhibits)

1 and 2

## *LATE-FILED EXHIBITS*

Arizona Public Service (APS Exhibits)

17

## *CONFIDENTIAL EXHIBITS*

Arizonans for Electric Choice & Competition (AECC Exhibits)

1A Delivered to CALJ Farmer

Staff Exhibits (S)

2 Delivered to CALJ Farmer

Copy to:

Ms. Lyn A. Farmer, Chief Administrative Law Judge
All parties of record as noted on Volume I, 01-26-2012

Arizona Court Reporters Association

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**HAND DELIVERED**

February 6, 2012

Ms. Lyn Farmer
Chief Administrative Law Judge
ACC – HEARING DIVISION
1200 West Washington, 1st Floor
Phoenix, AZ 85007

| | |
|---|---|
| Case: | APS / Rates |
| Number: | E-01345A-11-0224 |
| Date: | January 26 through February 3, 2012<br>Volumes I through VII, Concluded |

Dear CALJ Farmer:

For your safekeeping, we are enclosing Exhibits Nos. AECC-1A and S-2. These exhibits were designated confidential during the above-referenced matter.

Please let us know if you have any questions or if we may be of any further assistance.

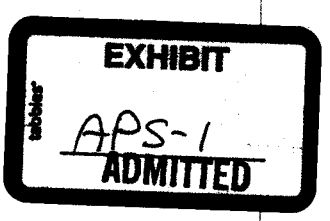
Very truly yours,

Marta T. Hetzer
Administrator/Owner

Enclosure

| | | |
|---|---|---|
| Copy to: | Docket Control | |
| | APS | Thomas L. Mumaw, Esq. |
| | AECC | C. Webb Crockett, Esq. |
| | Staff | Maureen A. Scott, Esq. |

APS Exhibit 1




# DIRECT TESTIMONY OF JEFFREY B. GULDNER

**On Behalf of Arizona Public Service Company**

**Docket No. E-01345A-11-_____**

June 1, 2011

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**DIRECT TESTIMONY OF JEFFREY B. GULDNER**
**ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY**
**(Docket No. E-01345A-11-_____)**

I. INTRODUCTION

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

A. My name is Jeffrey B. Guldner. My business address is 400 N. 5th Street, Phoenix, Arizona, 85004. I am Vice President of Rates and Regulation for APS. In that role, I am responsible for rate, regulatory and regulatory compliance matters before the Arizona Corporation Commission ("Commission") and the Federal Energy Regulatory Commission ("FERC") that affect the Company.

**Q. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?**

A. I joined APS in 2004 as Director of Regulatory Compliance, and then assumed responsibility for federal regulation and policy at the Company. Prior to joining APS, I was a partner in the Phoenix, Arizona office of Snell & Wilmer LLP, where I practiced energy and public utilities law. My practice focused primarily on electric utility rate and regulatory matters, including rate cases, power plant and transmission line siting, energy project finance, and utility mergers. Before practicing law, I was a Surface Warfare Officer in the United States Navy. I received a J.D., *magna cum laude*, from Arizona State University and a B.A. in political science from the University of Iowa.

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

A. I discuss several of the many benefits that resulted from the 2009 Settlement Agreement ("Settlement"), which was approved by the Commission in Decision No. 71448 (December 30, 2009), and the critical need to maintain in this proceeding the financial and regulatory momentum established by the Settlement. I then outline the scope of APS's rate request and describe the key issues in that request. Finally, I touch on some of the performance measures as set forth in

Section XIII of the Settlement, including the Reporting Requirements and the Benchmarking Study.

II. SUMMARY

**Q. PLEASE SUMMARIZE YOUR TESTIMONY.**

A. The Settlement marked a turning point in the challenging task of providing for the electric infrastructure needed for Arizona's future, while allowing APS the financial strength and stability to attract the capital required to build or acquire that infrastructure. It did so by providing for both significant cash rate relief and creative non-cash mechanisms that allowed APS to bridge the period from January 1, 2010 to the anticipated effective date of rates from this proceeding. That Settlement was favorably received by the financial community, as were subsequent constructive actions by this Commission. This rate request furthers this positive momentum and would allow the Company, the Commission and customers to continue taking important steps towards a sustainable energy future for Arizona.

The present request asks for an increase in base rates of $95.5 million, or 3.3%, to become effective July 1, 2012. Because the current negative Power Supply Adjustment ("PSA") charges would be reset to zero concurrently with the change in base rates, the actual percentage impact of the Company's request on APS customer bills will be higher, at approximately 6.6%. As discussed later in my Testimony, APS has sought to moderate the level of bill impact on customers by not seeking recovery of certain costs in this proceeding that APS believes are legitimate costs of providing service, including amounts that the Company had been granted in prior cases.

Although I will go into additional detail as to the principal drivers of the Company's rate request later in my Direct Testimony, it is fair to say that the three main issues in APS's rate Application are (1) inclusion by the Company in its Fair Value Rate Base of net plant additions through the proposed rate effective date; (2) expansion of the current Environmental Improvement Surcharge ("EIS") to an Environmental and Reliability Account ("ERA") that would encompass new generation additions and additional pollution control costs on existing generation on an annual basis; and (3) adoption of a rate decoupling plan, consistent with the Commission's 2010 Policy Statement Regarding Utility Disincentives to Energy Efficiency and Decoupled Rate Structures ("Decoupling Policy Statement"), through an Efficiency and Infrastructure Account ("EIA").

APS has achieved all the performance metrics and requirements of the Settlement that were targeted for 2010. For those that require performance over a period of time that encompasses future years, the Company is on track to meet them. Specifically, my testimony (as well as that of other APS witnesses) will discuss nine performance measures required by Section XIII of the Settlement:

- Expense reduction
- Equity infusion
- Debt ratio
- Financial plan to maintain investment grade ratings
- Renewable energy
- Energy efficiency
- Other reporting requirements
- Benchmarking study

## III. CONTINUING THE REGULATORY AND FINANCIAL MOMENTUM

**Q. DID THE SETTLEMENT GENERATE SIGNIFICANT REGULATORY AND FINANCIAL MOMENTUM FOR APS AND THE STATE OF ARIZONA?**

A. Absolutely. I will not repeat the quotes from Jim Hatfield's testimony, but there can be no question that the financial community viewed the Settlement and the Commission's approval thereof as constructive for APS, APS's relationship with the Commission, and the investment climate in Arizona.

**Q. WHY IS THAT THE CASE?**

A. There is an inherent tension between the need for APS to invest for a sustainable and reliable energy future in Arizona and the natural desire to keep electric rates as low as possible. The Company's financial condition has historically suffered in this "tug of war" between two often conflicting goals. The Settlement not only came up with creative ways of mediating that tension, it also established a regulatory framework for addressing this challenge in future APS rate proceedings.

**Q. CAN YOU BE MORE SPECIFIC?**

A. Certainly. The Settlement's inclusion of post-test period investment up until roughly the date of the Settlement significantly reduced regulatory lag for APS and, importantly, reduced the requested rate increase in this case by about $88 million. The deferrals of pension and Other Post Retirement Benefits ("OPEB") costs that exceeded the level reflected in the Settlement's revenue requirement, the early change in Palo Verde depreciation rates resulting from the license extension granted by the Nuclear Regulatory Commission, and the reclassification of Schedule 3 (line extension) proceeds as operating revenues rather than contributions all represented important accounting changes that allowed APS to agree to both a lower base rate increase in the Settlement and a 30 month moratorium before the Company could receive any additional base rate relief. Although still well below the authorized equity return, these Settlement

provisions coupled with aggressive cost management allowed APS's earned equity return in 2010 to get closer to its authorized return.

The Settlement also allowed concurrent recovery of capital carrying costs for APS-owned renewable generation, which formed the basis for the AZ Sun Program ("AZ Sun") and the Community Power Project - Flagstaff Program ("CPP") approved by this Commission in Decision Nos. 71502 (March 17, 2010) and 71646 (April 14, 2010). Those Decisions were also favorably received in the investment community. And, although not nearly as significant in terms of potential financial impact as either of the rulings involving renewable energy, the Commission's more recent determination in Decision No. 72214 (March 3, 2011) to allow some capital carrying costs to be recovered through the Demand Side Management Adjustment Clause ("DSMAC") was also another sign that APS investments in service to customers were receiving more timely recovery than had historically been the case.

The Settlement looked to future APS rate proceedings as well. For this Application, the Settlement established a goal of a 12-month resolution of the APS rate filing (from a finding of sufficiency) and set in place procedural innovations to facilitate achievement of that goal, including the 120-day pre-notification, the 60-day pre-filing conference with Staff and other interested parties, and the submission of responses to a standard set of data requests concurrent with the Application.

**Q. HOW DOES THE CURRENT RATE FILING ATTEMPT TO CONTINUE THAT REGULATORY AND FINANCIAL MOMENTUM?**

A. I believe everyone agrees on the benefits to APS customers, the Commission, and APS itself of less frequent general rate cases. The resources and attentions of all three can be redirected toward other worthwhile objectives. I also believe strongly in rate gradualism. In a national environment of increasing costs, and

therefore rates, smaller increases on a regular and more predictable basis are better for customers than large double-digit jumps every few years. They are also more effective in financing the needed investment in new, efficient and cleaner infrastructure and innovative technology. Thus, APS customers find themselves in a better position to manage and predict future bill impacts, while APS is similarly in a stronger financial position to attract the approximately $20 billion in new capital investments that customers will require between now and 2025.

The key to achieving both less frequent general rate cases and rate gradualism is to find mechanisms, as was done in the Settlement, which will maintain the Company's financial strength between general rate filings. I believe we have accomplished this with the rate proposals discussed in the testimony filed by the Company, including my own. In addition, APS has structured its rate case testimony to be primarily about what APS is doing and needs to do in the future to procure and deliver energy and related services to its customers, and less about numbers, accounting classifications, and ratings agencies. In other words, what are APS customers receiving for their money both now and in the future? I believe that the testimony will show that APS customers are and will be receiving good value in terms of cost management, reliability, customer service, and sustainability – both environmentally and economically.

**Q. ARE THERE OTHER ITEMS IN THE FILING THAT APS IS NOT INCLUDING OR FOR WHICH IT IS SEEKING A REDUCED AMOUNT?**

A. Yes. APS is aware of the difficulties our customers face in the current economic climate. Accordingly, APS carefully looked for opportunities to moderate the bill impact of this request to customers. Based on this consideration, APS is not requesting recovery of stock compensation or Supplemental Executive Retirement Benefits Plan ("SERP") costs in this case. These components to compensation are standard costs incurred by utilities throughout the United

States, and accordingly APS believes that they normally should be included in APS's cost of service. But in the context of this rate case, brought at a time when our customers are still trying to recover from a weak economy, APS concluded that it would not seek to include these costs in its rate request. For the same reason, APS decided to reduce the Fair Value increment it would request in this rate case below that supported by its expert, APS witness Dr. William Avera, and below even the level that was recommended by Commission Staff and incorporated in the 2009 Settlement Agreement. Dr. Avera explains in his testimony why a higher Fair Value increment is the most appropriate measure of Fair Value for APS. APS also chose to maintain the 11.0% return on equity ("ROE") authorized by the Settlement, rather than request the 11.25% Dr. Avera identifies as the mid-point of his range. APS was able to propose a lower Fair Value increment and authorized ROE because of the balance of other aspects of the case, such as inclusion of post-Test Year plant and the other proposed mechanisms—without those, APS would have to seek the higher Fair Value increment and ROE. Both of these steps, as well as the decision to not seek recovery of stock compensation and SERP, helped to moderate the requested rate increase below a 7.0% bill impact for customers and lowered the revenue requirement increase by over $50 million. This is in addition to over $37M in expense reductions achieved during the Test Year, which I will discuss later in my testimony.

## IV. OVERVIEW OF THE COMPANY'S RATE CASE FILING

**Q. WHAT LEVEL OF BASE RATE INCREASE IS APS REQUESTING?**

A. APS is seeking a base rate increase over adjusted Test Year base rate revenues of $95.5 million, to become effective July 1, 2012. This represents a 3.3% increase in base rate revenues. To be clear, however, the base rate increase is different from the bill impact to customers because of corresponding changes in several

adjustment mechanisms. For example, under the Company's proposal to reset the base fuel rate to reflect conditions and prices expected in 2012, the present PSA forward element adjustment is moved from an adjustment mechanism into base rates. Because that PSA forward element for both this year and 2012 is negative, the mathematical impact is to reduce the size of the proposed base rate increase shown on SFR Schedule A-1 without reducing the bill impact of APS's request on most customers. It is important, therefore, to also discuss the net bill impact, because that is what customers ultimately will care about. Considering surcharges such as those for energy efficiency, renewable energy, transmission, and environmental improvements along with adjusted base rate revenues, the overall bill impact of the Company's request would be an increase of 6.6%.

**Q. SOME APS CUSTOMERS HAVE EXPRESSED CONCERN THAT THIS RATE CASE REPRESENTS ANOTHER IN A LONG SERIES OF SIGNIFICANT RATE INCREASE REQUESTS BY THE COMPANY. IS THAT FACTUALLY CORRECT?**

A. While APS recognizes our customers' natural concerns over higher prices, the fact is that for the three and one-half years between January 1, 2009 and the proposed effective date for new rates in this proceeding, there will have been only one general rate case resulting in an increase for APS customers. There have been other rate changes in this period to date, including four related to Renewable Energy and Energy Efficiency programs that are overwhelmingly supported by APS customers. But I believe that customers perceive that there have been many more rate changes because they receive notices about the same rate change several times during a rate case process, and APS's approved adjustor mechanisms are implemented at different times during each calendar year.

**Q. WHAT HAS BEEN THE OVERALL TREND IN RATES PAID BY APS CUSTOMERS SINCE 2009?**

A. In January 2009, the average cost paid by APS customers was 10.2 cents per kWh. Today, the average rate is 10.6 cents per kWh. This is an increase of approximately 4% over two and one-half years. Renewable Energy and Energy Efficiency programs account for 3.4 percentage points of that 4%. Further, the base rate increase sought by APS in this case will not be implemented before July 1, 2012—more than 12 months from the filing of my testimony.

**Q. WHAT WITNESSES IS APS PRESENTING AS PART OF ITS DIRECT CASE?**

A. APS filed testimony from the following witnesses:

| | |
|---|---|
| Mr. Donald G. Robinson | State of the Company and general content of rate case |
| Mr. Jeffrey B. Guldner | Overview of the rate case and central issues |
| Mr. James R. Hatfield | Financial projections and bond rating information |
| Mr. Mark A. Schiavoni | Fossil generation operations and capital expenditures |
| Mr. Randy K. Edington | Nuclear generation operations and capital expenditures |
| Mr. Daniel T. Froetscher | Distribution operations and capital expenditures |
| Dr. William E. Avera | Cost of equity and fair value rate of return |
| Mr. Leland R. Snook | Efficiency and Infrastructure Account and the Environmental and Reliability Account |
| Mr. Zachary J. Fryer | Cost of service and fair value calculation |
| Mr. Jason C. La Benz | Historical accounting information and rate base and income statement pro formas |
| Dr. Ronald E. White | Depreciation study and cost expense |

| | |
|---|---|
| Mr. Peter M. Ewen | Base fuel cost and the Power Supply Adjustor |
| Mr. Charles A. Miessner | Rate design and programs |

**Q. WHAT ARE THE CENTRAL FACTORS NECESSITATING THIS BASE RATE INCREASE?**

A. By far the largest driver is the over $1.5 billion increase in APS investment between the time Settlement rates went into effect through the anticipated effective date of rates in this proceeding. This amount represents investments in reliability, power plant efficiency, environmental equipment, renewable energy and new technology. These investments made since the last rate case require new rates so that APS can earn closer to its cost of equity capital. There have also been some operating cost increases, but APS has essentially offset those increases through cost reductions elsewhere.

**Q. IN YOUR SUMMARY, YOU IDENTIFIED POST-TEST YEAR INVESTMENT, THE PROPOSED ENVIRONMENTAL AND RELIABILITY ACCOUNT AND THE EFFICIENCY AND INFRASTRUCTURE ACCOUNT AS THREE MAJOR ISSUES IN THIS CASE. WILL YOU PLEASE DISCUSS EACH OF THESE PROPOSALS?**

A. Certainly. First, the goal of the post-Test Year plant adjustment is to reflect the net plant additions that have actually been placed into service by the rate effective date, as well as some associated operating costs. "Net" plant additions recognize the increase in the depreciation reserve, changes in deferred income taxes, and (where applicable) investment tax credits as offsets to gross plant additions. In other words, these offsets lower the total amount of post-Test Year plant requested. Mr. La Benz will explain the details of these offsets in his testimony. Similarly, the heads of the business units responsible for energy delivery including general and intangible plant (Daniel Froetscher), fossil generation (Mark Schiavoni) and nuclear generation (Randy Edington) will discuss the plant additions within their respective areas in greater detail. As in the Settlement, the

post-Test Year plant adjustment will be updated to reflect actual plant additions closed to service by the effective date of new rates.

I will address post-Test Year plant associated with the Solar Additions portion of the post-Test Year plant additions pro forma. The adjustment includes post-Test Year plant additions associated with three of APS's renewable energy programs: AZ Sun, the Schools and Government Program ("S&G Program"), and the CPP. Each of APS's renewable energy programs included in the post-Test Year plant additions adjustment was previously approved by the Commission. Costs for these programs are currently recovered through APS's Renewable Energy Surcharge ("RES"). As explained by Mr. Miessner, APS plans to concurrently reduce its RES rates on the effective date of new base rates to reflect the transfer of these costs out of the RES and into base rates.

As noted earlier, AZ Sun was approved by the Commission in Decision No. 71502. Through this program, APS will own 100 MW of utility-scale solar photovoltaic power plants across Arizona, investing up to $500 million through 2014. APS uses competitive procurement processes to select projects under AZ Sun. As discussed by Mr. Robinson, APS has signed contracts to develop five generating facilities representing the first 83 MW of the 100 MW program. This post-Test Year plant additions adjustment includes three AZ Sun projects, totaling 50 MW, that are projected to be in service by June 30, 2012: a) Paloma, a 17 MW facility located in Gila Bend with a projected in-service date of September 2011; b) Cotton Center, a 17 MW facility also located in Gila Bend with a projected in-service date of November 2011; and c) Hyder, a 16 MW facility located east of Yuma with a projected in-service date of October 2011 for the first phase and March 2012 for the second phase of the facility. As provided in Decision No. 71502, the first 50 MW of AZ Sun will be recovered through the

RES until the investment is included in base rates or another recovery mechanism as determined in the Company's next rate case. APS recommends that after existing AZ Sun revenue requirements are moved from the RES into base rates in this case, the recovery of remaining costs associated with the second 50 MW occur through the RES until they can be incorporated in base rates by a future APS rate case rather than through a new adjustment mechanism.

The S&G Program was approved by the Commission, as amended, in Decision No. 72174 (February 11, 2011). As part of this program, rural and economically challenged school districts are provided with access to solar resources owned and operated by APS. As host for the APS-owned system, the school receives the benefits of solar produced by the system through a twenty-year fixed Solar Rate offering. Full deployment of 8 MW of APS-owned systems is expected to be complete by June 30, 2012.

The CPP was approved by the ACC in Decision No. 71646 (April 14, 2010), and through this program, APS will install and own up to 1.5 MW of distributed renewable energy systems in Flagstaff, AZ. Full deployment is expected to be complete by December 2011.

The renewable energy programs, including AZ Sun, the S&G Program and the CPP, which are included in the total post-Test Year numbers discussed above, increase Rate Base by $267,633,000 and decrease pre-tax operating income by $12,385,000. Please see Attachment JBG-1 for a calculation of this rate base adjustment.

**Q. PLEASE EXPLAIN THE ENVIRONMENTAL AND RELIABILITY ACCOUNT ("ERA").**

A. The second major issue is the Company's proposed ERA, which would replace the existing EIS. The account would include net investments in pollution control

equipment at the Company's power plants as well as investments in new non-renewable generation. The Company would propose continuing to recover the carrying costs and operating costs of Company-owned renewable generation through the RES until such time as such generation can be rolled into base rates during future APS general rate proceedings. The ERA allows rates to reflect the cost of investments in environmental equipment that are largely outside the control of either APS or the Commission. The details of the ERA are discussed in Mr. Snook's testimony.

It is important to note that the ERA would not divest this Commission of its power and responsibility to determine the prudence of new investments subject to the ERA. Prudence determinations would continue to be made in general rate proceedings or in other proceedings as the Commission determines are appropriate from time to time.

**Q. EXPLAIN THE EFFICIENCY AND INFRASTRUCTURE ACCOUNT ("EIA").**

A. Under the EIA, the Commission establishes a dollar amount of fixed costs for the adjusted test period (which in this case is historical, though it need not be) and divides it by the number of customers for that same adjusted test period. APS's goal is to make the mechanism as simple as possible while still being an accurate reflection of fixed cost per customer. Although Mr. Snook is discussing the EIA proposal in detail, I can say that we determined the fixed cost calculation using (with some minor exceptions) two broad groups of retail customers – all residential and all general service and industrial.

The total level of fixed costs to be recovered will vary from year to year depending on customer count. APS has further proposed an annual cap of 3% for any upward rate adjustment due to the EIA with a carryover to the succeeding

year. There would be no similar cap on downward adjustments, which would result in bill credits to customers.

**Q. WHY IS APS MAKING THIS PROPOSAL NOW?**

A. During the decoupling workshops conducted in the summer and fall of 2010, it was generally acknowledged by all participants expressing an opinion that the Commission's energy efficiency standard could not be met unless there was an alignment of interests between the Company and its customers. This conclusion is shared by numerous other state commissions and policy experts throughout the United States. This state's aggressive commitment to distributed generation is yet another reason that finding a way for APS to recover fixed costs in the face of declining sales per customer is imperative.

In recognition of these facts, the Commission issued a comprehensive Decoupling Policy Statement in December of 2010. In his testimony, Mr. Snook describes how the APS proposal matches up against the Decoupling Policy Statement and explains what minor deviations from that statement are included in the Company's filing.

**Q. COULD YOU OUTLINE SOME OF THE OTHER SIGNIFICANT COMPONENTS OF THE COMPANY'S RATE REQUEST?**

A. Yes. Although there are many aspects to this rate request (as there are for other major utilities in this state), I will elaborate here on the following:

- Changes to the Transmission Cost Adjustment ("TCA");
- Changes to the PSA;
- The Company's requested ROE; and
- Implementation of a revised line extension policy in the form of Revision 12 to Service Schedule 3.

**Q. PLEASE DESCRIBE THE PROPOSED CHANGES TO THE TCA.**

A. There are two. First, all transmission costs associated with serving retail customers would be recovered through the TCA rather than through a combination of base rates and the TCA. Second, changes to the TCA would take effect at the same time as new transmission rates become effective for wholesale customers of APS – June 1st of each year – without the need for a separate approval from the Commission.

The second modification of the TCA is related to the first. By federal law, FERC has exclusive jurisdiction over APS's transmission rates to both retail and wholesale customers. Retail customers are protected through this Commission's active participation in FERC formula rate proceedings – something it has done successfully in each of the past three years. It makes little sense for the Commission to simply reflect in a separate order a decision already made by another agency. And by putting all retail transmission costs into the TCA, APS customers can see the full impact of FERC decisions on their bills.

**Q. PLEASE DESCRIBE THE PROPOSED CHANGES TO THE PSA.**

A. Again, there are two significant changes to the PSA proposed in APS's filing. The first is to include chemical costs such as lime, ammonia, and sulfur in the costs recoverable through the PSA. Use of these environmental chemicals is directly related to generation output every bit as much as is fuel and should be treated accordingly for ratemaking purposes. Second, the Company seeks to remove the 90/10 "sharing" provision from the PSA. Although APS is currently benefiting from that sharing, this does not change the fact that no other Arizona utility has such a provision. Given the volatility of fuel prices, it is little more than an arbitrary penalty or, currently, benefit to the Company for something over which it has virtually no control. On the other hand, if fuel charges to APS customers are the result of imprudent acts of APS, the Commission has complete

authority to order such increased costs refunded or credited to customers as it did in Decision No. 69663 (June 28, 2007).

**Q. WHAT COST OF COMMON EQUITY DID APS USE IN ITS RATE REQUEST?**

A. Considering the cost of equity capital recommendation made by Dr. Avera and consistent with the findings in the Settlement, APS based its request on an 11% ROE. As discussed earlier, this request is lower than the midpoint of Dr. Avera's recommendation.

**Q. WHAT CHANGES ARE PROPOSED FOR SCHEDULE 3?**

A. Generally speaking, we are suggesting that the Company return to the traditional accounting treatments of line extension proceeds, which are either refundable advances or non-refundable contributions. Revenue treatment was a creative and necessary bridge in the Settlement, but its long-term instability as a revenue source has convinced the Company that a return to more conventional accounting should be made at this time.

As to the structure of Schedule 3, the Company wants to promote a sharing of the costs of new customer growth between the new customers and the existing customer base. I believe we have found a good balance between the somewhat divergent interests of these two customer groups.

**Q. ISN'T THERE A SEPARATE PROCEEDING UNDERWAY TO RE-EXAMINE SCHEDULE 3?**

A. Yes. On May 20, 2011, APS filed a revised Schedule 3 (Version 12) that reflected consensus with several affected parties. The intent of the Company and the other parties to that agreement is to implement this revised line extension policy concurrent with the effective date of new base rates as determined in this proceeding. However, creating more immediate certainty around the prospective line extension policy and receiving Commission approval to extend the refund

period of customer advances under previous revisions to Schedule 3 led APS to file for separate approval.

V. SETTLEMENT PERFORMANCE REQUIREMENTS

**Q. HOW IS APS DOING WITH REGARD TO THE PERFORMANCE STANDARDS ESTABLISHED IN THE SETTLEMENT?**

A. I will comment on these in the order listed in my Summary.

- Expense Reduction: On April 29, 2011, APS filed a letter detailing its compliance with the requirement that it achieve $30 million in expense savings in 2010. As can be seen by the letter, the Company actually achieved $37.4 million in expense reductions. This means that the current request was reduced by these and other cost reductions that did not meet the definition of expense reductions (largely reductions in capital investment).

- Equity Infusion: The Company received the first installment ($253 million) of this equity infusion in April of 2010 following a successful equity issuance by Pinnacle West Capital Corporation, the parent of APS. Future installments will get APS to the $700 million by 2014 referenced in the Settlement.

- Debt Ratio: APS is required to use "best efforts" to achieve a 52% long-term debt ratio as determined using Standard & Poor's ("S&P") calculation methodology by the end of 2012. At year-end 2010, APS had reduced its debt ratio using that methodology to 54.4% from 56.6% at year-end 2009. APS currently expects to reach 52% or less by the end of 2012.

- Financial Plan to Maintain Investment Grade Credit Ratings: On April 29, 2010, APS submitted such a Plan to the Commission. Mr. Hatfield addresses the details of the Plan, but generally it consists of seeking timely recovery of costs in rates, on-going cost management activities, and maintaining a balanced capital structure.

- Renewable Energy: APS made a number of commitments relative to renewable energy in Section XV of the Settlement. These included: (1) new resources capable of generating 1.7 million MWh by the end of 2015, (2) a "schools" program eliminating "up front" costs of solar, (3) a government institutions program with the same objective as the "schools" program, (4) an Arizona wind project, (5) a utility scale photovoltaic project, and (6) a renewable-related transmission project. As to items 2-6, I will not go into detail except to note that APS proposed and the Commission approved each of these required projects. As to item 1, APS acquired renewable resources in 2010 capable of providing 172,734 MWh out of a total renewable resource generation production of 826,534 MWh. The Company presently anticipates that total production will grow to over 3 million MWh by 2015 – exceeding the requirements of the Settlement.

- Energy Efficiency: Section XIV of the Settlement required APS to achieve 1% savings as measured by total energy resources. This is a somewhat higher requirement than in the Commission's Energy Efficiency Rules. In fact, the Company and our customers achieved 1.05% energy savings during 2010. The Commission approved the Company's 2011 DSM Implementation Plan (with minor modifications), which is aimed at the 1.25% goal for 2011. Both the 2011 and now the 2012 Implementation

Plans were filed as required by the Settlement and the Rules on June 1, 2010 and June 1, 2011, respectively.

- Other Reporting Requirements: Section XIII (B) of the Settlement set forth extensive reporting requirements relating to system operations, customer service, safety, and financial results. I will not repeat them all here, but suffice it to say all required reports were submitted to the Commission in a timely fashion.

- Benchmarking Study: The Company appreciates the effort and analysis presented by Liberty Consulting ("Liberty") in Liberty's report filed on February 28, 2011. APS is in partial agreement with Liberty's findings. Where we are not in agreement, or where the recommendation was for APS to more closely evaluate a potential finding in Liberty's higher level analysis, an APS witness will address certain issues, while a report prepared by the Company's independent benchmarking consultant, Concentric Energy Advisors ("Concentric") addresses others. APS believes that benchmarking, such as the process agreed to in the Settlement, is a worthwhile undertaking, and the Liberty and Concentric benchmarking analyses provide significant information for discussion and consideration in a rate case context.

**Q. WHAT ANALYSES DID CONCENTRIC UNDERTAKE?**

A. We asked Concentric to do several things. First, we asked them to review the Benchmarking Study performed by Liberty, and discuss the overall goals and objectives of a benchmarking process in somewhat more detail than Liberty had included in its report. Second, for areas where Liberty had identified the need for further analysis or action by the Company, we asked Concentric to conduct that further analysis and discuss their findings. Finally, the scope of the Liberty study

only included data through 2009. We asked Concentric to update the benchmarking to also include 2010. In some areas evaluated by Liberty, the trend after 2009 appeared necessary to interpret their findings. The complete Concentric report is attached to my testimony as Attachment JBG-2.

## VI. CONCLUSION

**Q. DO YOU HAVE ANY CONCLUDING REMARKS?**

A. As I noted in my Summary, the Settlement addressed in a very constructive manner the challenge of providing for the electric infrastructure needed for Arizona's future while allowing APS the financial strength and stability to attract the capital required to build or acquire that infrastructure. The Settlement was a major milestone for the settling parties and the Commission and has earned every word of the praise it has received.

The present request seeks to build on the constructive momentum of that Settlement by proposing means to reduce the frequency and magnitude of general rate cases while allowing for improved cost recovery and reduced regulatory lag. It also will align the financial interests of the Company with those of its customers to better promote energy efficiency, renewable energy, and environmental stewardship. Finally, APS has achieved all the performance metrics and requirements that were targeted for 2010 by the Settlement and is on track to achieve those that can only be finalized in future years.

**Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

A. Yes.

**ARIZONA PUBLIC SERVICE COMPANY**
**Detail of Pro Forma Adjustment to Original Cost Rate Base for Solar Generation Post-Test Year Plant Additions**
**as Shown on Schedule B-2, page 1, column 3**
**Total Company**
**(Thousands of Dollars)**

**Pro forma Adjustment:** **Post-Test Year Plant Additions**
**Adjustment to Test Year rate base to include Post-Test Year Plant Additions for solar generation with an estimated in-service date prior to 6/30/2012.**

| Line No. | Description | Total Company |
|---|---|---|
| 1. | Gross Utility Plant in Service | $ 277,411 |
| 2. | Less: Accumulated Depreciation and Amortization | 5,799 |
| 3. | Net Utility Plant in Service | 271,612 |
| 4. | Less: Total Deductions | 3,979 |
| 5. | Total Additions | - |
| 6. | **Total Rate Base** | **$ 267,633** |

# ARIZONA PUBLIC SERVICE COMPANY

# REVIEW OF LIBERTY BENCHMARKING STUDY AND SUPPLEMENTAL ANALYSES

*Prepared by:*

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Exhibit 1: Situational Assessment

Exhibit 2: Productive Efficiency

Exhibit 3: Benchmarking Workpapers

Attachment A: Matrix of Metrics and Panels

Attachment B: Nuclear O&M Expenses

Attachment C: Underground Distribution Systems

Attachment D: Labor Efficiency Metrics

Attachment E: Nuclear Plant Metrics

Attachment F: Fossil Plant Metrics

Attachment G: Distribution System Reliability Metrics

# I. EXECUTIVE SUMMARY

## A. PURPOSE OF THE ASSIGNMENT

Arizona Public Service Company ("APS") retained Concentric Energy Advisors, Inc. ("Concentric") to conduct an independent review of the benchmarking study prepared by Liberty Consulting Group ("Liberty") and commissioned by the Arizona Corporation Commission ("ACC" or "Commission") in Docket No. E-01345A-08-0172 (the "Liberty Study"). Our review included both an examination of the approaches and methods used by Liberty in measuring APS's performance, as well as an assessment of the recommendations made by Liberty for improvements in certain areas.

In addition to reviewing the Liberty Study, we also prepared an updated benchmarking study using operating data and costs through 2010 (the "Concentric Study"). The Concentric Study used our typical approach and method to benchmarking the performance of investor-owned utilities. In addition, we developed an analysis showing the areas in which the Concentric Study differed from the Liberty Study in terms of approach, analysis and results and reviewed the reasons for these differences.

## B. CONCLUSIONS

Based on our analysis, Concentric concludes the following:

- We generally found Liberty's approach to the APS benchmarking study to be reasonable and consistent with industry practice. However, we had a number of specific concerns with its comparison panels, presentation of results, and recommendations. We address each of these concerns in our review of its study.

- Our review of APS's performance has demonstrated that the Company has out-performed similarly sized companies across an array of financial and operational metrics. The Company has achieved this result in spite of the fact that it is somewhat disadvantaged by the exogenous factors that are known to have an impact on efficiency. APS is consistently one of the three most "situationally-challenged" companies within the comparison groups. APS's customer base consists of a high percentage of residential customers with low usage, its growth has been high, and its service territory is more rural than its peers. In addition, the state's energy policies will likely place future cost pressures on APS to continue to increase participation in demand-side management and energy efficiency programs, meet renewable energy portfolio requirements, and reduce air emissions from its generation fleet.

- In terms of productive efficiency, APS has ranked in the second and third quartile in ten out of eleven years in the Base Panel and ranks between the first and third quartile

in the Regional Panel in terms of productive efficiency over the course of the study period. Most importantly, APS's performance on the productive efficiency benchmark has not occurred at the expense of service reliability or customer satisfaction.

- Considering both the challenges identified in the situational assessment and the productive efficiency, APS's performance in 2010 was exceptionally good, and APS outperformed its Base Panel peers on a basis which considers both absolute productivity measures and the relative challenges it faced.

The remainder of this report is organized into the following sections:

- Section II provides a review of the Liberty Study, including i) the study approach; ii) the study findings and recommendations; and (iii) Concentric's assessment of the Liberty Study.
- Section III presents the Concentric Study. This section includes a review of: (i) the development of peer group panels; (ii) the data sources used; (iii) the exogenous factors that present performance-related and cost-related challenges to APS; (iv) productive efficiency metrics and performance metrics and a ranking of APS in each of these areas; and (v) an analysis of the differences between the Liberty Study and Concentric Study.
- Section IV summarizes our conclusions based on our updated study.

# II. REVIEW OF THE LIBERTY STUDY

## A. BACKGROUND

The ACC commissioned Liberty to conduct a benchmarking analysis of certain attributes of APS. The need for the study emerged from a rate proceeding under Docket No. E-01345A-08-0172, and a settlement reached among the parties defined the nature and scope of the analysis. Specifically, the settlement agreement required that the ACC select a firm to conduct a benchmarking analysis of APS's operational and cost performance relative to a peer group of at least 30 other investor-owned electric-only utility operating companies. The settlement agreement required that the study focus, at a minimum, on the following areas:

- Operational performance
  - ✓ Safety
  - ✓ Customer Satisfaction
  - ✓ Delivery reliability
  - ✓ Base load power plant performance
  - ✓ Sustainability performance
- Cost performance
  - ✓ Non-fuel operating expense per customer
  - ✓ Distribution additions to plant per new customer
  - ✓ Capital expenditures
  - ✓ Hedging
  - ✓ Management of Expense
- Financial Health
  - ✓ Debt/equity ratio
  - ✓ Dividend payout ratio
  - ✓ Return on average assets
  - ✓ Return on average equity
  - ✓ FFO/Debt
  - ✓ Debt Ratings
  - ✓ Earnings per share (PNW) Stock Performance (PNW)

APS was required to pay for all costs for the benchmarking study up to $500,000 and was not allowed to recover the costs in rates.

The ACC issued a request for proposals ("RFP") to conduct the benchmarking analysis of APS pursuant to the settlement agreement, and awarded the contract to Liberty on March 31, 2010. The Liberty Study was filed with the Commission on February 28, 2011.

## B. STUDY APPROACH

The process used by Liberty to conduct the benchmarking analysis included five basic elements: (i) panel design; (ii) definition of expectations; (iii) data acquisition; (iv) data analysis; and (v) presentation of recommendations. Each of these steps is discussed in further detail below.

### *i. Panel Design*

The study process began with Liberty selecting multiple peer groups, or panels, against which to measure APS's performance. The settlement agreement, and the RFP, specified certain requirements for peer groups. Where practical, peer groups were required to meet the following criteria:

- At least 30 other investor-owned electric-only utility operating companies;
- Comparable revenue, customers, ownership of nuclear generation, customer density, growth and fuel and resource mix as APS;
- Include Salt River Project;
- A 10 year running period; and
- Segregation of data where possible between metropolitan and rural areas.

Liberty began with a base panel designed to fulfill the literal requirements of the RFP. The formation of the base panel initially included 128 regulated energy companies corresponding to Federal Energy Regulatory Commission ("FERC") Form 1 data. This comprehensive list of companies was then filtered using the following criteria:

- More than 300,000 electric customers; and
- Ownership of regulated generation.

The resulting final base panel included 40 regulated electric utilities,[1] including APS, as shown in Table 1.[2]

[1] Please note, while some companies have "Gas" in its name, they no longer have gas operations.

[2] Salt River Project was added pursuant to the requirements contained in the RFP and settlement agreement. However, Salt River Project ceased filing a FERC Form 1 in 2004.

## TABLE 1: BASE PANEL

| Base Panel | |
|---|---|
| Alabama Power Company | Kansas City Power & Light Company |
| Appalachian Power Company | Kansas Gas and Electric Company |
| Arizona Public Service Company | KCP&L Greater Missouri Operations |
| Carolina Power & Light Company | Kentucky Utilities Company |
| Columbus Southern Power Company | Monongahela Power Company |
| Dayton Power and Light Company | Nevada Power Company |
| Detroit Edison Company | Ohio Power Company |
| Duke Energy Carolinas, LLC | Oklahoma Gas and Electric Company |
| Duke Energy Indiana, Inc. | PacifiCorp |
| El Paso Electric Company | Portland General Electric Company |
| Entergy Arkansas, Inc. | Public Service Company of New Hampshire |
| Entergy Louisiana, LLC | Public Service Company of New Mexico |
| Entergy Mississippi, Inc. | Public Service Company of Oklahoma |
| Florida Power & Light Company | Salt River Project |
| Florida Power Corporation | Southern California Edison Co. |
| Georgia Power Company | Southwestern Electric Power Company |
| Gulf Power Company | Southwestern Public Service Company |
| Idaho Power Co. | Tucson Electric Power Company |
| Indiana Michigan Power Company | Virginia Electric and Power Company |
| Indianapolis Power & Light Company | Westar Energy (KPL) |

While the RFP required electric only utilities, Liberty determined that in some cases, the electric/gas differentiation among the 128 regulated energy companies was irrelevant.[3] This resulted in an expanded base panel of 65 utilities, as shown in Figure 2 below.

[3] Liberty stated that this differentiation was irrelevant, but did not explain how they determined this irrelevance.

## TABLE 2: EXPANDED BASE PANEL

| Added Utilities in Expanded Base Panel | |
|---|---|
| Avista Corporation | Public Service Company of Colorado |
| Consolidated Edison Company of NY | Public Service Electric and Gas Company |
| Consumers Energy Company | Puget Sound Energy, Inc. |
| Duke Energy Ohio, Inc. | Rochester Gas and Electric Corp |
| Entergy Gulf States Louisiana, L.L.C. | San Diego Gas & Electric Co. |
| Interstate Power and Light Company | Sierra Pacific Power Company |
| Louisville Gas and Electric Company | South Carolina Electric & Gas Co. |
| MidAmerican Energy Company | Tampa Electric Company |
| New York State Electric & Gas Corp | Union Electric Company |
| Northern Indiana Public Service Co. | Wisconsin Electric Power Company |
| Northern States Power Company - MN | Wisconsin Power and Light Company |
| NorthWestern Energy Division | Wisconsin Public Service Corp |
| Pacific Gas and Electric Company | |

In addition to the base and expanded panels, Liberty developed several tailored panels which recognized certain characteristics of APS and were used by Liberty to provide additional context to certain metrics and findings. These included a high growth panel, a regional panel, and a nuclear panel. The high growth panel was developed to analyze metrics that are typically affected by growth rates, and was defined as the 10 top growth companies in the base panel, with growth rates ranging from 2.4 percent to 4.5 percent, as shown in Table 3.

## TABLE 3: HIGH GROWTH PANEL[4]

| High Growth Panel | Annual Growth |
|---|---|
| Nevada Power Company | 4.54% |
| Arizona Public Service Company | 4.22% |
| Public Service Company of New Mexico | 4.08% |
| Columbus Southern Power Company | 3.72% |
| Salt River Project | 3.64% |
| Florida Power & Light Company | 2.79% |
| Tucson Electric Power Company | 2.69% |
| Virginia Electric and Power Company | 2.45% |
| Georgia Power Company | 2.44% |
| Appalachian Power Company | 2.44% |
| *Gulf Power Company* | *2.36%* |
| Gulf Power used when SRP unavailable | |

[4] Note that growth was measured in terms of growth in MWh sales between 1999 and 2007.

Liberty created a regional panel to recognize similar locational characteristics. The nine companies included in the regional panel are shown in Table 4.

TABLE 4: REGIONAL PANEL

| Regional Panel |
|---|
| Arizona Public Service Company |
| El Paso Electric Company |
| Nevada Power Company |
| PacifiCorp |
| Public Service Company of New Mexico |
| Salt River Project |
| Southern California Edison Co. |
| Southwestern Public Service Company |
| Tucson Electric Power Company |

Liberty also created a nuclear panel to evaluate the costs associated with the ownership of nuclear generation. While a total of 18 companies in the Base Panel were found to have nuclear generation, as shown in Table 5, only eight fell within 50 percent of APS in terms of generation.

TABLE 5: NUCLEAR PANEL[5]

| Nuclear Panel | |
|---|---|
| Alabama Power Company ☆ | Florida Power Corporation ☆ |
| Arizona Public Service Company | Georgia Power Company ☆ |
| Carolina Power & Light Company | Indiana Michigan Power Company ☆ |
| Detroit Edison Company ☆ | Kansas City Power & Light Company |
| Duke Energy Carolinas, LLC | Kansas Gas and Electric Company |
| El Paso Electric Company ☆ | Public Service Company of NM |
| Entergy Arkansas, Inc. ☆ | Salt River Project |
| Entergy Louisiana, LLC ☆ | Southern California Edison Co. |
| Florida Power & Light Company | Virginia Electric and Power Company |

Note: ☆ indicates company within 50% of APS in terms of nuclear generation

In addition to the above base and tailored panels, Liberty developed several other generation-related panels which were used to evaluate the operational performance of APS's three coal-fired generating plants - Cholla, Four Corners, and Navajo; and one nuclear plant - Palo Verde. For the coal-fired units, Liberty developed two sets of panels using two databases and applied screens to these databases based on the general characteristics of the APS generating

[5] El Paso Electric Company, Salt River Project, Southern California Edison, and Public Service Company of NM are co-owners of the Palo Verde Station

units. The first database consisted of coal-fired plants operated by companies in the expanded base panel. Liberty then applied a capacity factor screen of greater than 60%. This group of units was then segregated into two panels: (i) large units with a capacity between 600MW and 1,000MW which totaled 68 units; and (ii) small units between 100 Megawatts ("MW") and 300MW which totaled 98 units. The second database consisted of all coal-fired units contained in the Generator Availability Data System ("GADS") sponsored by the North American Electric Reliability Corporation's ("NERC"). Liberty applied a size screen to this database and developed two panels: (i) large units with a capacity between 600MW and 1,000MW totaling 141 units; and (ii) small units with a capacity between 100MW and 300MW totaling 195 units.

Similar to the process used to develop the coal panels, Liberty developed the nuclear panels using two databases. The first database of nuclear plants included those plants operated by companies in the expanded base panel. This group of plants was then segregated into two panels: (i) those units with pressurized water reactors ("PWRs") which totaled 38 units; and (ii) those units with boiling water reactors ("BWRs"), which totaled 9 units. The second database consisted of all nuclear units contained in the NERC GADS. Liberty applied a size screen to this database and developed a panel of units with a capacity greater than 1,000MW totaling 51 units.

### *ii. Definition of Expectations*

In addition to focusing on operational and financial parameters, Liberty supplemented its findings in each subject area based upon its expectations of where APS should fall relative to the peer group companies based upon its relative position in terms of specific key parameters. For example, APS might be the 4th largest in a panel, suggesting that APS should generally rank approximately 4th in terms of certain size-related performance measures (such as number of employees, total O&M costs, distribution investment, for example). Liberty used this approach to compare APS's actual performance in each functional area to Liberty's expectations.

### *iii. Data Acquisition*

In terms of data acquisition and analysis, Liberty used various sources of publically available data, including the following sources:

- FERC Form 1;
- Occupational Safety and Health Administration ("OSHA");
- Edison Electric Institute ("EEI");
- NERC GADS; and
- Data provided by APS.

Liberty performed its analysis using this data to assess APS's performance in numerous areas, and attempted to supplement these findings with explanations and unique circumstances as provided through discussions with APS.

#### *iv. Data Analysis*

Liberty used the comparison panels and above sources of data to develop numerous operational and financial metrics to measure APS's performance against an applicable peer group. Specifically, Liberty gathered data in the areas of operational performance, cost performance and financial health from 2000-2009. Operational performance included an analysis of generating plant, distribution system, and customer service metrics. Cost performance included an analysis of the costs associated with the operation of APS's generating units as well as its transmission and distribution system, the hedging function and the management function in terms of number of employees and salaries and wages. These metrics were generally placed on a per unit output basis such as megawatt-hour ("MWh") sales or total customers. Finally, Liberty analyzed data related to APS's financial health such as returns and earnings. Once developed, all of the metrics in each of these functional areas were compared to the appropriate peer group over a specified time period. A list of metrics and the peer group used for each metric is shown in Attachment A.

In some cases, APS's metrics were averaged and shown against a peer group average over a ten year period. In other cases, APS's metrics were shown for each year against a peer group average.

#### *v. Presentation of Recommendations*

Based on its findings, Liberty provided several recommendations in each functional area that, in its opinion, warranted more analysis and focused follow-up.

### C. Study Findings and Recommendations

#### *i. Areas of Average/Above Average Performance*

Based on a review of Liberty's approach and the findings and recommendations outlined in the report, APS was found to compare well against its peers in the areas shown below.

**Cost and Performance:**

- **Safety**

  Based on limited data from OSHA and EEI, APS's injury incident rate was below industry average from 2004 through 2009.

- **Customer Satisfaction**

Based on the 2010 J.D. Power survey for residential customer satisfaction covering 121 firms, of which 35 were members of Liberty's base panel, APS ranked 4th out of the 35 utilities in the base panel and 19th out of 121 utilities on a national basis.

- **Reliability**

  Liberty examined four standard industry measures of distribution system reliability – SAIFI (number of interruptions a customer sees in a year), SAIDI (number of interrupted minutes a customer sees in a year), CAIDI (number of minutes an average interruption lasts) and MAIFI (number of momentary interruptions a customer sees in a year). Based on available data compiled by EEI, APS compared far better than industry average in all four metrics.

- **Coal Plant Performance – Capacity Factor and Availability**

  Liberty examined the operational performance of the five Four Corners units, the three Cholla units, and the three Navajo units[6] in terms of Capacity Factor ("CF"), Equivalent Availability Factor ("EAF"), and Equivalent Forced Outage Rate ("EFORd") using the tailored panels described in II.B.i. Against these panels, Liberty found the CF of the Cholla and Four Corners units to be in the first quartile in the respective panels based on an average CF from 2005-2009. In addition, Liberty found that when compared to the GADS panel, the EAF of the units was generally better than the industry with the exception of Four Corners Unit 5, which was primarily due to very poor performance in 2008 and 2009. It should be noted, however, that Concentric disagrees with the formation of the base panel used by Liberty. This is further discussed in Section II.D below.

- **Coal Plant Fuel Costs**

  Liberty examined fuel costs at all of APS units over an unspecified period of time and found that all APS coal units were well below industry average in terms of fuel costs.

- **Coal Plant Non-Fuel Operating and Maintenance ("O&M") Costs**

  Liberty examined APS's non-fuel O&M costs on an individual plant basis without regard to APS's ownership share of each plant. Liberty found that APS's non-fuel O&M costs were below industry average on an individual plant basis.

- **Nuclear Fuel Costs**

[6] While APS owns 14% of the three Navajo units, Salt River Project is the operator of these units.

Liberty examined Palo Verde's fuel costs from 2001 - 2009 by trending these fuel costs on a $/MWh basis by year. Liberty found that APS has been close to the industry average over the past ten years. It should be noted, however, that Concentric disagrees with the formation of the base panel used by Liberty. This is further discussed in Section II.D below.

- **Transmission O&M**

  Liberty compared APS's Transmission O&M costs against the base panel on a per MWh sales basis for 2009 and on a dollar per line mile basis trended from 2000-2009. The results of Liberty's analysis showed that APS's costs were well below the industry average for both metrics.

- **Total Electric O&M**

  Liberty compared APS's Total Electric O&M costs (excluding power production) against the base panel. The major cost categories included in this metric were transmission, distribution, customer expense and administrative and general expense. On a total basis, APS's O&M costs were average against the base panel companies.

- **Total Electric Plant % Change**

  Liberty compared APS's average annual change in total electric plant from 2000-2009 against both the base panel and the high growth panel. In both cases, APS's investment in plant was reasonably aligned with the average of the panel companies.

- **Total Steam Production Plant**

  Liberty compared APS's average Steam Production Plant from 2000-2009 against the base panel in terms of both total dollars invested and on a per MWh of generation basis. Both metrics showed APS to be roughly equal to the panel average.

**Hedging:**

Liberty found that APS performance was strong with respect to policy level best practices and governance and operational parameters. This conclusion was consistent with the findings of past Liberty and RW Beck reviews.

**Funds Paid Among Affiliates:**

Liberty concluded that benchmarking does not shed much light on issues involving payments among affiliates and recommended a direct examination of the nature, extent, and pricing of

any interchanges among Pinnacle West enterprises only in the event that the Commission or stakeholders had a concern about cross subsidization potential.

*ii. Areas of Below Average Performance*

While APS's financial and operational performance was evaluated by Liberty and found to be at or above industry average in the areas shown above, there were several areas in which Liberty found APS's performance to be below average when measured against industry peers. These are described in further detail below.

**Cost and Performance:**

- **Coal Plant Operational Performance**

  Liberty reviewed the operation of each of APS's coal units using the tailored panels described in Section II.B.i. While Liberty found the capacity factors and availability of APS's coal units to generally compare well to the peer group, it found the Four Corners and Cholla units to be higher than their industry peers in terms of outage rates, with Four Corners Unit 5 having an especially high EFORd.

  While both Concentric, as well as APS recognize that these units have been operationally challenged over the past several years, we found several concerns with the analysis and findings, as further discussed in Section II.D.

- **Nuclear Plant Operational and Financial Performance**

  Liberty reviewed the operation of the Palo Verde nuclear units using the tailored panels described in Section II.B.i. Against these panels, Liberty found that the Palo Verde units did not compare well against their industry peers in terms of capacity factor, availability and outage rate.

  Regarding Palo Verde's financial performance, while fuel costs were found to be very close to industry average using Liberty's comparison panels, Palo Verde's operating and maintenance costs were found to compare less favorably to the nuclear units in Liberty's nuclear panel.

  As with the coal units, Concentric and APS recognize that Palo Verde has experienced performance and financial challenges over the past decade. However, we had several concerns with Liberty's analysis, as further discussed in Section II.D

- **Steam Production and Other Production Non-Fuel O&M**

  Liberty assessed APS's total steam production (coal-fired) O&M costs and other production (gas-fired) costs over a ten year period against the base panel companies in order to compare these costs on a company basis as opposed to a plant basis, which was the approach used for the coal and nuclear analysis described above. Liberty's findings for steam production showed that these costs were above industry average. For other production (gas-fired) costs, APS's costs were found to be above industry average over the last ten years. However, other production costs reported in FERC Form 1 information consist of numerous forms of generation, including both combined cycle and simple cycle gas fired units, and other types of costs[7]. In an effort to recognize these challenges, Liberty constructed a new panel of combined cycle units owned by regulated utilities and compared plants of similar size (+/- 30%) to two specific APS plants – Redhawk and West Phoenix 4 and 5. Liberty found that the non-fuel O&M costs of APS's plants were still high compared to the panel.

- **Distribution O&M**

  Liberty compared APS's distribution O&M costs to those of the base panel companies and found that they compared well to the base panel from 2000 – 2009 on total dollar per customer basis. However, Liberty raised concerns about spikes in 2007 and 2008 and recommended that APS analyze distribution O&M costs to determine the reasons for these spikes.

- **Customer Expense**

  Liberty examined APS's customer expense, defined as the sum of: i) customer accounts; ii) customer service; and iii) sales expense.[8] Liberty found that APS's customer expenses were far above the average of both the base panel and the growth panel on a per MWh sales basis as well as a per customer basis over the past decade. However, a review of APS's administrative and general ("A&G") expenses showed that APS has been far below the average of the base panel over the last ten years.

- **Nuclear Production Plant**

  Liberty found APS's average nuclear investment on a total dollars per year basis to be somewhat higher than its peers when compared to the nuclear panel over a 10 year period.

[7] APS includes the costs associated with its renewable programs in its other production costs

[8] These are all expenses charged to FERC accounts 901-917.

- **Transmission Plant**

  When compared to the average transmission plant and percent annual additions to transmission plant of the base panel companies from 2000 – 2009, Liberty found that APS was considerably higher than average.

- **Distribution Plant**

  Liberty reviewed the levels of APS investment in distribution using several metrics. Liberty presented distribution investment on a distribution plant per customer basis against the base panel, the high growth panel, and the regional panel. It also examined this metric as a function of service territory density and customer growth. Liberty found that by any measure, APS's distribution plant was significantly higher than the panel averages. Liberty acknowledged that APS's distribution plant has been high for many years, and reviewed additions to distribution plant in terms of capital expenditures as percent of distribution plant on average from 2000-2009 and found APS's investment to be higher than average as well. Furthermore, as required under the settlement agreement, Liberty examined distribution additions to plant per new customer against the base, high growth and regional panels and found APS's expenditures to be consistent with the industry average.

- **Management and Labor Expenses**

  Liberty examined APS's labor expenses in terms of number of employees and salaries and wages against its base panel. APS has a total of 6,800 employees, which was adjusted to an equivalent staffing level of 4,600 pursuant to a reconciliation of staffing performed by APS. Liberty's analysis showed that when staffing levels were examined on a per customer and per MWh sales basis, APS was higher than the average of the base panel companies. Based on these results, one would expect that the salaries and wages would be high as well. Indeed, salaries and wages on a per customer basis and a per MWh sales basis were significantly higher than the base panel. While Liberty claimed that APS's pensions and benefits were about 30% above the base panel average, it presented no data to support this statement.

**Financial Benchmarks:**

Liberty examined several financial metrics and found APS's long-term debt and commercial paper credit ratings to be comparatively low. In addition, it found that APS's Earned Return on Average Equity ("ROAE") and Earned Return on Average Assets ("ROAA") have fallen below those of the comparative panels from 2002-2009. High growth in APS's capital expenditures and operating expenses combined with historical test periods in rate cases have contributed to earnings attrition during this period.

Furthermore, Liberty found that APS's earnings growth rates were negative and below those of comparative panel members for 2000-2005, but have been at or near the base, expanded, nuclear and high growth panel averages for 2004-2009. APS as an investment for its parent was negative for the first half of the period and average for the past five years.

## D. CONCENTRIC REVIEW

Based on our review, we generally found Liberty's approach to the APS benchmarking study to be reasonable and consistent with industry practice. However, we had a number of specific concerns with its approach and analysis, which are discussed below.

### *i. Panel Design*

The development of Liberty's base panel is consistent with Concentric's approach to the updated benchmarking study as presented in Section III. However, we disagree with Liberty's use of the expanded base panel as constructed. The expanded base panel included some gas utilities, because Liberty found the electric/gas differentiation for these utilities to be irrelevant. However, we believe that the inclusion of gas utilities in any comparison group to APS is inappropriate, since the cost structure of combination gas and electric utilities is significantly different than that of electric-only utilities. In addition, since the base panel includes 40 utilities, which provides for an ample number of companies on which to base a comparison to APS, we are unclear as to the value of using this expanded panel.

Regarding the use of tailored panels, while the use of tailored panels is standard practice in benchmarking studies, the tailored panels developed by Liberty are troublesome in that they do not provide a basis for an accurate comparison to APS. For example, Liberty developed a high growth panel in recognition of the challenges presented by APS's above average growth in terms of expenditures and capital investments. However, the high growth panel, which was defined by the growth in MWh sales from 1999-2007, contains companies with compound growth rates ranging from 4.54% to 2.36%. This extremely wide range in growth rates renders the use of these companies as a basis for comparison to APS to be inappropriate. In addition, a more appropriate measure of growth would be in terms of customer additions since this drives many of the cost related metrics and capital spending.

The use of a nuclear panel is reasonable considering that the ownership and operation of nuclear facilities as part of a company's generation portfolio adds costs and risks not faced by companies that do not own and operate such assets. However, there are several issues with the nuclear panel as constructed by Liberty. First, the nuclear panel does not make a distinction between fleet operators and non-fleet operators. Nuclear power generation requires specialized skills, knowledge and processes in many areas such as fuel procurement, refueling and maintenance, and operations. Companies owning and operating multiple nuclear plants (i.e., "nuclear fleets") have the capability to leverage and deploy these specialized skills, knowledge, and processes across the fleet and achieve economies of scale largely unavailable to those owning and operating a single plant. Thus, nuclear fleets are well positioned to achieve superior performance relative to plants operated by a company owning a single plant. Also, the nuclear panel includes the other owners of Palo Verde, which makes the comparison of APS's nuclear operations to the nuclear panel circular and erroneous. Finally, and most importantly, Liberty used this panel only to benchmark APS's investment in nuclear plant. The analysis of APS's nuclear operational and cost performance was based on two separately constructed panels as described above.

### *ii. Databases and Screens Used for Plant Performance*

There were several issues with the panels and the underlying databases used to assess APS's coal and nuclear unit operational and financial performance: i) the databases used to develop the coal and nuclear unit panels used in the analyses included only units operated by the expanded base panel companies. It is unclear why Liberty did not use all units operating in the United States of similar size and technology to the APS's coal and nuclear units; ii) the databases used to develop the nuclear panels included nuclear generating units using both BWRs and PWRs, while Palo Verde uses only PWR technology; and iii) neither nuclear panel recognized the issue of including units owned by major fleet operators since there are distinct operational and cost advantages to companies owning a large fleet of nuclear units.

### *iii. Use of Performance Expectations*

The only other issue we take with Liberty's approach to the benchmarking study is its inclusion of performance expectations based on APS's position in the relevant panel. For example, Liberty provided the following example of the process used in developing these expectations:

> *For example, APS might be the 4th largest in a panel, suggesting that APS should generally rank approximately 4th in terms of certain size-related performance measures (such as number of employees, total O&M costs, distribution investment, for example).*

This approach is problematic in that no company will track simplistic performance principle in each and every metric. Many factors can affect performance, and these factors can be

outside of the control of the company. Therefore, the application of such performance expectations is inappropriate.

*iv. Study Findings*

In the areas in which Liberty found APS to compare well against its peers, as shown in Section II.C.i, we generally concur with Liberty's findings. However, there were several areas in which Liberty found APS's performance to be either above or below average when measured against industry peers. In some cases, these findings were valid based on the comparison panels used and the data analyzed. In other cases, Concentric believes that the analysis was flawed in terms of approach, comparison panels and metrics. Concentric describes each of these areas in further detail below, and presents an alternate approach to evaluating these metrics and APS's performance in Section III.

**Cost and Performance:**

- **Coal Plant Operational Performance**

  Concentric has several concerns with the panels and the underlying databases used to assess the operational and financial performance of APS's coal units. In addition to the issues with the comparison panels, we have further concerns with aspects of Liberty's assessment of APS's coal unit performance. First, we believe it is inappropriate to include Navajo in any performance assessment. While APS owns 14% of Navajo Units 1 – 3, APS does not operate these units, and does not have direct control over their performance. Second, we believe that presenting a metric as an average over a specific time period can mask poor as well as good or improving performance. For all of metrics analyzed – capacity factor, availability, and forced outage rate – APS's coal units were compared to the peer group units based on an average of the metric over a five year period for the capacity factor and a ten year period for availability and forced outage rate. Even though the capacity factor and availability for APS's coal units were found by Liberty to be better than average, we maintain that a better presentation of the metrics is on a year by year basis, as shown in Section III.

  Regarding the forced outage rates for the Cholla and Four Corners units, which were found by Liberty to be higher than the average of the units in the comparison group, APS recognizes that these units have been challenged in this area over the past several years. APS has been proactive in its response to these performance issues. It recently completed extensive benchmarking studies to determine the root causes of these performance issues, and has implemented performance improvement strategies. A trending of these performance metrics, shown in Section III, displays a positive trend in forced outage rates.

While APS has demonstrated performance improvements at the Cholla and Four Corners plants, the challenges presented by coal quality have been difficult, and will continue to affect the operation of these plants in the future. Liberty did acknowledge the challenges presented by poor coal quality, but minimized the importance of the difficulties presented by low quality coal and further suggested that this was a new problem that primarily affected performance in 2010. In fact, low coal quality has been a challenge for APS for several years. Low quality coal can and typically does have a detrimental effect on unit operation, and results in higher outage rates and lower availability. Four Corners in particular faces even more challenges than Cholla since it is a mine mouth unit and does not have the flexibility to source various coals. As a result, when the coal at the mine is of low quality, the Four Corners units will likely experience poorer performance. The cost advantages of lower quality coal, as Liberty demonstrated in assessing APS's lower than average fuel costs, are to be expected to be partially offset by poorer unit performance.

- **Nuclear Plant Operational and Financial Performance**

Concentric has several concerns with the panels and the underlying databases used to assess the operational and financial performance of APS's Palo Verde station. In addition, as with the coal units, Liberty presented the metrics analyzed – capacity factor, availability, and forced outage rate –based on an average of the metric over a three year period for the capacity factor and a ten year period for availability and forced outage rate. We will show these metrics using a trending approach year over year in Section III.

Turning to financial performance, while fuel costs were found to be very close to industry average using Liberty's comparison panels, Palo Verde's operating and maintenance costs were found to compare less favorably to the nuclear units in Liberty's nuclear panel. It is unclear why Liberty separately analyzed plant operating and plant maintenance costs, since the allocation of costs to these accounts differs by company. Therefore, we believe operating and maintenance costs should be combined and compared to an appropriate peer group, as shown in Section III.

In addition, Palo Verde is not located near a water supply, and must transport cooling water using over 35 miles of piping to provide a continuous flow of cooling water to the site. This adds more than $1/MWh to Palo Verde's operating costs. Because this is a cost incurred by APS that is highly unusual and outside of industry norm, this cost should be separately accounted for in Palo Verde's O&M costs in order to compare the plant to the peer group on an

equitable basis.

As with the coal units, APS recognizes that Palo Verde has experienced performance and financial challenges over the past decade. APS has taken steps to aggressively address these performance issues and has put programs in place to ensure that Palo Verde's performance is restored to at or above industry averages. Specifically, APS has addressed refueling outages to shorten them and improve plant availability and has aggressively invested in major equipment replacement such as new reactor heads and steam generators to address past underinvestment. In addition, APS has put in place an aggressive cost management and efficiency improvement program using benchmarking data from third-party sources. These efforts have resulted in a positive trend in plant performance, as shown in Section III.

- **Steam Production and Other Production Non-Fuel O&M**

Liberty assessed APS's total steam production (coal-fired) O&M costs and other production (gas-fired) costs in order to compare these costs on a company basis as opposed to a plant basis, which is in contrast to the approach used for the coal and nuclear analysis described above. Liberty's findings for steam production showed that these costs were above industry average. This is not surprising in that APS has a large ownership share of small, inefficient, high cost units that puts APS at a disadvantage when compared to the O&M costs of the companies in the base panel. A review of a company's total production O&M costs can be beneficial in getting a general sense of how a company's total O&M production costs compare to its peers. However, since these costs were examined on a power plant basis by Liberty, there was no added benefit to a high level review when a detailed review was already performed. Reviewing the costs on a company level is frequently problematic, as Liberty found. Many factors, included reporting differences and the inclusion/exclusion of certain costs in the FERC accounts, present problems when trying to perform an accurate comparison.

The problem of comparing production costs on a company basis was also apparent in Liberty's comparison of other production (gas-fired) costs. In this category, APS's costs were above industry average over the last ten years. However, other production costs reported in FERC Form 1 information consist of numerous forms of generation, including both combined cycle and

simple cycle gas fired units, and other types of costs[9]. The costs associated with operating various generation technologies vary widely, and do not provide any sound basis for comparison. While Liberty acknowledged this challenge and attempted to address it by constructing an alternative panel of regulated gas-fired units, we believe that this panel should not have been restricted to those combined cycle units owned by regulated utilities, but should have included units owned by unregulated entities as well. The results of this alternate analysis are presented in Section III.

- **Distribution O&M**

  Liberty found that APS's distribution O&M costs compared well to those of the base panel. However, Liberty raised concerns about spikes in 2007 and 2008 and recommended that APS analyze distribution O&M costs to determine the reasons for these spikes.

  As explained to Liberty by APS in the process of conducting the study, the spikes in 2007 and 2008 were largely due to a one time severance charged to the distribution O&M account, vegetation management expenses, and expenses related to the Bark Beetle problems in the region. The cost to address the bark beetle issue was 20% of the total cost of overhead line maintenance in 2008.

  It is important to note that a majority of APS's distribution system is underground which makes system maintenance more demanding in terms of cost as compared to almost all of the utilities in the base panel. Even with this challenge, APS's distribution O&M costs have largely been below industry average over the past decade, as discussed in Section III.

- **Customer Expense**

  Liberty examined APS's customer expense and found that APS's customer expenses were far above the average while APS's A&G expenses were far below average. This is not surprising since, according to the participation agreements between the co-owners of Palo Verde and Four Corners, APS must functionalize shared services expenses to the accounts related to the functional areas of the groups supported. These expenses are not charged to A&G accounts, which is how other companies with shared services expenses record these costs. As discussed and presented in Section III, a reasonable approach to benchmarking APS's total customer expenses is to combine APS's customer

[9] APS includes the costs associated with its renewable programs in its other production costs

and A&G expenses to eliminate this reclassification difference between APS and the comparable companies.

- **Nuclear Production Plant**

  Liberty found that APS's average nuclear investment on a total dollars per year basis was somewhat higher than its peers. However, we believe a more reasonable approach would be to measure investment as a function of unit size. When measured on a total dollars per "MW" basis, Palo Verde is very close to the average when compared to a more appropriate panel, as further discussed in Section III.

- **Transmission Plant**

  When compared to the average transmission plant, Liberty found APS to compare favorably to the base panel. When Liberty analyzed APS's percent annual additions to transmission plant against the base panel companies from 2000 – 2009, Liberty found APS's investment in transmission plant to be considerably higher than average. However, placing these metrics on a total dollar invested basis does not recognize the size of the transmission system. When presented on a length of transmission lines basis, APS's total transmission plant compares favorably to the industry average. When percent annual additions to transmission plant are trended, APS's investment has come into line with the panel averages, as shown in Section III.

- **Distribution Plant**

  Liberty reviewed the levels of APS investment in distribution using several metrics and found that by any measure, APS's distribution plant was significantly higher than the panel averages. Liberty acknowledged that APS's distribution plant has been high for many years. Pursuant to the settlement agreement, Liberty examined distribution additions to plant per new customer against the base, high growth and regional panels and found APS's expenditures to be consistent with the industry average. However, Liberty dismissed these results as misleading and found that when examined on the basis of total number of customers, APS's investment in distribution was still high.

  Concentric takes exception to Liberty's dismissive nature of the history of APS's high levels of distribution plant. When examined on a percent additions to total distribution plant by year, APS is marginally above its peers from 2000-2008 and has trended down to below average in the last two years, as further shown in Section III. In addition, due to the relatively new age of APS's distribution system as a result of the high customer growth experienced over

the last decade, APS has a less depreciated system and therefore its net plant will naturally be higher than its peers.

- **Management and Labor Expenses**

  Liberty examined APS's labor expenses in terms of number of employees and salaries and wages and found that APS was significantly higher than the average of the base panel companies. Our review of Liberty's approach revealed a significant flaw in the use of the base panel against which to assess APS's staffing and salaries and wages levels. Over 95% of Pinnacle West's operating revenues come from APS's electric utility operations and all of the employees and associated salaries, wages pensions and benefits are reported by APS in the FERC Form 1 data. However, many of the companies in the base panel have shared services[10] provided by the parent company or power provided by separate generating companies and do not report these employees or the costs associated with these employees as part of the electric utility FERC Form 1 data. A more appropriate approach to assess this metric would be to develop a panel of electric holding companies with at least 70% of revenues from electric utility operations, and include pensions and benefits in the analysis. Concentric shows the results of this analysis in its updated benchmarking study in Section III.

**Financial Benchmarks:**

Generally, Concentric found that Liberty focused on the appropriate metrics related to financial health of a utility. In particular, Liberty focused on standard financial performance measures such as return on assets and return on equity, funds flow from operations as it relates to debt levels and interest costs, debt to capitalization levels, and cash flow to capital expenditure levels. Equity investors, and to a slightly different degree debt investors, focus on these metrics as they evaluate their interest in owning the securities of a company.

Liberty found that APS's equity and asset return levels were low relative to the companies in the base panel. Liberty also found that APS's bond credit ratings, at BBB-, are one and a half steps below that of Liberty's base panel of companies, where the bond credit ratings average between BBB and BBB+. Liberty also noted that (high) debt leverage (at 58.3% of capitalization including the impact of "imputed debt" using the S&P method) "has been a drag on APS credit ratings for several years" and "debt levels need to improve for credit upgrades".[11] Based on these findings, Liberty provided three recommendations relating to this

[10] Shared services are those functional areas that provide services across multiple business units within a company such as accounting, legal, taxes, etc.

[11] Liberty Benchmarking Study, page 44

financial section of its analysis: i) evaluate specific drivers and causes for consistently low APS rates of return; ii) determine how the credit rating effects of power purchase agreements, operating leases and pension/other post-employment benefits ("OPEB") may be economically mitigated; and 3) determine whether the APS's targeted adjusted debt level of 52 percent will provide improved credit ratings results.

Concentric does not disagree with the direction of Liberty's recommendations. We believe a review of Liberty's findings in this area suggests Liberty has identified the key issue associated with APS's historically subpar financial performance. The key issue is earnings attrition due to regulatory lag. Regulatory lag in Arizona has traditionally been significantly longer than nearly any other jurisdiction according to data compiled by Regulatory Research Associates ("RRA"), as further described in Section III. In the most recent rate case in front of the ACC, an order was issued within 21 months of filing. While the rate case lag was still substantial, in this case, the ACC permitted rate recognition of certain post-test-period adjustments, which mitigates some issues associated with regulatory lag. It is surprising, therefore, that Liberty sees the need to "evaluate specific drivers and causes" for APS's earnings attrition.

# III. CONCENTRIC UPDATED 2010 BENCHMARKING STUDY

## A. INTRODUCTION AND APPROACH

Concentric's overall approach to conducting the updated study involved an assessment of APS's productive efficiency relative to comparable groups of companies in specific years and across time in order to measure APS's performance in fulfilling its cost obligations. In addition, in order to assess whether any cost improvements that may have been achieved were done at the expense of reducing customer service or reliability, we assessed specific service quality metrics. We then developed a situational assessment to recognize that the cost advantages or disadvantages that many utilities face are the product of circumstances beyond their control. The situational assessment examined these exogenous factors, which were then used to place a utility's cost performance in the context of the market it serves.

### *i. Panel Selections*

The first step in performing the updated benchmarking study involved developing the composition of the peer groups used to compare to APS. Our objective in determining the sample set of electric utility companies was to achieve the largest group for which consistent data were available and which was operationally similar to APS. APS is an electric-only utility with over 1,000,000 customers and ownership in generating resources. Therefore, we established a group of companies with electric-only utility operations who have at least 300,000 customers and own generating resources. We did not include gas utilities in any comparison group to APS, since the cost structure of combination gas and electric utilities is significantly different than that of electric-only utilities. We define this group of 39 comparable companies as the "Base Panel." This Base Panel contains the same companies as Liberty's base panel, with the only difference being Liberty's inclusion of the Salt River Project in its base panel pursuant to the settlement agreement.[12]

In addition, we established a panel of other investor-owned electric utilities subject to the same jurisdictional authority. This "Regional Panel" includes the same nine companies contained in Liberty's regional panel.

While Liberty also created a high growth panel and a nuclear panel, for reasons discussed in Section II.D, we did not see the value in a high growth panel. However, we did create a nuclear panel for the purpose of comparing Total Non-Fuel O&M expenses. This panel consisted of Base Panel companies that own units that are part of a fleet operation, and excluded owners whose only nuclear ownership was in the Palo Verde plant.

[12] Since data for Salt River Project are not available beyond 2004, we did not include it in our Base Panel.

Overall, our comparisons panels are generally limited to the Base Panel and the Regional Panel for the total benchmarking assessment.

*v. Selection of Metrics*

After we developed our comparison panels, we defined the operational, financial and reliability/service quality metrics that were to be used in the benchmarking study. We compiled data from various sources to provide sufficient metrics to assess APS's overall performance relative to the comparable groups. Similar to Liberty, we relied on FERC Form 1 reports (as reported by SNL Financial). For supplemental metrics related to APS's operational and service quality performance, we used NERC GADS data as well as Edison Electric Institute ("EEI") data. We then defined the timeframe over which the analysis was to be performed. In general, we used the same time frame used by Liberty, 2000 – 2009, and added 2010 data. In some cases, such as for generating unit performance and reliability measures, data were only available for the most recent five years. We generally used the same operational and service quality metrics used by Liberty. However, there were some minor differences, as discussed in more detail below.

*vi. Data Analysis*

Following the selection of the metrics to be used, we developed merit order benchmarking results for the companies in the comparable groups in terms of operational and cost performance based on these metrics. In assessing APS's service quality, we compared customer satisfaction and distribution system reliability using the JD Power survey results to assess customer satisfaction and industry-wide EEI data to assess reliability. This is consistent with Liberty's approach.

In assessing operational performance, we developed coal panels based on comparable unit sizes and nuclear panels based on comparable unit technology, while Liberty restricted its coal and nuclear panels to those units owned by the companies in its expanded base panel. In addition, while Liberty showed averages of APS's generating unit performance metrics against a 10 year average of the units in the comparable panel, we showed year by year performance for each metric to capture important trends.

In assessing cost performance, we measured the level of cost input per unit of "output" in the same way Liberty did, such as customer service expense per customer, or O&M expense per MWh sold. While we present these cost diagnostics individually by rank or merit order, Liberty did not present a ranking of APS against the peer group companies in these metrics, but rather presented the average of the metric for APS against the average of the metric for the peer group companies. Finally, in order to develop an "overall" assessment based on rank order, we took an average of all the rank order values and developed a merit order based on those averages. This approach shows APS's relative overall merit order. Liberty did not present an overall ranking.

Finally, in recognition of the significantly different service area characteristics that the peer group members face, and the diverse performance challenges created by these service area characteristics, we developed a situational assessment ranking which reflects the degree of difficulty that each peer group member faces in seeking to maximize its productive efficiency. We used the same method described above to rank the level of challenges to performance that different companies face in order to put the benchmarking results in context. Liberty did not conduct a situational assessment.

### B. SITUATIONAL ASSESSMENT

As noted above, the purpose of the situational assessment is generally to provide insight into the companies' operations and, in turn, offer context and a deeper understanding of their performance and costs. The situational assessment helps to explain the challenges a utility faces in keeping costs low. Concentric's situational assessment considered ten specific metrics which were used to evaluate APS's business and operating environment relative to the various peer groups companies. For each metric and comparison group, we developed a rank order of the companies as well as an overall score based on the average rank. In this study, a high-ranking of "1" indicates the highest level of challenges. The more challenged a company is, the greater the difficulty can be expected in controlling costs. These factors largely represent exogenous factors that are defined by the company's customer base and service area, and are beyond the company's control.

The results of the situational assessment are shown in Exhibits 1 and 3, and a summary of each metric is provided below:

- **Percent Sales Residential**

  Nearly half of APS's sales by volume are sales to residential customers. APS is consistently in the top quartile of residential sales in both the Base and Regional Panels. In general, residential customers are more expensive to serve than commercial and industrial customers (driven by, e.g., customer-related expenses, load factor considerations). As a result, utilities with a higher proportion of residential customers tend to have higher costs.

- **Percent Sales Other**

  Other sales represent all sales other than those to residential, commercial, and industrial customers. This category also includes Sales for Resale. APS, with a very low volume of other sales, is in the top quartile of the Regional Panel and consistently ranks first or second in the Base Panel. These results are consistent with APS's ranking in the Percent Sales Residential metric.

- **Use per Customer**

Use per customer measures the average volume of sales to each customer. Since many of the costs of serving an individual customer do not vary with the level of consumption, utilities with lower use per customer levels tend to be higher cost operations. APS is consistently in the second quartile of the Base Panel. In the Regional Panel, APS's use per customer is comparable to the regional companies.

- **Change in Customers (%)**

  Increases or decreases (in absolute percentage terms) in the number of customers create challenges in terms of managing capital expenditures, plant utilization and fixed cost amortization. APS's customer growth rate has historically placed it in the top quartile of the Base and Regional Panels. However, APS growth rate has tempered somewhat in the most recent two years, where APS has ranked in the second quartile of the Base and Regional Panels.

- **Change in Sales Volume (Rolling Five Year Average)**

  Like changes in customer base, dramatic shifts in sales volume pose challenges to any company. When measured on a rolling five year basis[13], APS's change in sales volume has placed it in the top quartile in the Base Panel in ten of the last eleven years and the top quartile in the Regional Panel in eight of the last eleven years.

- **Customer Density**

  The customer density within a utility's service territory is an important factor in assessing the cost of serving customers. Companies whose service territory is more spread out require more infrastructure to provide service to customers and therefore incur higher costs. APS has a significantly more rural service territory when compared to both the Base and Regional Panels. APS has ranked in the top quartile in the Base Panel in each of the last eleven years and in the top quartile in seven of the last eleven years in the Regional Panel.

- **Percent Generation Nuclear**

  The costs for nuclear generation are comparatively higher than coal-fired, oil-fired, gas-fired and hydroelectric generating resources. APS has a higher percentage of its generation produced by nuclear resources than its peers in any of the comparison groups. APS has ranked in the second quartile over the last eleven years in terms of percentage nuclear generation in the Regional and Base

[13] This metric is calculated by comparing the current year sales volume to the average of the previous five years sales volume to calculate a percent change.

Panels. This places significant pressure on APS' cost structure and its ability to maintain competitive rates relative to its peers in the region.

- **Energy Losses**

  Energy losses are a product of the transmission and distribution infrastructure through which the energy is transmitted. Electric utilities which are more transmission dependent experience higher losses than utilities which are able to site generation closer to load centers. While APS has historically not been challenged in this area, it has been in the second quartile in four of the last five years in the Base Panel.

- **Depreciation to Gross Plant**

  This metric is a reasonable proxy for the age of a utility's asset base. Utilities with a higher proportion of accumulated depreciation to gross plant have delivery systems which tend to be older. Older systems tend to require more costly maintenance. This metric shows that APS has relatively newer infrastructure when compared to the Base and Regional Panels. This indicates that APS has not been challenged in terms of higher maintenance costs.

- **Regulatory Lag**

  Regulatory lag, as measured by rate case lag, represents the time it takes for a utility to recover through rates costs incurred to provide service to their customers, which impacts the financial health and capability of the utility. This metric represents the challenge that a utility faces in terms of regulatory uncertainty and cost recovery. Since 2006, APS has had the highest rate case lag in either the base panel, or the regional panel.

It is important to keep the situational assessment in context. We offer these metrics as a means of getting the lay of the land in better understanding the productive efficiency metrics. This is not a perfect means of capturing all of the challenges or advantages of the companies in the comparable groups, but represents a reasonable cross-section of publicly available measures of a utility's operating environment. While only a high-level snapshot, these data indicate that APS is consistently one of the more situationally-challenged companies within the comparison groups, as shown below.

**TABLE 6: SUMMARY OF SITUATIONAL ASSESSMENT RANKINGS**

| | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| APS in Base Panel | 9 | 6 | 6 | 5 | 8 | 6 | 4 | 2 | 1 | 2 | 3 |
| APS in Regional Panel | 3 | 2 | 3 | 3 | 3 | 3 | 1 | 2 | 1 | 2 | 1 |

### C. PRODUCTIVE EFFICIENCY ASSESSMENT

To assess APS's cost performance, we created unique categories of metrics against which to compare APS's performance to the two different peer groups across the 11-year study period.[14] By comparison, Liberty used similar metrics to assess APS's cost performance, although some of these metrics differed slightly.[15] In our productive efficiency assessment, a ranking of "1" indicates that the company is more efficient than the companies in the peer group. Exhibit 2 shows the merit order rankings for each company, on each metric, for each year. The underlying values for the productive efficiency metrics are provided in Exhibit 3. It should be noted that Liberty did not provide such a ranking, but rather showed its metrics on an average basis against the entire peer group average.

Concentric measured APS's performance across a variety of expense categories. Similar to Liberty, we included high-level measures, such as total non-fuel O&M expenses, as well as various subcategories. Most metrics are calculated on an expense per customer or an expense per MWh sold basis. The productive efficiency metrics presented in the analysis are an average of the per-customer values and the per MWh values for each cost element. For example, the Customer/A&G expenses metric reflects each utility's Customer/A&G expenses per MWh sold and Customer/A&G expenses per customer, and presents the average performance rank on these two metrics as the measure of Customer/A&G productive efficiency. To ensure that APS's performance on cost metrics did not occur at the cost of lower reliability or customer satisfaction, we also compiled a variety of metrics to measure APS's operational and service quality performance. The detailed definitions of each of the productive efficiency, operational and service quality metrics used are presented in Exhibit 3 and are described below.

- **Production O&M expenses**

  APS has shown consistent improvement in its Production O&M performance relative to the comparison groups. APS has consistently been in the second and third quartile for the Base Panel on a per customer basis.

  Liberty did not review Production O&M expenses on a total basis, but rather reviewed these expenses separately for steam production (coal-fired), other production (gas-fired), and nuclear production. The only category in which Liberty found APS's expenses to be unusually high was nuclear production. However, as discussed previously, Liberty analyzed nuclear plant operating and plant maintenance costs separately, and did not adjust for the cost of providing

[14] Concentric did not create metrics to assess the financial health of APS as Liberty was required to do pursuant to the settlement agreement.

[15] Liberty's metrics were largely dictated by the settlement agreement, while we used metrics that we consider to be most relevant in assessing a company's ability to control costs.

cooling water to the plant. As shown in Attachment B, when we make these adjustments and compare nuclear O&M costs against the peer group of units used in our performance analysis, as discussed below, APS's nuclear O&M costs compare much more favorably, ranking no worse than the third quartile for seven of the eleven years included in the study.

- **Transmission O&M expenses**

  In addition to the per-customer and per-MWh cost measurement used in other metrics, our overall merit-order ranking for Transmission O&M also takes into account Transmission O&M expenses per mile of transmission line. APS has consistently been in the second or third quartile of the Base Panel across all measures and in the first or second quartile in the Regional Panel by all measures over the last ten years. In 2010, APS achieved its best performance to-date relative to each of the comparison groups across all measures, ranking in the first quartile for the Regional Panel, and the second quartile for the Base Panel.

  Liberty compared the APS's transmission O&M costs to those of its base panel companies on a per MWh sales basis and per line mile basis and found APS's transmission O&M expenses to be below industry average.

- **Distribution O&M expenses**

  APS's distribution system has a large percentage of its infrastructure underground. This would suggest all else being equal, that APS Distribution O&M expenses would be higher than a utility with a largely above-ground distribution system. As shown in Attachment C, APS has the second-highest percentage of its distribution system underground of all utilities reported. However, APS has been in the second or third quartile of the Base Panel and the Regional Panel in terms of Distribution O&M expenses for all years on both a per customer and per MWh sales basis, demonstrating the Company's success at managing costs in this area.

  Liberty compared APS's distribution O&M costs to its base panel and high growth panel companies on a per customer basis and found APS to be competitive against both.

- **Customer and A&G expenses**

  Liberty reviewed customer expenses on a per MWh sales basis and a per customer basis against both its base and high growth panels and found them to be far above the panel averages. It also reviewed APS's A&G expenses on a per MWh sales basis against its base panel and found them to be far below the panel average in most years. As previously discussed, the participation agreements

between the co-owners of Palo Verde and Four Corners require APS to functionalize shared services expenses to the FERC customer accounts related to the functional areas of the groups supported, and not charge these expenses to A&G accounts, which is how other companies with shared services expenses record these costs. Given these facts, a reasonable approach to benchmarking APS's total customer expenses is to combine customer and A&G expenses to eliminate this reclassification difference between APS and the comparable companies. Based on this approach, APS has consistently been in the second or third quartile in the Base Panel, and the second quartile in the Regional Panel in each of the last seven years.

- **Total Non-Fuel O&M Expenses**

  Overall, APS has performed well in controlling Total Non-Fuel O&M expenses, falling in the second or third quartile of the Base Panel and Regional Panel in ten out of eleven years on a per customer and per MWh sales basis. Compared to the Nuclear Panel, APS ranks much more favorably, with an overall rank of one or two against the comparison companies.

- **Plant Investment**

  Liberty reviewed APS's overall Plant Investment and Plant Investments in a number of functional areas. Liberty noted APS has high levels of nuclear plant and distribution plant by measures of accumulated plant, and high levels of transmission new capital expenditures.

  Similar to Liberty's approach, Concentric looked at the overall level of investment for Production, Transmission, Distribution, and Total Electric Plant compared to existing plant balances. Production Plant Investment was in line with the Base Panel and the Regional Panel ranking in the first or second quartile for eight of the eleven years in the study period. However, Transmission Investment trends higher than the peer groups. Importantly, since 2006, APS has not dropped below the third quartile of the Base Panel which demonstrates the level of Transmission Investment has trended closer to the comparable group mean.

  Distribution Plant Investment was especially high in prior years, specifically 2000 through 2007, when it was ranked in the fourth quartile of the Base Panel. However, this can be expected due to APS's high customer growth over those years. Since 2007, APS's Distribution Plant Investment has moderated. On a Total Electric Plant basis, APS's level of Plant Investment has been consistent with the Base Panel, ranking in the second and third quartile in the Base Panel, and improving over time. Overall, APS's capital spending has been consistent

with industry averages, and has decreased relative to comparable companies in recent years.

- **Labor Efficiency**

  Liberty reviewed employee costs by analyzing APS's staffing levels on an employee per customer basis and employee per MWh sales basis compared to its base panel companies and found APS to be well above the average of the base panel. In addition, Liberty analyzed APS's salaries and wages on a per customer and per MWh sales basis against its base panel companies and found APS to be approximately 30% higher than the base panel average. However, as discussed above, we found Liberty's approach to be flawed in the use of the base panel against which to assess employee costs.

  Our standard approach to evaluating employee costs is to assess this cost in terms of Labor Efficiency. Labor Efficiency is a metric that combines Salaries, Wages, Pensions, and Benefits per Customer and Employees per Customer. Because utility companies vary greatly in organizational structure, and employees may be reported at different levels of a given company's organizational structure, comparisons to the Base Panel and Regional Panel were inconsistent. To reduce the potential incongruities between reporting structures, Concentric developed a panel of comparable companies, specifically for this metric, at the holding company-level. We used holding companies so that any job functions shared across various divisions of the company would be accounted for, and also would not be double-counted. The comparable group included companies, like Pinnacle West Capital, that are primarily engaged in electric utility operations. As shown in Attachment D, using this comparable group, APS, as represented by Pinnacle West Capital, ranked in the second and third quartiles for Employees per Customer and its Salaries, Wages, Pensions, and Benefits per Customer were reasonable.

- **Nuclear Plant Performance**

  As noted in the Liberty Study and acknowledged by APS, the performance of the Palo Verde units has left room for improvement. However, as noted in Section II.D, above, it is important to benchmark APS's nuclear operating performance against an appropriate nuclear peer group – one that includes all PWR units greater than 1,000 MW. When benchmarked against this nuclear peer group using data from the GADS database from 2005-2010, the results of APS's efforts to improve the performance of the Palo Verde units are evident. Palo Verde's EAF has gone from a low of 70% in 2006 to 89% in 2010 against an industry average of 87%. Similarly, in terms of outage rates, Palo Verde's EFORd has dropped dramatically from 14% in 2006 to 1.8% in 2008 against an industry average of 4.8%. Palo Verde's CF has gone from below the industry

average in 2006 to above the industry average in 2010.[16] Due to shorter refueling outages and investments in major equipment replacements, the Palo Verde station has show dramatic improvement in terms of availability, outage rates, and capacity factor, and continues to make significant operational improvements as shown in Attachment E.

- **Fossil Plant Performance**

  As previously discussed, APS recognizes that the coal units have been faced with performance challenges over the past several years. APS has been proactively addressing these challenges by uncovering the root causes of the performance issues and implementing improvement strategies. Liberty's findings reflected these challenges. However, as previously discussed above, it is important to benchmark APS's coal unit operating performance against an appropriate peer group – one that does not limit the peer group to units owned by the expanded base panel companies and includes screens for size.

  For Cholla Units 1-3 and Four Corners Units 1-3, a comparison to coal-fired units contained in the NERC GADS database between 100MW and 300MW using data from 2005-2010 shows that both the Four Corners and Cholla plants have experienced some variability in terms of EAF[17]. The Cholla units have been more consistent in terms of EFORd and CF, with the exception of Cholla Unit 2 which experienced a major equipment failure and significant outage in 2010. When compared to coal-fired units contained in the NERC GADS database between 600MW and 1,000MW, the Four Corners Units 4 and 5 have historically been at or near industry average, while Unit 5 has historically been more challenged in terms of EFORd and CF. These operation metrics are shown in Attachment F.

  While APS has demonstrated performance improvements at its coal-fired stations, the challenges presented by poor coal quality will continue to be an issue for APS. Low quality coal frequently has a negative effect on plant operations. Since APS's coal units do not have supply flexibility, the performance of its fossil units is a direct result of the quality of the coal at the mine where the plant is located. This has a negative impact on fossil plant O&M expenses, but is offset by substantially lower fuel costs. It is important to highlight that the availability of the units has compared favorably despite having higher than average forced outage rates, which is a reflection of APS's ability to return the units to service quickly.

[16] Palo Verde operational statistics from 2005-2010 were provided by APS.
[17] Coal plant operational statistics from 2005-2010 were provided by APS.

## D. SERVICE QUALITY ASSESSMENT

It is important to assess whether a particular company has successfully achieved both its cost and service obligations. In addition to productive efficiency, we evaluated APS's quality of service in terms of system reliability and customer service quality.

- **Distribution system reliability**

  Similar to the Liberty approach, we considered four measures in assessing distribution system reliability: (i) Distribution System Average Interruption Frequency Index ("SAIFI") is defined as the number of interruptions a customer sees in a year; (ii) Distribution System Average Interruption Duration Index ("SAIDI") is defined as the number of interrupted minutes a customer sees in a year; (iii) Customer Average Interruption Duration Index ("CAIDI") is defined as the number of minutes an average interruption lasts; and (iv) Momentary Average Interruption Frequency Index ("MAIFI") is defined as the average number of momentary interruptions that a customer would experience during a given period (typically a year). In analyzing SAIFI, APS has consistently outperformed the industry in each year since 2005. Similarly, APS's SAIDI has been in the top quartile in each year over the last five years. APS's CAIDI has been outstanding against industry peers in each year over the last five years. Finally, APS' MAIFI has been far below the industry average in each year since 2005. These metrics indicate that APS is providing high quality service to its customers in terms of reliability.

- **Customer service quality**

  Consistent with the Liberty approach, Concentric reviewed the 2010 JD Power survey for residential customer satisfaction as a measure of APS's relative customer service quality. The JD Power survey measures customer satisfaction of electric utility companies by examining six key factors: (i) power quality and reliability; (ii) price; (iii) billing and payment; (iv) corporate citizenship; (v) communications; and (vi) customer service. Based on the results of this survey, APS ranks in the top quartile of base panel companies, and 19$^{th}$ out of 121 utilities across the nation.

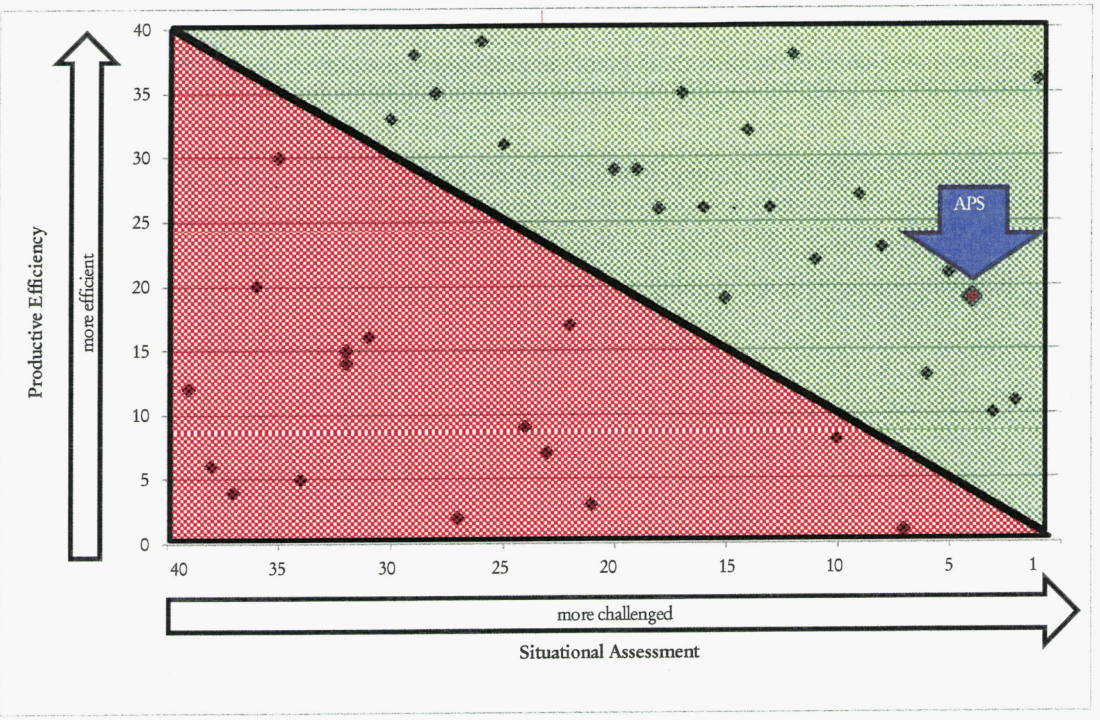
## IV. CONCLUSIONS

As shown in Exhibit 2, APS has ranked in the second and third quartile in ten out of eleven years in the Base Panel and ranks between the first and third quartile in the Regional Panel in terms of productive efficiency over the course of the study. Most importantly, APS's performance on the productive efficiency benchmark has not occurred at the expense of service reliability or customer satisfaction.

It should be noted that these results are based entirely on the ranking of the performance metrics, without any adjustment made for the challenges demonstrated in the Situational Assessment. While the situational assessment is not a perfect means of capturing all of the challenges or advantages of the companies in the comparables groups, it does represent a reasonable cross-section of publicly available measures of a utility's operating environment. While only a high-level snapshot, these data indicate that APS is consistently one of the ten most "situationally-challenged" companies within the Base Panel and one of the top three "situationally challenged" in the Regional Panel, as the results show in Exhibit 1.

Considering both the challenges identified in the situational assessment and the productive efficiency ranks from the benchmarking analysis is a valuable exercise in putting APS's performance in context. Figure 1 combines the productive efficiency merit order rankings and the situational assessment rankings. When viewed on these axes, a bandwidth around the diagonal line running from the upper left corner to the lower right corner reflects the utilities whose productivity is consistent with the challenges identified in the situational assessment. The further away (either above or below) that a utility's performance is from this line, the more exceptional is its performance (either exceptionally good or exceptionally poor).

## FIGURE 1: COMBINED ASSESSMENT 2010




As shown above, APS's performance in 2010 was exceptionally good, and APS outperformed its Base Panel peers on a basis which considers both absolute productivity measures and the relative challenges it faced.

## Situational Assessment Rankings - 2000

(a rank of 1 indicates the most challenged performer for each metric)

| Base Panel | Percent Sales (MWh) Residential | Percent Sales (MWh) Other | Use per Customer | Change in Customers (%) | Change in Sales Volume (%) | Percent Generation Nuclear (%) | Energy Losses (%) | Age of Plant (Depreciation/Gross Plant) | Customer Density | Regulatory Lag | Average Rank | Overall Rank |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| *Arizona Public Service Company* | *4* | *35* | *11* | *4* | *2* | *7* | *31* | *32* | *4* | *31* | *16.1* | *9* |
| Alabama Power Company | 24 | 19 | 36 | 24 | 14 | 15 | 38 | 31 | 11 | | 23.6 | 35 |
| Appalachian Power Company | 8 | 17 | 21 | 31 | 36 | 18 | 16 | 27 | 8 | 14 | 19.6 | 25 |
| Carolina Power & Light Company | 16 | 22 | 29 | 7 | 25 | 5 | 32 | 9 | 19 | | 18.2 | 18 |
| Columbus Southern Power Company | 10 | 13 | 10 | 8 | 27 | 18 | 22 | 29 | 28 | 11 | 17.6 | 15 |
| Dayton Power and Light Company | 21 | 16 | 16 | 37 | 37 | 18 | 9 | 13 | 24 | 16 | 20.7 | 28 |
| Detroit Edison Company | 34 | 7 | 7 | 33 | 29 | 16 | 13 | 21 | 34 | 26 | 22.0 | 31 |
| Duke Energy Carolinas, LLC | 27 | 6 | 32 | 10 | 30 | 4 | 20 | 24 | 13 | 26 | 19.2 | 23 |
| Duke Energy Indiana, Inc. | 30 | 34 | 31 | 14 | 22 | 18 | 7 | 22 | 23 | 6 | 20.7 | 28 |
| El Paso Electric Company | 31 | 32 | 4 | 12 | 31 | 1 | 23 | 1 | 7 | 3 | 14.5 | 4 |
| Entergy Arkansas, Inc. | 13 | 33 | 18 | 35 | 18 | 3 | 18 | 14 | 3 | 11 | 16.6 | 12 |
| Entergy Louisiana, LLC | | | | | | | | | | | | |
| Entergy Mississippi, Inc. | 6 | 12 | 22 | 18 | 16 | 18 | 4 | 34 | 9 | 31 | 17.0 | 13 |
| Florida Power & Light Company | 1 | 2 | 5 | 9 | 19 | 9 | 8 | 3 | 33 | | 9.9 | 2 |
| Florida Power Corporation | 2 | 14 | 9 | 19 | 12 | 14 | 14 | 5 | 30 | 22 | 14.1 | 3 |
| Georgia Power Company | 33 | 5 | 35 | 11 | 7 | 13 | 11 | 26 | 20 | 26 | 18.7 | 20 |
| Gulf Power Company | 3 | 24 | 13 | 13 | 4 | 18 | 29 | 19 | 10 | 22 | 15.5 | 6 |
| Idaho Power Co. | 29 | 25 | 33 | 6 | 5 | 18 | 12 | 33 | 1 | 22 | 18.4 | 19 |
| Indiana Michigan Power Company | 32 | 18 | 24 | 36 | 32 | 12 | 15 | 7 | 22 | 4 | 20.2 | 27 |
| Indianapolis Power & Light Company | 22 | 8 | 23 | 25 | 35 | 18 | 26 | 15 | 36 | 15 | 22.3 | 32 |
| Kansas City Power & Light Company | 20 | 9 | 19 | 27 | 6 | 11 | 21 | 30 | 16 | 33 | 19.2 | 23 |
| Kansas Gas and Electric Company | 23 | 10 | 20 | 26 | 23 | 8 | 1 | 37 | | 5 | 17.0 | 13 |
| KCP&L Greater Missouri Operations Company | 7 | 23 | 6 | 38 | 26 | 18 | 3 | 12 | 27 | 20 | 18.0 | 17 |
| Kentucky Utilities Company | 19 | 37 | 30 | 17 | 11 | 18 | 24 | 8 | 17 | 8 | 18.9 | 22 |
| Monongahela Power Company | 36 | 15 | 17 | 2 | 3 | 18 | 28 | 11 | 6 | 16 | 15.2 | 5 |
| Nevada Power Company | 5 | 3 | 15 | 3 | 1 | 18 | 27 | 38 | 25 | 26 | 16.1 | 9 |
| Ohio Power Company | 37 | 28 | 37 | 34 | 38 | 18 | 30 | 10 | 18 | 20 | 27.0 | 38 |
| Oklahoma Gas and Electric Company | 17 | 11 | 27 | 1 | 15 | 18 | 17 | 6 | 29 | 22 | 16.3 | 11 |
| PacifiCorp | 35 | 36 | 25 | 22 | 34 | 38 | 19 | 35 | 2 | 19 | 26.5 | 37 |
| Portland General Electric Company | 9 | 30 | 12 | 20 | 9 | 18 | 35 | 16 | 32 | 6 | 18.7 | 20 |
| Public Service Company of New Hampshire | 15 | 29 | 1 | 23 | 24 | 17 | 33 | 4 | 14 | | 17.8 | 16 |
| Public Service Company of New Mexico | 26 | 38 | 2 | 15 | 20 | 10 | 36 | 23 | 31 | 11 | 21.2 | 30 |
| Public Service Company of Oklahoma | 14 | 4 | 28 | 29 | 10 | 18 | 5 | 18 | 21 | 8 | 15.5 | 6 |
| Southern California Edison Co. | 25 | 1 | 3 | 28 | 8 | 2 | 2 | 2 | 15 | 1 | 8.7 | 1 |
| Southwestern Electric Power Company | 28 | 26 | 34 | 32 | 33 | 18 | 34 | 20 | 12 | 10 | 24.7 | 36 |
| Southwestern Public Service Company | 38 | 27 | 38 | 21 | 28 | 18 | 6 | 28 | 5 | 26 | 23.5 | 34 |
| Tucson Electric Power Company | 11 | 31 | 8 | 5 | 13 | 18 | 25 | 36 | 35 | 16 | 19.8 | 26 |
| Virginia Electric and Power Company | 12 | 20 | 26 | 16 | 21 | 6 | 10 | 17 | 26 | 2 | 15.6 | 8 |
| Westar Energy (KPL) | 18 | 21 | 14 | 30 | 17 | 18 | 37 | 25 | | | 22.5 | 33 |

| Regional Panel | Percent Sales (MWh) Residential | Percent Sales (MWh) Other | Use per Customer | Change in Customers (%) | Change in Sales Volume (%) | Percent Generation Nuclear (%) | Energy Losses (%) | Age of Plant (Depreciation/Gross Plant) | Customer Density | Regulatory Lag | Average Rank | Overall Rank |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| *Arizona Public Service Company* | *2* | *6* | *5* | *2* | *3* | *3* | *7* | *5* | *2* | *8* | *4.3* | *3* |
| El Paso Electric Company | 7 | 5 | 3 | 4 | 8 | 1 | 4 | 1 | 4 | 2 | 3.9 | 2 |
| Nevada Power Company | 3 | 2 | 6 | 1 | 1 | 6 | 6 | 8 | 6 | 6 | 4.5 | 4 |
| PacifiCorp | 8 | 7 | 8 | 7 | 9 | 9 | 3 | 6 | 1 | 5 | 6.3 | 9 |
| Public Service Company of New Mexico | 6 | 8 | 1 | 5 | 6 | 4 | 9 | 3 | 7 | 3 | 5.2 | 7 |
| Southern California Edison Co. | 5 | 1 | 2 | 8 | 4 | 2 | 1 | 2 | 5 | 1 | 3.1 | 1 |
| Southwestern Public Service Company | 9 | 3 | 9 | 6 | 7 | 6 | 2 | 4 | 3 | 6 | 5.5 | 8 |
| Tucson Electric Power Company | 4 | 4 | 4 | 3 | 5 | 6 | 5 | 7 | 8 | 4 | 5.0 | 6 |
| Salt River Project | 1 | | 7 | | 2 | 5 | 8 | | | | 4.6 | 5 |

## Situational Assessment Rankings - 2001

(a rank of 1 indicates the most challenged performer for each metric)

| Base Panel | Percent Sales (MWh) Residential | Percent Sales (MWh) Other | Use per Customer | Change in Customers (%) | Change in Sales Volume (%) | Percent Generation Nuclear (%) | Energy Losses (%) | Age of Plant (Depreciation/Gross Plant) | Customer Density | Regulatory Lag | Average Rank | Overall Rank |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| *Arizona Public Service Company* | *4* | *31* | *12* | *2* | *2* | *9* | *18* | *33* | *4* | *31* | *14.6* | *6* |
| Alabama Power Company | 24 | 22 | 34 | 22 | 33 | 15 | 24 | 31 | 11 | | 24.0 | 36 |
| Appalachian Power Company | 8 | 5 | 21 | 23 | 29 | 18 | 34 | 30 | 8 | 12 | 18.8 | 19 |
| Carolina Power & Light Company | 16 | 25 | 27 | 6 | 31 | 6 | 29 | 9 | 20 | | 18.8 | 18 |
| Columbus Southern Power Company | 10 | 4 | 10 | 15 | 12 | 18 | 36 | 25 | 28 | 9 | 16.7 | 10 |
| Dayton Power and Light Company | 20 | 19 | 16 | 28 | 34 | 18 | 17 | 11 | 24 | 15 | 20.2 | 26 |
| Detroit Edison Company | 30 | 6 | 5 | 27 | 35 | 16 | 10 | 20 | 34 | 26 | 20.9 | 29 |
| Duke Energy Carolinas, LLC | 26 | 8 | 32 | 5 | 36 | 5 | 12 | 21 | 14 | 26 | 18.5 | 14 |
| Duke Energy Indiana, Inc. | 29 | 34 | 33 | 17 | 14 | 18 | 13 | 23 | 23 | 5 | 20.9 | 29 |
| El Paso Electric Company | 33 | 35 | 4 | 16 | 15 | 2 | 16 | 1 | 7 | 3 | 13.2 | 3 |
| Entergy Arkansas, Inc. | 13 | 30 | 19 | 33 | 13 | 1 | 15 | 16 | 3 | 9 | 15.2 | 7 |
| Entergy Louisiana, LLC | | | | | | | | | | | | |
| Entergy Mississippi, Inc. | 7 | 12 | 22 | 26 | 21 | 18 | 4 | 36 | 9 | 31 | 18.6 | 15 |
| Florida Power & Light Company | 1 | 2 | 6 | 10 | 7 | 10 | 8 | 3 | 33 | | 8.9 | 2 |
| Florida Power Corporation | 2 | 16 | 9 | 3 | 10 | 14 | 28 | 4 | 30 | 22 | 13.8 | 4 |
| Georgia Power Company | 35 | 10 | 35 | 11 | 19 | 13 | 23 | 28 | 19 | 30 | 22.3 | 33 |
| Gulf Power Company | 3 | 21 | 14 | 14 | 8 | 18 | 21 | 27 | 10 | 22 | 15.8 | 9 |
| Idaho Power Co. | 22 | 24 | 29 | 7 | 37 | 18 | 6 | 32 | 1 | 22 | 19.8 | 24 |
| Indiana Michigan Power Company | 31 | 11 | 26 | 36 | 27 | 3 | 35 | 6 | 22 | 4 | 20.1 | 25 |
| Indianapolis Power & Light Company | 21 | 13 | 25 | 21 | 24 | 18 | 25 | 10 | 36 | 14 | 20.7 | 28 |
| Kansas City Power & Light Company | 17 | 7 | 17 | 12 | 23 | 11 | 22 | 29 | 16 | 33 | 18.7 | 16 |
| Kansas Gas and Electric Company | 27 | 17 | 20 | 30 | 26 | 8 | 2 | 37 | | 19 | 20.7 | 27 |
| KCP&L Greater Missouri Operations Company | 6 | 23 | 7 | 25 | 20 | 18 | 7 | 19 | 27 | 19 | 17.1 | 11 |
| Kentucky Utilities Company | 19 | 27 | 30 | 20 | 18 | 18 | 20 | 8 | 17 | 6 | 18.3 | 13 |
| Monongahela Power Company | 36 | 20 | 18 | 32 | 4 | 18 | 26 | 12 | 6 | 15 | 18.7 | 16 |
| Nevada Power Company | 5 | 9 | 15 | 1 | 1 | 18 | 33 | 38 | 25 | 26 | 17.1 | 11 |
| Ohio Power Company | 37 | 14 | 36 | 35 | 38 | 18 | 37 | 13 | 18 | 19 | 26.5 | 38 |
| Oklahoma Gas and Electric Company | 15 | 15 | 28 | 37 | 16 | 18 | 9 | 5 | 29 | 22 | 19.4 | 23 |
| PacifiCorp | 34 | 33 | 23 | 18 | 30 | 38 | 11 | 34 | 2 | 18 | 24.1 | 37 |
| Portland General Electric Company | 11 | 37 | 11 | 24 | 28 | 18 | 27 | 14 | 31 | 13 | 21.4 | 31 |
| Public Service Company of New Hampshire | 14 | 38 | 1 | 19 | 3 | 17 | 30 | 7 | 13 | | 15.8 | 8 |
| Public Service Company of New Mexico | 28 | 36 | 3 | 9 | 9 | 12 | 32 | 22 | 32 | 9 | 19.2 | 21 |
| Public Service Company of Oklahoma | 18 | 3 | 31 | 34 | 5 | 18 | 38 | 18 | 21 | 6 | 19.2 | 21 |
| Southern California Edison Co. | 25 | 1 | 2 | 4 | 32 | 4 | 1 | 2 | 15 | 1 | 8.7 | 1 |
| Southwestern Electric Power Company | 32 | 28 | 37 | 29 | 25 | 18 | 14 | 15 | 12 | 8 | 21.8 | 32 |
| Southwestern Public Service Company | 38 | 29 | 38 | 38 | 6 | 18 | 5 | 26 | 5 | 26 | 22.9 | 34 |
| Tucson Electric Power Company | 9 | 32 | 8 | 8 | 11 | 18 | 19 | 35 | 35 | 15 | 19.0 | 20 |
| Virginia Electric and Power Company | 12 | 18 | 24 | 13 | 17 | 7 | 3 | 17 | 26 | 2 | 13.9 | 5 |
| Westar Energy (KPL) | 23 | 26 | 13 | 31 | 22 | 18 | 31 | 24 | | | 23.5 | 35 |

| Regional Panel | Percent Sales (MWh) Residential | Percent Sales (MWh) Other | Use per Customer | Change in Customers (%) | Change in Sales Volume (%) | Percent Generation Nuclear (%) | Energy Losses (%) | Age of Plant (Depreciation/Gross Plant) | Customer Density | Regulatory Lag | Average Rank | Overall Rank |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| *Arizona Public Service Company* | *2* | *4* | *5* | *2* | *2* | *3* | *5* | *5* | *2* | *8* | *3.8* | *2* |
| El Paso Electric Company | 7 | 7 | 3 | 6 | 7 | 1 | 4 | 1 | 4 | 2 | 4.2 | 3 |
| Nevada Power Company | 3 | 2 | 6 | 1 | 1 | 5 | 9 | 8 | 6 | 6 | 4.7 | 5 |
| PacifiCorp | 8 | 6 | 8 | 7 | 8 | 8 | 3 | 6 | 1 | 5 | 6.0 | 9 |
| Public Service Company of New Mexico | 6 | 8 | 2 | 5 | 5 | 4 | 8 | 3 | 7 | 3 | 5.1 | 6 |
| Southern California Edison Co. | 5 | 1 | 1 | 3 | 9 | 2 | 1 | 2 | 5 | 1 | 3.0 | 1 |
| Southwestern Public Service Company | 9 | 3 | 9 | 8 | 4 | 5 | 2 | 4 | 3 | 6 | 5.3 | 7 |
| Tucson Electric Power Company | 4 | 5 | 4 | 4 | 6 | 5 | 6 | 7 | 8 | 4 | 5.3 | 7 |
| Salt River Project | 1 | | 7 | | 3 | | 7 | | | | 4.5 | 4 |

## Situational Assessment Rankings - 2002

(a rank of 1 indicates the most challenged performer for each metric)

| Base Panel | Percent Sales (MWh) Residential | Percent Sales (MWh) Other | Use per Customer | Change in Customers (%) | Change in Sales Volume (%) | Percent Generation Nuclear (%) | Energy Losses (%) | Age of Plant (Depreciation/Gross Plant) | Customer Density | Regulatory Lag | Average Rank | Overall Rank |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| *Arizona Public Service Company* | *4* | *20* | *11* | *2* | *7* | *8* | *20* | *33* | *4* | *31* | *14.0* | *6* |
| Alabama Power Company | 24 | 22 | 36 | 30 | 19 | 16 | 28 | 32 | 11 | | 24.2 | 36 |
| Appalachian Power Company | 8 | 37 | 22 | 31 | 23 | 17 | 15 | 28 | 8 | 13 | 20.2 | 24 |
| Carolina Power & Light Company | 14 | 18 | 28 | 5 | 20 | 6 | 34 | 8 | 20 | | 17.0 | 12 |
| Columbus Southern Power Company | 9 | 38 | 12 | 16 | 4 | 17 | 26 | 24 | 28 | 10 | 18.4 | 17 |
| Dayton Power and Light Company | 17 | 19 | 17 | 35 | 28 | 17 | 18 | 11 | 24 | 16 | 20.2 | 24 |
| Detroit Edison Company | 25 | 3 | 6 | 33 | 34 | 15 | 10 | 19 | 34 | 26 | 20.5 | 26 |
| Duke Energy Carolinas, LLC | 27 | 4 | 31 | 18 | 30 | 5 | 9 | 22 | 14 | 26 | 18.6 | 18 |
| Duke Energy Indiana, Inc. | 31 | 34 | 34 | 17 | 10 | 17 | 8 | 30 | 23 | 5 | 20.9 | 30 |
| El Paso Electric Company | 33 | 29 | 4 | 10 | 16 | 1 | 11 | 1 | 7 | 3 | 11.5 | 2 |
| Entergy Arkansas, Inc. | 15 | 27 | 18 | 37 | 18 | 2 | 6 | 15 | 3 | 10 | 15.1 | 9 |
| Entergy Louisiana, LLC | | | | | | | | | | | | |
| Entergy Mississippi, Inc. | 7 | 9 | 23 | 25 | 24 | 17 | 36 | 36 | 9 | 32 | 21.8 | 31 |
| Florida Power & Light Company | 1 | 2 | 7 | 6 | 3 | 11 | 7 | 3 | 33 | | 8.1 | 1 |
| Florida Power Corporation | 2 | 10 | 9 | 7 | 5 | 14 | 14 | 5 | 30 | 24 | 12.0 | 4 |
| Georgia Power Company | 34 | 5 | 35 | 9 | 14 | 13 | 35 | 29 | 19 | 29 | 22.2 | 32 |
| Gulf Power Company | 3 | 14 | 15 | 11 | 2 | 17 | 24 | 27 | 10 | 16 | 13.9 | 5 |
| Idaho Power Co. | 23 | 8 | 24 | 4 | 37 | 17 | 4 | 31 | 1 | 24 | 17.3 | 13 |
| Indiana Michigan Power Company | 32 | 36 | 30 | 34 | 15 | 4 | 25 | 4 | 22 | 4 | 20.6 | 28 |
| Indianapolis Power & Light Company | 22 | 6 | 25 | 22 | 17 | 17 | 19 | 12 | 36 | 15 | 19.1 | 19 |
| Kansas City Power & Light Company | 16 | 12 | 16 | 15 | 27 | 12 | 27 | 26 | 16 | 33 | 20.0 | 23 |
| Kansas Gas and Electric Company | 28 | 13 | 20 | 27 | 29 | 9 | 1 | 37 | | 21 | 20.6 | 27 |
| KCP&L Greater Missouri Operations Company | 10 | 17 | 8 | 14 | 12 | 17 | 3 | 20 | 27 | 21 | 14.9 | 8 |
| Kentucky Utilities Company | 18 | 28 | 32 | 20 | 8 | 17 | 22 | 9 | 18 | 7 | 17.9 | 15 |
| Monongahela Power Company | 36 | 16 | 19 | 29 | 6 | 17 | 21 | 14 | 6 | 16 | 18.0 | 16 |
| Nevada Power Company | 5 | 30 | 13 | 1 | 1 | 17 | 33 | 38 | 25 | 29 | 19.2 | 20 |
| Ohio Power Company | 37 | 35 | 37 | 36 | 38 | 17 | 38 | 16 | 17 | 21 | 29.2 | 38 |
| Oklahoma Gas and Electric Company | 20 | 11 | 26 | 24 | 25 | 17 | 5 | 6 | 29 | 5 | 16.8 | 11 |
| PacifiCorp | 35 | 21 | 21 | 19 | 35 | 38 | 17 | 34 | 2 | 20 | 24.2 | 35 |
| Portland General Electric Company | 12 | 26 | 10 | 23 | 33 | 17 | 32 | 10 | 31 | 14 | 20.8 | 29 |
| Public Service Company of New Hampshire | 13 | 31 | 1 | 13 | 13 | 17 | 31 | 7 | 13 | | 15.4 | 10 |
| Public Service Company of New Mexico | 30 | 33 | 3 | 12 | 11 | 10 | 30 | 21 | 32 | 10 | 19.2 | 20 |
| Public Service Company of Oklahoma | 19 | 7 | 27 | 32 | 26 | 17 | 2 | 18 | 21 | 7 | 17.6 | 14 |
| Southern California Edison Co. | 29 | 1 | 2 | 21 | 32 | 3 | 13 | 2 | 15 | 1 | 11.9 | 3 |
| Southwestern Electric Power Company | 26 | 23 | 33 | 26 | 36 | 17 | 29 | 13 | 12 | 9 | 22.4 | 33 |
| Southwestern Public Service Company | 38 | 25 | 38 | 38 | 22 | 17 | 23 | 23 | 5 | 26 | 25.5 | 37 |
| Tucson Electric Power Company | 6 | 32 | 5 | 3 | 31 | 17 | 12 | 35 | 35 | 16 | 19.2 | 20 |
| Virginia Electric and Power Company | 11 | 15 | 29 | 8 | 9 | 7 | 16 | 17 | 26 | 2 | 14.0 | 6 |
| Westar Energy (KPL) | 21 | 24 | 14 | 28 | 21 | 17 | 37 | 25 | | | 23.4 | 34 |

| Regional Panel | Percent Sales (MWh) Residential | Percent Sales (MWh) Other | Use per Customer | Change in Customers (%) | Change in Sales Volume (%) | Percent Generation Nuclear (%) | Energy Losses (%) | Age of Plant (Depreciation/Gross Plant) | Customer Density | Regulatory Lag | Average Rank | Overall Rank |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| *Arizona Public Service Company* | *2* | *2* | *5* | *2* | *2* | *3* | *5* | *5* | *2* | *8* | *3.6* | *3* |
| El Paso Electric Company | 7 | 5 | 3 | 4 | 5 | 1 | 1 | 1 | 4 | 2 | 3.3 | 1 |
| Nevada Power Company | 3 | 6 | 6 | 1 | 1 | 5 | 9 | 8 | 6 | 7 | 5.2 | 7 |
| PacifiCorp* | 8 | 3 | 8 | 6 | 9 | 8 | 4 | 6 | 1 | 5 | 5.8 | 8 |
| Public Service Company of New Mexico | 6 | 8 | 2 | 5 | 4 | 4 | 7 | 3 | 7 | 3 | 4.9 | 5 |
| Southern California Edison Co. | 5 | 1 | 1 | 7 | 8 | 2 | 3 | 2 | 5 | 1 | 3.5 | 2 |
| Southwestern Public Service Company | 9 | 4 | 9 | 8 | 6 | 5 | 6 | 4 | 3 | 6 | 6.0 | 9 |
| Tucson Electric Power Company | 4 | 7 | 4 | 3 | 7 | 5 | 2 | 7 | 8 | 4 | 5.1 | 6 |
| Salt River Project | 1 | | 7 | | 3 | | 8 | | | | 4.8 | 4 |

## Situational Assessment Rankings - 2003

(a rank of 1 indicates the most challenged performer for each metric)

| Base Panel | Percent Sales (MWh) Residential | Percent Sales (MWh) Other | Use per Customer | Change in Customers (%) | Change in Sales Volume (%) | Percent Generation Nuclear (%) | Energy Losses (%) | Age of Plant (Depreciation/Gross Plant) | Customer Density | Regulatory Lag | Average Rank | Overall Rank |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| *Arizona Public Service Company* | *4* | *6* | *12* | *2* | *3* | *7* | *35* | *33* | *4* | *30* | *13.6* | *5* |
| Alabama Power Company | 29 | 22 | 36 | 26 | 20 | 14 | 26 | 32 | 11 | | 24.0 | 34 |
| Appalachian Power Company | 7 | 25 | 21 | 32 | 29 | 17 | 19 | 29 | 8 | 12 | 19.9 | 22 |
| Carolina Power & Light Company | 14 | 19 | 27 | 11 | 27 | 6 | 31 | 13 | 21 | | 18.8 | 18 |
| Columbus Southern Power Company | 10 | 21 | 11 | 19 | 12 | 17 | 18 | 23 | 28 | 10 | 16.9 | 12 |
| Dayton Power and Light Company | 17 | 20 | 16 | 33 | 31 | | 17 | 12 | 24 | 15 | 20.6 | 25 |
| Detroit Edison Company | 19 | 8 | 5 | 36 | 38 | 15 | 12 | 18 | 34 | 25 | 21.0 | 28 |
| Duke Energy Carolinas, LLC | 27 | 3 | 31 | 37 | 33 | 5 | 14 | 21 | 13 | 25 | 20.9 | 27 |
| Duke Energy Indiana, Inc. | 31 | 38 | 33 | 22 | 14 | 17 | 4 | 31 | 23 | 5 | 21.8 | 32 |
| El Paso Electric Company | 33 | 33 | 4 | 7 | 10 | 2 | 11 | 1 | 7 | 3 | 11.1 | 3 |
| Entergy Arkansas, Inc. | 15 | 29 | 18 | 12 | 21 | 1 | 16 | 26 | 3 | 10 | 15.1 | 8 |
| Entergy Louisiana, LLC | | | | | | | | | | | | |
| Entergy Mississippi, Inc. | 8 | 7 | 24 | 23 | 25 | 17 | 6 | 37 | 9 | 31 | 18.7 | 17 |
| Florida Power & Light Company | 1 | 2 | 8 | 5 | 2 | 11 | 7 | 5 | 33 | | 8.2 | 1 |
| Florida Power Corporation | 2 | 11 | 10 | 6 | 4 | 16 | 13 | 10 | 30 | 22 | 12.4 | 4 |
| Georgia Power Company | 35 | 10 | 35 | 10 | 19 | 12 | 34 | 28 | 20 | 28 | 23.1 | 33 |
| Gulf Power Company | 3 | 17 | 15 | 9 | 6 | 17 | 28 | 22 | 10 | 15 | 14.2 | 7 |
| Idaho Power Co. | 23 | 9 | 22 | 3 | 36 | 17 | 3 | 34 | 1 | 22 | 17.0 | 13 |
| Indiana Michigan Power Company | 32 | 36 | 26 | 29 | 32 | 4 | 15 | 3 | 22 | 4 | 20.3 | 24 |
| Indianapolis Power & Light Company | 20 | 5 | 25 | 20 | 23 | 17 | 21 | 7 | 36 | 14 | 18.8 | 19 |
| Kansas City Power & Light Company | 16 | 18 | 17 | 17 | 24 | 13 | 30 | 17 | 16 | 33 | 20.1 | 23 |
| Kansas Gas and Electric Company | 30 | 24 | 20 | 27 | 28 | 9 | 1 | 36 | | 19 | 21.6 | 30 |
| KCP&L Greater Missouri Operations Company | 9 | 15 | 7 | 15 | 8 | 17 | 5 | 16 | 27 | 19 | 13.8 | 6 |
| Kentucky Utilities Company | 22 | 23 | 32 | 25 | 11 | 17 | 22 | 14 | 18 | 7 | 19.1 | 20 |
| Monongahela Power Company | 36 | 13 | 19 | 31 | 9 | 17 | 23 | 9 | 6 | 15 | 17.8 | 16 |
| Nevada Power Company | 5 | 16 | 14 | 1 | 1 | 17 | 27 | 38 | 25 | 28 | 17.2 | 14 |
| Ohio Power Company | 37 | 34 | 37 | 35 | 37 | 17 | 33 | 25 | 17 | 19 | 29.1 | 38 |
| Oklahoma Gas and Electric Company | 18 | 12 | 28 | 21 | 18 | 17 | 9 | 4 | 29 | 5 | 16.1 | 10 |
| PacifiCorp | 34 | 32 | 23 | 13 | 26 | 37 | 24 | 30 | 2 | 24 | 24.5 | 35 |
| Portland General Electric Company | 11 | 31 | 9 | 24 | 35 | 17 | 29 | 6 | 31 | 13 | 20.6 | 26 |
| Public Service Company of New Hampshire | 12 | 37 | 1 | 16 | 5 | 17 | 32 | 11 | 14 | | 16.1 | 11 |
| Public Service Company of New Mexico | 28 | 35 | 3 | 4 | 13 | 10 | 36 | 24 | 32 | 31 | 21.6 | 31 |
| Public Service Company of Oklahoma | 21 | 4 | 30 | 38 | 22 | 17 | 25 | 15 | 19 | 7 | 19.8 | 21 |
| Southern California Edison Co. | 25 | 1 | 2 | 18 | 16 | 3 | 2 | 2 | 15 | 1 | 8.5 | 2 |
| Southwestern Electric Power Company | 26 | 30 | 34 | 30 | 34 | 17 | 10 | 8 | 12 | 9 | 21.0 | 28 |
| Southwestern Public Service Company | 38 | 28 | 38 | 28 | 15 | 17 | 37 | 20 | 5 | 25 | 25.1 | 36 |
| Tucson Electric Power Company | 6 | 27 | 6 | 8 | 17 | 17 | 8 | 35 | 35 | 15 | 17.4 | 15 |
| Virginia Electric and Power Company | 13 | 14 | 29 | 14 | 7 | 8 | 20 | 27 | 26 | 2 | 16.0 | 9 |
| Westar Energy (KPL) | 24 | 26 | 13 | 34 | 30 | 17 | 38 | 19 | | | 25.1 | 37 |

| Regional Panel | Percent Sales (MWh) Residential | Percent Sales (MWh) Other | Use per Customer | Change in Customers (%) | Change in Sales Volume (%) | Percent Generation Nuclear (%) | Energy Losses (%) | Age of Plant (Depreciation/Gross Plant) | Customer Density | Regulatory Lag | Average Rank | Overall Rank |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| *Arizona Public Service Company* | *2* | *2* | *5* | *2* | *2* | *3* | *7* | *6* | *2* | *7* | *3.8* | *3* |
| El Paso Electric Company | 7 | 7 | 3 | 4 | 4 | 1 | 3 | 1 | 4 | 2 | 3.6 | 2 |
| Nevada Power Company | 3 | 3 | 6 | 1 | 1 | 5 | 5 | 8 | 6 | 6 | 4.4 | 5 |
| PacifiCorp | 8 | 6 | 8 | 6 | 9 | 8 | 4 | 5 | 1 | 4 | 5.9 | 8 |
| Public Service Company of New Mexico | 6 | 8 | 2 | 3 | 5 | 4 | 8 | 4 | 7 | 8 | 5.5 | 7 |
| Southern California Edison Co. | 5 | 1 | 1 | 7 | 7 | 2 | 1 | 2 | 5 | 1 | 3.2 | 1 |
| Southwestern Public Service Company | 9 | 5 | 9 | 8 | 6 | 5 | 9 | 3 | 3 | 5 | 6.2 | 9 |
| Tucson Electric Power Company | 4 | 4 | 4 | 5 | 8 | 5 | 2 | 7 | 8 | 3 | 5.0 | 6 |
| Salt River Project | 1 | | 7 | | 3 | | 6 | | | | 4.3 | 4 |

## Situational Assessment Rankings - 2004

(a rank of 1 indicates the most challenged performer for each metric)

| Base Panel | Percent Sales (MWh) Residential | Percent Sales (MWh) Other | Use per Customer | Change in Customers (%) | Change in Sales Volume (%) | Percent Generation Nuclear (%) | Energy Losses (%) | Age of Plant (Depreciation/Gross Plant) | Customer Density | Regulatory Lag | Average Rank | Overall Rank |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| *Arizona Public Service Company* | *4* | *26* | *13* | *3* | *2* | *8* | *36* | *33* | *4* | *31* | *16.0* | *8* |
| Alabama Power Company | 29 | 24 | 37 | 24 | 10 | 14 | 27 | 32 | 11 | | 23.1 | 34 |
| Appalachian Power Company | 8 | 38 | 24 | 34 | 21 | 17 | 30 | 31 | 8 | 12 | 22.3 | 31 |
| Carolina Power & Light Company | 15 | 20 | 28 | 14 | 13 | 6 | 31 | 12 | 21 | | 17.8 | 14 |
| Columbus Southern Power Company | 10 | 31 | 11 | 20 | 20 | 17 | 16 | 21 | 28 | 10 | 18.4 | 18 |
| Dayton Power and Light Company | 17 | 25 | 17 | 37 | 32 | 17 | 15 | 10 | 23 | 16 | 20.9 | 26 |
| Detroit Edison Company | 14 | 8 | 4 | 36 | 38 | 16 | 8 | 20 | 34 | 5 | 18.3 | 17 |
| Duke Energy Carolinas, LLC | 25 | 5 | 31 | 15 | 29 | 5 | 14 | 26 | 13 | 26 | 18.9 | 20 |
| Duke Energy Indiana, Inc. | 31 | 29 | 34 | 32 | 17 | 17 | 18 | 28 | 24 | 6 | 23.6 | 35 |
| El Paso Electric Company | 32 | 28 | 5 | 6 | 9 | 2 | 10 | 1 | 7 | 3 | 10.3 | 3 |
| Entergy Arkansas, Inc. | 16 | 30 | 18 | 28 | 26 | 1 | 13 | 22 | 3 | 10 | 16.7 | 12 |
| Entergy Louisiana, LLC | | | | | | | | | | | | |
| Entergy Mississippi, Inc. | 9 | 2 | 23 | 19 | 27 | 17 | 4 | 37 | 9 | 32 | 17.9 | 15 |
| Florida Power & Light Company | 1 | 1 | 8 | 7 | 5 | 11 | 7 | 9 | 33 | | 9.1 | 1 |
| Florida Power Corporation | 2 | 11 | 10 | 8 | 7 | 15 | 11 | 11 | 30 | 24 | 12.9 | 5 |
| Georgia Power Company | 34 | 12 | 35 | 12 | 11 | 13 | 34 | 29 | 20 | 29 | 22.9 | 33 |
| Gulf Power Company | 3 | 22 | 15 | 11 | 6 | 17 | 26 | 25 | 10 | 16 | 15.1 | 7 |
| Idaho Power Co. | 19 | 6 | 21 | 4 | 35 | 17 | 3 | 34 | 1 | 24 | 16.4 | 10 |
| Indiana Michigan Power Company | 33 | 35 | 27 | 33 | 31 | 3 | 25 | 3 | 22 | 4 | 21.6 | 27 |
| Indianapolis Power & Light Company | 20 | 4 | 25 | 22 | 23 | 17 | 21 | 7 | 36 | 14 | 18.9 | 20 |
| Kansas City Power & Light Company | 18 | 18 | 16 | 27 | 30 | 12 | 32 | 15 | 16 | 34 | 21.8 | 29 |
| Kansas Gas and Electric Company | 30 | 17 | 19 | 29 | 25 | 9 | 1 | 36 | | 21 | 20.8 | 25 |
| KCP&L Greater Missouri Operations Company | 11 | 9 | 9 | 18 | 15 | 17 | 5 | 19 | 27 | 16 | 14.6 | 6 |
| Kentucky Utilities Company | 22 | 21 | 32 | 23 | 8 | 17 | 22 | 14 | 18 | 26 | 20.3 | 23 |
| Monongahela Power Company | 36 | 13 | 20 | 35 | 16 | 17 | 19 | 6 | 6 | 16 | 18.4 | 18 |
| Nevada Power Company | 5 | 10 | 14 | 1 | 1 | 17 | 24 | 38 | 25 | 29 | 16.4 | 10 |
| Ohio Power Company | 37 | 36 | 36 | 30 | 36 | 17 | 29 | 24 | 17 | 21 | 28.3 | 38 |
| Oklahoma Gas and Electric Company | 21 | 15 | 26 | 25 | 28 | 17 | 6 | 8 | 29 | 6 | 18.1 | 16 |
| PacifiCorp | 35 | 33 | 22 | 13 | 24 | 38 | 12 | 30 | 2 | 15 | 22.4 | 32 |
| Portland General Electric Company | 6 | 34 | 7 | 17 | 37 | 17 | 28 | 5 | 31 | 13 | 19.5 | 22 |
| Public Service Company of New Hampshire | 12 | 3 | 1 | 2 | 3 | 17 | 17 | 16 | 14 | 21 | 10.6 | 4 |
| Public Service Company of New Mexico | 24 | 37 | 3 | 5 | 19 | 10 | 33 | 23 | 32 | 32 | 21.8 | 29 |
| Public Service Company of Oklahoma | 27 | 14 | 30 | 31 | 22 | 17 | 23 | 13 | 19 | 8 | 20.4 | 24 |
| Southern California Edison Co. | 26 | 7 | 2 | 21 | 14 | 4 | 2 | 2 | 15 | 1 | 9.4 | 2 |
| Southwestern Electric Power Company | 28 | 19 | 33 | 26 | 33 | 17 | 35 | 4 | 12 | 9 | 21.6 | 27 |
| Southwestern Public Service Company | 38 | 32 | 38 | 9 | 18 | 17 | 38 | 18 | 5 | 26 | 23.9 | 36 |
| Tucson Electric Power Company | 7 | 23 | 6 | 10 | 12 | 17 | 9 | 35 | 35 | 16 | 17.0 | 13 |
| Virginia Electric and Power Company | 13 | 16 | 29 | 16 | 4 | 7 | 20 | 27 | 26 | 2 | 16.0 | 8 |
| Westar Energy (KPL) | 23 | 27 | 12 | 38 | 34 | 17 | 37 | 17 | | | 25.6 | 37 |

| Regional Panel | Percent Sales (MWh) Residential | Percent Sales (MWh) Other | Use per Customer | Change in Customers (%) | Change in Sales Volume (%) | Percent Generation Nuclear (%) | Energy Losses (%) | Age of Plant (Depreciation/Gross Plant) | Customer Density | Regulatory Lag | Average Rank | Overall Rank |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| *Arizona Public Service Company* | *2* | *4* | *5* | *2* | *2* | *3* | *8* | *6* | *2* | *7* | *4.1* | *3* |
| El Paso Electric Company | 7 | 5 | 3 | 4 | 3 | 1 | 3 | 1 | 4 | 2 | 3.3 | 1 |
| Nevada Power Company | 3 | 2 | 6 | 1 | 1 | 5 | 5 | 8 | 6 | 6 | 4.3 | 4 |
| PacifiCorp | 8 | 7 | 8 | 7 | 9 | 8 | 4 | 5 | 1 | 3 | 6.0 | 8 |
| Public Service Company of New Mexico | 5 | 8 | 2 | 3 | 8 | 4 | 7 | 4 | 7 | 8 | 5.6 | 7 |
| Southern California Edison Co. | 6 | 1 | 1 | 8 | 6 | 2 | 1 | 2 | 5 | 1 | 3.3 | 1 |
| Southwestern Public Service Company | 9 | 6 | 9 | 5 | 7 | 5 | 9 | 3 | 3 | 5 | 6.1 | 9 |
| Tucson Electric Power Company | 4 | 3 | 4 | 6 | 5 | 5 | 2 | 7 | 8 | 4 | 4.8 | 6 |
| Salt River Project | 1 | | 7 | | 4 | | 6 | | | | 4.5 | 5 |

## Situational Assessment Rankings - 2005

(a rank of 1 indicates the most challenged performer for each metric)

| Base Panel | Percent Sales (MWh) Residential | Percent Sales (MWh) Other | Use per Customer | Change in Customers (%) | Change in Sales Volume (%) | Percent Generation Nuclear (%) | Energy Losses (%) | Age of Plant (Depreciation/Gross Plant) | Customer Density | Regulatory Lag | Average Rank | Overall Rank |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| *Arizona Public Service Company* | *4* | *38* | *13* | *2* | *2* | *9* | *35* | *36* | *4* | *2* | *14.5* | *6* |
| Alabama Power Company | 29 | 23 | 36 | 25 | 11 | 13 | 34 | 31 | 11 | | 23.7 | 35 |
| Appalachian Power Company | 8 | 1 | 25 | 30 | 19 | 17 | 16 | 35 | 8 | 11 | 17.0 | 12 |
| Carolina Power & Light Company | 14 | 19 | 24 | 10 | 27 | 6 | 33 | 10 | 22 | | 18.3 | 16 |
| Columbus Southern Power Company | 9 | 28 | 11 | 29 | 21 | 17 | 24 | 26 | 27 | 9 | 20.1 | 27 |
| Dayton Power and Light Company | 17 | 22 | 17 | 33 | 32 | 17 | 15 | 8 | 23 | 15 | 19.9 | 25 |
| Detroit Edison Company | 15 | 14 | 5 | 35 | 37 | 15 | 17 | 18 | 34 | 6 | 19.6 | 23 |
| Duke Energy Carolinas, LLC | 26 | 7 | 30 | 11 | 33 | 5 | 10 | 24 | 13 | 26 | 18.5 | 17 |
| Duke Energy Indiana, Inc. | 31 | 33 | 34 | 18 | 8 | 17 | 1 | 28 | 24 | 7 | 20.1 | 27 |
| El Paso Electric Company | 32 | 31 | 4 | 5 | 26 | 3 | 4 | 1 | 7 | 3 | 11.6 | 2 |
| Entergy Arkansas, Inc. | 16 | 34 | 21 | 32 | 9 | 1 | 11 | 22 | 3 | 9 | 15.8 | 8 |
| Entergy Louisiana, LLC | | | | | | | | | | | | |
| Entergy Mississippi, Inc. | 10 | 6 | 22 | 31 | 30 | 17 | 3 | 37 | 9 | 32 | 19.7 | 24 |
| Florida Power & Light Company | 1 | 4 | 8 | 7 | 6 | 11 | 6 | 12 | 33 | | 9.8 | 1 |
| Florida Power Corporation | 2 | 17 | 10 | 8 | 12 | 16 | 20 | 13 | 30 | 24 | 15.2 | 7 |
| Georgia Power Company | 35 | 10 | 33 | 13 | 23 | 14 | 38 | 27 | 20 | 30 | 24.3 | 36 |
| Gulf Power Company | 3 | 29 | 15 | 19 | 16 | 17 | 30 | 25 | 10 | 15 | 17.9 | 14 |
| Idaho Power Co. | 19 | 16 | 16 | 3 | 36 | 17 | 8 | 32 | 1 | 24 | 17.2 | 13 |
| Indiana Michigan Power Company | 33 | 36 | 28 | 36 | 29 | 2 | 27 | 2 | 21 | 4 | 21.8 | 32 |
| Indianapolis Power & Light Company | 20 | 9 | 26 | 28 | 18 | 17 | 23 | 5 | 36 | 13 | 19.5 | 22 |
| Kansas City Power & Light Company | 18 | 27 | 18 | 26 | 15 | 12 | 28 | 15 | 16 | 34 | 20.9 | 30 |
| Kansas Gas and Electric Company | 30 | 20 | 23 | 24 | 14 | 8 | 2 | 34 | | 20 | 19.4 | 21 |
| KCP&L Greater Missouri Operations Company | 11 | 12 | 9 | 15 | 3 | 17 | 5 | 20 | 28 | 15 | 13.5 | 5 |
| Kentucky Utilities Company | 23 | 25 | 32 | 23 | 5 | 17 | 19 | 11 | 18 | 26 | 19.9 | 25 |
| Monongahela Power Company | 34 | 8 | 19 | 34 | 31 | 17 | 13 | 4 | 6 | 15 | 18.1 | 15 |
| Nevada Power Company | 5 | 5 | 12 | 1 | 1 | 17 | 31 | 38 | 25 | 30 | 16.5 | 9 |
| Ohio Power Company | 37 | 35 | 37 | 37 | 17 | 17 | 32 | 29 | 17 | 20 | 27.8 | 38 |
| Oklahoma Gas and Electric Company | 22 | 13 | 27 | 21 | 20 | 17 | 7 | 9 | 29 | 26 | 19.1 | 20 |
| PacifiCorp | 36 | 18 | 20 | 9 | 34 | 38 | 12 | 30 | 2 | 23 | 22.2 | 33 |
| Portland General Electric Company | 6 | 26 | 6 | 14 | 38 | 17 | 29 | 7 | 31 | 12 | 18.6 | 18 |
| Public Service Company of New Hampshire | 12 | 2 | 1 | 16 | 7 | 17 | 22 | 19 | 14 | 20 | 13.0 | 4 |
| Public Service Company of New Mexico | 24 | 37 | 3 | 4 | 25 | 10 | 18 | 21 | 32 | 32 | 20.6 | 29 |
| Public Service Company of Oklahoma | 25 | 3 | 31 | 27 | 13 | 17 | 37 | 14 | 19 | 4 | 19.0 | 19 |
| Southern California Edison Co. | 27 | 11 | 2 | 17 | 22 | 4 | 21 | 3 | 15 | 1 | 12.3 | 3 |
| Southwestern Electric Power Company | 28 | 24 | 35 | 20 | 24 | 17 | 36 | 6 | 12 | 8 | 21.0 | 31 |
| Southwestern Public Service Company | 38 | 32 | 38 | 38 | 28 | 17 | 9 | 17 | 5 | 26 | 24.8 | 37 |
| Tucson Electric Power Company | 7 | 21 | 7 | 6 | 10 | 17 | 14 | 33 | 35 | 15 | 16.5 | 9 |
| Virginia Electric and Power Company | 13 | 15 | 29 | 12 | 4 | 7 | 26 | 23 | 26 | 13 | 16.8 | 11 |
| Westar Energy (KPL) | 21 | 30 | 14 | 22 | 35 | 17 | 25 | 16 | | | 22.5 | 34 |

| Regional Panel | Percent Sales (MWh) Residential | Percent Sales (MWh) Other | Use per Customer | Change in Customers (%) | Change in Sales Volume (%) | Percent Generation Nuclear (%) | Energy Losses (%) | Age of Plant (Depreciation/Gross Plant) | Customer Density | Regulatory Lag | Average Rank | Overall Rank |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| *Arizona Public Service Company* | *2* | *8* | *6* | *2* | *2* | *3* | *9* | *7* | *2* | *2* | *4.3* | *3* |
| El Paso Electric Company | 7 | 5 | 3 | 4 | 7 | 1 | 1 | 1 | 4 | 3 | 3.6 | 1 |
| Nevada Power Company | 3 | 1 | 5 | 1 | 1 | 5 | 7 | 8 | 6 | 7 | 4.4 | 4 |
| PacifiCorp | 8 | 3 | 8 | 6 | 9 | 8 | 3 | 5 | 1 | 5 | 5.6 | 8 |
| Public Service Company of New Mexico | 5 | 7 | 2 | 3 | 6 | 4 | 5 | 4 | 7 | 8 | 5.1 | 7 |
| Southern California Edison Co. | 6 | 2 | 1 | 7 | 5 | 2 | 6 | 2 | 5 | 1 | 3.7 | 2 |
| Southwestern Public Service Company | 9 | 6 | 9 | 8 | 8 | 5 | 2 | 3 | 3 | 6 | 5.9 | 9 |
| Tucson Electric Power Company | 4 | 4 | 4 | 5 | 3 | 5 | 4 | 6 | 8 | 4 | 4.7 | 5 |
| Salt River Project | 1 | | 7 | | 4 | | 8 | | | | 5.0 | 6 |

## Situational Assessment Rankings - 2006

(a rank of 1 indicates the most challenged performer for each metric)

| Base Panel | Percent Sales (MWh) Residential | Percent Sales (MWh) Other | Use per Customer | Change in Customers (%) | Change in Sales Volume (%) | Percent Generation Nuclear (%) | Energy Losses (%) | Age of Plant (Depreciation/Gross Plant) | Customer Density | Regulatory Lag | Average Rank | Overall Rank |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| *Arizona Public Service Company* | *4* | *36* | *13* | *3* | *2* | *10* | *17* | *35* | *4* | *1* | *12.5* | *4* |
| Alabama Power Company | 28 | 24 | 37 | 28 | 13 | 14 | 32 | 30 | 11 | | 24.1 | 35 |
| Appalachian Power Company | 14 | 33 | 30 | 32 | 3 | 18 | 12 | 37 | 8 | 7 | 19.4 | 23 |
| Carolina Power & Light Company | 12 | 26 | 20 | 11 | 33 | 7 | 35 | 7 | 22 | | 19.2 | 22 |
| Columbus Southern Power Company | 13 | 28 | 11 | 4 | 5 | 18 | 27 | 26 | 29 | 9 | 17.0 | 12 |
| Dayton Power and Light Company | 18 | 19 | 17 | 34 | 36 | 18 | 16 | 9 | 24 | 15 | 20.6 | 27 |
| Detroit Edison Company | 27 | 11 | 5 | 33 | 24 | 17 | 10 | 20 | 35 | 30 | 21.2 | 28 |
| Duke Energy Carolinas, LLC | 26 | 7 | 29 | 14 | 31 | 6 | 11 | 25 | 13 | 25 | 18.7 | 17 |
| Duke Energy Indiana, Inc. | 36 | 35 | 35 | 30 | 26 | 18 | 36 | 29 | 25 | 6 | 27.6 | 38 |
| El Paso Electric Company | 34 | 29 | 4 | 8 | 19 | 4 | 7 | 1 | 7 | 2 | 11.5 | 3 |
| Entergy Arkansas, Inc. | 17 | 25 | 21 | 23 | 10 | 1 | 22 | 19 | 3 | 9 | 15.0 | 6 |
| Entergy Louisiana, LLC | 31 | 1 | 38 | | | 3 | 20 | 28 | 21 | | 20.3 | 26 |
| Entergy Mississippi, Inc. | 8 | 6 | 23 | 20 | 27 | 18 | 2 | 38 | 9 | 33 | 18.4 | 15 |
| Florida Power & Light Company | 1 | 2 | 7 | 13 | 15 | 11 | 3 | 11 | 34 | | 10.8 | 2 |
| Florida Power Corporation | 2 | 17 | 9 | 9 | 22 | 16 | 23 | 14 | 31 | 24 | 16.7 | 11 |
| Georgia Power Company | 33 | 14 | 34 | 1 | 4 | 15 | 37 | 27 | 23 | 30 | 21.8 | 31 |
| Gulf Power Company | 3 | 22 | 15 | 7 | 20 | 18 | 29 | 24 | 10 | 15 | 16.3 | 9 |
| Idaho Power Co. | 15 | 12 | 19 | 5 | 14 | 18 | 9 | 34 | 1 | 25 | 15.2 | 7 |
| Indiana Michigan Power Company | 35 | 38 | 26 | 35 | 32 | 5 | 31 | 2 | 20 | 3 | 22.7 | 34 |
| Indianapolis Power & Light Company | 22 | 5 | 24 | 31 | 34 | 18 | 38 | 4 | 37 | 12 | 22.5 | 33 |
| Kansas City Power & Light Company | 16 | 20 | 18 | 27 | 17 | 13 | 30 | 16 | 16 | 12 | 18.5 | 16 |
| Kansas Gas and Electric Company | 32 | 21 | 25 | 24 | 8 | 9 | 1 | 31 | | 20 | 19.0 | 20 |
| KCP&L Greater Missouri Operations Company | 9 | 10 | 10 | 18 | 7 | 18 | 5 | 18 | 28 | 15 | 13.8 | 5 |
| Kentucky Utilities Company | 24 | 30 | 32 | 22 | 23 | 18 | 15 | 12 | 18 | 25 | 21.9 | 32 |
| Monongahela Power Company | 30 | 9 | 16 | 38 | 38 | 18 | 8 | 3 | 6 | 15 | 18.1 | 14 |
| Nevada Power Company | 5 | 4 | 12 | 2 | 1 | 18 | 25 | 39 | 26 | 30 | 16.2 | 8 |
| Ohio Power Company | 38 | 37 | 33 | 36 | 37 | 18 | 21 | 36 | 17 | 20 | 29.3 | 39 |
| Oklahoma Gas and Electric Company | 20 | 15 | 28 | 19 | 18 | 18 | 4 | 10 | 30 | 25 | 18.7 | 17 |
| PacifiCorp | 37 | 18 | 22 | 10 | 11 | 39 | 6 | 33 | 2 | 23 | 20.1 | 25 |
| Portland General Electric Company | 6 | 32 | 6 | 16 | 35 | 18 | 34 | 6 | 32 | 11 | 19.6 | 24 |
| Public Service Company of New Hampshire | 10 | 3 | 1 | 21 | 29 | 18 | 26 | 22 | 14 | 20 | 16.4 | 10 |
| Public Service Company of New Mexico | 21 | 39 | 2 | 6 | 12 | 12 | 33 | 21 | 33 | 33 | 21.2 | 28 |
| Public Service Company of Oklahoma | 25 | 8 | 31 | 29 | 21 | 18 | 18 | 15 | 19 | 3 | 18.7 | 17 |
| Southern California Edison Co. | 23 | 13 | 3 | 17 | 9 | 2 | 14 | 5 | 15 | 5 | 10.6 | 1 |
| Southwestern Electric Power Company | 29 | 27 | 36 | 25 | 28 | 18 | 24 | 8 | 12 | 7 | 21.4 | 30 |
| Southwestern Public Service Company | 39 | 34 | 39 | 37 | 16 | 18 | 19 | 13 | 5 | 25 | 24.5 | 37 |
| Tucson Electric Power Company | 7 | 23 | 8 | 12 | 6 | 18 | 13 | 32 | 36 | 15 | 17.0 | 12 |
| Virginia Electric and Power Company | 11 | 16 | 27 | 15 | 25 | 8 | 28 | 23 | 27 | 12 | 19.2 | 21 |
| Westar Energy (KPL) | 19 | 31 | 14 | 26 | 30 | 18 | 39 | 17 | | | 24.3 | 36 |

| Regional Panel | Percent Sales (MWh) Residential | Percent Sales (MWh) Other | Use per Customer | Change in Customers (%) | Change in Sales Volume (%) | Percent Generation Nuclear (%) | Energy Losses (%) | Age of Plant (Depreciation/Gross Plant) | Customer Density | Regulatory Lag | Average Rank | Overall Rank |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| *Arizona Public Service Company* | *2* | *7* | *6* | *2* | *2* | *3* | *5* | *7* | *2* | *1* | *3.7* | *1* |
| El Paso Electric Company | 7 | 5 | 3 | 4 | 9 | 2 | 2 | 1 | 4 | 2 | 3.9 | 3 |
| Nevada Power Company | 3 | 1 | 5 | 1 | 1 | 5 | 7 | 8 | 6 | 7 | 4.4 | 4 |
| PacifiCorp | 8 | 3 | 8 | 5 | 6 | 8 | 1 | 6 | 1 | 5 | 5.1 | 7 |
| Public Service Company of New Mexico | 5 | 8 | 1 | 3 | 7 | 4 | 8 | 4 | 7 | 8 | 5.5 | 8 |
| Southern California Edison Co. | 6 | 2 | 2 | 7 | 5 | 1 | 4 | 2 | 5 | 3 | 3.7 | 1 |
| Southwestern Public Service Company | 9 | 6 | 9 | 8 | 8 | 5 | 6 | 3 | 3 | 6 | 6.3 | 9 |
| Tucson Electric Power Company | 4 | 4 | 4 | 6 | 4 | 5 | 3 | 5 | 8 | 4 | 4.7 | 5 |
| Salt River Project | 1 | | 7 | | 3 | | 9 | | | | 5.0 | 6 |

## Situational Assessment Rankings - 2007

(a rank of 1 indicates the most challenged performer for each metric)

| Base Panel | Percent Sales (MWh) Residential | Percent Sales (MWh) Other | Use per Customer | Change in Customers (%) | Change in Sales Volume (%) | Percent Generation Nuclear (%) | Energy Losses (%) | Age of Plant (Depreciation/Gross Plant) | Customer Density | Regulatory Lag | Average Rank | Overall Rank |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| *Arizona Public Service Company* | *4* | *34* | *12* | *2* | *3* | *10* | *11* | *35* | *5* | *1* | *11.7* | *2* |
| Alabama Power Company | 26 | 25 | 37 | 19 | 22 | 14 | 22 | 29 | 10 | | 22.7 | 35 |
| Appalachian Power Company | 13 | 33 | 31 | 31 | 5 | 18 | 21 | 36 | 8 | 25 | 22.1 | 33 |
| Carolina Power & Light Company | 11 | 22 | 21 | 10 | 31 | 7 | 32 | 4 | 22 | | 17.8 | 14 |
| Columbus Southern Power Company | 20 | 23 | 16 | 30 | 2 | 18 | 27 | 23 | 29 | 7 | 19.5 | 20 |
| Dayton Power and Light Company | 14 | 24 | 17 | 37 | 33 | 18 | 14 | 8 | 24 | 17 | 20.6 | 27 |
| Detroit Edison Company | 28 | 8 | 7 | 38 | 9 | 17 | 20 | 19 | 33 | 31 | 21.0 | 29 |
| Duke Energy Carolinas, LLC | 22 | 3 | 29 | 9 | 27 | 6 | 15 | 16 | 13 | 26 | 16.6 | 8 |
| Duke Energy Indiana, Inc. | 32 | 20 | 35 | 23 | 16 | 18 | 37 | 28 | 25 | 4 | 23.8 | 37 |
| El Paso Electric Company | 31 | 31 | 4 | 7 | 15 | 4 | 17 | 1 | 7 | 8 | 12.5 | 4 |
| Entergy Arkansas, Inc. | 15 | 32 | 20 | 32 | 20 | 2 | 10 | 14 | 3 | 10 | 15.8 | 5 |
| Entergy Louisiana, LLC | 36 | 6 | 38 | 24 | 34 | 5 | 18 | 13 | 21 | | 21.7 | 31 |
| Entergy Mississippi, Inc. | 9 | 5 | 22 | 26 | 32 | 18 | 2 | 38 | 9 | 33 | 19.4 | 19 |
| Florida Power & Light Company | 1 | 1 | 8 | 11 | 21 | 13 | 5 | 12 | 34 | | 11.8 | 3 |
| Florida Power Corporation | 2 | 14 | 9 | 29 | 35 | 16 | 19 | 21 | 31 | 23 | 19.9 | 24 |
| Georgia Power Company | 34 | 15 | 33 | 13 | 7 | 15 | 25 | 27 | 23 | 26 | 21.8 | 32 |
| Gulf Power Company | 3 | 27 | 13 | 3 | 28 | 18 | 29 | 24 | 11 | 17 | 17.3 | 10 |
| Idaho Power Co. | 16 | 30 | 18 | 5 | 8 | 18 | 3 | 34 | 1 | 26 | 15.9 | 6 |
| Indiana Michigan Power Company | 33 | 39 | 27 | 35 | 29 | 3 | 31 | 2 | 20 | 2 | 22.1 | 33 |
| Indianapolis Power & Light Company | 18 | 7 | 25 | 34 | 23 | 18 | 36 | 3 | 37 | 10 | 21.1 | 30 |
| Kansas City Power & Light Company | 17 | 19 | 19 | 33 | 12 | 12 | 26 | 15 | 16 | 17 | 18.6 | 17 |
| Kansas Gas and Electric Company | 35 | 9 | 24 | 27 | 11 | 9 | 1 | 31 | | 21 | 18.7 | 18 |
| KCP&L Greater Missouri Operations Company | 8 | 16 | 6 | 20 | 38 | 18 | 6 | 26 | 28 | 10 | 17.6 | 12 |
| Kentucky Utilities Company | 21 | 21 | 32 | 22 | 13 | 18 | 13 | 22 | 18 | 26 | 20.6 | 27 |
| Monongahela Power Company | 29 | 17 | 15 | 25 | 39 | 18 | 9 | 5 | 6 | 10 | 17.3 | 10 |
| Nevada Power Company | 6 | 2 | 11 | 4 | 4 | 18 | 28 | 39 | 27 | 26 | 16.5 | 7 |
| Ohio Power Company | 38 | 38 | 36 | 36 | 36 | 18 | 24 | 37 | 17 | 21 | 30.1 | 39 |
| Oklahoma Gas and Electric Company | 23 | 12 | 26 | 18 | 25 | 18 | 7 | 9 | 30 | 31 | 19.9 | 24 |
| PacifiCorp | 37 | 18 | 23 | 8 | 10 | 18 | 8 | 33 | 2 | 23 | 18.0 | 15 |
| Portland General Electric Company | 5 | 36 | 5 | 14 | 37 | 18 | 33 | 7 | 32 | 10 | 19.7 | 23 |
| Public Service Company of New Hampshire | 10 | 10 | 1 | 28 | 30 | 18 | 23 | 25 | 14 | 8 | 16.7 | 9 |
| Public Service Company of New Mexico | 24 | 37 | 3 | 1 | 1 | 11 | 38 | 18 | 35 | 33 | 20.1 | 26 |
| Public Service Company of Oklahoma | 27 | 11 | 30 | 21 | 26 | 18 | 16 | 17 | 19 | 10 | 19.5 | 20 |
| Southern California Edison Co. | 25 | 4 | 2 | 17 | 19 | 1 | 4 | 6 | 15 | 3 | 9.6 | 1 |
| Southwestern Electric Power Company | 30 | 26 | 34 | 6 | 18 | 18 | 34 | 11 | 12 | 6 | 19.5 | 20 |
| Southwestern Public Service Company | 39 | 35 | 39 | 39 | 24 | 18 | 30 | 10 | 4 | 5 | 24.3 | 38 |
| Tucson Electric Power Company | 7 | 29 | 10 | 12 | 6 | 18 | 12 | 30 | 36 | 17 | 17.7 | 13 |
| Virginia Electric and Power Company | 12 | 13 | 28 | 15 | 14 | 8 | 35 | 20 | 26 | 10 | 18.1 | 16 |
| Westar Energy (KPL) | 19 | 28 | 14 | 16 | 17 | 18 | 39 | 32 | | | 22.9 | 36 |

| Regional Panel | Percent Sales (MWh) Residential | Percent Sales (MWh) Other | Use per Customer | Change in Customers (%) | Change in Sales Volume (%) | Percent Generation Nuclear (%) | Energy Losses (%) | Age of Plant (Depreciation/Gross Plant) | Customer Density | Regulatory Lag | Average Rank | Overall Rank |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| *Arizona Public Service Company* | *2* | *6* | *6* | *2* | *3* | *3* | *3* | *7* | *3* | *1* | *3.6* | *2* |
| El Paso Electric Company | 7 | 5 | 3 | 4 | 7 | 2 | 5 | 1 | 4 | 4 | 4.2 | 3 |
| Nevada Power Company | 3 | 1 | 5 | 3 | 4 | 5 | 6 | 8 | 6 | 7 | 4.8 | 5 |
| PacifiCorp | 8 | 3 | 8 | 5 | 6 | 5 | 2 | 6 | 1 | 6 | 5.0 | 7 |
| Public Service Company of New Mexico | 5 | 8 | 2 | 1 | 1 | 4 | 9 | 4 | 7 | 8 | 4.9 | 6 |
| Southern California Edison Co. | 6 | 2 | 1 | 7 | 8 | 1 | 1 | 2 | 5 | 2 | 3.5 | 1 |
| Southwestern Public Service Company | 9 | 7 | 9 | 8 | 9 | 5 | 7 | 3 | 2 | 3 | 6.2 | 9 |
| Tucson Electric Power Company | 4 | 4 | 4 | 6 | 5 | 5 | 4 | 5 | 8 | 5 | 5.0 | 7 |
| Salt River Project | 1 | | 7 | | 2 | | 8 | | | | 4.5 | 4 |

## Situational Assessment Rankings - 2008

(a rank of 1 indicates the most challenged performer for each metric)

| Base Panel | Percent Sales (MWh) Residential | Percent Sales (MWh) Other | Use per Customer | Change in Customers (%) | Change in Sales Volume (%) | Percent Generation Nuclear (%) | Energy Losses (%) | Age of Plant (Depreciation/Gross Plant) | Customer Density | Regulatory Lag | Average Rank | Overall Rank |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| *Arizona Public Service Company* | *3* | *12* | *11* | *6* | *7* | *10* | *10* | *32* | *5* | *1* | *9.7* | *1* |
| Alabama Power Company | 27 | 22 | 36 | 18 | 32 | 14 | 26 | 22 | 11 | | 23.1 | 36 |
| Appalachian Power Company | 14 | 33 | 31 | 20 | 3 | 18 | 19 | 37 | 8 | 33 | 21.6 | 32 |
| Carolina Power & Light Company | 11 | 26 | 20 | 3 | 28 | 7 | 32 | 3 | 22 | | 16.9 | 11 |
| Columbus Southern Power Company | 25 | 30 | 17 | 33 | 1 | 18 | 31 | 21 | 29 | 9 | 21.4 | 29 |
| Dayton Power and Light Company | 13 | 23 | 16 | 35 | 31 | 18 | 13 | 7 | 24 | 19 | 19.9 | 24 |
| Detroit Edison Company | 31 | 10 | 6 | 38 | 10 | 15 | 14 | 15 | 33 | 1 | 17.3 | 12 |
| Duke Energy Carolinas, LLC | 19 | 4 | 27 | 5 | 26 | 6 | 12 | 14 | 14 | 27 | 15.4 | 6 |
| Duke Energy Indiana, Inc. | 30 | 25 | 35 | 31 | 29 | 18 | 36 | 23 | 25 | 6 | 25.8 | 38 |
| El Paso Electric Company | 33 | 34 | 4 | 2 | 11 | 3 | 24 | 1 | 7 | 11 | 13.0 | 3 |
| Entergy Arkansas, Inc. | 15 | 28 | 22 | 25 | 22 | 2 | 21 | 11 | 3 | 13 | 16.2 | 9 |
| Entergy Louisiana, LLC | 36 | 5 | 38 | 14 | 30 | 5 | 22 | 13 | 21 | | 20.4 | 26 |
| Entergy Mississippi, Inc. | 8 | 11 | 21 | 29 | 34 | 18 | 4 | 38 | 9 | 34 | 20.6 | 27 |
| Florida Power & Light Company | 1 | 1 | 8 | 32 | 27 | 12 | 6 | 10 | 34 | | 14.6 | 4 |
| Florida Power Corporation | 2 | 19 | 9 | 27 | 35 | 17 | 23 | 26 | 31 | 26 | 21.5 | 30 |
| Georgia Power Company | 34 | 16 | 33 | 15 | 13 | 16 | 20 | 24 | 23 | 27 | 22.1 | 34 |
| Gulf Power Company | 4 | 29 | 14 | 28 | 19 | 18 | 28 | 28 | 10 | 19 | 19.7 | 22 |
| Idaho Power Co. | 16 | 15 | 19 | 4 | 8 | 18 | 3 | 30 | 2 | 31 | 14.6 | 5 |
| Indiana Michigan Power Company | 32 | 38 | 26 | 34 | 33 | 4 | 27 | 4 | 20 | 3 | 22.1 | 34 |
| Indianapolis Power & Light Company | 17 | 7 | 25 | 37 | 25 | 18 | 34 | 2 | 37 | 13 | 21.5 | 30 |
| Kansas City Power & Light Company | 18 | 24 | 18 | 24 | 16 | 13 | 30 | 19 | 16 | 19 | 19.7 | 22 |
| Kansas Gas and Electric Company | 35 | 8 | 23 | 17 | 15 | 9 | 1 | 31 | | 22 | 17.9 | 15 |
| KCP&L Greater Missouri Operations Company | 6 | 13 | 7 | | | 18 | 9 | 34 | 26 | 13 | 15.8 | 8 |
| Kentucky Utilities Company | 20 | 21 | 32 | 23 | 17 | 18 | 16 | 27 | 18 | 27 | 21.9 | 33 |
| Monongahela Power Company | 28 | 9 | 15 | 19 | 38 | 18 | 2 | 8 | 6 | 13 | 15.6 | 7 |
| Nevada Power Company | 7 | 2 | 12 | 11 | 5 | 18 | 38 | 39 | 28 | 27 | 18.7 | 19 |
| Ohio Power Company | 38 | 37 | 37 | 36 | 23 | 18 | 18 | 36 | 17 | 22 | 28.2 | 39 |
| Oklahoma Gas and Electric Company | 21 | 17 | 29 | 12 | 12 | 18 | 11 | 12 | 30 | 31 | 19.3 | 21 |
| PacifiCorp | 37 | 20 | 24 | 8 | 6 | 18 | 8 | 35 | 1 | 25 | 18.2 | 17 |
| Portland General Electric Company | 5 | 35 | 5 | 7 | 37 | 18 | 29 | 5 | 32 | 13 | 18.6 | 18 |
| Public Service Company of New Hampshire | 10 | 3 | 1 | 30 | 36 | 18 | 17 | 29 | 13 | 11 | 16.8 | 10 |
| Public Service Company of New Mexico | 22 | 39 | 3 | 9 | 2 | 11 | 33 | 17 | 35 | 7 | 17.8 | 14 |
| Public Service Company of Oklahoma | 26 | 14 | 30 | 21 | 24 | 18 | 7 | 18 | 19 | 13 | 19.0 | 20 |
| Southern California Edison Co. | 24 | 6 | 2 | 26 | 14 | 1 | 5 | 6 | 15 | 4 | 10.3 | 2 |
| Southwestern Electric Power Company | 29 | 27 | 34 | 13 | 20 | 18 | 35 | 16 | 12 | 8 | 21.2 | 28 |
| Southwestern Public Service Company | 39 | 32 | 39 | 1 | 4 | 18 | 25 | 9 | 4 | 9 | 18.0 | 16 |
| Tucson Electric Power Company | 9 | 31 | 10 | 16 | 9 | 18 | 15 | 25 | 36 | 4 | 17.3 | 12 |
| Virginia Electric and Power Company | 12 | 18 | 28 | 10 | 18 | 8 | 37 | 20 | 27 | 22 | 20.0 | 25 |
| Westar Energy (KPL) | 23 | 36 | 13 | 22 | 21 | 18 | 39 | 33 | | | 25.6 | 37 |

| Regional Panel | Percent Sales (MWh) Residential | Percent Sales (MWh) Other | Use per Customer | Change in Customers (%) | Change in Sales Volume (%) | Percent Generation Nuclear (%) | Energy Losses (%) | Age of Plant (Depreciation/Gross Plant) | Customer Density | Regulatory Lag | Average Rank | Overall Rank |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| *Arizona Public Service Company* | *2* | *3* | *5* | *3* | *6* | *3* | *3* | *6* | *3* | *1* | *3.5* | *1* |
| El Paso Electric Company | 7 | 7 | 3 | 2 | 8 | 2 | 5 | 1 | 4 | 6 | 4.5 | 4 |
| Nevada Power Company | 3 | 1 | 6 | 6 | 4 | 5 | 9 | 8 | 6 | 8 | 5.6 | 9 |
| PacifiCorp | 8 | 4 | 8 | 4 | 5 | 5 | 2 | 7 | 1 | 7 | 5.1 | 7 |
| Public Service Company of New Mexico | 5 | 8 | 2 | 5 | 1 | 4 | 8 | 4 | 7 | 4 | 4.8 | 5 |
| Southern California Edison Co. | 6 | 2 | 1 | 8 | 9 | 1 | 1 | 2 | 5 | 2 | 3.7 | 2 |
| Southwestern Public Service Company | 9 | 6 | 9 | 1 | 3 | 5 | 6 | 3 | 2 | 5 | 4.9 | 6 |
| Tucson Electric Power Company | 4 | 5 | 4 | 7 | 7 | 5 | 4 | 5 | 8 | 2 | 5.1 | 7 |
| Salt River Project | 1 | | 7 | | 2 | | 7 | | | | 4.3 | 3 |

## Situational Assessment Rankings - 2009

(a rank of 1 indicates the most challenged performer for each metric)

| Base Panel | Percent Sales (MWh) Residential | Percent Sales (MWh) Other | Use per Customer | Change in Customers (%) | Change in Sales Volume (%) | Percent Generation Nuclear (%) | Energy Losses (%) | Age of Plant (Depreciation/Gross Plant) | Customer Density | Regulatory Lag | Average Rank | Overall Rank |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| *Arizona Public Service Company* | *4* | *14* | *11* | *15* | *8* | *10* | *17* | *28* | *5* | *1* | *11.3* | *2* |
| Alabama Power Company | 23 | 25 | 37 | 28 | 34 | 15 | 29 | 22 | 11 | | 24.9 | 37 |
| Appalachian Power Company | 10 | 35 | 28 | 24 | 29 | 18 | 15 | 34 | 8 | 20 | 22.1 | 34 |
| Carolina Power & Light Company | 11 | 24 | 22 | 3 | 18 | 6 | 33 | 3 | 22 | | 15.8 | 9 |
| Columbus Southern Power Company | 26 | 30 | 17 | 22 | 4 | 18 | 30 | 20 | 29 | 6 | 20.2 | 27 |
| Dayton Power and Light Company | 15 | 20 | 16 | 30 | 37 | 18 | 4 | 39 | 25 | 13 | 21.7 | 32 |
| Detroit Edison Company | 30 | 13 | 5 | 38 | 32 | 16 | 16 | 10 | 33 | 2 | 19.5 | 22 |
| Duke Energy Carolinas, LLC | 17 | 10 | 27 | 17 | 23 | 5 | 20 | 15 | 14 | 26 | 17.4 | 13 |
| Duke Energy Indiana, Inc. | 31 | 29 | 32 | 31 | 35 | 18 | 34 | 24 | 26 | 4 | 26.4 | 38 |
| El Paso Electric Company | 32 | 37 | 4 | 2 | 3 | 2 | 25 | 2 | 7 | 26 | 14.0 | 5 |
| Entergy Arkansas, Inc. | 16 | 28 | 20 | 23 | 28 | 1 | 22 | 5 | 3 | 9 | 15.5 | 7 |
| Entergy Louisiana, LLC | 36 | 6 | 38 | 18 | 9 | 4 | 23 | 12 | 21 | | 18.6 | 19 |
| Entergy Mississippi, Inc. | 7 | 9 | 21 | 20 | 27 | 18 | 3 | 36 | 9 | 34 | 18.4 | 17 |
| Florida Power & Light Company | 1 | 1 | 7 | 35 | 12 | 12 | 6 | 11 | 34 | | 13.2 | 3 |
| Florida Power Corporation | 2 | 21 | 8 | 37 | 21 | 17 | 18 | 27 | 31 | 24 | 20.6 | 28 |
| Georgia Power Company | 35 | 15 | 35 | 19 | 14 | 14 | 24 | 29 | 24 | 26 | 23.5 | 35 |
| Gulf Power Company | 3 | 23 | 12 | 36 | 26 | 18 | 26 | 32 | 10 | 13 | 19.9 | 25 |
| Idaho Power Co. | 14 | 11 | 18 | 8 | 11 | 18 | 5 | 17 | 2 | 33 | 13.7 | 4 |
| Indiana Michigan Power Company | 33 | 39 | 25 | 32 | 33 | 8 | 14 | 4 | 20 | 6 | 21.4 | 30 |
| Indianapolis Power & Light Company | 19 | 5 | 24 | 33 | 31 | 18 | 36 | 1 | 37 | 9 | 21.3 | 29 |
| Kansas City Power & Light Company | 22 | 22 | 19 | 25 | 16 | 13 | 31 | 19 | 16 | 13 | 19.6 | 23 |
| Kansas Gas and Electric Company | 34 | 12 | 23 | 4 | 22 | 9 | 1 | 25 | | 24 | 17.1 | 12 |
| KCP&L Greater Missouri Operations Company | 6 | 8 | 10 | | | 18 | 11 | 35 | 23 | 13 | 15.5 | 7 |
| Kentucky Utilities Company | 20 | 26 | 34 | 7 | 20 | 18 | 19 | 26 | 18 | 26 | 21.4 | 30 |
| Monongahela Power Company | 27 | 2 | 15 | 13 | 38 | 18 | 8 | 6 | 6 | 9 | 14.2 | 6 |
| Nevada Power Company | 8 | 3 | 13 | 26 | 5 | 18 | 35 | 38 | 28 | 26 | 20.0 | 26 |
| Ohio Power Company | 38 | 38 | 36 | 34 | 36 | 18 | 21 | 30 | 17 | 20 | 28.8 | 39 |
| Oklahoma Gas and Electric Company | 21 | 19 | 29 | 5 | 13 | 18 | 7 | 14 | 30 | 26 | 18.2 | 16 |
| PacifiCorp | 37 | 18 | 26 | 10 | 7 | 18 | 13 | 37 | 1 | 18 | 18.5 | 18 |
| Portland General Electric Company | 5 | 31 | 6 | 16 | 15 | 18 | 28 | 7 | 32 | 9 | 16.7 | 11 |
| Public Service Company of New Hampshire | 12 | 4 | 1 | 27 | 24 | 18 | 37 | 31 | 13 | 8 | 17.5 | 14 |
| Public Service Company of New Mexico | 18 | 36 | 3 | 29 | 2 | 11 | 10 | 13 | 35 | 20 | 17.7 | 15 |
| Public Service Company of Oklahoma | 24 | 16 | 30 | 12 | 25 | 18 | 12 | 16 | 19 | 26 | 19.8 | 24 |
| Southern California Edison Co. | 28 | 7 | 2 | 21 | 17 | 3 | 2 | 9 | 15 | 5 | 10.9 | 1 |
| Southwestern Electric Power Company | 29 | 27 | 33 | 11 | 30 | 18 | 27 | 18 | 12 | 13 | 21.8 | 33 |
| Southwestern Public Service Company | 39 | 32 | 39 | 1 | 1 | 18 | 32 | 8 | 4 | 19 | 19.3 | 20 |
| Tucson Electric Power Company | 9 | 33 | 9 | 14 | 6 | 18 | 9 | 23 | 36 | 3 | 16.0 | 10 |
| Virginia Electric and Power Company | 13 | 17 | 31 | 9 | 10 | 7 | 38 | 21 | 27 | 20 | 19.3 | 20 |
| Westar Energy (KPL) | 25 | 34 | 14 | 6 | 19 | 18 | 39 | 33 | | | 23.5 | 35 |

| Regional Panel | Percent Sales (MWh) Residential | Percent Sales (MWh) Other | Use per Customer | Change in Customers (%) | Change in Sales Volume (%) | Percent Generation Nuclear (%) | Energy Losses (%) | Age of Plant (Depreciation/Gross Plant) | Customer Density | Regulatory Lag | Average Rank | Overall Rank |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| *Arizona Public Service Company* | *2* | *3* | *5* | *5* | *7* | *3* | *5* | *6* | *3* | *1* | *4.0* | *2* |
| El Paso Electric Company | 7 | 8 | 3 | 2 | 3 | 1 | 6 | 1 | 4 | 7 | 4.2 | 3 |
| Nevada Power Company | 3 | 1 | 6 | 7 | 4 | 5 | 9 | 8 | 6 | 7 | 5.6 | 8 |
| PacifiCorp | 8 | 4 | 8 | 3 | 6 | 5 | 4 | 7 | 1 | 4 | 5.0 | 7 |
| Public Service Company of New Mexico | 5 | 7 | 2 | 8 | 2 | 4 | 3 | 4 | 7 | 6 | 4.8 | 6 |
| Southern California Edison Co. | 6 | 2 | 1 | 6 | 9 | 2 | 1 | 3 | 5 | 3 | 3.8 | 1 |
| Southwestern Public Service Company | 9 | 5 | 9 | 1 | 1 | 5 | 8 | 2 | 2 | 5 | 4.7 | 5 |
| Tucson Electric Power Company | 4 | 6 | 4 | 4 | 5 | 5 | 2 | 5 | 8 | 2 | 4.5 | 4 |
| Salt River Project | 1 | | 7 | | 8 | | 7 | | | | 5.8 | 9 |

## Situational Assessment Rankings - 2010

(a rank of 1 indicates the most challenged performer for each metric)

| Base Panel | Percent Sales (MWh) Residential | Percent Sales (MWh) Other | Use per Customer | Change in Customers (%) | Change in Sales Volume (%) | Percent Generation Nuclear (%) | Energy Losses (%) | Age of Plant (Depreciation/Gross Plant) | Customer Density | Regulatory Lag | Average Rank | Overall Rank |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| *Arizona Public Service Company* | *4* | *12* | *10* | *13* | *31* | *10* | *20* | *26* | *5* | *1* | *13.2* | *3* |
| Alabama Power Company | 25 | 29 | 37 | 33 | 18 | 15 | 27 | 20 | 11 | | 23.9 | 36 |
| Appalachian Power Company | 11 | 30 | 27 | 30 | 28 | 17 | 14 | 33 | 8 | 7 | 20.5 | 25 |
| Carolina Power & Light Company | 7 | 26 | 25 | 38 | 10 | 8 | 32 | 3 | 22 | | 19.0 | 20 |
| Columbus Southern Power Company | 22 | 23 | 18 | 34 | 14 | 17 | 37 | 17 | 29 | 5 | 21.6 | 29 |
| Dayton Power and Light Company | 14 | 27 | 17 | 35 | 35 | 17 | 38 | 39 | 25 | 16 | 26.3 | 38 |
| Detroit Edison Company | 23 | 14 | 5 | 37 | 38 | 16 | 15 | 10 | 33 | 10 | 20.1 | 24 |
| Duke Energy Carolinas, LLC | 16 | 6 | 28 | 18 | 13 | 5 | 24 | 13 | 14 | 29 | 16.6 | 13 |
| Duke Energy Indiana, Inc. | 31 | 24 | 32 | 7 | 26 | 17 | 34 | 27 | 26 | 3 | 22.7 | 34 |
| El Paso Electric Company | 33 | 38 | 4 | 2 | 2 | 2 | 23 | 2 | 7 | 25 | 13.8 | 4 |
| Entergy Arkansas, Inc. | 15 | 34 | 23 | 15 | 7 | 1 | 8 | 5 | 3 | 20 | 13.1 | 1 |
| Entergy Louisiana, LLC | 36 | 4 | 38 | 10 | 1 | 4 | 25 | 9 | 21 | | 16.4 | 12 |
| Entergy Mississippi, Inc. | 6 | 5 | 22 | 12 | 12 | 17 | 2 | 35 | 9 | 35 | 15.5 | 9 |
| Florida Power & Light Company | 1 | 2 | 8 | 21 | 21 | 12 | 13 | 12 | 34 | 7 | 13.1 | 1 |
| Florida Power Corporation | 2 | 15 | 9 | 11 | 23 | 17 | 3 | 28 | 31 | 10 | 14.9 | 7 |
| Georgia Power Company | 32 | 8 | 35 | 28 | 9 | 14 | 22 | 29 | 24 | 34 | 23.5 | 35 |
| Gulf Power Company | 3 | 17 | 12 | 23 | 22 | 17 | 28 | 30 | 10 | 16 | 17.8 | 17 |
| Idaho Power Co. | 21 | 19 | 15 | 17 | 36 | 17 | 6 | 21 | 1 | 29 | 18.2 | 18 |
| Indiana Michigan Power Company | 35 | 33 | 26 | 32 | 27 | 3 | 19 | 4 | 19 | 20 | 21.8 | 31 |
| Indianapolis Power & Light Company | 17 | 10 | 21 | 31 | 32 | 17 | 36 | 1 | 37 | 14 | 21.6 | 29 |
| Kansas City Power & Light Company | 19 | 25 | 19 | 26 | 17 | 13 | 30 | 15 | 16 | 10 | 19.0 | 20 |
| Kansas Gas and Electric Company | 34 | 9 | 24 | 22 | 16 | 9 | 1 | 25 | | 25 | 18.3 | 19 |
| KCP&L Greater Missouri Operations Company | 5 | 3 | 13 | 29 | | 17 | 5 | 32 | 23 | 16 | 15.9 | 11 |
| Kentucky Utilities Company | 27 | 20 | 33 | 9 | 8 | 17 | 11 | 38 | 18 | 24 | 20.5 | 25 |
| Monongahela Power Company | 29 | 1 | 16 | 19 | 30 | 17 | 10 | 6 | 6 | 14 | 14.8 | 6 |
| Nevada Power Company | 10 | 7 | 11 | 24 | 29 | 17 | 33 | 37 | 28 | 29 | 22.5 | 33 |
| Ohio Power Company | 38 | 39 | 36 | 36 | 34 | 17 | 26 | 23 | 17 | 20 | 28.6 | 39 |
| Oklahoma Gas and Electric Company | 24 | 21 | 30 | 5 | 6 | 17 | 9 | 19 | 30 | 29 | 19.0 | 20 |
| PacifiCorp | 37 | 22 | 20 | 4 | 20 | 17 | 12 | 36 | 2 | 28 | 19.8 | 23 |
| Portland General Electric Company | 8 | 31 | 6 | 14 | 24 | 17 | 29 | 7 | 32 | 6 | 17.4 | 14 |
| Public Service Company of New Hampshire | 12 | 11 | 1 | 8 | 33 | 17 | 21 | 34 | 13 | 7 | 15.7 | 10 |
| Public Service Company of New Mexico | 18 | 36 | 3 | 3 | 3 | 11 | 4 | 14 | 35 | 20 | 14.7 | 5 |
| Public Service Company of Oklahoma | 20 | 18 | 31 | 20 | 19 | 17 | 17 | 18 | 20 | 29 | 20.9 | 28 |
| Southern California Edison Co. | 30 | 13 | 2 | 16 | 37 | 6 | 18 | 11 | 15 | 4 | 15.2 | 8 |
| Southwestern Electric Power Company | 28 | 28 | 34 | 1 | 5 | 17 | 35 | 22 | 12 | 25 | 20.7 | 27 |
| Southwestern Public Service Company | 39 | 35 | 39 | 39 | 4 | 17 | 16 | 8 | 4 | 19 | 22.0 | 32 |
| Tucson Electric Power Company | 9 | 32 | 7 | 25 | 25 | 17 | 7 | 16 | 36 | 2 | 17.6 | 15 |
| Virginia Electric and Power Company | 13 | 16 | 29 | 6 | 11 | 7 | 31 | 24 | 27 | 13 | 17.7 | 16 |
| Westar Energy (KPL) | 26 | 37 | 14 | 27 | 15 | 17 | 39 | 31 | | | 25.8 | 37 |

| Regional Panel | Percent Sales (MWh) Residential | Percent Sales (MWh) Other | Use per Customer | Change in Customers (%) | Change in Sales Volume (%) | Percent Generation Nuclear (%) | Energy Losses (%) | Age of Plant (Depreciation/Gross Plant) | Customer Density | Regulatory Lag | Average Rank | Overall Rank |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| *Arizona Public Service Company* | *1* | *2* | *5* | *4* | *7* | *3* | *6* | *6* | *3* | *1* | *3.8* | *1* |
| El Paso Electric Company | 6 | 8 | 3 | 1 | 1 | 1 | 7 | 1 | 4 | 6 | 3.8 | 1 |
| Nevada Power Company | 3 | 1 | 6 | 6 | 6 | 5 | 8 | 8 | 6 | 8 | 5.7 | 8 |
| PacifiCorp | 7 | 4 | 7 | 3 | 4 | 5 | 3 | 7 | 1 | 7 | 4.8 | 6 |
| Public Service Company of New Mexico | 4 | 7 | 2 | 2 | 2 | 4 | 1 | 4 | 7 | 5 | 3.8 | 1 |
| Southern California Edison Co. | 5 | 3 | 1 | 5 | 8 | 2 | 5 | 3 | 5 | 3 | 4.0 | 4 |
| Southwestern Public Service Company | 8 | 6 | 8 | 8 | 3 | 5 | 4 | 2 | 2 | 4 | 5.0 | 7 |
| Tucson Electric Power Company | 2 | 5 | 4 | 7 | 5 | 5 | 2 | 5 | 8 | 2 | 4.5 | 5 |
| Salt River Project | | | | | | | | | | | | |

## Productive Efficiency Rankings - 2000

(a rank of 1 indicates the most efficient performer for each metric)

| Base Panel | Production O&M | Transmission O&M | Distribution O&M | Customer and A&G Expenses | Total Non-Fuel O&M | Plant Investment | Overall Average | Overall Rank |
|---|---|---|---|---|---|---|---|---|
| *Arizona Public Service Company* | *18* | *22* | *17* | *10* | *16* | *30* | *18.6* | *14* |
| Alabama Power Company | 28 | 23 | 29 | 19 | 26 | 29 | 25.2 | 35 |
| Appalachian Power Company | 12 | 19 | 32 | 19 | 18 | 18 | 19.4 | 16 |
| Carolina Power & Light Company | 20 | 25 | 6 | 29 | 24 | 28 | 21.6 | 25 |
| Columbus Southern Power Company | 10 | 37 | 26 | 9 | 21 | 21 | 20.3 | 20 |
| Dayton Power and Light Company | 8 | 2 | 5 | 8 | 8 | 3 | 5.4 | 1 |
| Detroit Edison Company | 13 | 4 | 32 | 26 | 23 | 18 | 19.0 | 15 |
| Duke Energy Carolinas, LLC | 15 | 17 | 18 | 35 | 33 | 23 | 23.3 | 28 |
| Duke Energy Indiana, Inc. | 18 | 31 | 6 | 32 | 22 | 15 | 20.3 | 21 |
| El Paso Electric Company | 28 | 11 | 11 | 37 | 33 | 13 | 22.1 | 27 |
| Entergy Arkansas, Inc. | 23 | 17 | 34 | 33 | 31 | 37 | 29.1 | 38 |
| Entergy Louisiana, LLC | | | | | | | | |
| Entergy Mississippi, Inc. | 28 | 15 | 26 | 16 | 2 | 32 | 19.8 | 19 |
| Florida Power & Light Company | 22 | 13 | 21 | 3 | 4 | 27 | 14.7 | 7 |
| Florida Power Corporation | 30 | 19 | 11 | 18 | 18 | 22 | 19.6 | 18 |
| Georgia Power Company | 26 | 25 | 27 | 25 | 26 | 28 | 26.0 | 37 |
| Gulf Power Company | 26 | 13 | 21 | 19 | 23 | 16 | 19.5 | 17 |
| Idaho Power Co. | 1 | 17 | 35 | 14 | 4 | 8 | 13.0 | 4 |
| Indiana Michigan Power Company | 38 | 1 | 23 | 25 | 38 | 27 | 25.2 | 34 |
| Indianapolis Power & Light Company | 13 | 10 | 16 | 38 | 33 | 14 | 20.4 | 22 |
| Kansas City Power & Light Company | 15 | 18 | 36 | 28 | 31 | 28 | 25.7 | 36 |
| Kansas Gas and Electric Company | 23 | 23 | 26 | 24 | 35 | 12 | 23.7 | 29 |
| KCP&L Greater Missouri Operations Company | 17 | 28 | 26 | 27 | 19 | 32 | 24.8 | 33 |
| Kentucky Utilities Company | 10 | 7 | 9 | 3 | 8 | 13 | 7.9 | 2 |
| Monongahela Power Company | 9 | 13 | 32 | 17 | 14 | 17 | 16.8 | 11 |
| Nevada Power Company | 27 | 11 | 1 | 11 | 7 | 29 | 14.3 | 6 |
| Ohio Power Company | 32 | 34 | 16 | 16 | 29 | 18 | 23.8 | 30 |
| Oklahoma Gas and Electric Company | 30 | 10 | 14 | 17 | 9 | 14 | 15.3 | 9 |
| PacifiCorp | 6 | 33 | 29 | 2 | 17 | 9 | 15.9 | 10 |
| Portland General Electric Company | 11 | 35 | 15 | 17 | 13 | 17 | 17.8 | 13 |
| Public Service Company of New Hampshire | 2 | 35 | 27 | 23 | 23 | 18 | 21.2 | 23 |
| Public Service Company of New Mexico | 22 | 34 | 16 | 26 | 30 | 3 | 21.8 | 26 |
| Public Service Company of Oklahoma | 34 | 13 | 11 | 3 | 5 | 6 | 11.8 | 3 |
| Southern California Edison Co. | 10 | 25 | 10 | 20 | 17 | 20 | 16.8 | 12 |
| Southwestern Electric Power Company | 33 | 26 | 33 | 20 | 18 | 18 | 24.5 | 31 |
| Southwestern Public Service Company | 29 | 20 | 6 | 11 | 1 | 13 | 13.2 | 5 |
| Tucson Electric Power Company | 33 | 11 | 5 | 33 | 26 | 21 | 21.3 | 24 |
| Virginia Electric and Power Company | 10 | 14 | 19 | 11 | 14 | 24 | 15.2 | 8 |
| Westar Energy (KPL) | 23 | 21 | 24 | 26 | 30 | 25 | 24.6 | 32 |

| Regional Panel | Production O&M | Transmission O&M | Distribution O&M | Customer and A&G Expenses | Total Non-Fuel O&M | Plant Investment | Overall Average | Overall Rank |
|---|---|---|---|---|---|---|---|---|
| *Arizona Public Service Company* | *3* | *5* | *7* | *3* | *4* | *7* | *4.7* | *5* |
| El Paso Electric Company | 6 | 2 | 4 | 8 | 8 | 4 | 5.4 | 7 |
| Nevada Power Company | 6 | 2 | 1 | 4 | 2 | 8 | 3.8 | 2 |
| PacifiCorp | 2 | 8 | 8 | 1 | 4 | 3 | 4.2 | 4 |
| Public Service Company of New Mexico | 5 | 8 | 6 | 6 | 7 | 1 | 5.6 | 8 |
| Southern California Edison Co. | 2 | 6 | 4 | 5 | 4 | 5 | 4.1 | 3 |
| Southwestern Public Service Company | 6 | 4 | 4 | 4 | 1 | 3 | 3.7 | 1 |
| Tucson Electric Power Company | 7 | 3 | 3 | 7 | 6 | 6 | 5.0 | 6 |
| Salt River Project | | 7 | 9 | | | 8 | 7.8 | 9 |

## Productive Efficiency Rankings - 2001

(a rank of 1 indicates the most efficient performer for each metric)

| Base Panel | Production O&M | Transmission O&M | Distribution O&M | Customer and A&G Expenses | Total Non-Fuel O&M | Plant Investment | Overall Average | Overall Rank |
|---|---|---|---|---|---|---|---|---|
| *Arizona Public Service Company* | *21* | *18* | *15* | *10* | *17* | *25* | *17.5* | *13* |
| Alabama Power Company | 24 | 15 | 24 | 16 | 22 | 32 | 22.0 | 24 |
| Appalachian Power Company | 12 | 16 | 31 | 10 | 12 | 17 | 15.9 | 8 |
| Carolina Power & Light Company | 20 | 28 | 5 | 23 | 23 | 30 | 21.3 | 20 |
| Columbus Southern Power Company | 13 | 37 | 16 | 5 | 13 | 22 | 17.3 | 11 |
| Dayton Power and Light Company | 14 | 2 | 4 | 3 | 4 | 11 | 6.2 | 1 |
| Detroit Edison Company | 12 | 24 | 28 | 37 | 32 | 18 | 24.9 | 35 |
| Duke Energy Carolinas, LLC | 13 | 17 | 13 | 35 | 33 | 19 | 21.5 | 22 |
| Duke Energy Indiana, Inc. | 19 | 17 | 8 | 27 | 17 | 21 | 18.1 | 14 |
| El Paso Electric Company | 32 | 11 | 13 | 37 | 34 | 9 | 22.4 | 26 |
| Entergy Arkansas, Inc. | 29 | 15 | 31 | 11 | 35 | 18 | 23.0 | 30 |
| Entergy Louisiana, LLC | | | | | | | | |
| Entergy Mississippi, Inc. | 37 | 8 | 22 | 17 | 24 | 20 | 21.3 | 21 |
| Florida Power & Light Company | 31 | 10 | 19 | 2 | 11 | 26 | 16.4 | 9 |
| Florida Power Corporation | 27 | 19 | 9 | 5 | 6 | 8 | 12.1 | 3 |
| Georgia Power Company | 22 | 25 | 29 | 28 | 25 | 23 | 25.1 | 37 |
| Gulf Power Company | 24 | 16 | 24 | 21 | 20 | 14 | 19.6 | 19 |
| Idaho Power Co. | 2 | 20 | 36 | 23 | 2 | 30 | 18.7 | 17 |
| Indiana Michigan Power Company | 26 | 1 | 34 | 27 | 38 | 11 | 22.6 | 28 |
| Indianapolis Power & Light Company | 10 | 7 | 14 | 37 | 31 | 6 | 17.5 | 12 |
| Kansas City Power & Light Company | 10 | 15 | 37 | 19 | 27 | 31 | 22.9 | 29 |
| Kansas Gas and Electric Company | 20 | 29 | 25 | 32 | 33 | 11 | 24.8 | 34 |
| KCP&L Greater Missouri Operations Company | 14 | 27 | 30 | 20 | 18 | 27 | 22.5 | 27 |
| Kentucky Utilities Company | 9 | 6 | 4 | 12 | 5 | 22 | 9.5 | 2 |
| Monongahela Power Company | 9 | 15 | 31 | 17 | 14 | 5 | 15.0 | 6 |
| Nevada Power Company | 1 | 18 | 2 | 24 | 1 | 33 | 13.0 | 4 |
| Ohio Power Company | 28 | 29 | 22 | 12 | 28 | 25 | 23.7 | 32 |
| Oklahoma Gas and Electric Company | 27 | 7 | 16 | 23 | 7 | 11 | 14.8 | 5 |
| PacifiCorp | 6 | 34 | 25 | 17 | 17 | 13 | 18.5 | 15 |
| Portland General Electric Company | 20 | 36 | 10 | 27 | 15 | 27 | 22.2 | 25 |
| Public Service Company of New Hampshire | 14 | 33 | 29 | 22 | 22 | 21 | 23.3 | 31 |
| Public Service Company of New Mexico | 25 | 35 | 20 | 22 | 29 | 27 | 26.2 | 38 |
| Public Service Company of Oklahoma | 35 | 22 | 14 | 3 | 12 | 27 | 18.6 | 16 |
| Southern California Edison Co. | 14 | 30 | 12 | 22 | 16 | 9 | 17.1 | 10 |
| Southwestern Electric Power Company | 33 | 25 | 33 | 16 | 14 | 12 | 21.9 | 23 |
| Southwestern Public Service Company | 37 | 28 | 5 | 17 | 33 | 23 | 23.7 | 32 |
| Tucson Electric Power Company | 31 | 9 | 6 | 26 | 19 | 23 | 18.8 | 18 |
| Virginia Electric and Power Company | 18 | 11 | 23 | 12 | 15 | 14 | 15.2 | 7 |
| Westar Energy (KPL) | 16 | 23 | 31 | 31 | 26 | 24 | 25.0 | 36 |

| Regional Panel | Production O&M | Transmission O&M | Distribution O&M | Customer and A&G Expenses | Total Non-Fuel O&M | Plant Investment | Overall Average | Overall Rank |
|---|---|---|---|---|---|---|---|---|
| *Arizona Public Service Company* | *4* | *4* | *6* | *2* | *4* | *6* | *3.9* | *2* |
| El Paso Electric Company | 7 | 2 | 5 | 8 | 8 | 2 | 5.1 | 6 |
| Nevada Power Company | 1 | 3 | 2 | 5 | 1 | 9 | 3.3 | 1 |
| PacifiCorp | 3 | 7 | 8 | 4 | 4 | 4 | 4.7 | 5 |
| Public Service Company of New Mexico | 5 | 8 | 7 | 5 | 7 | 7 | 6.3 | 9 |
| Southern California Edison Co. | 3 | 7 | 4 | 5 | 4 | 3 | 4.0 | 3 |
| Southwestern Public Service Company | 8 | 6 | 3 | 4 | 7 | 6 | 5.7 | 7 |
| Tucson Electric Power Company | 7 | 2 | 3 | 6 | 4 | 6 | 4.3 | 4 |
| Salt River Project | | 6 | 9 | | | 4 | 6.1 | 8 |

## Productive Efficiency Rankings - 2002

(a rank of 1 indicates the most efficient performer for each metric)

| Base Panel | Production O&M | Transmission O&M | Distribution O&M | Customer and A&G Expenses | Total Non-Fuel O&M | Plant Investment | Overall Average | Overall Rank |
|---|---|---|---|---|---|---|---|---|
| *Arizona Public Service Company* | *13* | *16* | *22* | *11* | *19* | *26* | *17.7* | *11* |
| Alabama Power Company | 24 | 12 | 25 | 19 | 20 | 16 | 19.4 | 16 |
| Appalachian Power Company | 11 | 3 | 31 | 13 | 11 | 16 | 14.0 | 8 |
| Carolina Power & Light Company | 26 | 26 | 15 | 23 | 24 | 28 | 23.4 | 27 |
| Columbus Southern Power Company | 8 | 33 | 19 | 8 | 11 | 11 | 14.8 | 9 |
| Dayton Power and Light Company | 10 | 2 | 3 | 2 | 3 | 9 | 4.7 | 1 |
| Detroit Edison Company | 15 | 31 | 33 | 35 | 28 | 25 | 27.5 | 38 |
| Duke Energy Carolinas, LLC | 15 | 12 | 34 | 32 | 30 | 26 | 24.7 | 31 |
| Duke Energy Indiana, Inc. | 18 | 24 | 6 | 34 | 22 | 27 | 21.7 | 23 |
| El Paso Electric Company | 26 | 33 | 12 | 37 | 34 | 6 | 24.4 | 29 |
| Entergy Arkansas, Inc. | 20 | 12 | 24 | 38 | 37 | 22 | 25.3 | 35 |
| Entergy Louisiana, LLC | | | | | | | | |
| Entergy Mississippi, Inc. | 34 | 11 | 24 | 19 | 24 | 30 | 23.6 | 28 |
| Florida Power & Light Company | 28 | 13 | 17 | 4 | 7 | 29 | 16.0 | 10 |
| Florida Power Corporation | 29 | 18 | 11 | 17 | 10 | 28 | 18.5 | 13 |
| Georgia Power Company | 26 | 26 | 29 | 23 | 25 | 19 | 24.4 | 30 |
| Gulf Power Company | 33 | 12 | 30 | 18 | 21 | 37 | 25.1 | 34 |
| Idaho Power Co. | 28 | 16 | 36 | 19 | 36 | 18 | 25.4 | 36 |
| Indiana Michigan Power Company | 27 | 1 | 21 | 29 | 36 | 6 | 19.7 | 18 |
| Indianapolis Power & Light Company | 6 | 11 | 23 | 4 | 8 | 31 | 13.5 | 6 |
| Kansas City Power & Light Company | 9 | 18 | 38 | 27 | 29 | 16 | 22.4 | 25 |
| Kansas Gas and Electric Company | 21 | 36 | 16 | 32 | 35 | 11 | 25.0 | 33 |
| KCP&L Greater Missouri Operations Company | 12 | 25 | 32 | 16 | 15 | 31 | 21.7 | 24 |
| Kentucky Utilities Company | 15 | 16 | 6 | 12 | 9 | 16 | 12.0 | 4 |
| Monongahela Power Company | 6 | 24 | 31 | 28 | 17 | 13 | 19.6 | 17 |
| Nevada Power Company | 36 | 8 | 2 | 15 | 33 | 28 | 20.1 | 20 |
| Ohio Power Company | 22 | 24 | 17 | 17 | 24 | 17 | 20.0 | 19 |
| Oklahoma Gas and Electric Company | 24 | 7 | 11 | 16 | 5 | 20 | 13.4 | 5 |
| PacifiCorp | 7 | 28 | 14 | 26 | 24 | 16 | 18.8 | 14 |
| Portland General Electric Company | 16 | 36 | 14 | 20 | 16 | 15 | 19.2 | 15 |
| Public Service Company of New Hampshire | 20 | 31 | 29 | 21 | 22 | 27 | 24.7 | 32 |
| Public Service Company of New Mexico | 22 | 31 | 17 | 29 | 28 | 35 | 26.8 | 37 |
| Public Service Company of Oklahoma | 14 | 17 | 16 | 3 | 1 | 5 | 9.2 | 3 |
| Southern California Edison Co. | 15 | 24 | 22 | 24 | 17 | 23 | 20.6 | 22 |
| Southwestern Electric Power Company | 31 | 22 | 30 | 14 | 14 | 12 | 20.2 | 21 |
| Southwestern Public Service Company | 29 | 29 | 9 | 5 | 6 | 6 | 13.7 | 7 |
| Tucson Electric Power Company | 30 | 9 | 6 | 25 | 21 | 20 | 18.5 | 12 |
| Virginia Electric and Power Company | 15 | 6 | 2 | 6 | 5 | 12 | 7.3 | 2 |
| Westar Energy (KPL) | 10 | 35 | 25 | 32 | 23 | 12 | 22.6 | 26 |

| Regional Panel | Production O&M | Transmission O&M | Distribution O&M | Customer and A&G Expenses | Total Non-Fuel O&M | Plant Investment | Overall Average | Overall Rank |
|---|---|---|---|---|---|---|---|---|
| *Arizona Public Service Company* | *2* | *3* | *8* | *2* | *3* | *5* | *3.7* | *2* |
| *El Paso Electric Company* | *6* | *8* | *4* | *8* | *8* | *2* | *5.9* | *7* |
| Nevada Power Company | 8 | 2 | 1 | 3 | 7 | 7 | 4.4 | 4 |
| PacifiCorp | 2 | 6 | 6 | 6 | 5 | 4 | 4.5 | 5 |
| Public Service Company of New Mexico | 4 | 7 | 5 | 7 | 6 | 8 | 6.0 | 8 |
| Southern California Edison Co. | 3 | 5 | 7 | 5 | 3 | 5 | 4.5 | 5 |
| Southwestern Public Service Company | 6 | 7 | 4 | 2 | 2 | 2 | 3.5 | 1 |
| Tucson Electric Power Company | 6 | 2 | 3 | 5 | 4 | 5 | 3.9 | 3 |
| Salt River Project | | 5 | 9 | | | 8 | 7.4 | 9 |
| | | | | | | | | |

## Productive Efficiency Rankings - 2003

(a rank of 1 indicates the most efficient performer for each metric)

| Base Panel | Production O&M | Transmission O&M | Distribution O&M | Customer and A&G Expenses | Total Non-Fuel O&M | Plant Investment | Overall Average | Overall Rank |
|---|---|---|---|---|---|---|---|---|
| *Arizona Public Service Company* | *25* | *17* | *15* | *15* | *18* | *31* | *19.9* | *20* |
| Alabama Power Company | 24 | 19 | 27 | 22 | 22 | 29 | 23.7 | 34 |
| Appalachian Power Company | 12 | 8 | 33 | 5 | 8 | 9 | 12.5 | 3 |
| Carolina Power & Light Company | 24 | 26 | 5 | 25 | 27 | 22 | 21.2 | 25 |
| Columbus Southern Power Company | 8 | 34 | 24 | 6 | 9 | 11 | 15.2 | 8 |
| Dayton Power and Light Company | | 2 | 3 | | | 6 | 3.5 | 1 |
| Detroit Edison Company | 13 | 30 | 35 | 36 | 32 | 19 | 27.3 | 38 |
| Duke Energy Carolinas, LLC | 15 | 13 | 33 | 23 | 28 | 26 | 22.8 | 30 |
| Duke Energy Indiana, Inc. | 23 | 13 | 7 | 32 | 28 | 26 | 21.5 | 26 |
| El Paso Electric Company | 26 | 11 | 7 | 37 | 34 | 26 | 23.4 | 33 |
| Entergy Arkansas, Inc. | 5 | 12 | 22 | 29 | 22 | 24 | 18.8 | 16 |
| Entergy Louisiana, LLC | | | | | | | | |
| Entergy Mississippi, Inc. | 19 | 12 | 26 | 18 | 2 | 29 | 17.3 | 14 |
| Florida Power & Light Company | 30 | 11 | 10 | 2 | 2 | 32 | 14.3 | 6 |
| Florida Power Corporation | 30 | 13 | 13 | 21 | 11 | 31 | 19.7 | 18 |
| Georgia Power Company | 22 | 24 | 23 | 19 | 19 | 25 | 22.0 | 27 |
| Gulf Power Company | 30 | 17 | 26 | 24 | 23 | 18 | 22.7 | 29 |
| Idaho Power Co. | 11 | 23 | 35 | 16 | 32 | 22 | 23.0 | 31 |
| Indiana Michigan Power Company | 24 | 1 | 19 | 23 | 34 | 19 | 19.9 | 20 |
| Indianapolis Power & Light Company | 10 | 13 | 24 | 9 | 14 | 5 | 12.3 | 2 |
| Kansas City Power & Light Company | 9 | 23 | 33 | 32 | 31 | 16 | 24.0 | 35 |
| Kansas Gas and Electric Company | 19 | 37 | 22 | 24 | 36 | 5 | 23.4 | 32 |
| KCP&L Greater Missouri Operations Company | 13 | 23 | 23 | 16 | 9 | 17 | 16.9 | 12 |
| Kentucky Utilities Company | 15 | 20 | 11 | 8 | 5 | 19 | 12.8 | 5 |
| Monongahela Power Company | 7 | 30 | 31 | 32 | 21 | 13 | 22.2 | 28 |
| Nevada Power Company | 30 | 12 | 1 | 20 | 26 | 29 | 19.5 | 17 |
| Ohio Power Company | 21 | 23 | 20 | 4 | 25 | 26 | 19.7 | 19 |
| Oklahoma Gas and Electric Company | 29 | 5 | 9 | 16 | 4 | 12 | 12.5 | 3 |
| PacifiCorp | 7 | 29 | 25 | 22 | 24 | 20 | 21.0 | 24 |
| Portland General Electric Company | 12 | 36 | 13 | 20 | 15 | 16 | 18.4 | 15 |
| Public Service Company of New Hampshire | 23 | 29 | 28 | 24 | 24 | 32 | 26.4 | 37 |
| Public Service Company of New Mexico | 19 | 33 | 11 | 34 | 30 | 25 | 25.1 | 36 |
| Public Service Company of Oklahoma | 35 | 12 | 14 | 3 | 11 | 19 | 15.5 | 9 |
| Southern California Edison Co. | 11 | 26 | 22 | 29 | 21 | 18 | 20.8 | 23 |
| Southwestern Electric Power Company | 31 | 20 | 32 | 7 | 13 | 19 | 20.1 | 22 |
| Southwestern Public Service Company | 31 | 30 | 5 | 15 | 8 | 6 | 15.5 | 10 |
| Tucson Electric Power Company | 26 | 10 | 7 | 25 | 22 | 13 | 17.0 | 13 |
| Virginia Electric and Power Company | 13 | 5 | 37 | 5 | 6 | 24 | 14.9 | 7 |
| Westar Energy (KPL) | 11 | 36 | 19 | 14 | 16 | 6 | 16.6 | 11 |

| Regional Panel | Production O&M | Transmission O&M | Distribution O&M | Customer and A&G Expenses | Total Non-Fuel O&M | Plant Investment | Overall Average | Overall Rank |
|---|---|---|---|---|---|---|---|---|
| *Arizona Public Service Company* | *5* | *4* | *6* | *2* | *3* | *8* | *4.4* | *3* |
| El Paso Electric Company | 6 | 2 | 3 | 8 | 8 | 6 | 5.6 | 7 |
| Nevada Power Company | 7 | 3 | 1 | 3 | 5 | 8 | 4.4 | 3 |
| PacifiCorp | 2 | 6 | 8 | 5 | 5 | 4 | 4.8 | 6 |
| Public Service Company of New Mexico | 4 | 8 | 5 | 7 | 7 | 6 | 5.9 | 8 |
| Southern California Edison Co. | 2 | 6 | 8 | 6 | 4 | 4 | 4.6 | 5 |
| Southwestern Public Service Company | 6 | 7 | 4 | 3 | 2 | 1 | 3.5 | 1 |
| Tucson Electric Power Company | 6 | 2 | 4 | 4 | 4 | 3 | 3.7 | 2 |
| Salt River Project | | 6 | 9 | | | 6 | 6.9 | 9 |

## Productive Efficiency Rankings - 2004

(a rank of 1 indicates the most efficient performer for each metric)

| Base Panel | Production O&M | Transmission O&M | Distribution O&M | Customer and A&G Expenses | Total Non-Fuel O&M | Plant Investment | Overall Average | Overall Rank |
|---|---|---|---|---|---|---|---|---|
| *Arizona Public Service Company* | *21* | *16* | *19* | *17* | *16* | *23* | *18.4* | *15* |
| Alabama Power Company | 25 | 14 | 26 | 23 | 22 | 24 | 22.3 | 27 |
| Appalachian Power Company | 15 | 7 | 33 | 7 | 10 | 20 | 14.9 | 5 |
| Carolina Power & Light Company | 24 | 20 | 16 | 26 | 24 | 13 | 20.3 | 22 |
| Columbus Southern Power Company | 11 | 32 | 32 | 6 | 13 | 14 | 17.6 | 14 |
| Dayton Power and Light Company | 18 | 17 | 3 | 25 | 17 | 17 | 16.1 | 8 |
| Detroit Edison Company | 13 | 30 | 31 | 37 | 34 | 15 | 26.4 | 38 |
| Duke Energy Carolinas, LLC | 15 | 9 | 14 | 16 | 19 | 31 | 17.2 | 13 |
| Duke Energy Indiana, Inc. | 21 | 16 | 7 | 34 | 26 | 17 | 20.0 | 21 |
| El Paso Electric Company | 28 | 10 | 8 | 38 | 33 | 8 | 20.6 | 23 |
| Entergy Arkansas, Inc. | 8 | 13 | 17 | 21 | 25 | 17 | 16.6 | 11 |
| Entergy Louisiana, LLC | | | | | | | | |
| Entergy Mississippi, Inc. | 33 | 10 | 16 | 20 | 32 | 33 | 23.8 | 32 |
| Florida Power & Light Company | 32 | 11 | 12 | 1 | 3 | 25 | 13.8 | 4 |
| Florida Power Corporation | 30 | 10 | 8 | 17 | 7 | 24 | 16.0 | 7 |
| Georgia Power Company | 25 | 25 | 30 | 25 | 23 | 15 | 23.6 | 31 |
| Gulf Power Company | 33 | 12 | 21 | 32 | 24 | 31 | 25.4 | 35 |
| Idaho Power Co. | 4 | 22 | 27 | 28 | 28 | 22 | 21.8 | 26 |
| Indiana Michigan Power Company | 21 | 1 | 26 | 27 | 35 | 20 | 21.3 | 24 |
| Indianapolis Power & Light Company | 9 | 11 | 12 | 12 | 9 | 20 | 12.0 | 3 |
| Kansas City Power & Light Company | 8 | 25 | 32 | 34 | 33 | 12 | 23.9 | 33 |
| Kansas Gas and Electric Company | 15 | 37 | 26 | 27 | 36 | 9 | 24.9 | 34 |
| KCP&L Greater Missouri Operations Company | 13 | 21 | 27 | 23 | 13 | 18 | 19.0 | 19 |
| Kentucky Utilities Company | 16 | 13 | 9 | 6 | 3 | 22 | 11.2 | 1 |
| Monongahela Power Company | 9 | 24 | 29 | 16 | 14 | 7 | 16.3 | 10 |
| Nevada Power Company | 26 | 11 | 1 | 12 | 22 | 26 | 16.2 | 9 |
| Ohio Power Company | 22 | 21 | 29 | 13 | 29 | 24 | 22.7 | 29 |
| Oklahoma Gas and Electric Company | 32 | 9 | 10 | 13 | 3 | 25 | 15.2 | 6 |
| PacifiCorp | 6 | 27 | 37 | 22 | 26 | 22 | 23.1 | 30 |
| Portland General Electric Company | 13 | 36 | 19 | 18 | 11 | 22 | 19.6 | 20 |
| Public Service Company of New Hampshire | 22 | 33 | 26 | 27 | 25 | 24 | 26.1 | 37 |
| Public Service Company of New Mexico | 15 | 33 | 11 | 34 | 30 | 13 | 22.6 | 28 |
| Public Service Company of Oklahoma | 33 | 25 | 30 | 3 | 7 | 15 | 18.6 | 16 |
| Southern California Edison Co. | 14 | 30 | 32 | 29 | 23 | 27 | 25.6 | 36 |
| Southwestern Electric Power Company | 28 | 29 | 26 | 7 | 12 | 11 | 18.6 | 16 |
| Southwestern Public Service Company | 34 | 27 | 7 | 8 | 4 | 21 | 16.6 | 12 |
| Tucson Electric Power Company | 26 | 8 | 9 | 30 | 24 | 18 | 18.8 | 18 |
| Virginia Electric and Power Company | 23 | 8 | 4 | 4 | 10 | 22 | 11.6 | 2 |
| Westar Energy (KPL) | 13 | 35 | 27 | 15 | 25 | 16 | 21.5 | 25 |

| Regional Panel | Production O&M | Transmission O&M | Distribution O&M | Customer and A&G Expenses | Total Non-Fuel O&M | Plant Investment | Overall Average | Overall Rank |
|---|---|---|---|---|---|---|---|---|
| *Arizona Public Service Company* | *5* | *4* | *6* | *4* | *3* | *5* | *4.2* | *4* |
| El Paso Electric Company | 7 | 2 | 3 | 8 | 8 | 2 | 5.0 | 6 |
| Nevada Power Company | 7 | 3 | 1 | 2 | 4 | 6 | 3.7 | 1 |
| PacifiCorp | 2 | 5 | 8 | 4 | 6 | 5 | 4.8 | 5 |
| Public Service Company of New Mexico | 3 | 7 | 4 | 7 | 7 | 3 | 5.0 | 7 |
| Southern California Edison Co. | 2 | 7 | 8 | 5 | 4 | 7 | 5.3 | 8 |
| Southwestern Public Service Company | 7 | 6 | 4 | 2 | 1 | 5 | 3.9 | 2 |
| Tucson Electric Power Company | 6 | 2 | 4 | 6 | 5 | 4 | 4.2 | 3 |
| Salt River Project | | | | | | | | |

## Productive Efficiency Rankings - 2005

(a rank of 1 indicates the most efficient performer for each metric)

| Base Panel | Production O&M | Transmission O&M | Distribution O&M | Customer and A&G Expenses | Total Non-Fuel O&M | Plant Investment | Overall Average | Overall Rank |
|---|---|---|---|---|---|---|---|---|
| *Arizona Public Service Company* | *21* | *19* | *17* | *21* | *25* | *29* | *21.9* | *24* |
| Alabama Power Company | 26 | 16 | 29 | 24 | 28 | 26 | 24.5 | 31 |
| Appalachian Power Company | 16 | 13 | 27 | 4 | 14 | 25 | 16.3 | 13 |
| Carolina Power & Light Company | 24 | 17 | 16 | 26 | 20 | 16 | 19.8 | 20 |
| Columbus Southern Power Company | 16 | 29 | 24 | 5 | 19 | 26 | 19.7 | 19 |
| Dayton Power and Light Company | 19 | 32 | 4 | 7 | 19 | 7 | 14.6 | 7 |
| Detroit Edison Company | 15 | 35 | 34 | 36 | 35 | 3 | 26.0 | 36 |
| Duke Energy Carolinas, LLC | 15 | 6 | 21 | 23 | 25 | 22 | 18.6 | 18 |
| Duke Energy Indiana, Inc. | 16 | 11 | 6 | 32 | 18 | 25 | 18.0 | 15 |
| El Paso Electric Company | 32 | 17 | 10 | 38 | 33 | 11 | 23.4 | 27 |
| Entergy Arkansas, Inc. | 2 | 9 | 12 | 23 | 6 | 16 | 11.2 | 2 |
| Entergy Louisiana, LLC | | | | | | | | |
| Entergy Mississippi, Inc. | 18 | 7 | 10 | 18 | 1 | 26 | 13.1 | 4 |
| Florida Power & Light Company | 31 | 12 | 7 | 7 | 3 | 33 | 15.2 | 8 |
| Florida Power Corporation | 34 | 12 | 25 | 32 | 24 | 27 | 25.4 | 34 |
| Georgia Power Company | 28 | 26 | 27 | 25 | 26 | 22 | 25.7 | 35 |
| Gulf Power Company | 32 | 11 | 25 | 34 | 29 | 28 | 26.0 | 37 |
| Idaho Power Co. | 3 | 19 | 22 | 22 | 18 | 27 | 18.4 | 16 |
| Indiana Michigan Power Company | 18 | 1 | 35 | 19 | 35 | 12 | 19.9 | 21 |
| Indianapolis Power & Light Company | 8 | 6 | 15 | 16 | 16 | 10 | 11.6 | 3 |
| Kansas City Power & Light Company | 10 | 19 | 32 | 32 | 33 | 27 | 25.4 | 33 |
| Kansas Gas and Electric Company | 19 | 36 | 26 | 28 | 36 | 7 | 25.3 | 32 |
| KCP&L Greater Missouri Operations Company | 16 | 25 | 27 | 25 | 16 | 37 | 24.1 | 30 |
| Kentucky Utilities Company | 24 | 16 | 11 | 9 | 13 | 7 | 13.1 | 5 |
| Monongahela Power Company | 10 | 23 | 30 | 12 | 11 | 8 | 15.4 | 10 |
| Nevada Power Company | 19 | 11 | 1 | 19 | 5 | 25 | 13.2 | 6 |
| Ohio Power Company | 23 | 20 | 27 | 5 | 30 | 23 | 21.2 | 22 |
| Oklahoma Gas and Electric Company | 32 | 14 | 8 | 10 | 7 | 28 | 16.4 | 14 |
| PacifiCorp | 7 | 27 | 37 | 20 | 29 | 24 | 23.7 | 29 |
| Portland General Electric Company | 6 | 35 | 21 | 23 | 15 | 12 | 18.6 | 17 |
| Public Service Company of New Hampshire | 24 | 31 | 27 | 29 | 26 | 32 | 28.0 | 38 |
| Public Service Company of New Mexico | 17 | 32 | 8 | 34 | 33 | 15 | 23.2 | 26 |
| Public Service Company of Oklahoma | 35 | 21 | 22 | 2 | 3 | 13 | 15.6 | 11 |
| Southern California Edison Co. | 7 | 32 | 24 | 31 | 23 | 25 | 23.6 | 28 |
| Southwestern Electric Power Company | 32 | 27 | 34 | 5 | 19 | 11 | 21.2 | 23 |
| Southwestern Public Service Company | 35 | 28 | 5 | 11 | 5 | 12 | 15.9 | 12 |
| Tucson Electric Power Company | 21 | 7 | 8 | 21 | 18 | 18 | 15.3 | 9 |
| Virginia Electric and Power Company | 25 | 3 | 6 | 6 | 11 | 14 | 10.6 | 1 |
| Westar Energy (KPL) | 12 | 35 | 30 | 15 | 24 | 17 | 21.9 | 25 |

| Regional Panel | Production O&M | Transmission O&M | Distribution O&M | Customer and A&G Expenses | Total Non-Fuel O&M | Plant Investment | Overall Average | Overall Rank |
|---|---|---|---|---|---|---|---|---|
| *Arizona Public Service Company* | *5* | *3* | *7* | *4* | *5* | *6* | *4.9* | *4* |
| El Paso Electric Company | 8 | 3 | 4 | 8 | 8 | 2 | 5.3 | 8 |
| Nevada Power Company | 5 | 2 | 1 | 3 | 2 | 6 | 2.9 | 1 |
| PacifiCorp | 2 | 6 | 8 | 4 | 6 | 6 | 5.2 | 5 |
| Public Service Company of New Mexico | 4 | 7 | 3 | 7 | 7 | 4 | 5.3 | 6 |
| Southern California Edison Co. | 2 | 7 | 7 | 6 | 5 | 6 | 5.3 | 7 |
| Southwestern Public Service Company | 7 | 6 | 4 | 2 | 2 | 3 | 3.8 | 3 |
| Tucson Electric Power Company | 5 | 2 | 4 | 3 | 3 | 4 | 3.4 | 2 |
| Salt River Project | | | | | | | | |

## Productive Efficiency Rankings - 2006

(a rank of 1 indicates the most efficient performer for each metric)

| Base Panel | Production O&M | Transmission O&M | Distribution O&M | Customer and A&G Expenses | Total Non-Fuel O&M | Plant Investment | Overall Average | Overall Rank |
|---|---|---|---|---|---|---|---|---|
| *Arizona Public Service Company* | *26* | *20* | *17* | *23* | *22* | *20* | *21.2* | *21* |
| Alabama Power Company | 26 | 18 | 31 | 24 | 25 | 21 | 24.1 | 33 |
| Appalachian Power Company | 16 | 4 | 28 | 2 | 7 | 30 | 14.3 | 6 |
| Carolina Power & Light Company | 25 | 17 | 14 | 19 | 23 | 12 | 18.2 | 14 |
| Columbus Southern Power Company | 12 | 32 | 15 | 5 | 10 | 23 | 15.9 | 10 |
| Dayton Power and Light Company | 15 | 34 | 6 | 10 | 13 | 13 | 14.9 | 8 |
| Detroit Edison Company | 11 | 36 | 34 | 36 | 35 | 20 | 28.5 | 39 |
| Duke Energy Carolinas, LLC | 16 | 4 | 15 | 31 | 23 | 19 | 17.6 | 11 |
| Duke Energy Indiana, Inc. | 25 | 15 | 6 | 36 | 36 | 19 | 22.8 | 26 |
| El Paso Electric Company | 26 | 25 | 16 | 39 | 35 | 3 | 23.7 | 30 |
| Entergy Arkansas, Inc. | 19 | 18 | 11 | 30 | 37 | 14 | 21.3 | 23 |
| Entergy Louisiana, LLC | 35 | 12 | 4 | 23 | 11 | 26 | 18.4 | 15 |
| Entergy Mississippi, Inc. | 37 | 11 | 12 | 26 | 36 | 30 | 24.9 | 34 |
| Florida Power & Light Company | 36 | 12 | 15 | 6 | 22 | 23 | 18.8 | 17 |
| Florida Power Corporation | 30 | 14 | 26 | 14 | 7 | 26 | 19.2 | 18 |
| Georgia Power Company | 28 | 27 | 30 | 21 | 21 | 34 | 26.8 | 37 |
| Gulf Power Company | 34 | 11 | 23 | 36 | 24 | 16 | 23.7 | 30 |
| Idaho Power Co. | 2 | 20 | 25 | 23 | 9 | 17 | 15.9 | 9 |
| Indiana Michigan Power Company | 17 | 1 | 29 | 21 | 33 | 27 | 21.1 | 20 |
| Indianapolis Power & Light Company | 13 | 14 | 17 | 21 | 16 | 9 | 14.9 | 7 |
| Kansas City Power & Light Company | 7 | 24 | 24 | 32 | 28 | 30 | 23.8 | 32 |
| Kansas Gas and Electric Company | 10 | 36 | 36 | 28 | 35 | 7 | 25.2 | 35 |
| KCP&L Greater Missouri Operations Company | 16 | 30 | 28 | 30 | 19 | 15 | 22.9 | 27 |
| Kentucky Utilities Company | 24 | 7 | 13 | 5 | 4 | 4 | 9.3 | 1 |
| Monongahela Power Company | 9 | 19 | 30 | 13 | 7 | 7 | 14.1 | 5 |
| Nevada Power Company | 22 | 8 | 1 | 13 | 1 | 37 | 13.6 | 4 |
| Ohio Power Company | 23 | 24 | 21 | 7 | 31 | 23 | 21.2 | 22 |
| Oklahoma Gas and Electric Company | 27 | 8 | 4 | 13 | 2 | 27 | 13.3 | 3 |
| PacifiCorp | 6 | 29 | 38 | 19 | 24 | 24 | 23.2 | 28 |
| Portland General Electric Company | 5 | 36 | 28 | 20 | 12 | 9 | 18.1 | 13 |
| Public Service Company of New Hampshire | 20 | 31 | 29 | 30 | 24 | 33 | 27.6 | 38 |
| Public Service Company of New Mexico | 14 | 31 | 11 | 30 | 29 | 23 | 22.7 | 25 |
| Public Service Company of Oklahoma | 36 | 14 | 35 | 3 | 20 | 26 | 22.3 | 24 |
| Southern California Edison Co. | 8 | 31 | 29 | 32 | 21 | 22 | 23.6 | 29 |
| Southwestern Electric Power Company | 27 | 18 | 32 | 11 | 14 | 21 | 20.3 | 19 |
| Southwestern Public Service Company | 35 | 28 | 6 | 11 | 22 | 12 | 18.7 | 16 |
| Tucson Electric Power Company | 24 | 14 | 5 | 23 | 19 | 22 | 17.6 | 12 |
| Virginia Electric and Power Company | 17 | 7 | 11 | 6 | 9 | 13 | 10.4 | 2 |
| Westar Energy (KPL) | 10 | 37 | 34 | 18 | 26 | 30 | 25.8 | 36 |

| Regional Panel | Production O&M | Transmission O&M | Distribution O&M | Customer and A&G Expenses | Total Non-Fuel O&M | Plant Investment | Overall Average | Overall Rank |
|---|---|---|---|---|---|---|---|---|
| *Arizona Public Service Company* | *6* | *3* | *6* | *4* | *5* | *5* | *4.6* | *4* |
| El Paso Electric Company | 6 | 5 | 5 | 8 | 8 | 1 | 5.4 | 8 |
| Nevada Power Company | 6 | 1 | 1 | 2 | 1 | 8 | 3.1 | 1 |
| PacifiCorp | 2 | 6 | 8 | 4 | 5 | 5 | 4.9 | 5 |
| Public Service Company of New Mexico | 3 | 7 | 4 | 6 | 6 | 5 | 5.1 | 6 |
| Southern California Edison Co. | 2 | 7 | 7 | 7 | 4 | 5 | 5.2 | 7 |
| Southwestern Public Service Company | 7 | 5 | 4 | 2 | 5 | 3 | 4.2 | 3 |
| Tucson Electric Power Company | 6 | 2 | 3 | 4 | 4 | 5 | 3.6 | 2 |
| Salt River Project | | | | | | | | |

## Productive Efficiency Rankings - 2007

(a rank of 1 indicates the most efficient performer for each metric)

| Base Panel | Production O&M | Transmission O&M | Distribution O&M | Customer and A&G Expenses | Total Non-Fuel O&M | Plant Investment | Overall Average | Overall Rank |
|---|---|---|---|---|---|---|---|---|
| *Arizona Public Service Company* | *25* | *22* | *26* | *18* | *23* | *21* | *22.2* | *26* |
| Alabama Power Company | 27 | 17 | 34 | 28 | 29 | 18 | 25.0 | 35 |
| Appalachian Power Company | 18 | 3 | 26 | 4 | 10 | 29 | 14.7 | 6 |
| Carolina Power & Light Company | 26 | 20 | 17 | 17 | 31 | 16 | 21.0 | 21 |
| Columbus Southern Power Company | 13 | 29 | 20 | 2 | 8 | 29 | 16.6 | 10 |
| Dayton Power and Light Company | 14 | 37 | 6 | 12 | 25 | 24 | 19.5 | 18 |
| Detroit Edison Company | 10 | 36 | 36 | 37 | 35 | 18 | 28.5 | 38 |
| Duke Energy Carolinas, LLC | 15 | 4 | 13 | 23 | 22 | 22 | 16.2 | 9 |
| Duke Energy Indiana, Inc. | 15 | 13 | 4 | 36 | 22 | 29 | 19.7 | 19 |
| El Paso Electric Company | 27 | 24 | 11 | 39 | 34 | 12 | 24.2 | 30 |
| Entergy Arkansas, Inc. | 4 | 16 | 14 | 27 | 11 | 11 | 13.8 | 4 |
| Entergy Louisiana, LLC | 37 | 14 | 7 | 24 | 26 | 5 | 18.5 | 15 |
| Entergy Mississippi, Inc. | 32 | 13 | 13 | 20 | 4 | 19 | 16.6 | 10 |
| Florida Power & Light Company | 36 | 10 | 12 | 5 | 3 | 24 | 14.7 | 5 |
| Florida Power Corporation | 31 | 12 | 29 | 28 | 16 | 29 | 24.0 | 29 |
| Georgia Power Company | 31 | 24 | 27 | 20 | 20 | 14 | 22.5 | 27 |
| Gulf Power Company | 34 | 9 | 28 | 35 | 27 | 19 | 25.1 | 36 |
| Idaho Power Co. | 2 | 20 | 27 | 29 | 2 | 26 | 17.4 | 13 |
| Indiana Michigan Power Company | 18 | 1 | 29 | 21 | 36 | 22 | 21.0 | 22 |
| Indianapolis Power & Light Company | 8 | 14 | 9 | 18 | 12 | 19 | 13.2 | 3 |
| Kansas City Power & Light Company | 8 | 25 | 20 | 32 | 30 | 12 | 21.0 | 23 |
| Kansas Gas and Electric Company | 9 | 37 | 35 | 29 | 34 | 11 | 25.4 | 37 |
| KCP&L Greater Missouri Operations Company | 13 | 27 | 24 | 28 | 15 | 5 | 18.6 | 16 |
| Kentucky Utilities Company | 21 | 9 | 10 | 3 | 4 | 14 | 10.1 | 1 |
| Monongahela Power Company | 22 | 21 | 23 | 22 | 16 | 11 | 18.9 | 17 |
| Nevada Power Company | 32 | 5 | 1 | 16 | 27 | 27 | 17.8 | 14 |
| Ohio Power Company | 24 | 8 | 22 | 8 | 30 | 30 | 20.1 | 20 |
| Oklahoma Gas and Electric Company | 30 | 10 | 6 | 8 | 8 | 29 | 14.9 | 7 |
| PacifiCorp | 12 | 29 | 36 | 9 | 20 | 26 | 22.0 | 24 |
| Portland General Electric Company | 14 | 35 | 26 | 23 | 17 | 33 | 24.6 | 33 |
| Public Service Company of New Hampshire | 20 | 35 | 31 | 33 | 28 | 26 | 28.5 | 39 |
| Public Service Company of New Mexico | 16 | 30 | 12 | 27 | 30 | 18 | 22.2 | 25 |
| Public Service Company of Oklahoma | 32 | 21 | 39 | 4 | 24 | 28 | 24.4 | 31 |
| Southern California Edison Co. | 8 | 30 | 27 | 35 | 24 | 25 | 24.8 | 34 |
| Southwestern Electric Power Company | 28 | 24 | 29 | 8 | 16 | 33 | 22.9 | 28 |
| Southwestern Public Service Company | 33 | 26 | 7 | 10 | 12 | 6 | 15.6 | 8 |
| Tucson Electric Power Company | 24 | 19 | 4 | 21 | 22 | 13 | 17.1 | 12 |
| Virginia Electric and Power Company | 13 | 13 | 14 | 9 | 4 | 20 | 11.9 | 2 |
| Westar Energy (KPL) | 12 | 36 | 34 | 21 | 34 | 12 | 24.5 | 32 |

| Regional Panel | Production O&M | Transmission O&M | Distribution O&M | Customer and A&G Expenses | Total Non-Fuel O&M | Plant Investment | Overall Average | Overall Rank |
|---|---|---|---|---|---|---|---|---|
| *Arizona Public Service Company* | *5* | *3* | *7* | *4* | *4* | *5* | *4.4* | *4* |
| El Paso Electric Company | 6 | 4 | 4 | 8 | 8 | 3 | 5.4 | 8 |
| Nevada Power Company | 8 | 1 | 1 | 3 | 6 | 7 | 4.0 | 3 |
| PacifiCorp | 2 | 6 | 8 | 2 | 4 | 6 | 4.5 | 5 |
| Public Service Company of New Mexico | 3 | 7 | 5 | 6 | 7 | 4 | 5.2 | 6 |
| Southern California Edison Co. | 2 | 7 | 7 | 7 | 4 | 6 | 5.2 | 7 |
| Southwestern Public Service Company | 7 | 5 | 4 | 3 | 2 | 2 | 3.7 | 2 |
| Tucson Electric Power Company | 5 | 2 | 3 | 5 | 3 | 4 | 3.5 | 1 |
| Salt River Project | | | | | | | | |

## Productive Efficiency Rankings - 2008

(a rank of 1 indicates the most efficient performer for each metric)

| Base Panel | Production O&M | Transmission O&M | Distribution O&M | Customer and A&G Expenses | Total Non-Fuel O&M | Plant Investment | Overall Average | Overall Rank |
|---|---|---|---|---|---|---|---|---|
| *Arizona Public Service Company* | *26* | *16* | *27* | *21* | *27* | *22* | *22.8* | *30* |
| Alabama Power Company | 29 | 18 | 32 | 27 | 29 | 21 | 25.9 | 35 |
| Appalachian Power Company | 14 | 2 | 30 | 3 | 9 | 14 | 11.8 | 2 |
| Carolina Power & Light Company | 24 | 17 | 11 | 18 | 21 | 14 | 17.3 | 11 |
| Columbus Southern Power Company | 12 | 35 | 18 | 5 | 14 | 28 | 18.4 | 15 |
| Dayton Power and Light Company | 16 | 38 | 6 | 5 | 25 | 15 | 17.4 | 12 |
| Detroit Edison Company | 9 | 37 | 34 | 34 | 34 | 21 | 28.1 | 37 |
| Duke Energy Carolinas, LLC | 16 | 8 | 10 | 20 | 22 | 21 | 16.0 | 10 |
| Duke Energy Indiana, Inc. | 19 | 13 | 26 | 33 | 28 | 18 | 22.6 | 28 |
| El Paso Electric Company | 28 | 22 | 12 | 35 | 34 | 23 | 25.4 | 34 |
| Entergy Arkansas, Inc. | 6 | 19 | 39 | 22 | 31 | 23 | 23.0 | 31 |
| Entergy Louisiana, LLC | 38 | 17 | 6 | 22 | 20 | 8 | 18.2 | 14 |
| Entergy Mississippi, Inc. | 31 | 12 | 12 | 25 | 2 | 12 | 15.4 | 9 |
| Florida Power & Light Company | 35 | 9 | 12 | 1 | 2 | 18 | 12.6 | 3 |
| Florida Power Corporation | 33 | 10 | 27 | 21 | 13 | 18 | 20.2 | 19 |
| Georgia Power Company | 30 | 21 | 25 | 21 | 22 | 26 | 23.8 | 33 |
| Gulf Power Company | 33 | 6 | 23 | 34 | 24 | 16 | 22.5 | 26 |
| Idaho Power Co. | 2 | 16 | 23 | 34 | 13 | 26 | 18.9 | 17 |
| Indiana Michigan Power Company | 18 | 1 | 33 | 19 | 35 | 14 | 19.8 | 18 |
| Indianapolis Power & Light Company | 8 | 14 | 18 | 22 | 16 | 2 | 13.1 | 4 |
| Kansas City Power & Light Company | 7 | 23 | 18 | 35 | 32 | 12 | 21.2 | 21 |
| Kansas Gas and Electric Company | 11 | 35 | 31 | 29 | 35 | 18 | 26.5 | 36 |
| KCP&L Greater Missouri Operations Company | 11 | 31 | 26 | 32 | 19 | 25 | 23.8 | 32 |
| Kentucky Utilities Company | 21 | 8 | 11 | 6 | 5 | 29 | 13.3 | 5 |
| Monongahela Power Company | 16 | 16 | 28 | 17 | 5 | 8 | 14.7 | 6 |
| Nevada Power Company | 26 | 9 | 2 | 17 | 5 | 31 | 14.7 | 7 |
| Ohio Power Company | 24 | 27 | 20 | 11 | 32 | 23 | 22.6 | 27 |
| Oklahoma Gas and Electric Company | 29 | 9 | 12 | 6 | 10 | 27 | 15.3 | 8 |
| PacifiCorp | 10 | 29 | 35 | 9 | 18 | 26 | 21.3 | 23 |
| Portland General Electric Company | 15 | 35 | 28 | 23 | 17 | 12 | 21.4 | 24 |
| Public Service Company of New Hampshire | 20 | 33 | 33 | 33 | 28 | 32 | 29.6 | 39 |
| Public Service Company of New Mexico | 20 | 29 | 9 | 27 | 28 | 25 | 22.8 | 29 |
| Public Service Company of Oklahoma | 34 | 25 | 1 | 4 | 9 | 34 | 17.7 | 13 |
| Southern California Edison Co. | 9 | 29 | 20 | 38 | 25 | 8 | 21.3 | 22 |
| Southwestern Electric Power Company | 28 | 22 | 32 | 10 | 17 | 22 | 21.7 | 25 |
| Southwestern Public Service Company | 35 | 24 | 7 | 13 | 21 | 13 | 18.6 | 16 |
| Tucson Electric Power Company | 23 | 20 | 4 | 22 | 29 | 24 | 20.2 | 20 |
| Virginia Electric and Power Company | 11 | 7 | 15 | 11 | 4 | 24 | 11.7 | 1 |
| Westar Energy (KPL) | 14 | 35 | 34 | 23 | 31 | 33 | 28.2 | 38 |

| Regional Panel | Production O&M | Transmission O&M | Distribution O&M | Customer and A&G Expenses | Total Non-Fuel O&M | Plant Investment | Overall Average | Overall Rank |
|---|---|---|---|---|---|---|---|---|
| *Arizona Public Service Company* | *6* | *2* | *7* | *4* | *5* | *5* | *4.6* | *5* |
| El Paso Electric Company | 7 | 4 | 5 | 7 | 8 | 5 | 5.8 | 8 |
| Nevada Power Company | 6 | 2 | 1 | 3 | 1 | 6 | 3.1 | 1 |
| PacifiCorp | 2 | 7 | 8 | 2 | 4 | 6 | 4.5 | 3 |
| Public Service Company of New Mexico | 3 | 7 | 4 | 6 | 5 | 5 | 4.8 | 7 |
| Southern California Edison Co. | 2 | 6 | 6 | 8 | 4 | 2 | 4.6 | 6 |
| Southwestern Public Service Company | 7 | 5 | 4 | 4 | 5 | 3 | 4.5 | 3 |
| Tucson Electric Power Company | 4 | 3 | 3 | 4 | 5 | 6 | 4.1 | 2 |
| Salt River Project | | | | | | | | |

## Productive Efficiency Rankings - 2009

(a rank of 1 indicates the most efficient performer for each metric)

| Base Panel | Production O&M | Transmission O&M | Distribution O&M | Customer and A&G Expenses | Total Non-Fuel O&M | Plant Investment | Overall Average | Overall Rank |
|---|---|---|---|---|---|---|---|---|
| *Arizona Public Service Company* | *28* | *16* | *20* | *22* | *27* | *16* | *21.3* | *25* |
| Alabama Power Company | 28 | 17 | 34 | 24 | 26 | 21 | 25.0 | 34 |
| Appalachian Power Company | 13 | 2 | 39 | 4 | 9 | 26 | 15.2 | 8 |
| Carolina Power & Light Company | 32 | 16 | 14 | 15 | 32 | 13 | 20.3 | 22 |
| Columbus Southern Power Company | 13 | 32 | 25 | 5 | 10 | 31 | 19.3 | 16 |
| Dayton Power and Light Company | 20 | 37 | 6 | 12 | 25 | 9 | 18.1 | 13 |
| Detroit Edison Company | 9 | 36 | 33 | 34 | 33 | 28 | 28.5 | 37 |
| Duke Energy Carolinas, LLC | 15 | 5 | 10 | 16 | 15 | 16 | 12.7 | 1 |
| Duke Energy Indiana, Inc. | 22 | 10 | 27 | 32 | 27 | 9 | 20.7 | 23 |
| El Paso Electric Company | 19 | 22 | 8 | 36 | 32 | 19 | 22.5 | 30 |
| Entergy Arkansas, Inc. | 8 | 15 | 23 | 26 | 27 | 20 | 19.6 | 18 |
| Entergy Louisiana, LLC | 22 | 17 | 5 | 12 | 3 | 25 | 13.8 | 4 |
| Entergy Mississippi, Inc. | 27 | 13 | 6 | 20 | 19 | 12 | 16.0 | 10 |
| Florida Power & Light Company | 34 | 8 | 6 | 4 | 3 | 23 | 12.8 | 2 |
| Florida Power Corporation | 36 | 9 | 19 | 14 | 9 | 30 | 19.3 | 15 |
| Georgia Power Company | 34 | 19 | 16 | 18 | 12 | 12 | 18.2 | 14 |
| Gulf Power Company | 35 | 7 | 21 | 31 | 20 | 27 | 23.2 | 33 |
| Idaho Power Co. | 4 | 15 | 21 | 37 | 29 | 12 | 19.4 | 17 |
| Indiana Michigan Power Company | 25 | 1 | 30 | 21 | 34 | 15 | 20.8 | 24 |
| Indianapolis Power & Light Company | 11 | 14 | 10 | 26 | 15 | 2 | 12.9 | 3 |
| Kansas City Power & Light Company | 9 | 24 | 20 | 34 | 28 | 19 | 22.3 | 28 |
| Kansas Gas and Electric Company | 9 | 37 | 32 | 33 | 36 | 15 | 26.7 | 36 |
| KCP&L Greater Missouri Operations Company | 17 | 27 | 27 | 27 | 14 | 26 | 23.0 | 32 |
| Kentucky Utilities Company | 22 | 7 | 16 | 12 | 6 | 27 | 14.8 | 6 |
| Monongahela Power Company | 22 | 21 | 34 | 17 | 6 | 28 | 21.3 | 26 |
| Nevada Power Company | 31 | 9 | 1 | 20 | 22 | 24 | 17.6 | 12 |
| Ohio Power Company | 23 | 22 | 26 | 9 | 29 | 30 | 22.9 | 31 |
| Oklahoma Gas and Electric Company | 22 | 11 | 22 | 2 | 7 | 25 | 14.6 | 5 |
| PacifiCorp | 12 | 30 | 34 | 7 | 17 | 23 | 20.2 | 21 |
| Portland General Electric Company | 16 | 35 | 22 | 20 | 13 | 30 | 22.4 | 29 |
| Public Service Company of New Hampshire | 20 | 35 | 30 | 36 | 31 | 24 | 29.4 | 38 |
| Public Service Company of New Mexico | 15 | 30 | 10 | 31 | 26 | 9 | 20.0 | 19 |
| Public Service Company of Oklahoma | 10 | 26 | 36 | 3 | 2 | 15 | 15.2 | 7 |
| Southern California Edison Co. | 7 | 27 | 26 | 38 | 24 | 31 | 25.3 | 35 |
| Southwestern Electric Power Company | 24 | 21 | 23 | 10 | 12 | 14 | 17.1 | 11 |
| Southwestern Public Service Company | 23 | 28 | 6 | 12 | 13 | 14 | 15.8 | 9 |
| Tucson Electric Power Company | 25 | 15 | 3 | 31 | 30 | 18 | 20.1 | 20 |
| Virginia Electric and Power Company | 31 | 29 | 10 | 13 | 35 | 16 | 22.0 | 27 |
| Westar Energy (KPL) | 17 | 35 | 36 | 25 | 33 | 31 | 29.5 | 39 |

| Regional Panel | Production O&M | Transmission O&M | Distribution O&M | Customer and A&G Expenses | Total Non-Fuel O&M | Plant Investment | Overall Average | Overall Rank |
|---|---|---|---|---|---|---|---|---|
| *Arizona Public Service Company* | *7* | *2* | *7* | *4* | *5* | *4* | *4.6* | *6* |
| El Paso Electric Company | 4 | 4 | 4 | 7 | 8 | 4 | 5.0 | 7 |
| Nevada Power Company | 8 | 2 | 1 | 3 | 4 | 5 | 3.6 | 1 |
| PacifiCorp | 3 | 7 | 8 | 2 | 3 | 6 | 4.5 | 5 |
| Public Service Company of New Mexico | 3 | 7 | 5 | 6 | 5 | 2 | 4.4 | 3 |
| Southern California Edison Co. | 2 | 6 | 7 | 8 | 4 | 7 | 5.6 | 8 |
| Southwestern Public Service Company | 5 | 6 | 4 | 3 | 3 | 4 | 3.9 | 2 |
| Tucson Electric Power Company | 6 | 2 | 3 | 6 | 7 | 5 | 4.5 | 4 |
| Salt River Project | | | | | | | | |

## Productive Efficiency Rankings - 2010

(a rank of 1 indicates the most efficient performer for each metric)

| Base Panel | Production O&M | Transmission O&M | Distribution O&M | Customer and A&G Expenses | Total Non-Fuel O&M | Plant Investment | Overall Average | Overall Rank |
|---|---|---|---|---|---|---|---|---|
| *Arizona Public Service Company* | *27* | *13* | *19* | *27* | *28* | *21* | *22.2* | *27* |
| Alabama Power Company | 28 | 20 | 36 | 24 | 29 | 27 | 27.4 | 38 |
| Appalachian Power Company | 24 | 6 | 27 | 2 | 14 | 21 | 15.4 | 6 |
| Carolina Power & Light Company | 31 | 16 | 12 | 16 | 30 | 20 | 20.8 | 19 |
| Columbus Southern Power Company | 18 | 32 | 30 | 9 | 14 | 14 | 19.3 | 15 |
| Dayton Power and Light Company | 20 | 38 | 6 | 23 | 29 | 8 | 20.4 | 18 |
| Detroit Edison Company | 8 | 37 | 35 | 30 | 33 | 15 | 26.3 | 35 |
| Duke Energy Carolinas, LLC | 19 | 3 | 11 | 27 | 24 | 21 | 17.3 | 11 |
| Duke Energy Indiana, Inc. | 20 | 16 | 7 | 32 | 18 | 8 | 16.7 | 9 |
| El Paso Electric Company | 17 | 17 | 10 | 36 | 29 | 17 | 20.8 | 20 |
| Entergy Arkansas, Inc. | 9 | 12 | 14 | 24 | 28 | 9 | 16.0 | 7 |
| Entergy Louisiana, LLC | 31 | 18 | 5 | 8 | 16 | 3 | 13.5 | 5 |
| Entergy Mississippi, Inc. | 18 | 11 | 8 | 12 | 2 | 18 | 11.3 | 3 |
| Florida Power & Light Company | 27 | 10 | 9 | 2 | 2 | 11 | 9.9 | 1 |
| Florida Power Corporation | 34 | 6 | 23 | 26 | 12 | 26 | 21.1 | 24 |
| Georgia Power Company | 35 | 22 | 24 | 15 | 17 | 23 | 22.4 | 30 |
| Gulf Power Company | 38 | 8 | 23 | 20 | 20 | 27 | 22.4 | 31 |
| Idaho Power Co. | 3 | 13 | 23 | 37 | 30 | 22 | 21.0 | 23 |
| Indiana Michigan Power Company | 20 | 1 | 32 | 23 | 34 | 16 | 20.9 | 22 |
| Indianapolis Power & Light Company | 14 | 13 | 10 | 17 | 16 | 10 | 13.1 | 4 |
| Kansas City Power & Light Company | 9 | 26 | 19 | 35 | 30 | 30 | 24.7 | 33 |
| Kansas Gas and Electric Company | 10 | 36 | 32 | 32 | 35 | 10 | 25.8 | 34 |
| KCP&L Greater Missouri Operations Company | 15 | 27 | 25 | 18 | 11 | 28 | 20.4 | 17 |
| Kentucky Utilities Company | 24 | 11 | 13 | 11 | 7 | 33 | 16.3 | 8 |
| Monongahela Power Company | 30 | 19 | 20 | 14 | 12 | 13 | 17.7 | 13 |
| Nevada Power Company | 26 | 7 | 1 | 14 | 9 | 4 | 10.2 | 2 |
| Ohio Power Company | 23 | 24 | 31 | 16 | 33 | 17 | 23.9 | 32 |
| Oklahoma Gas and Electric Company | 27 | 22 | 24 | 6 | 12 | 29 | 19.7 | 16 |
| PacifiCorp | 10 | 30 | 32 | 6 | 20 | 28 | 20.8 | 21 |
| Portland General Electric Company | 13 | 35 | 23 | 18 | 13 | 27 | 21.2 | 25 |
| Public Service Company of New Hampshire | 21 | 32 | 33 | 35 | 26 | 26 | 28.7 | 39 |
| Public Service Company of New Mexico | 15 | 28 | 10 | 33 | 28 | 21 | 22.3 | 28 |
| Public Service Company of Oklahoma | 14 | 26 | 38 | 4 | 3 | 25 | 18.1 | 14 |
| Southern California Edison Co. | 8 | 27 | 30 | 39 | 24 | 31 | 26.3 | 36 |
| Southwestern Electric Power Company | 25 | 21 | 33 | 6 | 14 | 35 | 22.3 | 28 |
| Southwestern Public Service Company | 24 | 28 | 7 | 17 | 13 | 18 | 17.7 | 12 |
| Tucson Electric Power Company | 28 | 15 | 3 | 24 | 33 | 27 | 21.5 | 26 |
| Virginia Electric and Power Company | 14 | 16 | 14 | 24 | 9 | 27 | 17.1 | 10 |
| Westar Energy (KPL) | 15 | 35 | 35 | 26 | 34 | 18 | 27.0 | 37 |

| Regional Panel | Production O&M | Transmission O&M | Distribution O&M | Customer and A&G Expenses | Total Non-Fuel O&M | Plant Investment | Overall Average | Overall Rank |
|---|---|---|---|---|---|---|---|---|
| *Arizona Public Service Company* | *7* | *2* | *6* | *4* | *6* | *4* | *4.7* | *4* |
| El Paso Electric Company | 4 | 3 | 4 | 7 | 6 | 4 | 4.6 | 3 |
| Nevada Power Company | 7 | 2 | 1 | 3 | 2 | 2 | 2.5 | 1 |
| PacifiCorp | 3 | 7 | 8 | 2 | 4 | 7 | 4.8 | 5 |
| Public Service Company of New Mexico | 3 | 7 | 4 | 6 | 6 | 5 | 4.9 | 7 |
| Southern California Edison Co. | 2 | 6 | 8 | 8 | 5 | 6 | 5.7 | 8 |
| Southwestern Public Service Company | 5 | 6 | 4 | 3 | 3 | 4 | 4.1 | 2 |
| Tucson Electric Power Company | 7 | 3 | 3 | 4 | 7 | 6 | 4.8 | 5 |
| Salt River Project | | | | | | | | |

# Benchmarking Workpapers
## Comparable Groups

| | Base Panel | Regional Panel | Nuclear Panel |
|---|---|---|---|
| *Arizona Public Service Company* | X | X | X |
| Alabama Power Company | X | | |
| Appalachian Power Company | X | | |
| Carolina Power & Light Company | X | | |
| Columbus Southern Power Company | X | | |
| Dayton Power and Light Company | X | | |
| Detroit Edison Company | X | | X |
| Duke Energy Carolinas, LLC | X | | |
| Duke Energy Indiana, Inc. | X | | |
| El Paso Electric Company | X | X | |
| Entergy Arkansas, Inc. | X | | |
| Entergy Louisiana, LLC | X | | |
| Entergy Mississippi, Inc. | X | | |
| Florida Power & Light Company | X | | |
| Florida Power Corporation | X | | |
| Georgia Power Company | X | | |
| Gulf Power Company | X | | |
| Idaho Power Co. | X | | |
| Indiana Michigan Power Company | X | | X |
| Indianapolis Power & Light Company | X | | |
| Kansas City Power & Light Company | X | | X |
| Kansas Gas and Electric Company | X | | X |
| KCP&L Greater Missouri Operations Company | X | | |
| Kentucky Utilities Company | X | | |
| Monongahela Power Company | X | | |
| Nevada Power Company | X | X | |
| Ohio Power Company | X | | |
| Oklahoma Gas and Electric Company | X | | |
| PacifiCorp | X | X | |
| Portland General Electric Company | X | | |
| Public Service Company of New Hampshire | X | | |
| Public Service Company of New Mexico | X | X | |
| Public Service Company of Oklahoma | X | | |
| Southern California Edison Co. | X | X | X |
| Southwestern Electric Power Company | X | | |
| Southwestern Public Service Company | X | X | |
| Tucson Electric Power Company | X | X | |
| Virginia Electric and Power Company | X | | |
| Westar Energy (KPL) | X | | |

# Benchmarking Workpapers
## Definitions

### Situational Assessment

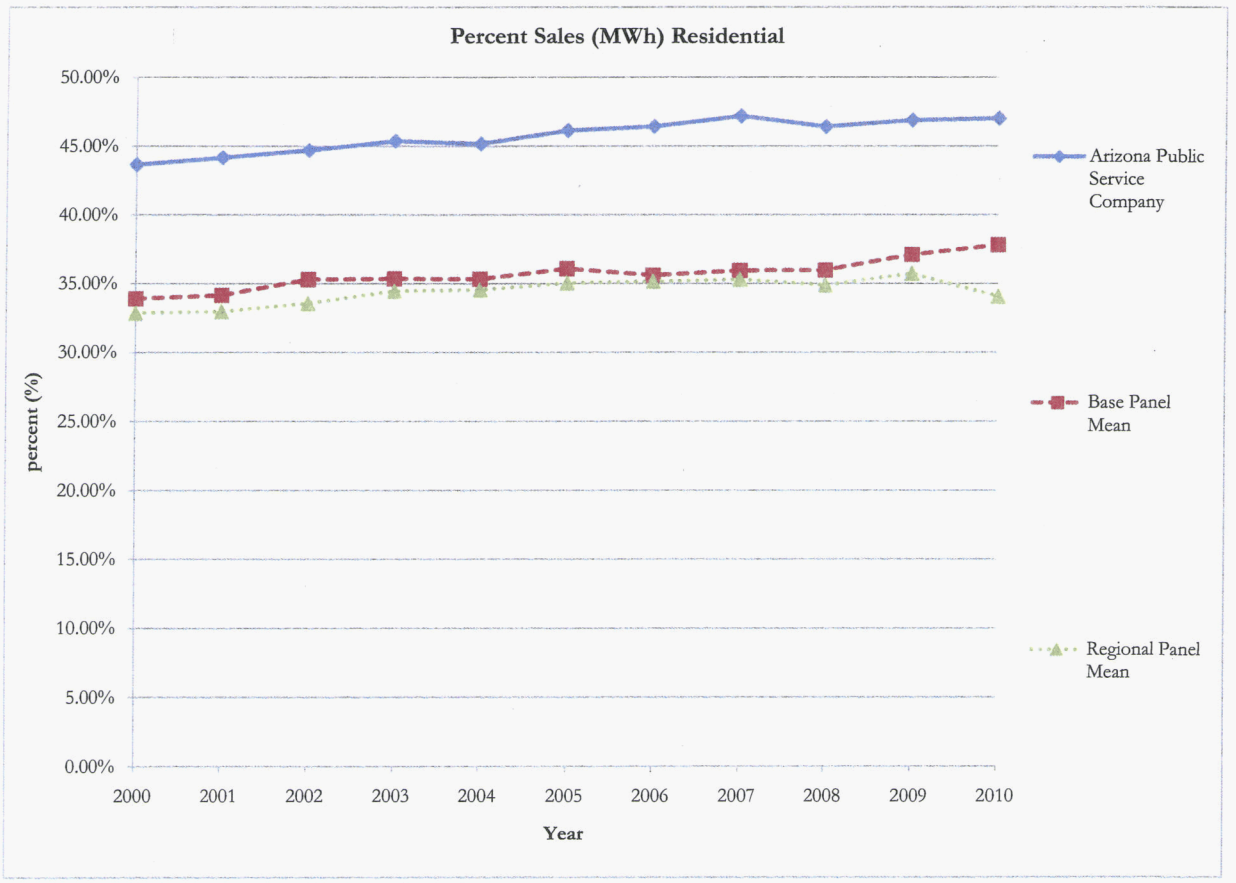
| Metric | Unit | Calculation |
|---|---|---|
| Percent Sales (MWh) Residential | percent (%) | Residential Electric Sales Vol (MWh) / Tot Sales: Ult Cnsmr-Mwhrs Sold (MWh) |
| Percent Sales (MWh) Other | percent (%) | Other Electric Sales Vol (MWh) / Total Electricity Sales Vol (MWh) |
| Use per Customer | MWh/customer | Tot Sales: Ult Cnsmr-Mwhrs Sold (MWh) / Ult Consumer Electric Customers |
| Change in Customers (%) | percent (%) | Change in Customers (%) YoY |
| Change in Sales Volume (%) | percent (%) | Change in MWh Sales to Ult. Consumer vs. 5 Year Average |
| Percent Generation Nuclear (%) | percent (%) | Nuclear Generation (MWh) / Net Generation (MWh) |
| Energy Losses (%) | percent (%) | Energy Losses (MWh) / Total Disposition of Energy (MWh) |
| Age of Plant (Depreciation/Gross Plant) | percent (%) | Accum Deprec-Total Elec Plant ($000) / Total Util Plant-Electric ($000) |
| Customer Density | customer/sq. mile | Ult Consumer Electric Customers / Service Territory (sq. miles) |
| Regulatory Lag | months | Rate Case Lag since last case as defined by Regulatory Research Associates |

### Productive Efficiency

| Metric Group | Metric | Unit | Calculation |
|---|---|---|---|
| Production O&M | Production O&M per Customer | $/customer | Production O&M Exp less Rents and Purchased Power ($000) / Ult Consumer Electric Customers |
| | Production O&M per MWh Generated | $/MWh | Production O&M Exp less Rents and Purchased Power ($000) / Net Generation (MWh) |
| Transmission O&M | Transmission O&M per Customer | $/customer | Transmiss-O&M Exp ($000) / Ult Consumer Electric Customers |
| | Transmission O&M per kWh Sold | $/kWh | Transmiss-O&M Exp ($000) / Tot Sales: Ult Cnsmr-Mwhrs Sold (MWh) |
| | Transmission O&M per Mile of Transmission Line | $/mile | Transmiss-O&M Exp ($000) / Length of Transmission Lines (Miles) |
| Distribution O&M | Distribution O&M per Customer | $/customer | Distr-O&M Exp ($000) / Ult Consumer Electric Customers |
| | Distribution O&M per MWh Sold | $/MWh | Distr-O&M Exp ($000) / Tot Sales: Ult Cnsmr-Mwhrs Sold (MWh) |
| Customer and A&G Expenses | Customer and A&G Expenses per Customer | $/customer | Customer Accounts Exp plus Customer Service Exp plus Sales Exp plus A&G Exp ($000) / Ult Consumer Electric Customers |
| | Customer and A&G Expenses per MWh Sold | $/MWh | Customer Accounts Exp plus Customer Service Exp plus Sales Exp plus A&G Exp ($000) / Tot Sales: Ult Cnsmr-Mwhrs Sold (MWh) |
| Total Non-Fuel O&M | Total Non-Fuel O&M per Customer | $/customer | Total Electric O&M Exp less Fuel Exp less Purchased Power less Franchise Requirements less Rents ($000) / Ult Consumer Electric Customers |
| | Total Non-Fuel O&M per MWh Sold | $/MWh | Total Electric O&M Exp less Fuel Exp less Purchased Power less Franchise Requirements less Rents ($000) / Tot Sales: Ult Cnsmr-Mwhrs Sold (MWh) |
| Plant Investment | Production Plant Additions | percent (%) | Total Production Plant-Addns($000) / Total Production Plant-BOY($000) |
| | Transmission Plant Additions | percent (%) | Total Transmission Plant-Addns($000) / Total Transmission Plant-BOY($000) |
| | Distribution Plant Additions | percent (%) | Total Distr Plant-Addns($000) / Total Distr Plant-BOY($000) |
| | Total Plant Additions | percent (%) | Total Elec Plt In Service-Addns($000) / Total Elec Plt In Service-BOY($000) |

# Benchmarking Workpapers

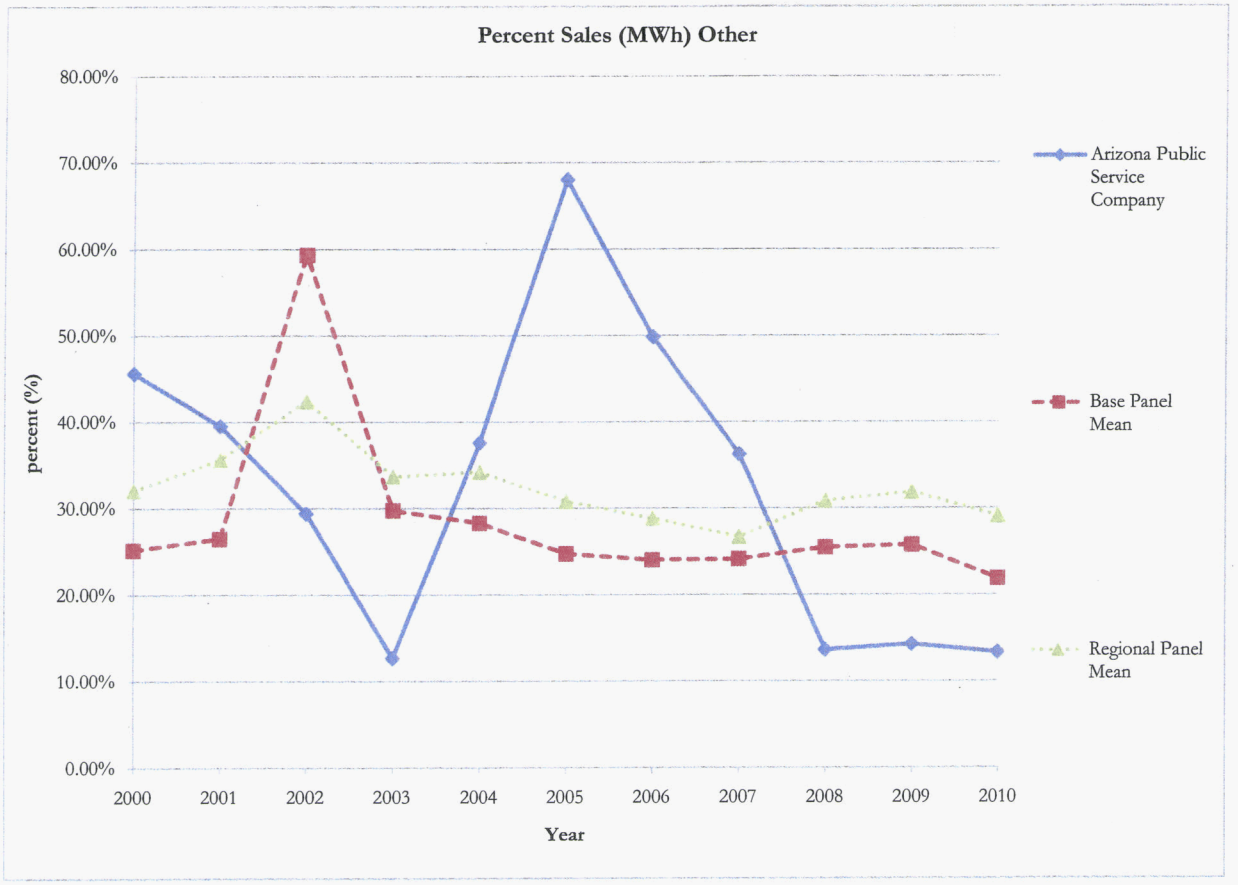
## Situational Assessment




| Percent Sales (MWh) Residential | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| *Annual Values* | | | | | | | | | | | |
| | **2000** | **2001** | **2002** | **2003** | **2004** | **2005** | **2006** | **2007** | **2008** | **2009** | **2010** |
| Arizona Public Service Company | 43.66% | 44.18% | 44.70% | 45.38% | 45.19% | 46.17% | 46.46% | 47.21% | 46.43% | 46.90% | 47.04% |
| Base Panel Mean | 33.90% | 34.16% | 35.30% | 35.37% | 35.34% | 36.10% | 35.61% | 35.95% | 35.98% | 37.11% | 37.81% |
| Regional Panel Mean | 32.86% | 32.97% | 33.57% | 34.46% | 34.55% | 35.05% | 35.16% | 35.31% | 34.89% | 35.74% | 34.06% |
| *Rankings* | | | | | | | | | | | |
| | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
| APS Rank vs. Base Panel | 4 / 38 | 4 / 38 | 4 / 38 | 4 / 38 | 4 / 38 | 4 / 38 | 4 / 39 | 4 / 39 | 3 / 39 | 4 / 39 | 4 / 39 |
| APS Rank vs. Regional Panel | 2 / 9 | 2 / 9 | 2 / 9 | 2 / 9 | 2 / 9 | 2 / 9 | 2 / 9 | 2 / 9 | 2 / 9 | 2 / 9 | 1 / 8 |

Source: FERC Form 1 and SNL Financial
Residential Electric Sales Vol (MWh); Tot Sales: Ult Cnsmr-Mwhrs Sold (MWh)

# Benchmarking Workpapers
## Situational Assessment

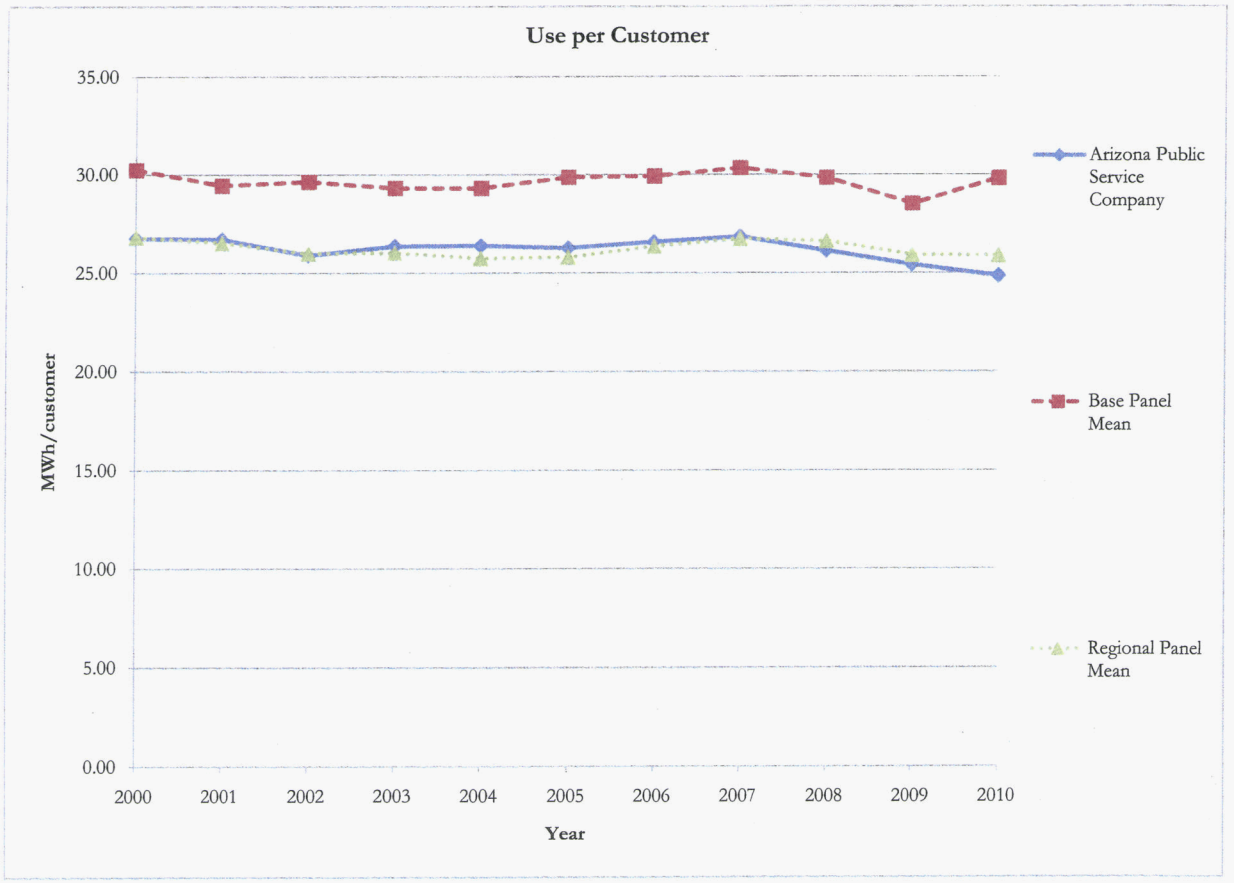



| Percent Sales (MWh) Other | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| *Annual Values* | | | | | | | | | | | |
| | **2000** | **2001** | **2002** | **2003** | **2004** | **2005** | **2006** | **2007** | **2008** | **2009** | **2010** |
| Arizona Public Service Company | 45.63% | 39.53% | 29.43% | 12.66% | 37.58% | 68.04% | 49.86% | 36.26% | 13.62% | 14.25% | 13.33% |
| Base Panel Mean | 25.17% | 26.49% | 59.37% | 29.75% | 28.30% | 24.74% | 24.03% | 24.11% | 25.47% | 25.76% | 21.86% |
| Regional Panel Mean | 32.05% | 35.63% | 42.42% | 33.67% | 34.19% | 30.78% | 28.82% | 26.71% | 30.84% | 31.86% | 29.12% |
| *Rankings* | | | | | | | | | | | |
| | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
| APS Rank vs. Base Panel | 35 / 38 | 31 / 38 | 20 / 38 | 6 / 38 | 26 / 38 | 38 / 38 | 36 / 39 | 34 / 39 | 12 / 39 | 14 / 39 | 12 / 39 |
| APS Rank vs. Regional Panel | 6 / 8 | 4 / 8 | 2 / 8 | 2 / 8 | 4 / 8 | 8 / 8 | 7 / 8 | 6 / 8 | 3 / 8 | 3 / 8 | 2 / 8 |

Source: FERC Form 1 and SNL Financial
Other Electric Sales Vol (MWh); Total Electricity Sales Vol (MWh)

# Benchmarking Workpapers

## Situational Assessment




| Use per Customer | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| *Annual Values* | | | | | | | | | | | |
| | **2000** | **2001** | **2002** | **2003** | **2004** | **2005** | **2006** | **2007** | **2008** | **2009** | **2010** |
| Arizona Public Service Company | 26.76 | 26.71 | 25.90 | 26.37 | 26.40 | 26.28 | 26.59 | 26.85 | 26.13 | 25.41 | 24.84 |
| Base Panel Mean | 30.24 | 29.45 | 29.64 | 29.31 | 29.32 | 29.86 | 29.92 | 30.34 | 29.83 | 28.51 | 29.81 |
| Regional Panel Mean | 26.81 | 26.52 | 25.99 | 26.02 | 25.74 | 25.79 | 26.35 | 26.73 | 26.62 | 25.91 | 25.88 |
| *Rankings* | | | | | | | | | | | |
| | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
| APS Rank vs. Base Panel | 11 / 38 | 12 / 38 | 11 / 38 | 12 / 38 | 13 / 38 | 13 / 38 | 13 / 39 | 12 / 39 | 11 / 39 | 11 / 39 | 10 / 39 |
| APS Rank vs. Regional Panel | 5 / 9 | 5 / 9 | 5 / 9 | 5 / 9 | 5 / 9 | 6 / 9 | 6 / 9 | 6 / 9 | 5 / 9 | 5 / 9 | 5 / 8 |

Source: FERC Form 1 and SNL Financial
Tot Sales: Ult Cnsmr-Mwhrs Sold (MWh); Ult Consumer Electric Customers

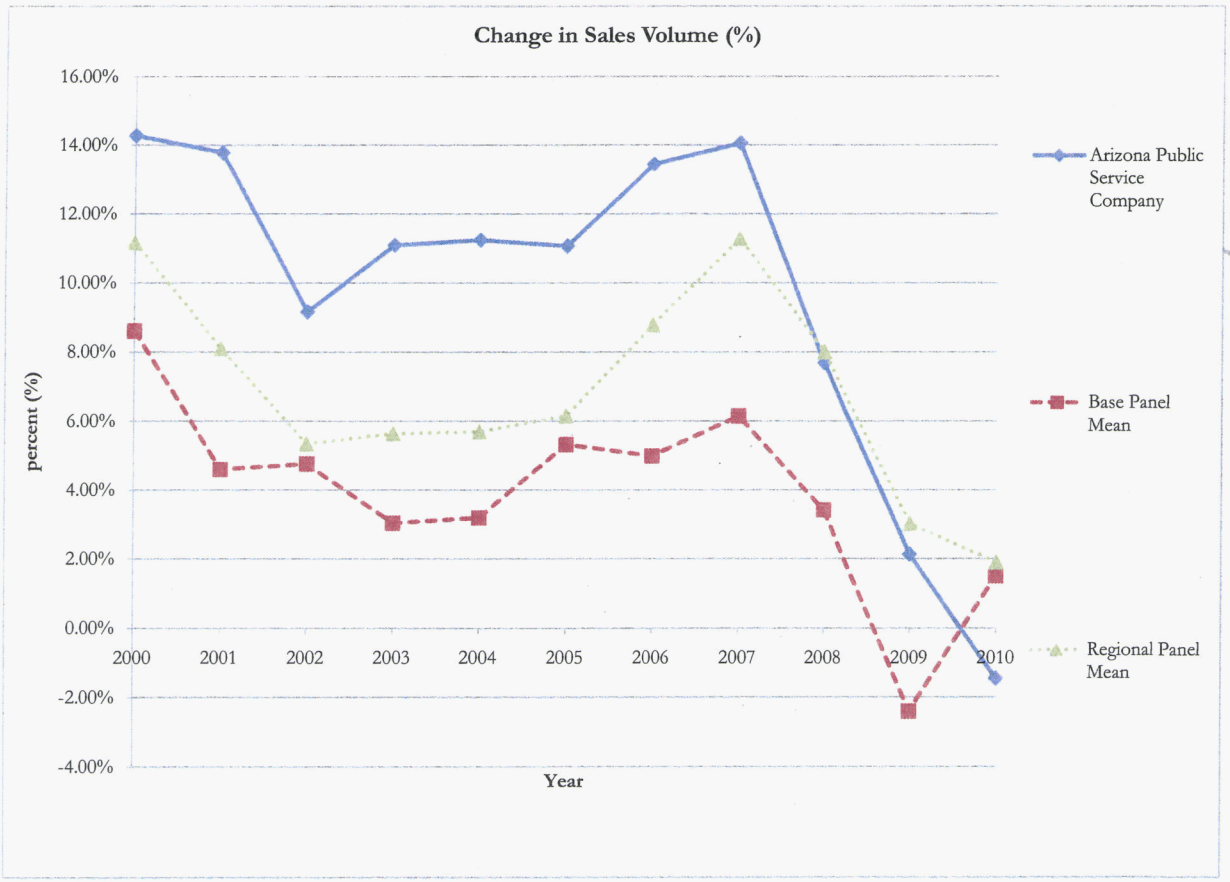
# Benchmarking Workpapers

## Situational Assessment

| Change in Customers (%) | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| *Annual Values* | | | | | | | | | | | |
| | **2000** | **2001** | **2002** | **2003** | **2004** | **2005** | **2006** | **2007** | **2008** | **2009** | **2010** |
| Arizona Public Service Company | 3.64% | 4.28% | 3.05% | 3.16% | 3.60% | 4.11% | 4.21% | 3.17% | 1.41% | 0.62% | 0.59% |
| Base Panel Mean | 2.01% | 1.49% | 1.39% | 1.38% | 1.57% | 1.52% | 1.53% | 1.46% | 0.74% | 0.39% | 0.33% |
| Regional Panel Mean | 2.34% | 2.21% | 1.73% | 2.27% | 2.56% | 2.38% | 2.05% | 3.05% | 1.27% | 0.84% | 0.10% |
| *Rankings* | | | | | | | | | | | |
| | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
| APS Rank vs. Base Panel | 4 / 38 | 2 / 38 | 2 / 38 | 2 / 38 | 3 / 38 | 2 / 38 | 3 / 38 | 2 / 39 | 6 / 38 | 15 / 38 | 13 / 39 |
| APS Rank vs. Regional Panel | 2 / 8 | 2 / 8 | 2 / 8 | 2 / 8 | 2 / 8 | 2 / 8 | 2 / 8 | 2 / 8 | 3 / 8 | 5 / 8 | 4 / 8 |

Source: FERC Form 1 and SNL Financial
Change in Customers (%)

# Benchmarking Workpapers
## Situational Assessment




| Change in Sales Volume (%) | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| *Annual Values* | | | | | | | | | | | |
| | **2000** | **2001** | **2002** | **2003** | **2004** | **2005** | **2006** | **2007** | **2008** | **2009** | **2010** |
| Arizona Public Service Company | 14.28% | 13.78% | 9.16% | 11.09% | 11.24% | 11.07% | 13.45% | 14.06% | 7.69% | 2.14% | -1.45% |
| Base Panel Mean | 8.61% | 4.60% | 4.76% | 3.04% | 3.19% | 5.32% | 4.99% | 6.14% | 3.41% | -2.41% | 1.51% |
| Regional Panel Mean | 11.17% | 8.10% | 5.34% | 5.64% | 5.69% | 6.15% | 8.79% | 11.28% | 8.01% | 3.03% | 1.90% |
| *Rankings* | | | | | | | | | | | |
| | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
| APS Rank vs. Base Panel | 2 / 38 | 2 / 38 | 7 / 38 | 3 / 38 | 2 / 38 | 2 / 38 | 2 / 38 | 3 / 39 | 7 / 38 | 8 / 38 | 31 / 38 |
| APS Rank vs. Regional Panel | 3 / 9 | 2 / 9 | 2 / 9 | 2 / 9 | 2 / 9 | 2 / 9 | 2 / 9 | 3 / 9 | 6 / 9 | 7 / 9 | 7 / 8 |

Source: FERC Form 1 and SNL Financial
Change in MWh Sales to Ult. Consumer vs. 5 Year Average

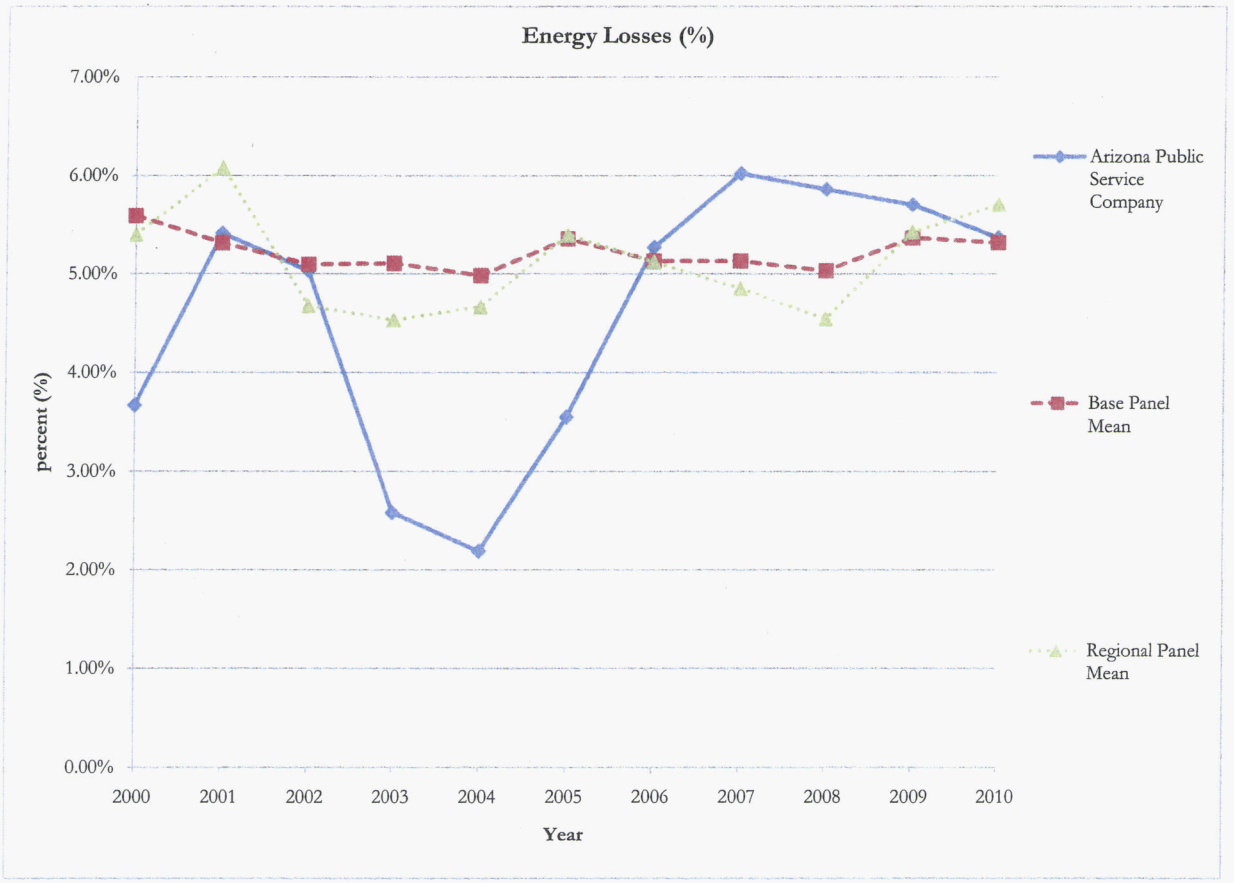
# Benchmarking Workpapers

## Situational Assessment

| Percent Generation Nuclear (%) | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| *Annual Values* | | | | | | | | | | | |
| | **2000** | **2001** | **2002** | **2003** | **2004** | **2005** | **2006** | **2007** | **2008** | **2009** | **2010** |
| Arizona Public Service Company | 36.63% | 34.30% | 39.81% | 40.07% | 37.36% | 31.37% | 25.43% | 28.00% | 30.36% | 32.59% | 33.84% |
| Base Panel Mean | 14.17% | 15.01% | 15.14% | 15.01% | 14.79% | 14.32% | 15.58% | 15.91% | 15.87% | 15.64% | 15.13% |
| Regional Panel Mean | 20.38% | 19.51% | 21.44% | 20.39% | 19.82% | 18.99% | 19.32% | 21.86% | 22.09% | 20.93% | 20.08% |
| *Rankings* | | | | | | | | | | | |
| | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
| APS Rank vs. Base Panel | 7 / 38 | 9 / 38 | 8 / 38 | 7 / 37 | 8 / 38 | 9 / 38 | 10 / 39 | 10 / 39 | 10 / 39 | 10 / 39 | 10 / 39 |
| APS Rank vs. Regional Panel | 3 / 9 | 3 / 8 | 3 / 8 | 3 / 8 | 3 / 8 | 3 / 8 | 3 / 8 | 3 / 8 | 3 / 8 | 3 / 8 | 3 / 8 |

Source: FERC Form 1 and SNL Financial
Nuclear Generation (MWh); Net Generation (MWh)

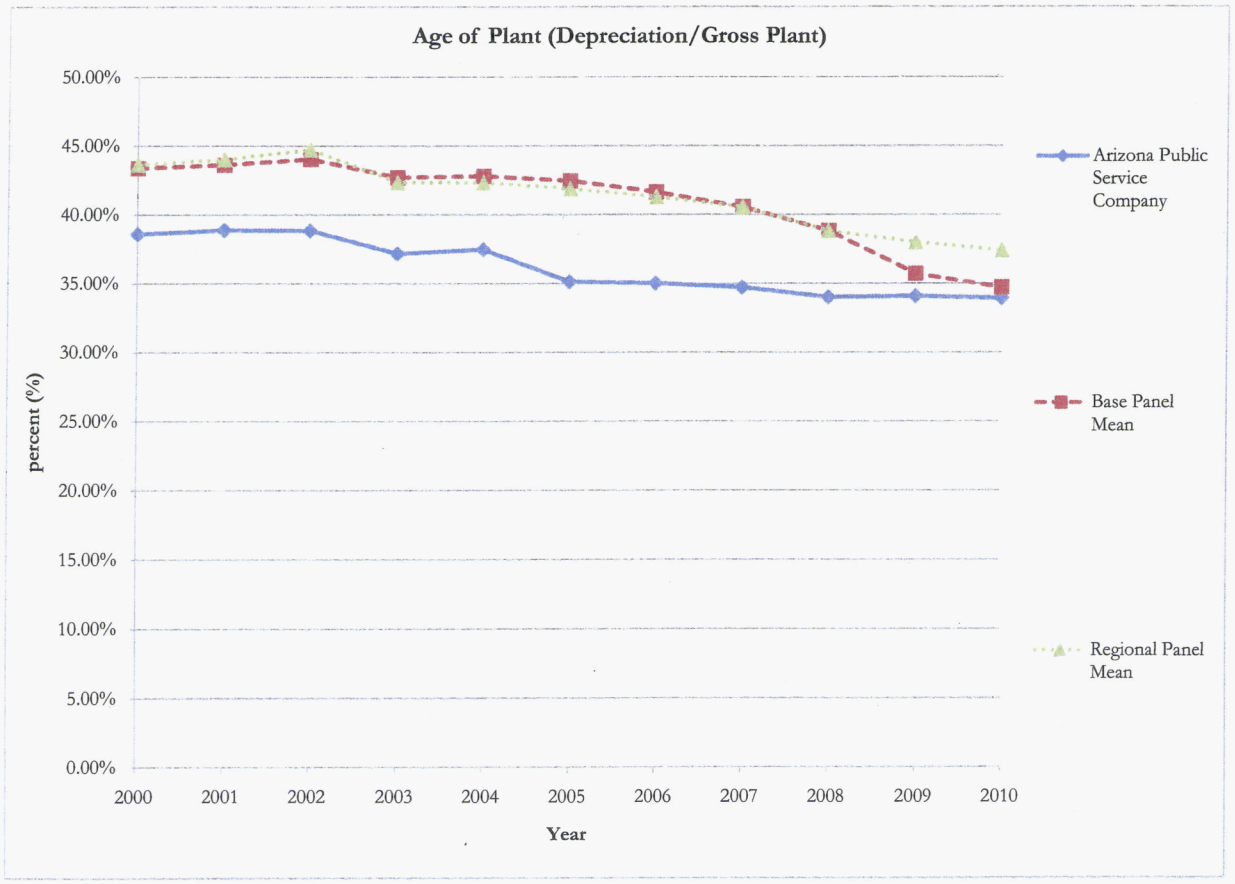
## Benchmarking Workpapers
### Situational Assessment




| Energy Losses (%) | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| *Annual Values* | | | | | | | | | | | |
| | **2000** | **2001** | **2002** | **2003** | **2004** | **2005** | **2006** | **2007** | **2008** | **2009** | **2010** |
| Arizona Public Service Company | 3.67% | 5.41% | 5.03% | 2.58% | 2.19% | 3.55% | 5.27% | 6.02% | 5.86% | 5.70% | 5.37% |
| Base Panel Mean | 5.59% | 5.31% | 5.10% | 5.11% | 4.98% | 5.36% | 5.13% | 5.13% | 5.03% | 5.37% | 5.32% |
| Regional Panel Mean | 5.40% | 6.08% | 4.68% | 4.53% | 4.67% | 5.40% | 5.12% | 4.85% | 4.54% | 5.43% | 5.70% |
| | | | | | | | | | | | |
| *Rankings* | | | | | | | | | | | |
| | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
| APS Rank vs. Base Panel | 31 / 38 | 18 / 38 | 20 / 38 | 35 / 38 | 36 / 38 | 35 / 38 | 17 / 39 | 11 / 39 | 10 / 39 | 17 / 39 | 20 / 39 |
| APS Rank vs. Regional Panel | 7 / 9 | 5 / 9 | 5 / 9 | 7 / 9 | 8 / 9 | 9 / 9 | 5 / 9 | 3 / 9 | 3 / 9 | 5 / 9 | 6 / 8 |

Source: FERC Form 1 and SNL Financial
Energy Losses (MWh); Total Disposition of Energy (MWh)

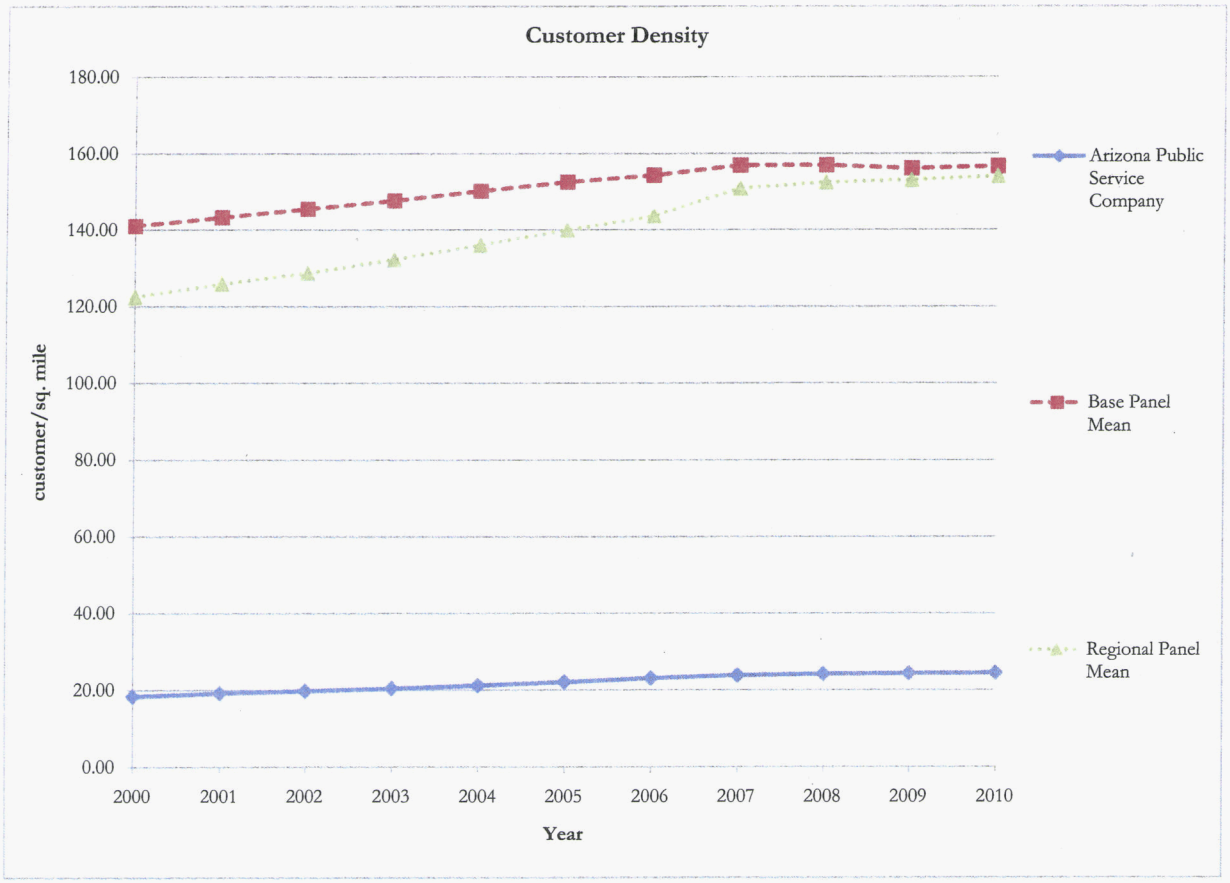
## Benchmarking Workpapers
### Situational Assessment




| Age of Plant (Depreciation/Gross Plant) | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| *Annual Values* | | | | | | | | | | | |
| | **2000** | **2001** | **2002** | **2003** | **2004** | **2005** | **2006** | **2007** | **2008** | **2009** | **2010** |
| Arizona Public Service Company | 38.61% | 38.89% | 38.86% | 37.19% | 37.49% | 35.13% | 35.03% | 34.72% | 34.02% | 34.09% | 33.95% |
| Base Panel Mean | 43.37% | 43.62% | 44.03% | 42.70% | 42.80% | 42.45% | 41.64% | 40.55% | 38.84% | 35.71% | 34.71% |
| Regional Panel Mean | 43.65% | 44.02% | 44.74% | 42.34% | 42.32% | 41.88% | 41.29% | 40.56% | 38.83% | 38.01% | 37.42% |
| *Rankings* | | | | | | | | | | | |
| | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
| APS Rank vs. Base Panel | 32 / 38 | 33 / 38 | 33 / 38 | 33 / 38 | 33 / 38 | 36 / 38 | 35 / 39 | 35 / 39 | 32 / 39 | 28 / 39 | 26 / 39 |
| APS Rank vs. Regional Panel | 5 / 8 | 5 / 8 | 5 / 8 | 6 / 8 | 6 / 8 | 7 / 8 | 7 / 8 | 7 / 8 | 6 / 8 | 6 / 8 | 6 / 8 |

Source: FERC Form 1 and SNL Financial
Accum Deprec-Total Elec Plant ($000); Total Util Plant-Electric ($000)

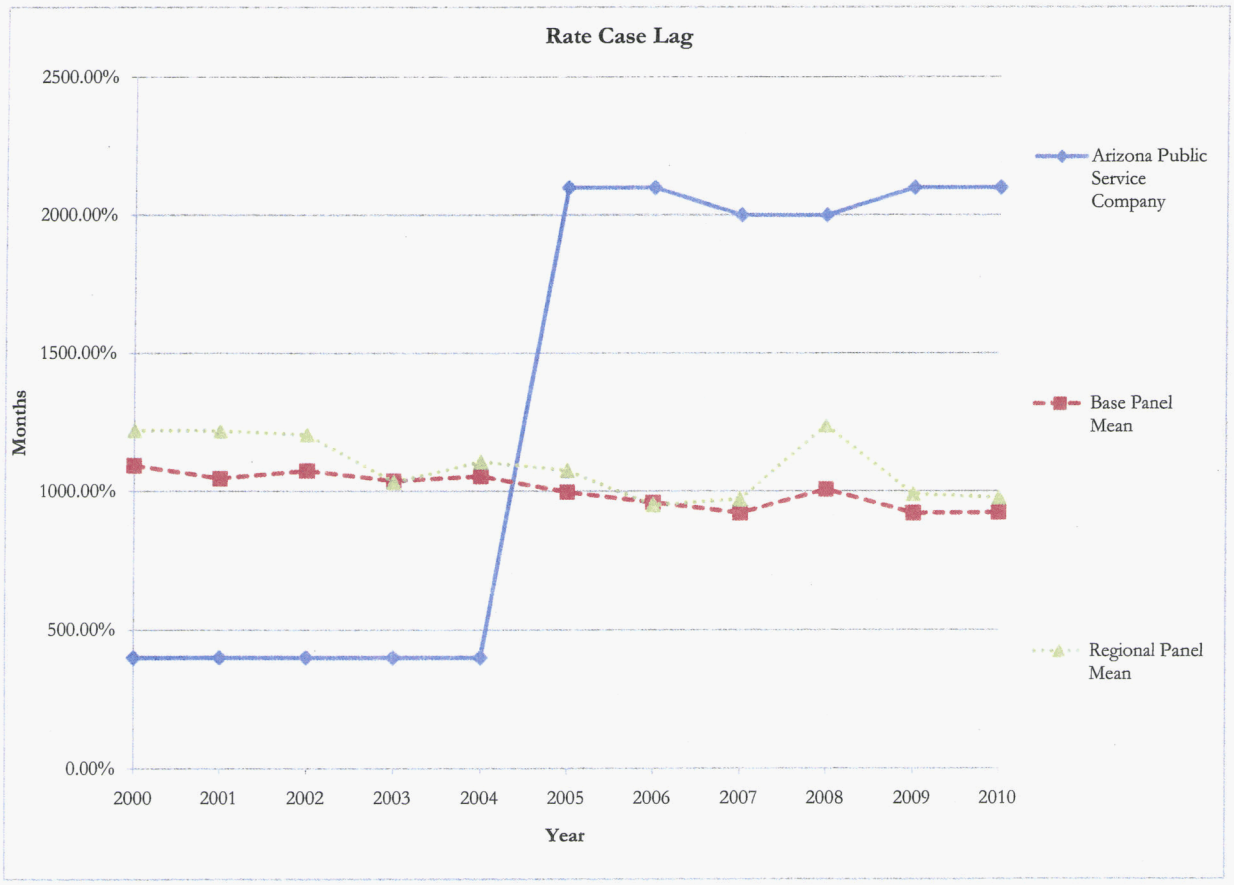
# Benchmarking Workpapers
## Situational Assessment




| Customer Density | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| *Annual Values* | | | | | | | | | | | |
| | **2000** | **2001** | **2002** | **2003** | **2004** | **2005** | **2006** | **2007** | **2008** | **2009** | **2010** |
| Arizona Public Service Company | 18.33 | 19.15 | 19.76 | 20.40 | 21.16 | 22.07 | 23.04 | 23.79 | 24.13 | 24.28 | 24.43 |
| Base Panel Mean | 141.06 | 143.32 | 145.52 | 147.74 | 150.24 | 152.61 | 154.37 | 156.96 | 157.00 | 156.19 | 156.73 |
| Regional Panel Mean | 122.51 | 125.88 | 128.75 | 132.33 | 136.01 | 139.94 | 143.69 | 150.95 | 152.52 | 153.14 | 154.08 |
| *Rankings* | | | | | | | | | | | |
| | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
| APS Rank vs. Base Panel | 4 / 36 | 4 / 36 | 4 / 36 | 4 / 36 | 4 / 36 | 4 / 36 | 4 / 37 | 5 / 37 | 5 / 37 | 5 / 37 | 5 / 37 |
| APS Rank vs. Regional Panel | 2 / 8 | 2 / 8 | 2 / 8 | 2 / 8 | 2 / 8 | 2 / 8 | 2 / 8 | 3 / 8 | 3 / 8 | 3 / 8 | 3 / 8 |

Source: FERC Form 1 and SNL Financial and EEI
Ult Consumer Electric Customers ; Service Territory (sq. miles)

## Benchmarking Workpapers
### Situational Assessment




| Rate Case Lag | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| *Annual Values* | | | | | | | | | | | |
| | **2000** | **2001** | **2002** | **2003** | **2004** | **2005** | **2006** | **2007** | **2008** | **2009** | **2010** |
| Arizona Public Service Company | 400.00% | 400.00% | 400.00% | 400.00% | 400.00% | ##### | ##### | ##### | ##### | ##### | ##### |
| Base Panel Mean | ##### | ##### | ##### | ##### | ##### | 996.46% | 959.09% | 921.72% | ##### | 920.45% | 922.37% |
| Regional Panel Mean | ##### | ##### | ##### | ##### | ##### | ##### | 950.00% | 971.43% | ##### | 989.29% | 976.53% |
| | | | | | | | | | | | |
| *Rankings* | | | | | | | | | | | |
| | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
| APS Rank vs. Base Panel | 31 / 33 | 31 / 33 | 31 / 33 | 30 / 33 | 31 / 34 | 2 / 34 | 1 / 34 | 1 / 34 | 1 / 34 | 1 / 34 | 1 / 35 |
| APS Rank vs. Regional Panel | 8 / 8 | 8 / 8 | 8 / 8 | 7 / 8 | 7 / 8 | 2 / 8 | 1 / 8 | 1 / 8 | 1 / 8 | 1 / 8 | 1 / 8 |

Source: FERC Form 1 and SNL Financial

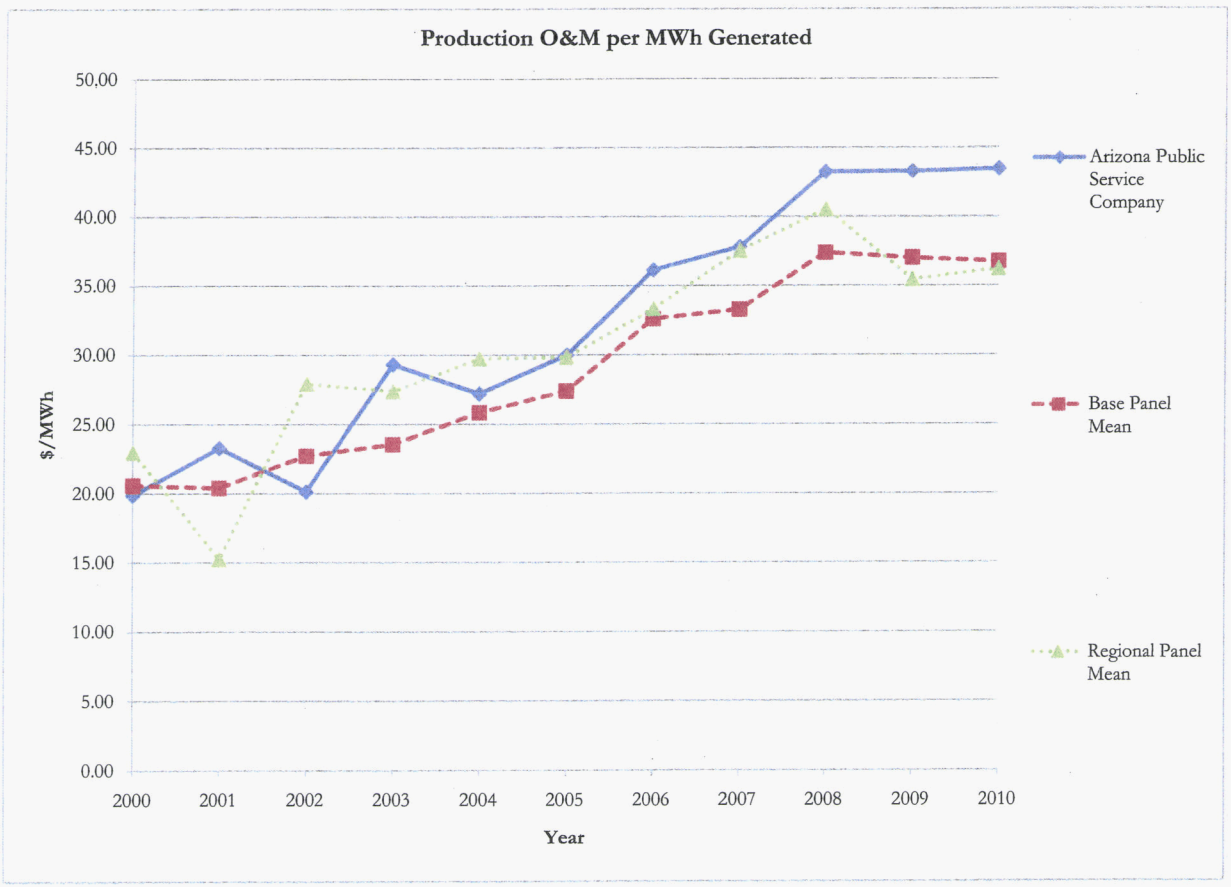
# Benchmarking Workpapers
## Productive Efficiency

| Production O&M per Customer | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| *Annual Values* | | | | | | | | | | | |
| | **2000** | **2001** | **2002** | **2003** | **2004** | **2005** | **2006** | **2007** | **2008** | **2009** | **2010** |
| Arizona Public Service Company | 573.61 | 651.21 | 503.72 | 653.54 | 616.64 | 712.28 | 943.88 | 968.70 | 1,100.39 | 1,068.97 | 1,045.66 |
| Base Panel Mean | 686.86 | 685.81 | 691.17 | 716.38 | 756.42 | 835.96 | 955.03 | 989.23 | 1,097.50 | 974.65 | 1,053.30 |
| Regional Panel Mean | 679.90 | 606.42 | 694.50 | 694.97 | 732.52 | 774.35 | 881.48 | 962.78 | 1,063.14 | 867.66 | 881.30 |
| *Rankings* | | | | | | | | | | | |
| | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
| APS Rank vs. Base Panel | 15 / 38 | 17 / 38 | 8 / 38 | 19 / 37 | 13 / 38 | 16 / 38 | 22 / 39 | 20 / 39 | 22 / 39 | 25 / 39 | 23 / 39 |
| APS Rank vs. Regional Panel | 3 / 8 | 4 / 8 | 2 / 8 | 4 / 8 | 4 / 8 | 5 / 8 | 6 / 8 | 4 / 8 | 6 / 8 | 6 / 8 | 6 / 8 |

Source: FERC Form 1 and SNL Financial
Production O&M Exp ($000); Ult Consumer Electric Customers

# Benchmarking Workpapers

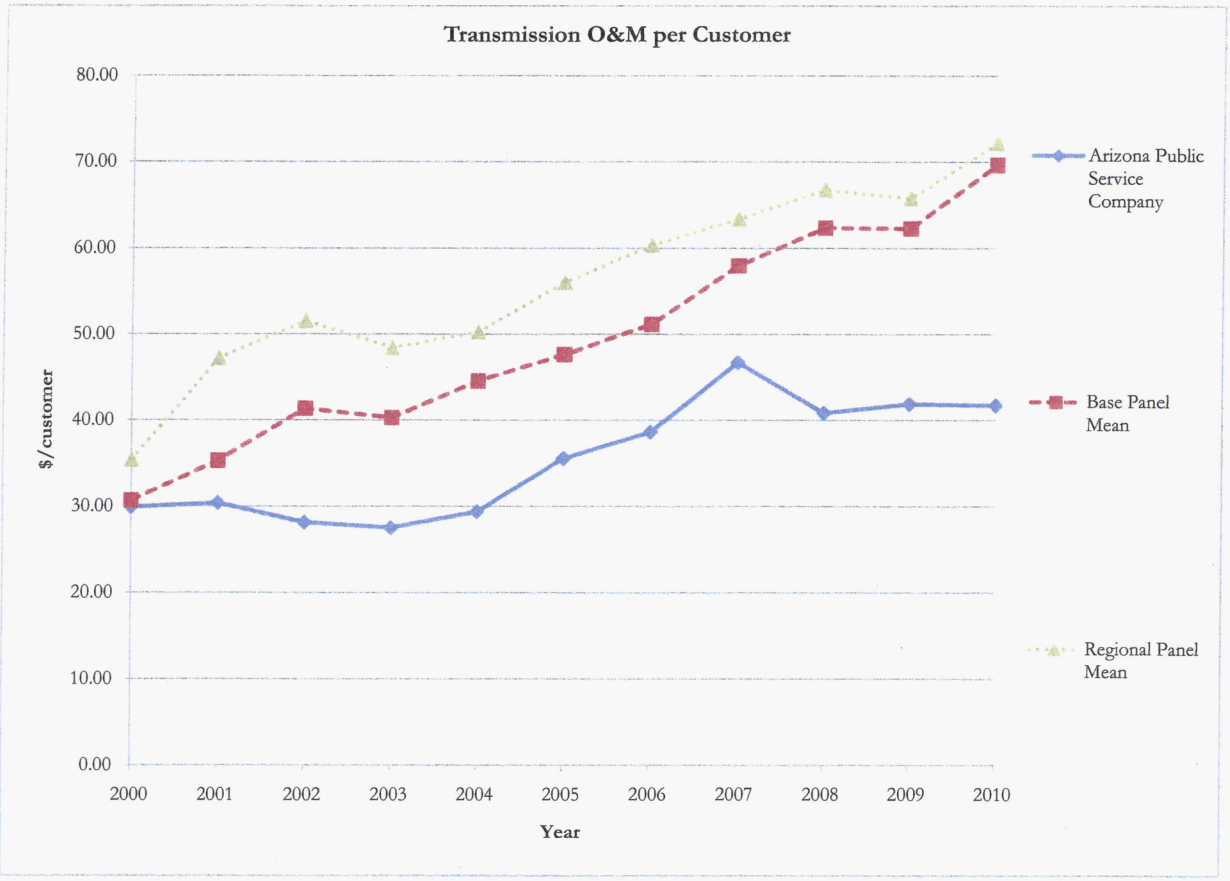
## Productive Efficiency




| Production O&M per MWh Generated | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| *Annual Values* | | | | | | | | | | | |
| | **2000** | **2001** | **2002** | **2003** | **2004** | **2005** | **2006** | **2007** | **2008** | **2009** | **2010** |
| Arizona Public Service Company | 19.89 | 23.30 | 20.14 | 29.33 | 27.20 | 29.98 | 36.14 | 37.80 | 43.25 | 43.30 | 43.47 |
| Base Panel Mean | 20.59 | 20.41 | 22.73 | 23.54 | 25.84 | 27.38 | 32.61 | 33.29 | 37.39 | 37.02 | 36.75 |
| Regional Panel Mean | 22.99 | 15.26 | 27.93 | 27.38 | 29.74 | 29.83 | 33.35 | 37.54 | 40.55 | 35.47 | 36.23 |
| *Rankings* | | | | | | | | | | | |
| | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
| APS Rank vs. Base Panel | 20 / 38 | 25 / 38 | 18 / 38 | 30 / 37 | 28 / 38 | 26 / 38 | 29 / 39 | 29 / 39 | 29 / 39 | 30 / 39 | 31 / 39 |
| APS Rank vs. Regional Panel | 3 / 8 | 4 / 8 | 2 / 8 | 6 / 8 | 5 / 8 | 5 / 8 | 5 / 8 | 6 / 8 | 5 / 8 | 7 / 8 | 7 / 8 |

Source: FERC Form 1 and SNL Financial
Production O&M Exp ($000); Net Generation (MWh)

## Benchmarking Workpapers
### Productive Efficiency




| Transmission O&M per Customer | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| *Annual Values* | | | | | | | | | | | |
| | **2000** | **2001** | **2002** | **2003** | **2004** | **2005** | **2006** | **2007** | **2008** | **2009** | **2010** |
| Arizona Public Service Company | 29.91 | 30.39 | 28.15 | 27.52 | 29.39 | 35.56 | 38.63 | 46.72 | 40.85 | 41.90 | 41.73 |
| Base Panel Mean | 30.67 | 35.28 | 41.34 | 40.27 | 44.55 | 47.64 | 51.17 | 58.00 | 62.39 | 62.31 | 69.65 |
| Regional Panel Mean | 35.35 | 47.24 | 51.57 | 48.43 | 50.29 | 56.03 | 60.39 | 63.42 | 66.78 | 65.79 | 72.19 |
| *Rankings* | | | | | | | | | | | |
| | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
| APS Rank vs. Base Panel | 21 / 38 | 19 / 38 | 16 / 38 | 16 / 38 | 14 / 38 | 17 / 38 | 17 / 39 | 23 / 39 | 15 / 39 | 16 / 39 | 10 / 39 |
| APS Rank vs. Regional Panel | 5 / 9 | 4 / 9 | 3 / 9 | 4 / 9 | 4 / 8 | 4 / 8 | 3 / 8 | 4 / 8 | 2 / 8 | 3 / 8 | 2 / 8 |

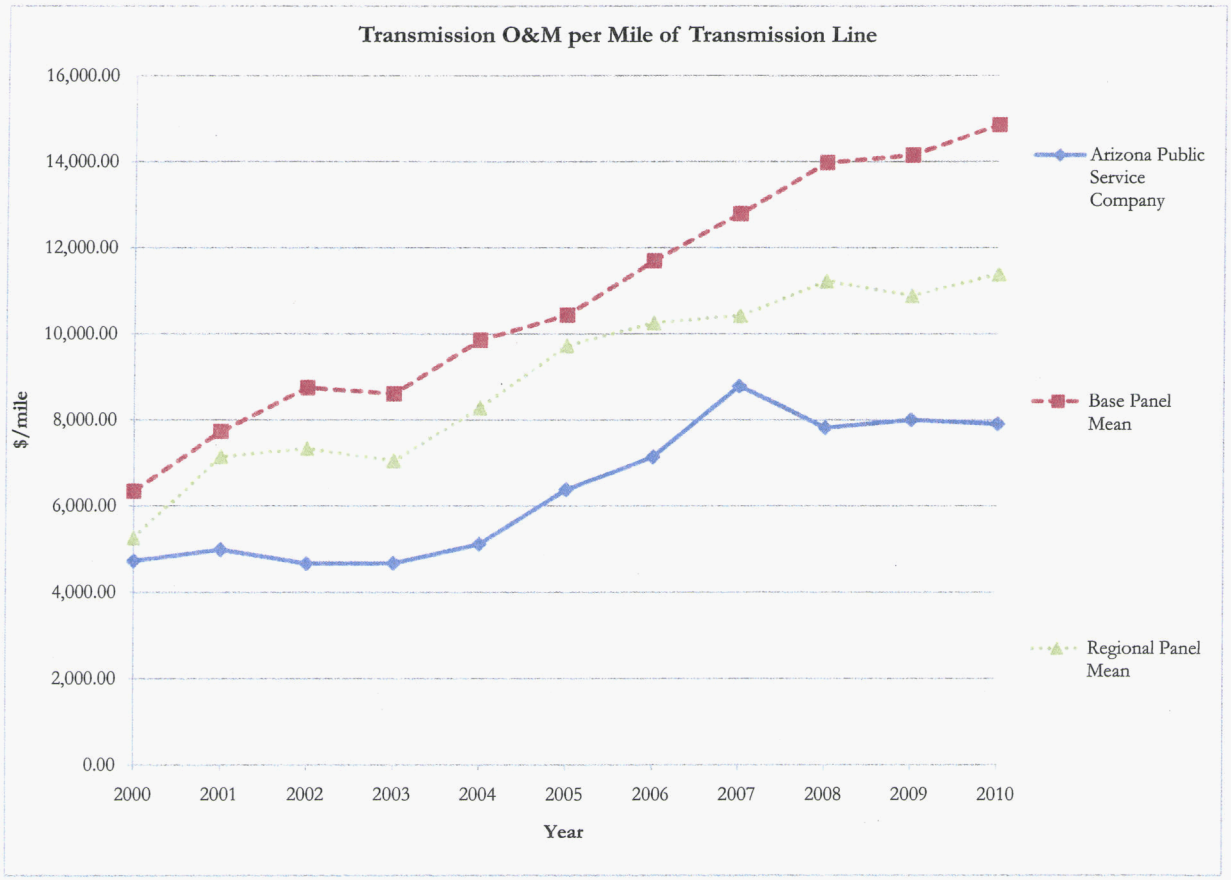
Source: FERC Form 1 and SNL Financial
Transmiss-O&M Exp ($000); Ult Consumer Electric Customers

# Benchmarking Workpapers
## Productive Efficiency

| Transmission O&M per kWh Sold | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| *Annual Values* | | | | | | | | | | | |
| | **2000** | **2001** | **2002** | **2003** | **2004** | **2005** | **2006** | **2007** | **2008** | **2009** | **2010** |
| Arizona Public Service Company | 1,117.58 | 1,137.78 | 1,086.73 | 1,043.47 | 1,113.11 | 1,353.30 | 1,452.79 | 1,739.69 | 1,563.16 | 1,648.83 | 1,679.53 |
| Base Panel Mean | 1,077.28 | 1,272.27 | 1,496.94 | 1,456.06 | 1,631.04 | 1,731.06 | 1,851.99 | 2,079.09 | 2,249.18 | 2,353.22 | 2,476.12 |
| Regional Panel Mean | 1,351.29 | 1,816.00 | 2,021.33 | 1,865.86 | 2,042.76 | 2,281.29 | 2,392.17 | 2,448.51 | 2,599.66 | 2,563.70 | 2,694.73 |
| *Rankings* | | | | | | | | | | | |
| | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
| APS Rank vs. Base Panel | 28 / 38 | 22 / 38 | 20 / 38 | 20 / 38 | 21 / 38 | 23 / 38 | 24 / 39 | 23 / 39 | 19 / 39 | 18 / 39 | 17 / 39 |
| APS Rank vs. Regional Panel | 5 / 9 | 4 / 9 | 3 / 9 | 4 / 9 | 4 / 8 | 3 / 8 | 3 / 8 | 2 / 8 | 2 / 8 | 2 / 8 | 2 / 8 |

Source: FERC Form 1 and SNL Financial
Transmiss-O&M Exp ($000); Tot Sales: Ult Cnsmr-Mwhrs Sold (MWh)

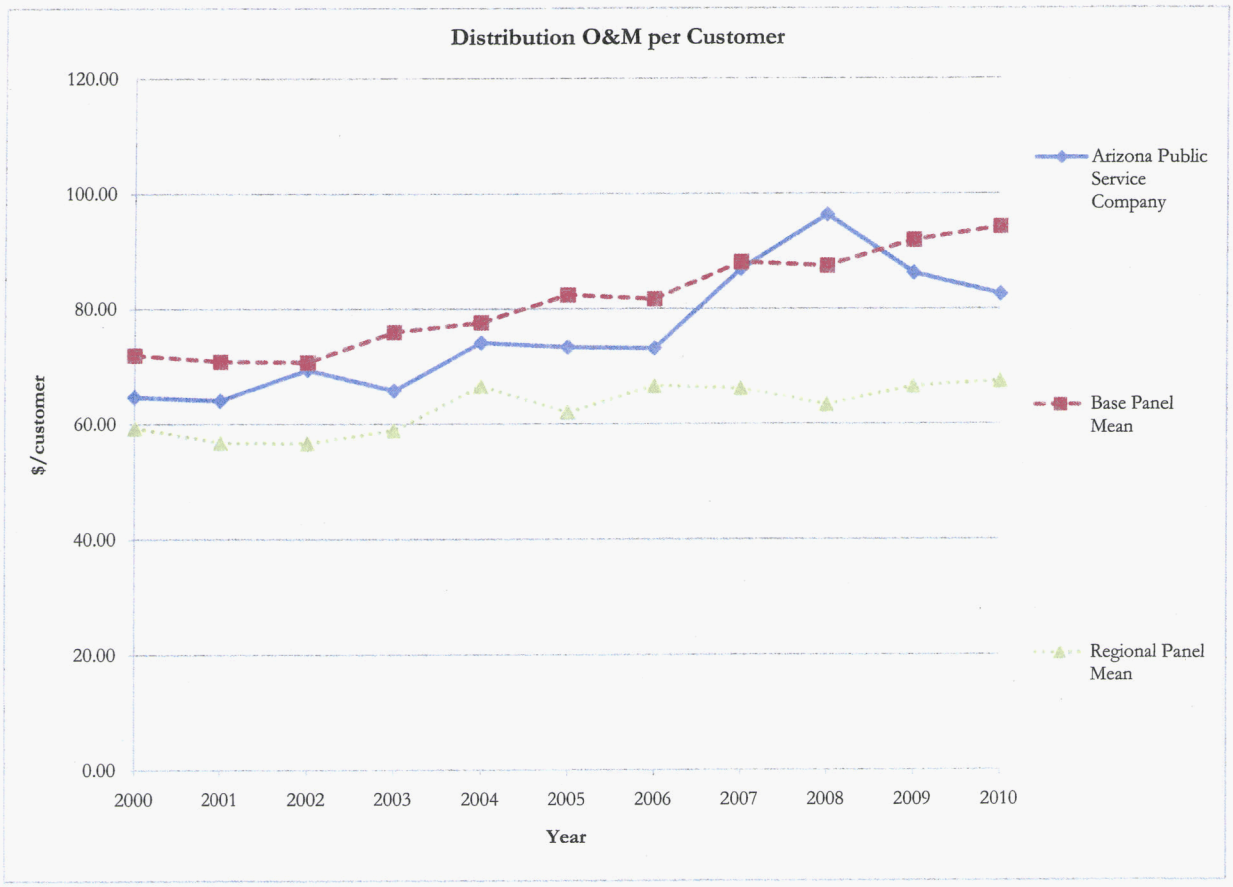
# Benchmarking Workpapers
## Productive Efficiency




| Transmission O&M per Mile of Transmission Line | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| *Annual Values* | | | | | | | | | | | |
| | **2000** | **2001** | **2002** | **2003** | **2004** | **2005** | **2006** | **2007** | **2008** | **2009** | **2010** |
| Arizona Public Service Company | 4,726.26 | 4,988.93 | 4,666.91 | 4,673.60 | 5,115.86 | 6,380.34 | 7,133.95 | 8,783.14 | 7,816.78 | 8,002.24 | 7,905.38 |
| Base Panel Mean | 6,342.53 | 7,733.55 | 8,749.18 | 8,601.91 | 9,855.46 | 10,438.88 | 11,697.47 | 12,792.72 | 13,981.67 | 14,154.10 | 14,857.41 |
| Regional Panel Mean | 5,262.37 | 7,146.95 | 7,338.71 | 7,046.05 | 8,283.81 | 9,723.04 | 10,260.71 | 10,427.21 | 11,225.68 | 10,893.08 | 11,385.56 |
| *Rankings* | | | | | | | | | | | |
| | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
| APS Rank vs. Base Panel | 17 / 37 | 14 / 37 | 12 / 36 | 15 / 37 | 12 / 37 | 18 / 37 | 19 / 38 | 21 / 38 | 15 / 38 | 15 / 38 | 11 / 38 |
| APS Rank vs. Regional Panel | 4 / 8 | 3 / 8 | 2 / 8 | 3 / 8 | 3 / 8 | 3 / 8 | 4 / 8 | 4 / 8 | 2 / 8 | 2 / 8 | 1 / 8 |

Source: FERC Form 1 and SNL Financial
Transmiss-O&M Exp ($000); Length of Transmission Lines (Miles)

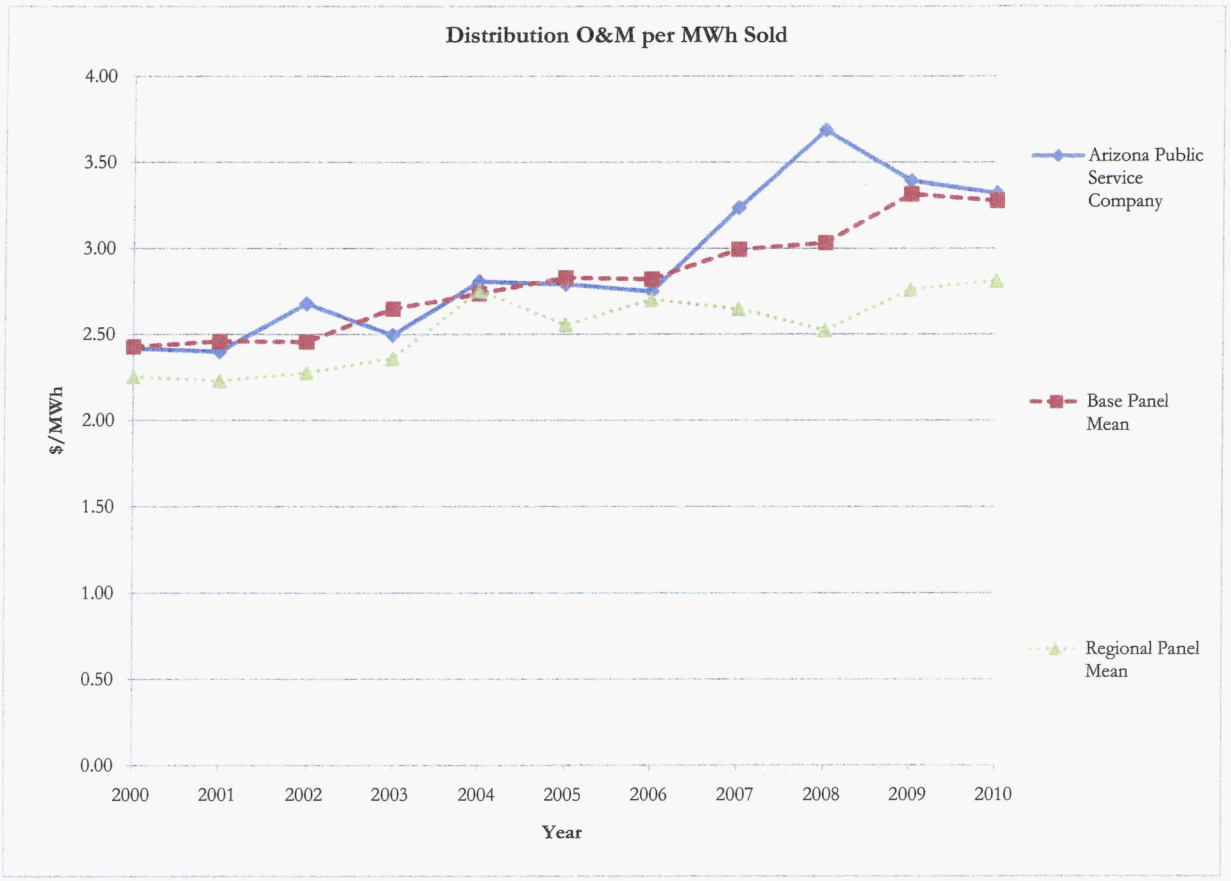
# Benchmarking Workpapers
## Productive Efficiency




| Distribution O&M per Customer | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| *Annual Values* | | | | | | | | | | | |
| | **2000** | **2001** | **2002** | **2003** | **2004** | **2005** | **2006** | **2007** | **2008** | **2009** | **2010** |
| Arizona Public Service Company | 64.71 | 64.06 | 69.37 | 65.80 | 74.13 | 73.36 | 73.13 | 86.96 | 96.35 | 86.26 | 82.55 |
| Base Panel Mean | 71.95 | 70.82 | 70.73 | 75.98 | 77.63 | 82.44 | 81.70 | 88.12 | 87.46 | 91.93 | 94.24 |
| Regional Panel Mean | 59.30 | 56.73 | 56.61 | 58.91 | 66.54 | 62.08 | 66.61 | 66.17 | 63.35 | 66.53 | 67.44 |
| *Rankings* | | | | | | | | | | | |
| | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
| APS Rank vs. Base Panel | 16 / 38 | 15 / 38 | 17 / 38 | 14 / 38 | 16 / 38 | 16 / 38 | 16 / 39 | 25 / 39 | 25 / 39 | 17 / 39 | 16 / 39 |
| APS Rank vs. Regional Panel | 7 / 9 | 7 / 9 | 8 / 9 | 7 / 9 | 6 / 8 | 7 / 8 | 6 / 8 | 7 / 8 | 7 / 8 | 7 / 8 | 6 / 8 |

Source: FERC Form 1 and SNL Financial
Distr-O&M Exp ($000); Ult Consumer Electric Customers

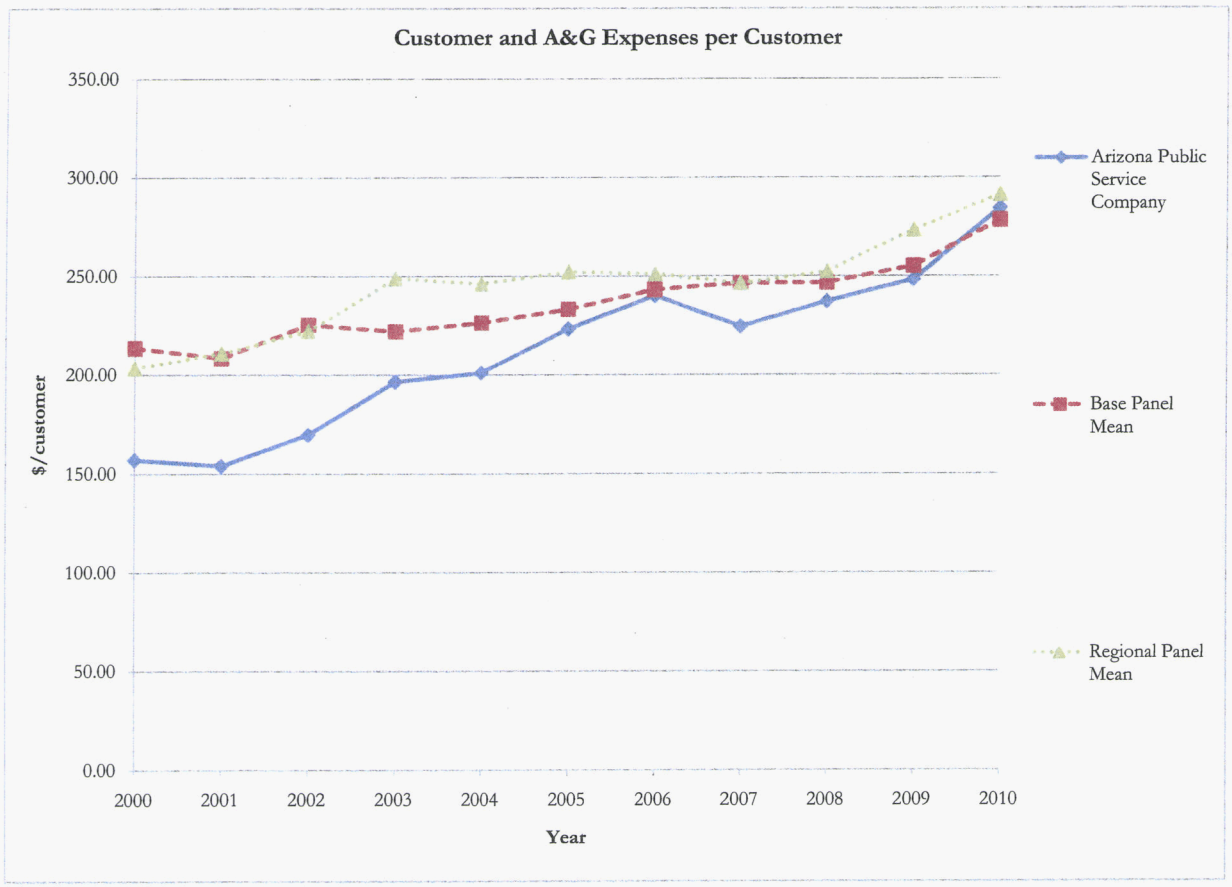
## Benchmarking Workpapers
### Productive Efficiency




| Distribution O&M per MWh Sold | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| *Annual Values* | | | | | | | | | | | |
| | **2000** | **2001** | **2002** | **2003** | **2004** | **2005** | **2006** | **2007** | **2008** | **2009** | **2010** |
| Arizona Public Service Company | 2.42 | 2.40 | 2.68 | 2.50 | 2.81 | 2.79 | 2.75 | 3.24 | 3.69 | 3.39 | 3.32 |
| Base Panel Mean | 2.43 | 2.46 | 2.46 | 2.65 | 2.74 | 2.83 | 2.82 | 2.99 | 3.03 | 3.32 | 3.28 |
| Regional Panel Mean | 2.25 | 2.23 | 2.28 | 2.36 | 2.75 | 2.56 | 2.70 | 2.65 | 2.53 | 2.76 | 2.81 |
| *Rankings* | | | | | | | | | | | |
| | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
| APS Rank vs. Base Panel | 18 / 38 | 15 / 38 | 27 / 38 | 15 / 38 | 22 / 38 | 18 / 38 | 18 / 39 | 27 / 39 | 28 / 39 | 22 / 39 | 21 / 39 |
| APS Rank vs. Regional Panel | 6 / 9 | 4 / 9 | 7 / 9 | 5 / 9 | 6 / 8 | 6 / 8 | 5 / 8 | 6 / 8 | 6 / 8 | 6 / 8 | 6 / 8 |

Source: FERC Form 1 and SNL Financial
Distr-O&M Exp ($000); Tot Sales: Ult Cnsmr-Mwhrs Sold (MWh)

# Benchmarking Workpapers
## Productive Efficiency

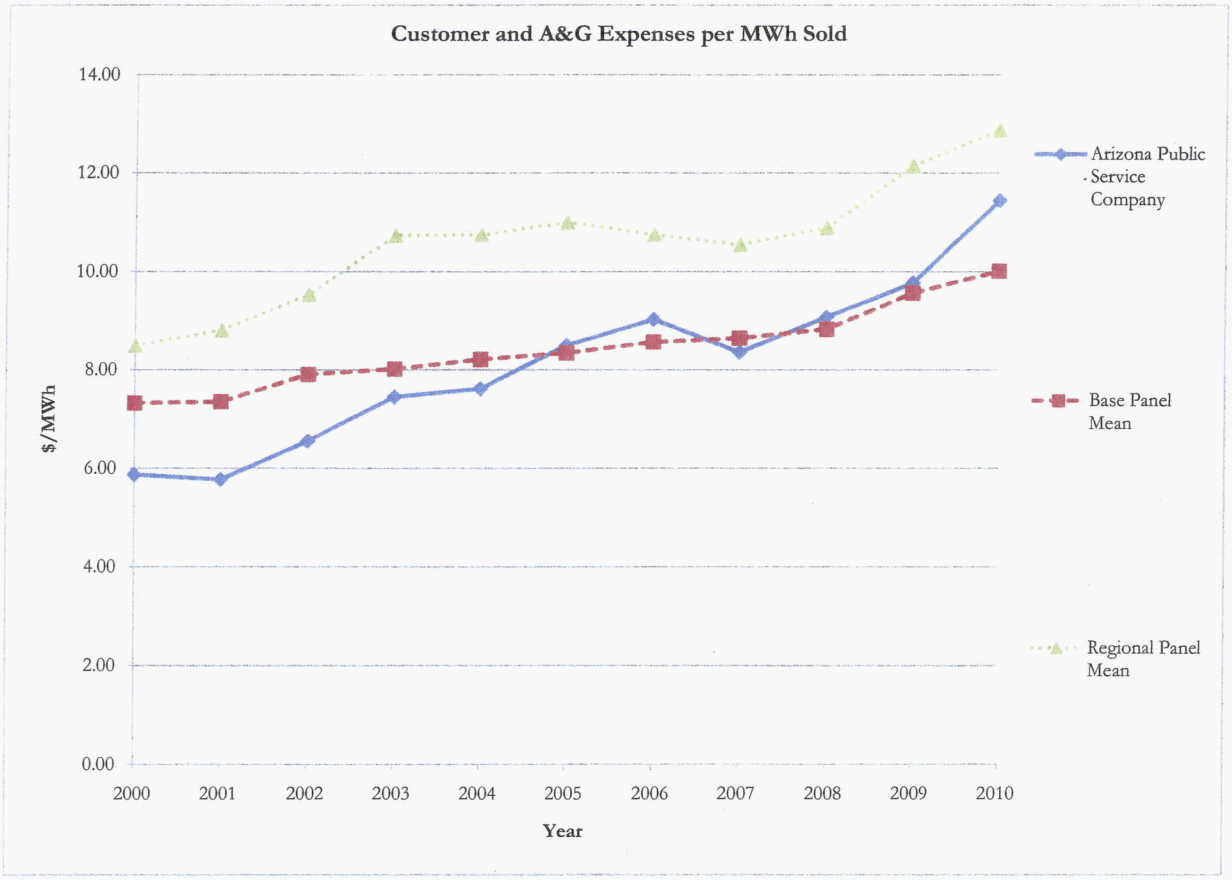



| Customer and A&G Expenses per Customer | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| *Annual Values* | | | | | | | | | | | |
| | **2000** | **2001** | **2002** | **2003** | **2004** | **2005** | **2006** | **2007** | **2008** | **2009** | **2010** |
| Arizona Public Service Company | 157.12 | 154.09 | 169.68 | 196.52 | 201.10 | 223.31 | 240.15 | 224.57 | 237.19 | 248.27 | 284.32 |
| Base Panel Mean | 213.62 | 208.53 | 225.42 | 222.02 | 226.42 | 233.24 | 243.22 | 246.40 | 246.65 | 255.13 | 278.18 |
| Regional Panel Mean | 203.46 | 210.93 | 222.12 | 248.85 | 246.13 | 252.19 | 251.19 | 246.37 | 252.43 | 273.42 | 291.21 |
| *Rankings* | | | | | | | | | | | |
| | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
| APS Rank vs. Base Panel | 6 / 38 | 6 / 38 | 7 / 38 | 12 / 37 | 14 / 38 | 17 / 38 | 18 / 39 | 13 / 39 | 17 / 39 | 19 / 39 | 23 / 39 |
| APS Rank vs. Regional Panel | 2 / 8 | 1 / 8 | 1 / 8 | 1 / 8 | 3 / 8 | 4 / 8 | 4 / 8 | 3 / 8 | 4 / 8 | 3 / 8 | 4 / 8 |

Source: FERC Form 1 and SNL Financial
Customer Expenses + A&G Exp ($000); Ult Consumer Electric Customers

# Benchmarking Workpapers

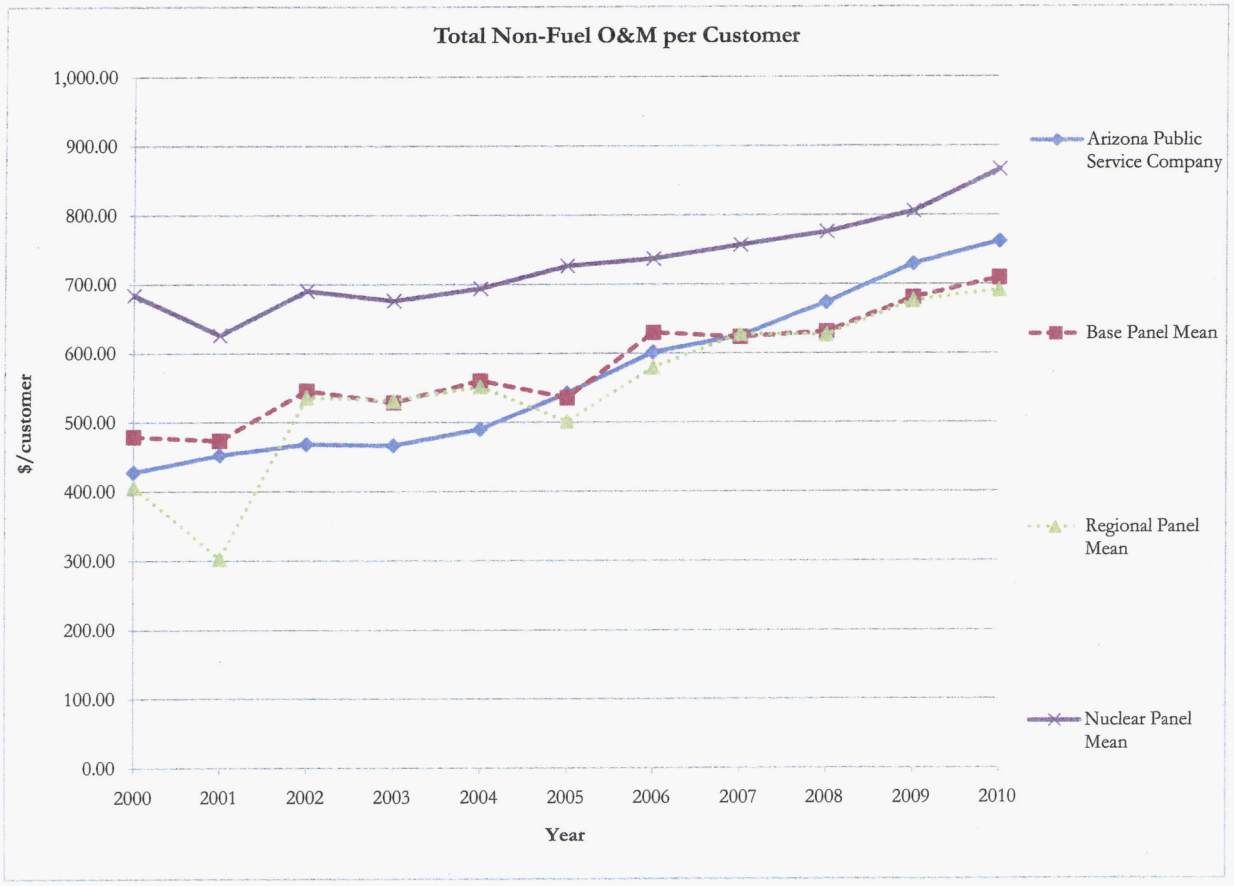
## Productive Efficiency




| Customer and A&G Expenses per MWh Sold | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| *Annual Values* | | | | | | | | | | | |
| | **2000** | **2001** | **2002** | **2003** | **2004** | **2005** | **2006** | **2007** | **2008** | **2009** | **2010** |
| Arizona Public Service Company | 5.87 | 5.77 | 6.55 | 7.45 | 7.62 | 8.50 | 9.03 | 8.36 | 9.08 | 9.77 | 11.44 |
| Base Panel Mean | 7.32 | 7.35 | 7.91 | 8.02 | 8.21 | 8.34 | 8.57 | 8.65 | 8.83 | 9.56 | 10.01 |
| Regional Panel Mean | 8.50 | 8.81 | 9.54 | 10.74 | 10.75 | 11.00 | 10.75 | 10.55 | 10.89 | 12.15 | 12.88 |
| *Rankings* | | | | | | | | | | | |
| | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
| APS Rank vs. Base Panel | 13 / 38 | 13 / 38 | 14 / 38 | 18 / 37 | 20 / 38 | 25 / 38 | 28 / 39 | 22 / 39 | 24 / 39 | 25 / 39 | 30 / 39 |
| APS Rank vs. Regional Panel | 3 / 8 | 2 / 8 | 2 / 8 | 2 / 8 | 4 / 8 | 4 / 8 | 4 / 8 | 4 / 8 | 4 / 8 | 4 / 8 | 4 / 8 |

Source: FERC Form 1 and SNL Financial
Customer Expenses + A&G Exp ($000); Tot Sales: Ult Cnsmr-Mwhrs Sold (MWh)

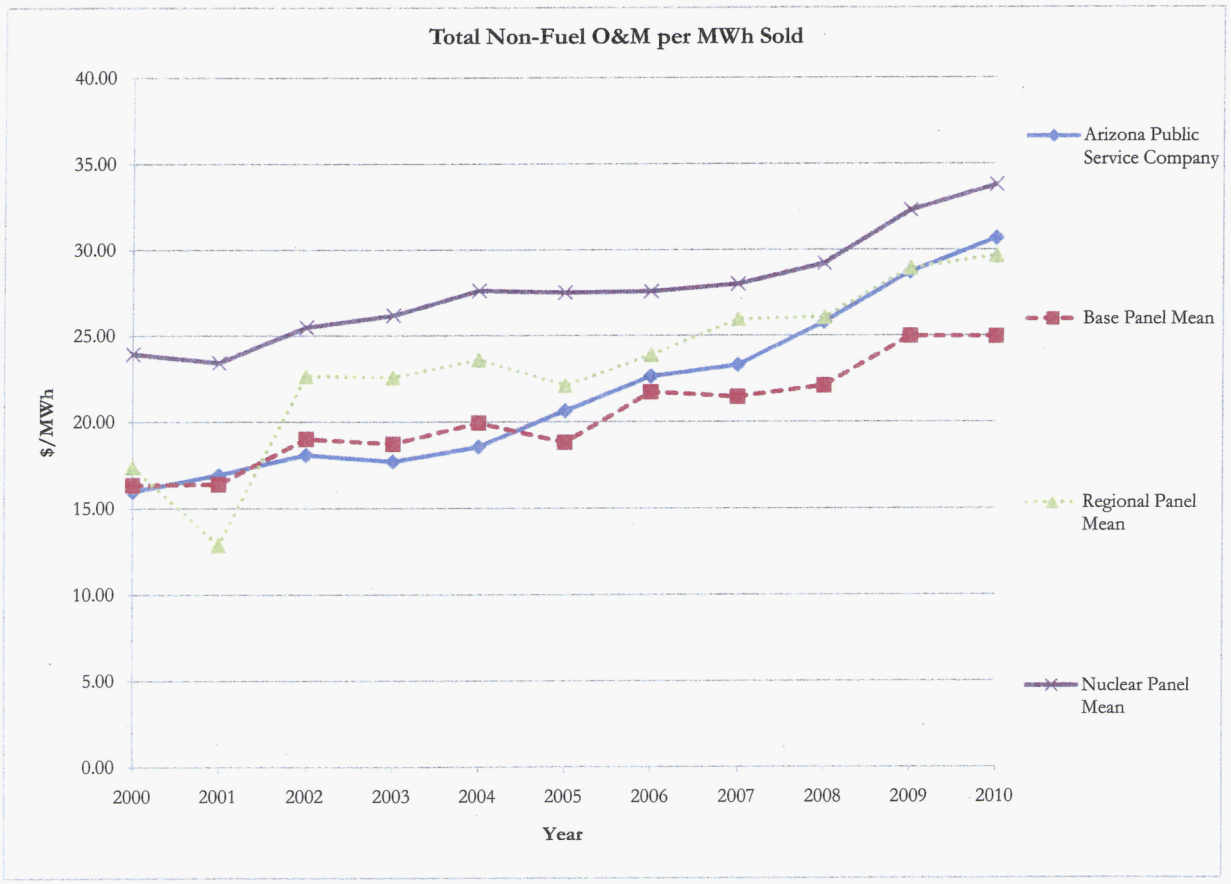
# Benchmarking Workpapers
## Productive Efficiency




| Total Non-Fuel O&M per Customer | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| *Annual Values* | | | | | | | | | | | |
| | **2000** | **2001** | **2002** | **2003** | **2004** | **2005** | **2006** | **2007** | **2008** | **2009** | **2010** |
| Arizona Public Service Company | 427.94 | 452.47 | 468.55 | 466.76 | 490.03 | 542.35 | 601.87 | 625.52 | 673.85 | 729.78 | 762.38 |
| Base Panel Mean | 478.96 | 473.51 | 545.95 | 528.86 | 560.55 | 535.64 | 629.70 | 623.57 | 631.34 | 680.55 | 709.47 |
| Regional Panel Mean | 406.30 | 302.98 | 536.13 | 531.97 | 551.72 | 501.56 | 579.35 | 627.89 | 626.90 | 676.53 | 691.73 |
| Nuclear Panel Mean | 684.31 | 625.99 | 690.62 | 676.39 | 694.17 | 726.83 | 736.89 | 757.04 | 776.05 | 806.05 | 866.46 |
| *Rankings* | | | | | | | | | | | |
| | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
| APS Rank vs. Base Panel | 15 / 38 | 15 / 38 | 17 / 38 | 16 / 37 | 14 / 38 | 22 / 38 | 19 / 39 | 19 / 39 | 24 / 39 | 25 / 39 | 25 / 39 |
| APS Rank vs. Regional Panel | 4 / 8 | 4 / 8 | 4 / 8 | 3 / 8 | 3 / 8 | 5 / 8 | 4 / 8 | 4 / 8 | 6 / 8 | 6 / 8 | 7 / 8 |
| APS Rank vs. Nuclear Panel | 2 / 6 | 2 / 6 | 2 / 6 | 2 / 6 | 2 / 6 | 2 / 6 | 2 / 6 | 2 / 6 | 2 / 6 | 2 / 6 | 2 / 6 |

Source: FERC Form 1 and SNL Financial
Total Non-Fuel Elec O&M ($000); Ult Consumer Electric Customers

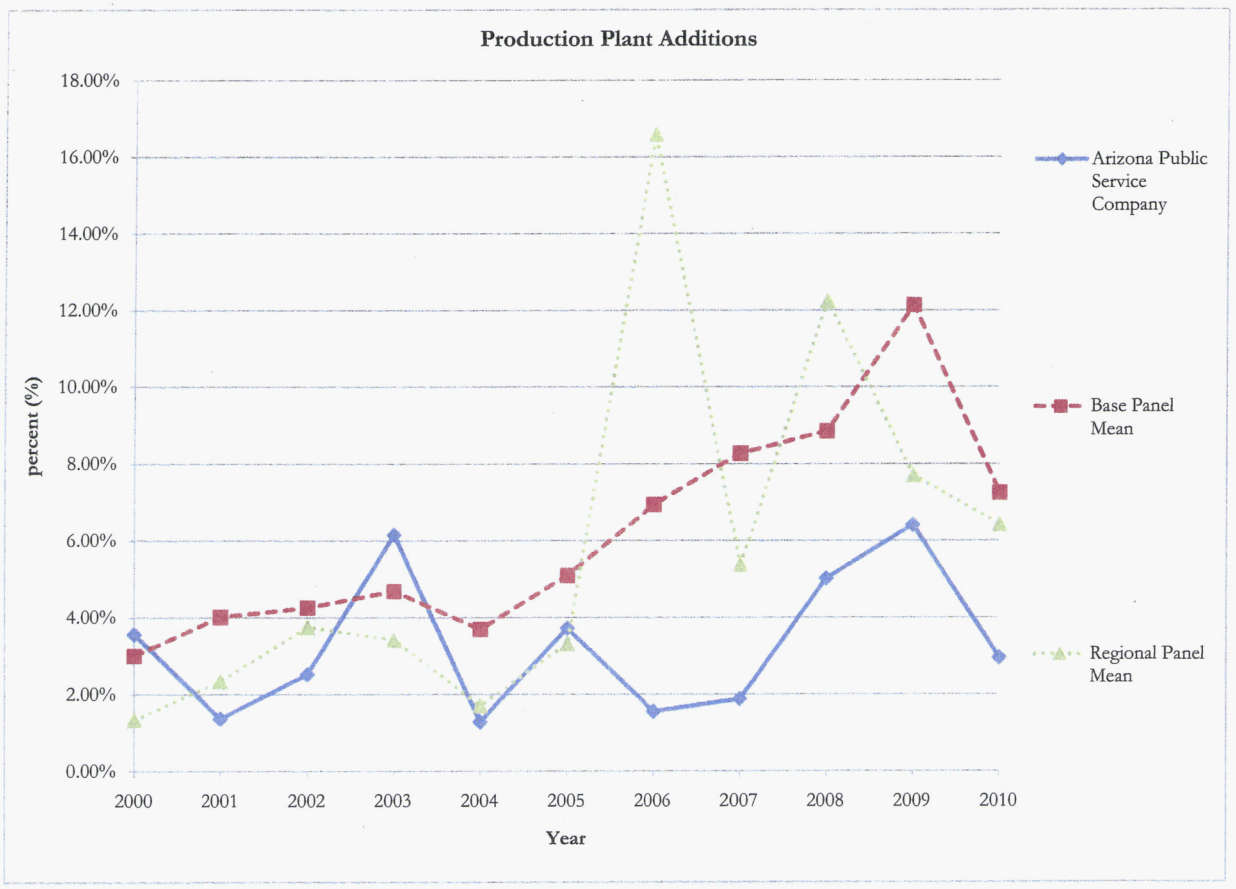
# Benchmarking Workpapers
## Productive Efficiency




| Total Non-Fuel O&M per MWh Sold | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| *Annual Values* | | | | | | | | | | | |
| | **2000** | **2001** | **2002** | **2003** | **2004** | **2005** | **2006** | **2007** | **2008** | **2009** | **2010** |
| Arizona Public Service Company | 15.99 | 16.94 | 18.09 | 17.70 | 18.56 | 20.64 | 22.63 | 23.29 | 25.79 | 28.72 | 30.69 |
| Base Panel Mean | 16.36 | 16.40 | 19.01 | 18.73 | 19.94 | 18.81 | 21.72 | 21.44 | 22.10 | 24.97 | 24.95 |
| Regional Panel Mean | 17.41 | 12.88 | 22.65 | 22.59 | 23.61 | 22.10 | 23.90 | 25.96 | 26.08 | 28.94 | 29.66 |
| Nuclear Panel Mean | 23.94 | 23.43 | 25.51 | 26.19 | 27.63 | 27.52 | 27.59 | 28.02 | 29.22 | 32.31 | 33.79 |
| *Rankings* | | | | | | | | | | | |
| | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
| APS Rank vs. Base Panel | 17 / 38 | 18 / 38 | 20 / 38 | 19 / 37 | 18 / 38 | 27 / 38 | 24 / 39 | 26 / 39 | 29 / 39 | 28 / 39 | 30 / 39 |
| APS Rank vs. Regional Panel | 4 / 8 | 3 / 8 | 2 / 8 | 2 / 8 | 2 / 8 | 4 / 8 | 5 / 8 | 3 / 8 | 4 / 8 | 4 / 8 | 4 / 8 |
| APS Rank vs. Nuclear Panel | 1 / 6 | 1 / 6 | 1 / 6 | 1 / 6 | 1 / 6 | 1 / 6 | 1 / 6 | 1 / 6 | 1 / 6 | 2 / 6 | 2 / 6 |

Source: FERC Form 1 and SNL Financial
Total Non-Fuel Elec O&M ($000); Tot Sales: Ult Cnsmr-Mwhrs Sold (MWh)

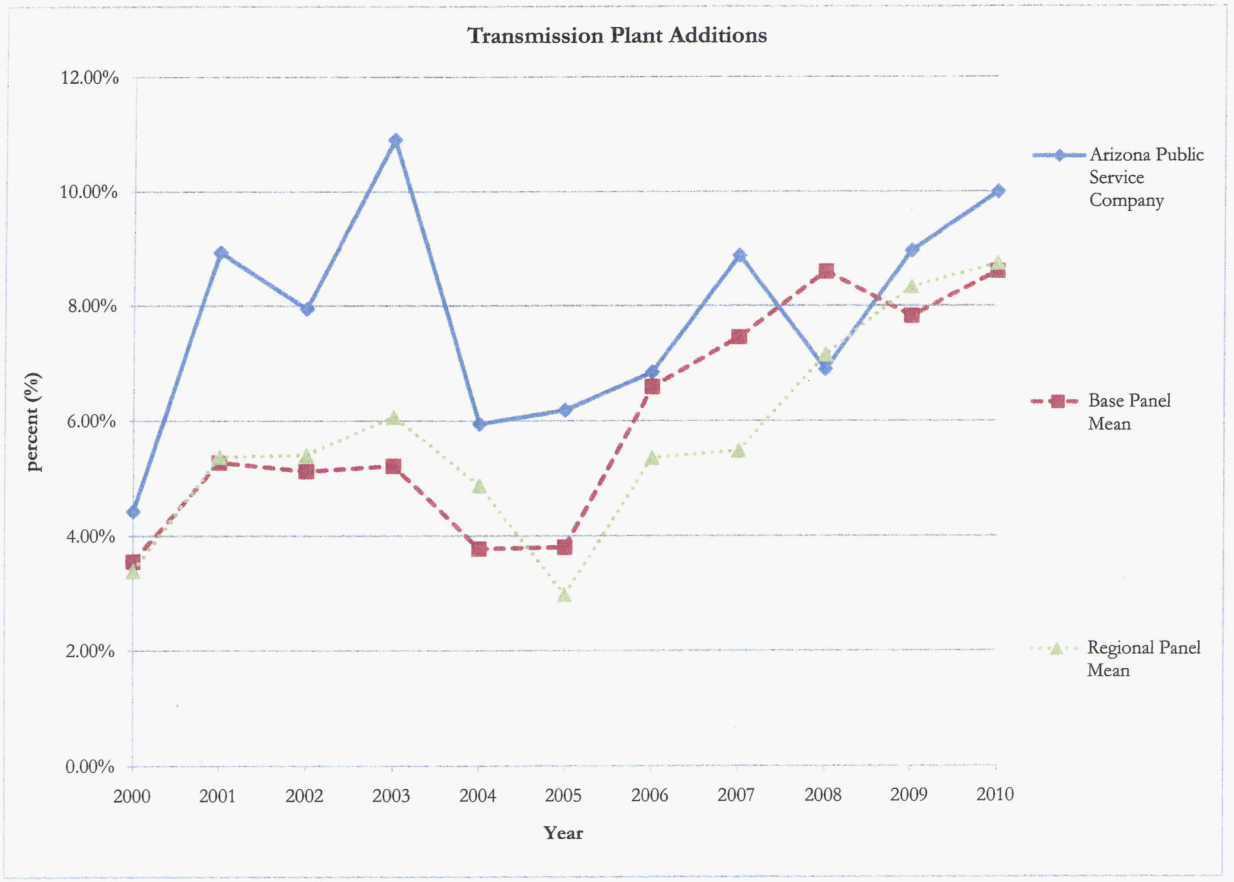
# Benchmarking Workpapers
## Productive Efficiency




| Production Plant Additions | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| *Annual Values* | | | | | | | | | | | |
| | **2000** | **2001** | **2002** | **2003** | **2004** | **2005** | **2006** | **2007** | **2008** | **2009** | **2010** |
| Arizona Public Service Company | 3.57% | 1.37% | 2.53% | 6.16% | 1.29% | 3.73% | 1.55% | 1.88% | 5.02% | 6.42% | 2.95% |
| Base Panel Mean | 3.00% | 4.01% | 4.26% | 4.69% | 3.70% | 5.10% | 6.94% | 8.27% | 8.85% | 12.14% | 7.24% |
| Regional Panel Mean | 1.34% | 2.35% | 3.75% | 3.42% | 1.71% | 3.32% | 16.60% | 5.38% | 12.25% | 7.71% | 6.42% |
| *Rankings* | | | | | | | | | | | |
| | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
| APS Rank vs. Base Panel | 26 / 38 | 11 / 38 | 18 / 38 | 27 / 38 | 6 / 38 | 21 / 38 | 9 / 39 | 3 / 39 | 19 / 39 | 16 / 39 | 17 / 39 |
| APS Rank vs. Regional Panel | 9 / 9 | 4 / 9 | 4 / 9 | 8 / 9 | 4 / 8 | 6 / 8 | 3 / 8 | 2 / 8 | 4 / 8 | 3 / 8 | 3 / 8 |

Source: FERC Form 1 and SNL Financial
Total Production Plant-Addns($000); Total Production Plant-BOY($000)

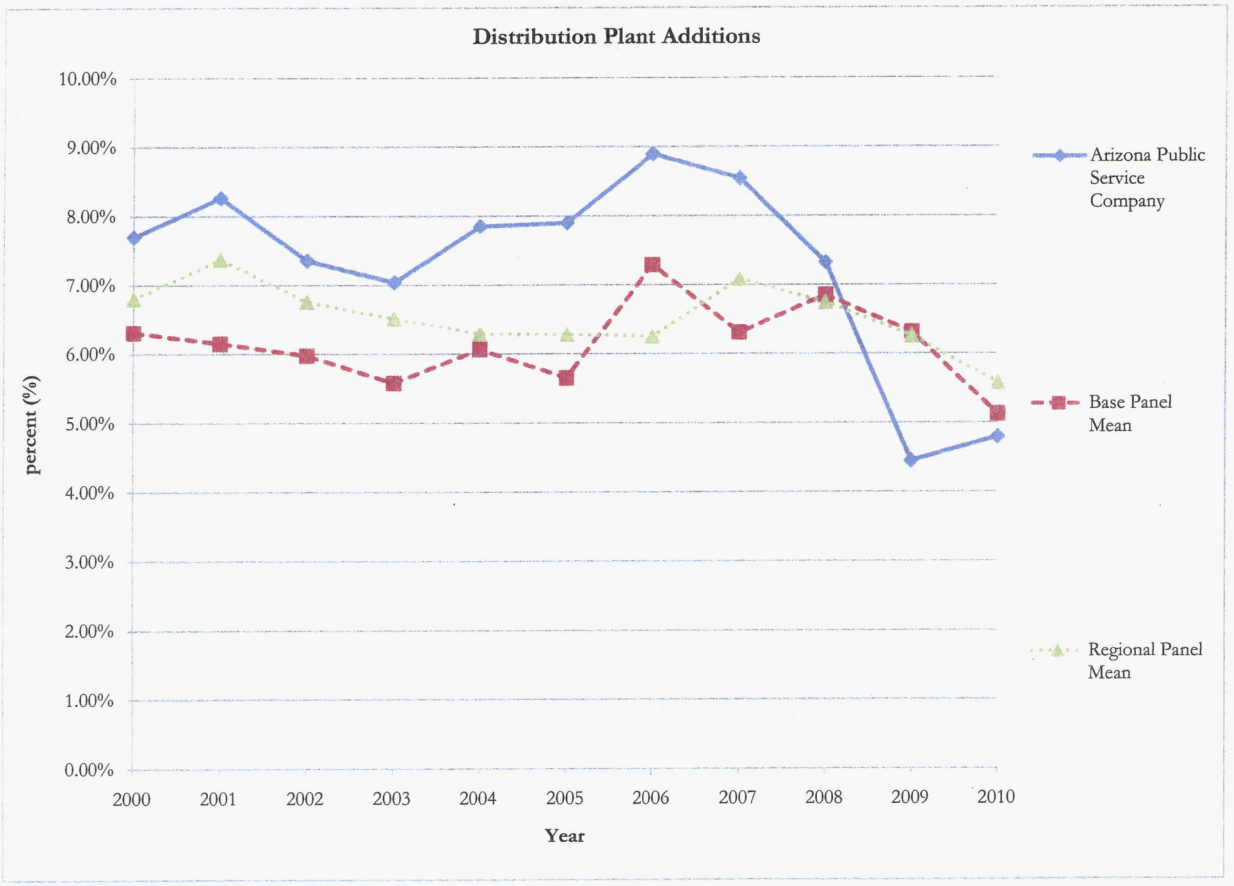
## Benchmarking Workpapers
### Productive Efficiency




| Transmission Plant Additions | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| *Annual Values* | | | | | | | | | | | |
| | **2000** | **2001** | **2002** | **2003** | **2004** | **2005** | **2006** | **2007** | **2008** | **2009** | **2010** |
| Arizona Public Service Company | 4.43% | 8.93% | 7.94% | 10.91% | 5.95% | 6.19% | 6.84% | 8.88% | 6.90% | 8.96% | 10.00% |
| Base Panel Mean | 3.55% | 5.28% | 5.12% | 5.22% | 3.77% | 3.80% | 6.59% | 7.45% | 8.60% | 7.82% | 8.61% |
| Regional Panel Mean | 3.39% | 5.38% | 5.41% | 6.07% | 4.88% | 2.98% | 5.36% | 5.48% | 7.15% | 8.34% | 8.75% |
| *Rankings* | | | | | | | | | | | |
| | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
| APS Rank vs. Base Panel | 29 / 38 | 32 / 38 | 29 / 38 | 35 / 38 | 30 / 38 | 34 / 38 | 24 / 39 | 31 / 39 | 20 / 39 | 28 / 39 | 29 / 39 |
| APS Rank vs. Regional Panel | 6 / 9 | 7 / 9 | 6 / 9 | 8 / 9 | 5 / 8 | 7 / 8 | 5 / 8 | 7 / 8 | 4 / 8 | 5 / 8 | 6 / 8 |

Source: FERC Form 1 and SNL Financial
Total Transmission Plant-Addns($000); Total Transmission Plant-BOY($000)

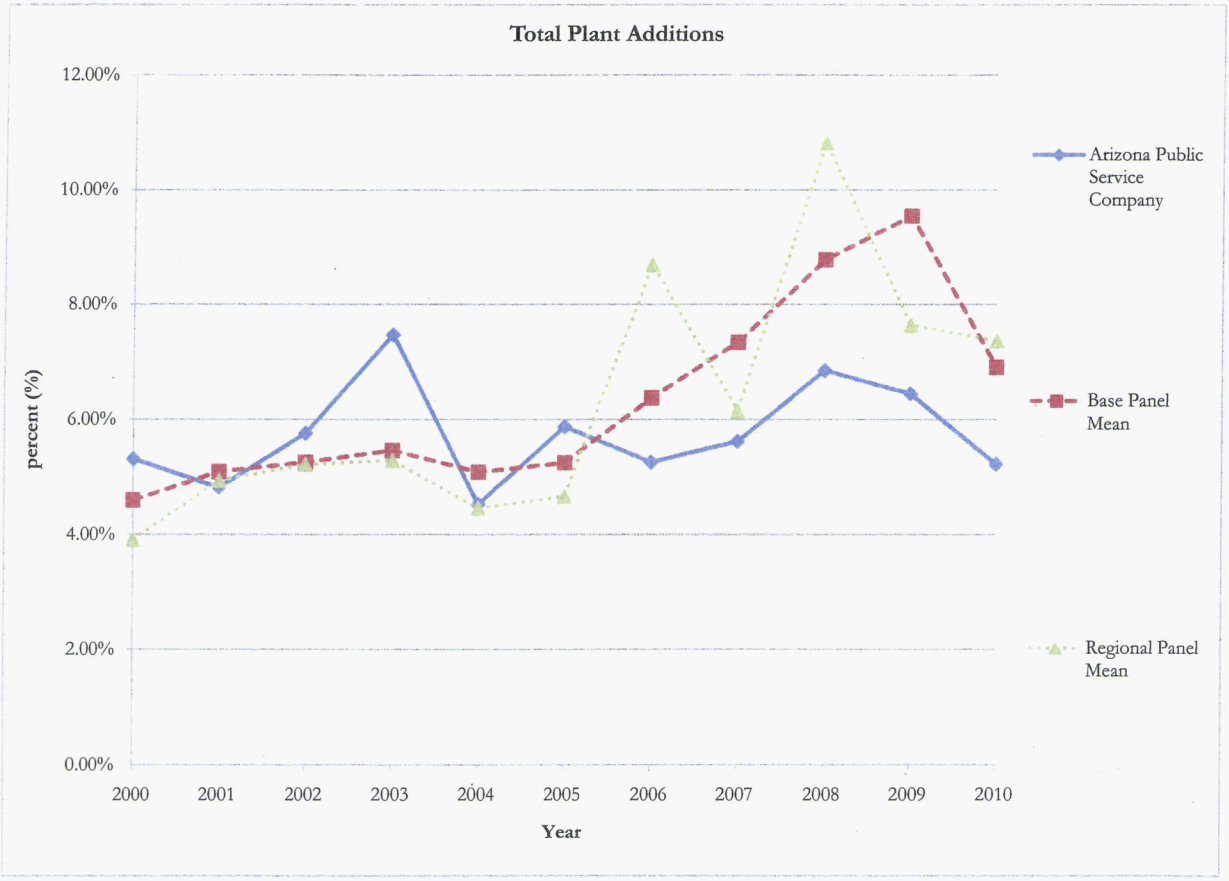
# Benchmarking Workpapers
## Productive Efficiency




| Distribution Plant Additions | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| *Annual Values* | | | | | | | | | | | |
| | **2000** | **2001** | **2002** | **2003** | **2004** | **2005** | **2006** | **2007** | **2008** | **2009** | **2010** |
| Arizona Public Service Company | 7.70% | 8.27% | 7.36% | 7.04% | 7.85% | 7.90% | 8.90% | 8.55% | 7.33% | 4.45% | 4.79% |
| Base Panel Mean | 6.31% | 6.15% | 5.98% | 5.58% | 6.06% | 5.65% | 7.29% | 6.31% | 6.85% | 6.31% | 5.12% |
| Regional Panel Mean | 6.80% | 7.37% | 6.76% | 6.52% | 6.29% | 6.28% | 6.26% | 7.09% | 6.75% | 6.26% | 5.58% |
| *Rankings* | | | | | | | | | | | |
| | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
| APS Rank vs. Base Panel | 33 / 38 | 36 / 38 | 30 / 38 | 33 / 38 | 34 / 38 | 35 / 38 | 31 / 39 | 34 / 39 | 28 / 39 | 4 / 39 | 20 / 39 |
| APS Rank vs. Regional Panel | 6 / 9 | 6 / 9 | 5 / 9 | 6 / 9 | 7 / 8 | 6 / 8 | 7 / 8 | 6 / 8 | 6 / 8 | 2 / 8 | 4 / 8 |

Source: FERC Form 1 and SNL Financial
Total Distr Plant-Addns($000); Total Distr Plant-BOY($000)

# Benchmarking Workpapers
## Productive Efficiency




| Total Plant Additions | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| *Annual Values* | | | | | | | | | | | |
| | **2000** | **2001** | **2002** | **2003** | **2004** | **2005** | **2006** | **2007** | **2008** | **2009** | **2010** |
| Arizona Public Service Company | 5.31% | 4.82% | 5.76% | 7.47% | 4.52% | 5.88% | 5.26% | 5.62% | 6.85% | 6.44% | 5.22% |
| Base Panel Mean | 4.59% | 5.09% | 5.25% | 5.46% | 5.08% | 5.25% | 6.37% | 7.33% | 8.78% | 9.55% | 6.91% |
| Regional Panel Mean | 3.91% | 4.94% | 5.22% | 5.29% | 4.46% | 4.66% | 8.69% | 6.15% | 10.82% | 7.64% | 7.37% |
| *Rankings* | | | | | | | | | | | |
| | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
| APS Rank vs. Base Panel | 30 / 38 | 20 / 38 | 27 / 38 | 29 / 38 | 20 / 38 | 25 / 38 | 16 / 39 | 14 / 39 | 19 / 39 | 16 / 39 | 18 / 39 |
| APS Rank vs. Regional Panel | 8 / 9 | 5 / 9 | 6 / 9 | 8 / 9 | 4 / 8 | 6 / 8 | 3 / 8 | 4 / 8 | 4 / 8 | 4 / 8 | 4 / 8 |

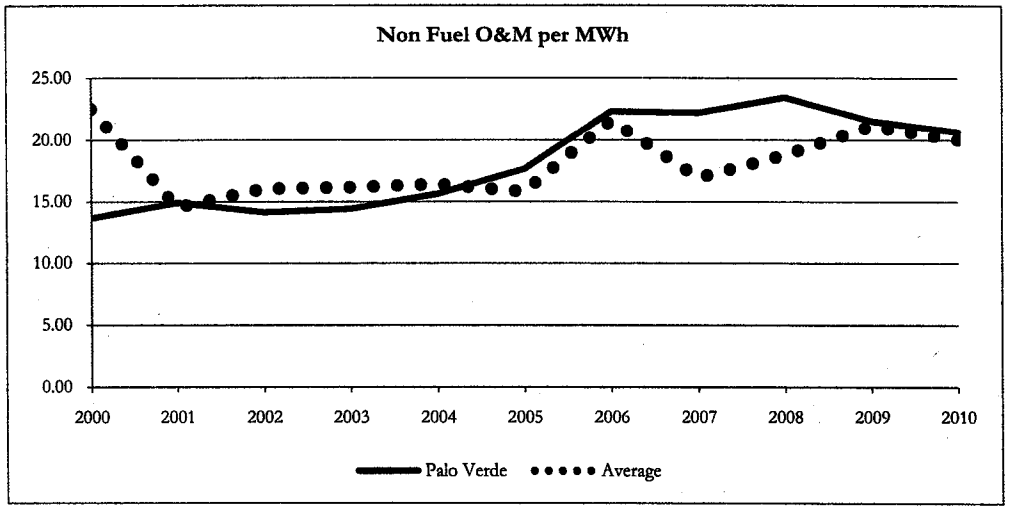
Source: FERC Form 1 and SNL Financial
Total Elec Plt In Service-Addns($000); Total Elec Plt In Service-BOY($000)

Attachment A
Page 1 of 2

| | Base Panel | Expanded Base Panel | High Growth Panel | Regional Panel | Nuclear Panel | Industry Wide | Other |
|---|---|---|---|---|---|---|---|
| **Safety/Customer Service/Reliability** | | | | | | | |
| Injury Incident Rate | | | | | | ✓ | |
| Residential Customer Satisfaction | | | | | | ✓ | |
| SAIFI /SAIDI/CAIDI/MAIFI | | | | | | ✓ | |
| Capacity Factor | | | | | | | |
| **Base Load Coal Performance – By Unit** | | | | | | | |
| Capacity Factor | | | | | | | ✓ |
| Equivalent Availability Factor | | | | | | | ✓ |
| Equivalent Forced Outage Rate | | | | | | | ✓ |
| **Base Load Coal Performance – By Plant** | | | | | | | |
| Fuel costs ($/MWh) | | | | | | | ✓ |
| Non-fuel O&M costs ($/MWh) | | | | | | | ✓ |
| **Nuclear Performance – By Unit** | | | | | | | |
| Capacity Factor | | | | | | | ✓ |
| Equivalent Availability Factor | | | | | | | ✓ |
| Equivalent Forced Outage Rate | | | | | | | ✓ |
| **Nuclear Performance – By Plant** | | | | | | | |
| Fuel costs ($/MWh) | | | | | | | ✓ |
| Non-fuel Operating costs ($/MWh) | | | | | | | ✓ |
| Non-fuel Maintenance costs ($/MWh) | | | | | | | ✓ |
| **Sustainability** | | | | | | | |
| CO2 (Tons per year) | | | | | | | ✓ |
| NOX (Tons per year) | | | | | | | ✓ |
| SO2 (Tons per year) | | | | | | | ✓ |
| **Non-Fuel Operating and Maintenance Costs** | | | | | | | |
| Steam Production (coal-fired) ($/MWh) | ✓ | | | | | | |
| Other Production (gas-fired) ($/MWh) | ✓ | | | | | | ✓ |
| Distribution O&M ($/Customer, $/Unit Sales) | ✓ | | ✓ | | | | |
| Transmission O&M ($/Line Mile, $/Unit Sales) | ✓ | | ✓ | | | | |
| Customer Expense (Sum of: Customer accounts, Customer service, and Sales expense) ($/ Customer, $/ Unit Sales) | ✓ | | ✓ | | | | |
| A&G Expense ($/MWh Sales, $/Sales Revenue) | ✓ | | | | | | |
| Total Electric O&M (per MWh sales, per Customer | ✓ | | | | | | |
| **Capital Investment** | | | | | | | |
| Total Electric Plant (% change) | ✓ | | ✓ | | | | |
| Steam Production Plant ($ invested) | ✓ | | | | | | |
| Nuclear Production Plant ($ invested, $ MWh generated) | | | | | ✓ | | |
| Other Production Plant ($/MWh generated) | ✓ | | | | | | |
| Transmission Plant ($ invested and % change) | ✓ | | | | | | |
| Distribution Plant per Customer ($ invested per Customer; $ invested per Customer vs. Customers per Square Mile) | ✓ | | ✓ | ✓ | | | |
| Distribution Plant ($ invested over study period; % change) | ✓ | | ✓ | | | | |
| Distribution Plant per New Customer | ✓ | | ✓ | ✓ | | | |

| | Base Panel | Expanded Base Panel | High Growth Panel | Regional Panel | Nuclear Panel | Industry Wide | Other |
|---|---|---|---|---|---|---|---|
| **Management, Labor and Regulatory Expense** | | | | | | | |
| Employees (per customer, per MWh sales) | ✓ | | | | | | |
| Salaries and Wages (per customer, per MWh sales, and per employee) | ✓ | | | | | | |
| Regulatory Commission Expenses (total $$) | ✓ | | | | ✓ | | |
| **Financial Performance** | | | | | | | |
| Earned Return on Average Equity | ✓ | ✓ | ✓ | | ✓ | | |
| Earned Return on Average Assets | ✓ | ✓ | ✓ | | ✓ | | |
| Earnings Growth Rates | ✓ | ✓ | ✓ | | ✓ | | |
| Total Return to Parent Company | ✓ | ✓ | ✓ | | ✓ | | |
| Funds Flow from Operations/Average Debt | | | | | | | ✓ |
| FFO Interest Coverage | | | | | | | ✓ |
| Total Debt/Capitalization Ratio | | | | | | | ✓ |
| Debt and Commercial Paper Ratings | | | | | | | ✓ |
| Net Cash Flow/Capex | ✓ | ✓ | ✓ | ✓ | ✓ | | |
| Dividend Payout Ratio to Parent | ✓ | | | | | | |
| Construction Work in Progress/Net Property, Plant and Equipment | ✓ | ✓ | ✓ | ✓ | ✓ | | |
| Hedging | Qualitative Assessment | | | | | | |
| Funds Paid Among Affiliates | Qualitative Assessment | | | | | | |

# Nuclear Non-Fuel O&M Expense by Plant




| | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| *Palo Verde* | *13.66* | *14.90* | *14.11* | *14.39* | *15.60* | *17.62* | *22.31* | *22.20* | *23.45* | *21.53* | *20.66* |
| Beaver Valley | 30.94 | 22.82 | 23.48 | 28.40 | 22.70 | 21.92 | 84.32 | 55.78 | 53.67 | 55.60 | NA |
| Callaway | 9.00 | 14.89 | 15.56 | 11.59 | 20.99 | 18.14 | 11.77 | 15.82 | 16.38 | 10.91 | 18.28 |
| Comanche Peak | 10.02 | 9.17 | 13.37 | 12.05 | 13.09 | 14.55 | 10.64 | 12.28 | 13.01 | 12.15 | NA |
| Davis-Besse | 17.42 | 10.74 | NM | NM | 18.06 | 15.76 | 16.97 | 12.61 | 13.71 | 10.55 | NA |
| Diablo Canyon | 10.59 | 10.38 | 13.26 | 13.09 | 19.94 | 13.58 | 13.84 | 13.87 | 15.37 | 18.04 | 14.17 |
| Donald C. Cook | 107.80 | 17.58 | 20.46 | 18.58 | 13.46 | 12.43 | 14.43 | 12.53 | 15.30 | 25.92 | 15.64 |
| Fort Calhoun Nuclear Station | 22.91 | 24.67 | 21.64 | 25.57 | 14.47 | 22.73 | 19.81 | 7.53 | 11.47 | NA | NA |
| Prairie Island | 11.19 | 14.17 | 15.81 | 14.32 | 15.06 | 15.30 | 19.94 | 15.13 | 16.28 | 22.36 | 22.58 |
| San Onofre | 15.55 | 17.33 | 18.43 | 17.10 | 27.46 | 16.56 | 30.41 | 21.27 | 26.81 | 31.02 | 37.17 |
| South Texas Project | 8.79 | 10.56 | 10.73 | 12.74 | 8.64 | 11.73 | 10.90 | 11.24 | 12.53 | 12.65 | NA |
| V.C. Summer | 13.80 | 11.68 | 11.62 | 12.58 | 11.24 | 12.79 | 13.33 | 13.04 | 15.17 | 17.56 | 16.26 |
| Wolf Creek | 12.31 | 10.20 | 11.96 | 11.54 | 11.49 | 13.73 | 12.60 | 11.77 | 15.42 | 15.63 | 16.08 |

| | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| *Palo Verde* | *13.66* | *14.90* | *14.11* | *14.39* | *15.60* | *17.62* | *22.31* | *22.20* | *23.45* | *21.53* | *20.66* |
| Average | 22.53 | 14.52 | 16.03 | 16.14 | 16.38 | 15.77 | 21.58 | 16.91 | 18.76 | 21.13 | 20.03 |
| Palo Verde Rank | 7 | 9 | 6 | 8 | 8 | 10 | 11 | 12 | 11 | 8 | 6 |

Source: SNL Financial

# Underground Distribution Systems

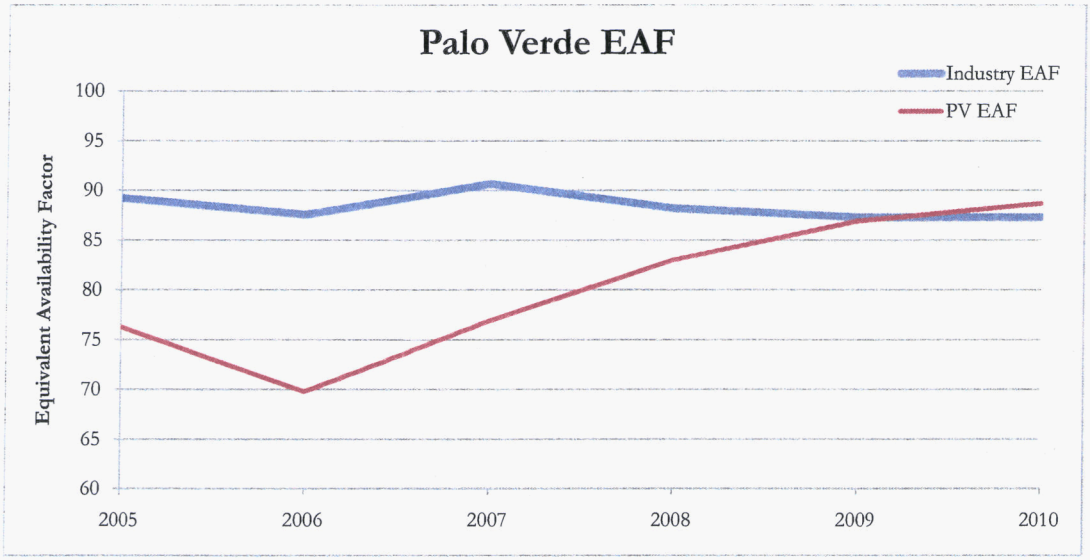
# Labor Efficiency Metrics

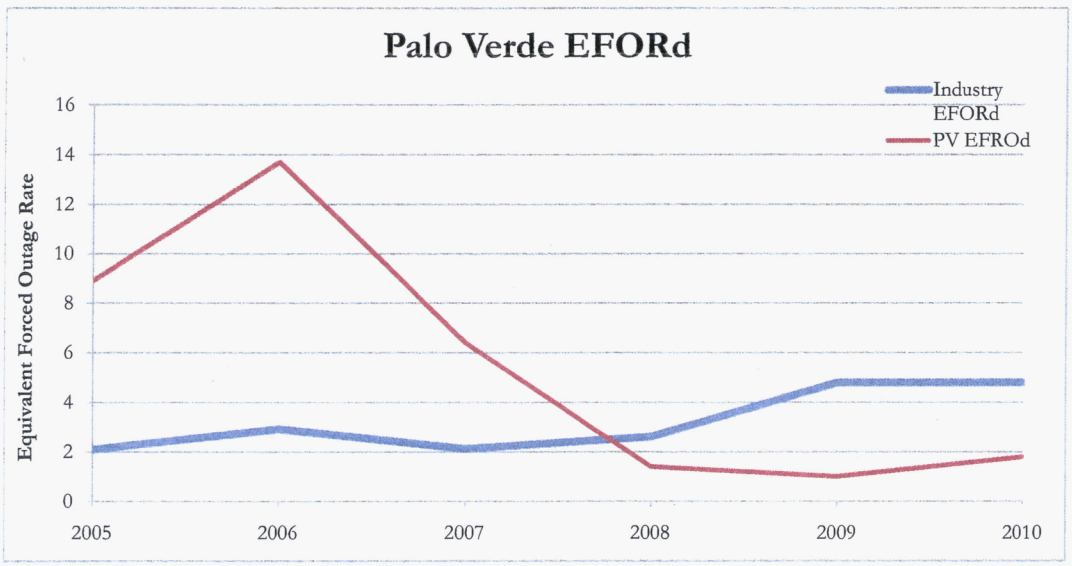
| Employees per 1,000 Customers | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| **Company** | **2010** | **2009** | **2008** | **2007** | **2006** | **2005** | **2004** | **Average** |
| DPL | 2.74 | 2.90 | 2.87 | 2.82 | 2.59 | 2.48 | 2.61 | 2.72 |
| NV Energy | 2.44 | 2.59 | 2.79 | 2.77 | 2.79 | 2.86 | 2.99 | 2.75 |
| NextEra Energy | 3.31 | 3.41 | 3.39 | 3.19 | 2.98 | 2.83 | 2.82 | 3.14 |
| Portland General | 3.26 | 3.32 | 3.39 | 3.38 | 3.34 | 3.38 | 3.47 | 3.36 |
| Westar Energy | 3.51 | 3.51 | 3.56 | 3.45 | 3.34 | 3.33 | 3.23 | 3.42 |
| Central Vermont Public Service | 3.24 | 3.37 | 3.47 | 3.50 | 3.42 | 3.50 | 3.68 | 3.45 |
| OGE | 4.38 | 4.35 | 4.49 | 4.24 | 4.16 | 4.11 | 4.12 | 4.26 |
| IDACORP | 4.16 | 4.08 | 4.28 | 4.28 | 4.25 | 4.44 | 4.48 | 4.28 |
| Great Plains Energy | 3.87 | 3.89 | 3.97 | 4.94 | 4.91 | 4.78 | 4.91 | 4.47 |
| *Pinnacle West Capital - Adjusting for Employees at Jointly Owned facilities* | *3.89* | *4.30* | *4.59* | *4.72* | *4.75* | *4.38* | *4.97* | *4.51* |
| Cleco Corp. | 4.57 | 4.77 | 4.86 | 4.51 | 4.39 | 4.39 | 4.45 | 4.56 |
| American Electric Power | 4.37 | 5.08 | 5.15 | 4.92 | 4.86 | 4.72 | 4.82 | 4.84 |
| Otter Tail Corp | 5.22 | 5.35 | 5.39 | 5.23 | 5.08 | 5.04 | 5.07 | 5.20 |
| Entergy | 5.45 | 5.59 | 5.45 | 6.29 | 5.22 | 5.29 | 5.39 | 5.53 |
| PNM Resources | 4.25 | 4.31 | 5.78 | 6.38 | 6.87 | 7.24 | 6.45 | 5.90 |
| Southern Company | 5.88 | 5.93 | 6.20 | 6.13 | 6.08 | 6.04 | 6.14 | 6.06 |
| Hawaiian Electric | 7.70 | 7.80 | 8.09 | 8.03 | 7.97 | 9.58 | 9.61 | 8.40 |
| Allete | 8.94 | 9.11 | 9.54 | 9.34 | 9.43 | 9.56 | 9.33 | 9.32 |

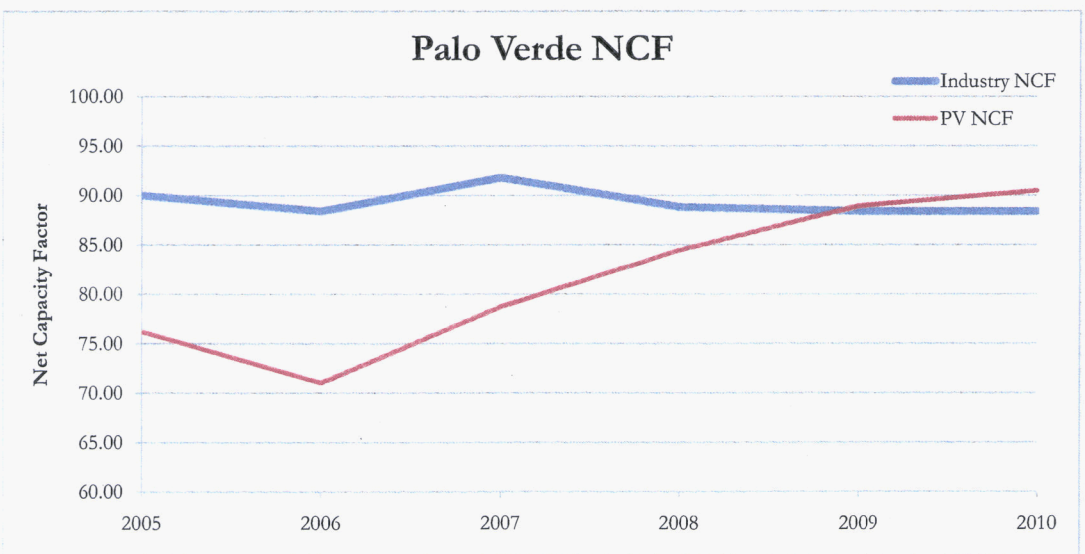
| Salaries and Wages and Pensions and Benefits per Customer | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| **Company** | **2010** | **2009** | **2008** | **2007** | **2006** | **2005** | **2004** | **Average** |
| NV Energy | 0.14 | 0.17 | 0.14 | 0.14 | 0.14 | 0.14 | 0.15 | 0.15 |
| NextEra Energy | 0.18 | 0.17 | 0.16 | 0.17 | 0.16 | 0.15 | 0.13 | 0.16 |
| Cleco Corp. | 0.27 | 0.23 | 0.20 | 0.20 | 0.12 | 0.13 | 0.12 | 0.18 |
| Entergy | 0.20 | 0.17 | 0.17 | 0.22 | 0.19 | 0.16 | 0.16 | 0.18 |
| American Electric Power | 0.24 | 0.21 | 0.20 | 0.18 | 0.18 | 0.17 | 0.17 | 0.19 |
| DPL | 0.26 | 0.23 | 0.21 | 0.19 | 0.19 | 0.16 | 0.15 | 0.20 |
| OGE | 0.26 | 0.23 | 0.20 | 0.21 | 0.20 | 0.19 | 0.19 | 0.21 |
| Portland General | 0.23 | 0.22 | 0.22 | 0.22 | 0.21 | 0.19 | 0.18 | 0.21 |
| Hawaiian Electric | 0.00 | 0.10 | 0.34 | 0.33 | 0.30 | 0.23 | 0.26 | 0.22 |
| Southern Company | 0.25 | 0.23 | 0.25 | 0.25 | 0.26 | 0.25 | 0.24 | 0.25 |
| PNM Resources | 0.00 | 0.33 | 0.29 | 0.30 | 0.30 | 0.27 | 0.28 | 0.25 |
| Westar Energy | 0.31 | 0.30 | 0.27 | 0.26 | 0.24 | 0.23 | 0.21 | 0.26 |
| IDACORP | 0.24 | 0.29 | 0.26 | 0.27 | 0.27 | 0.26 | 0.27 | 0.27 |
| Central Vermont Public Service | 0.30 | 0.30 | 0.30 | 0.28 | 0.28 | 0.26 | 0.25 | 0.28 |
| *Pinnacle West Capital* | *0.42* | *0.39* | *0.37* | *0.35* | *0.35* | *0.30* | *0.32* | *0.36* |
| Great Plains Energy | 0.38 | 0.38 | 0.38 | 0.42 | 0.40 | 0.39 | 0.38 | 0.39 |
| Otter Tail Corp | 0.52 | 0.50 | 0.48 | 0.47 | 0.46 | 0.46 | 0.40 | 0.47 |
| Allete | 0.54 | 0.52 | 0.53 | 0.51 | 0.49 | 0.46 | 0.43 | 0.50 |

Source: SNL Financial, FERC Form 1, and SEC Form 10-K

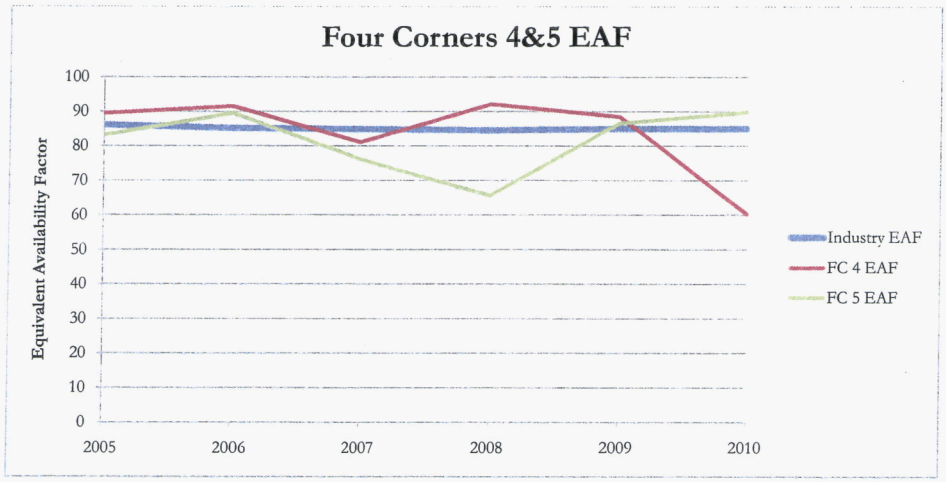
## Nuclear Plant Metrics

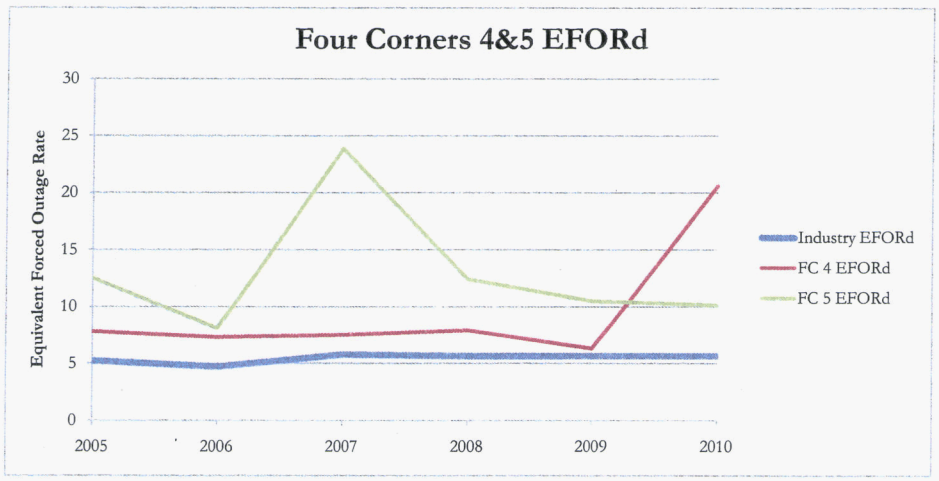


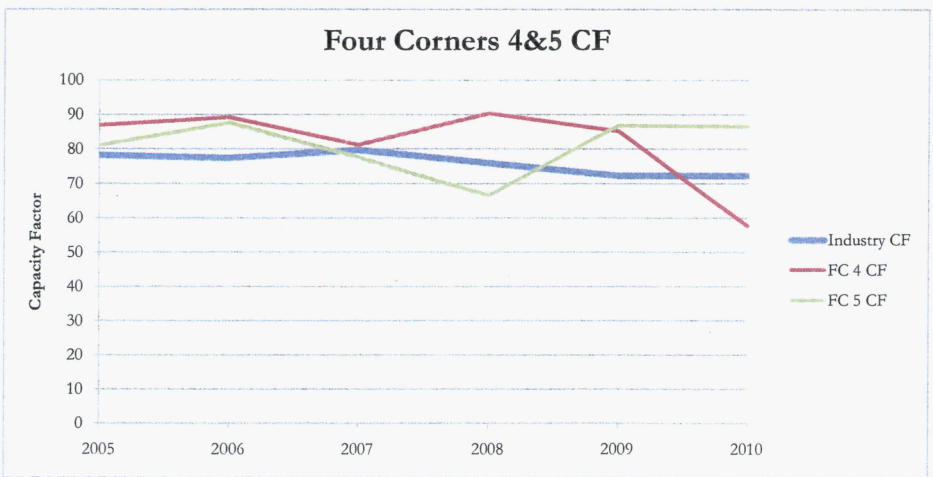



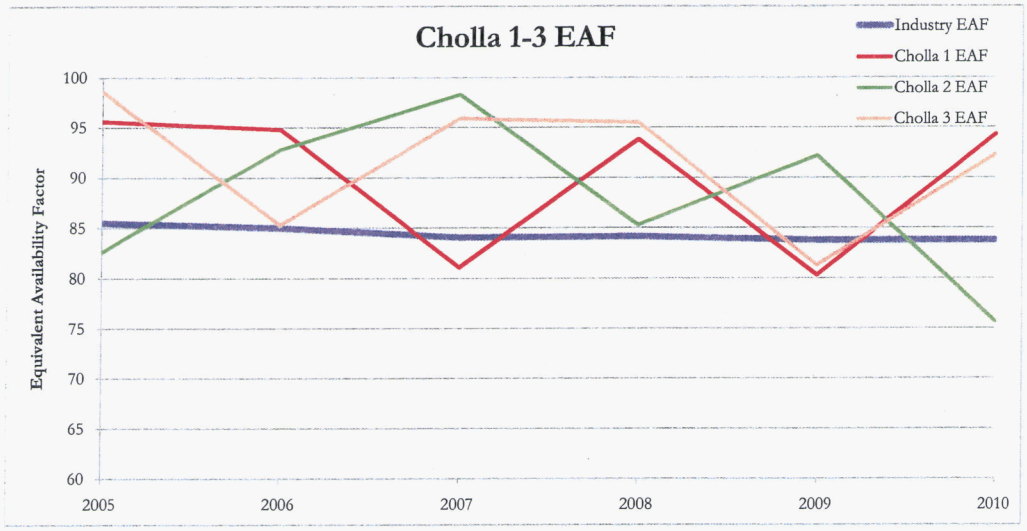
Fossil Plant Metrics

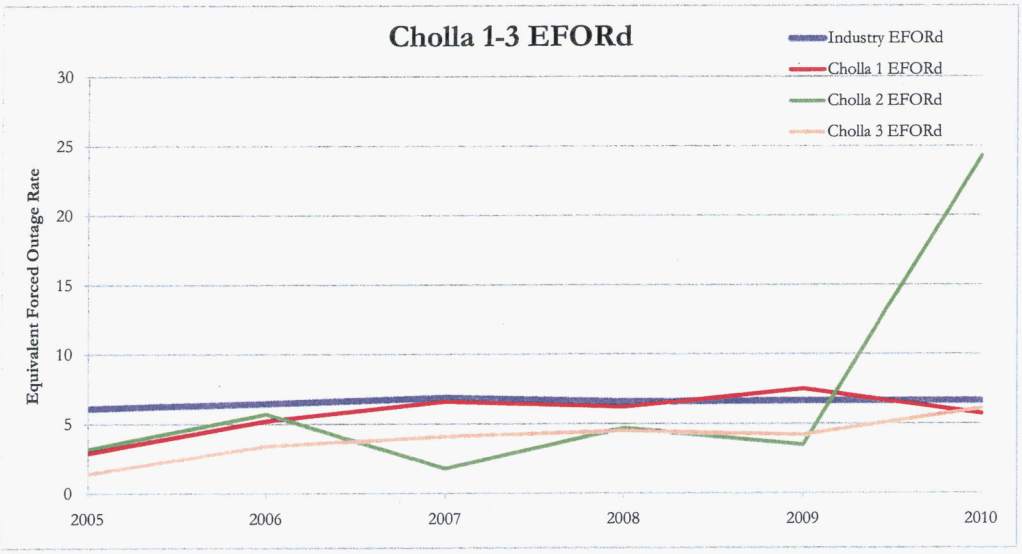


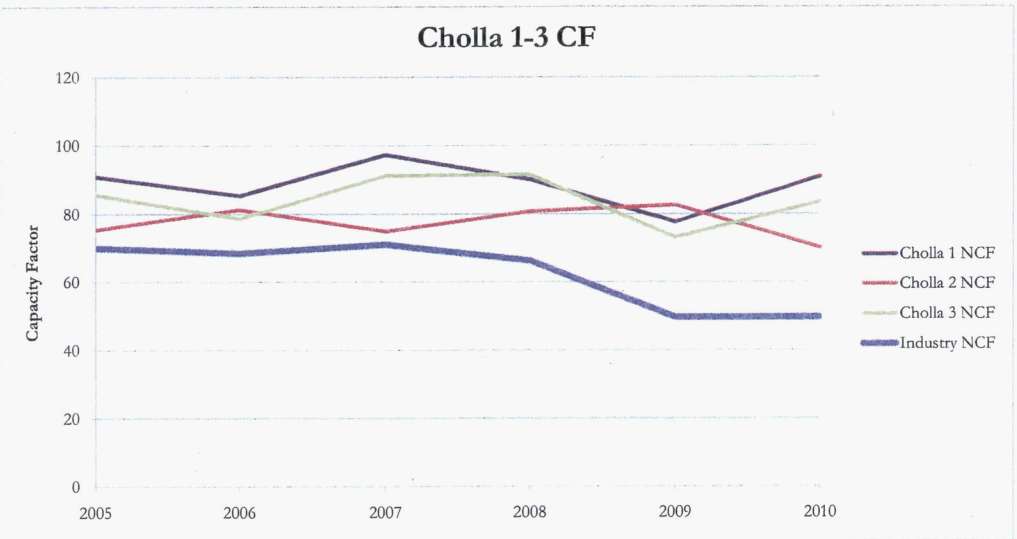



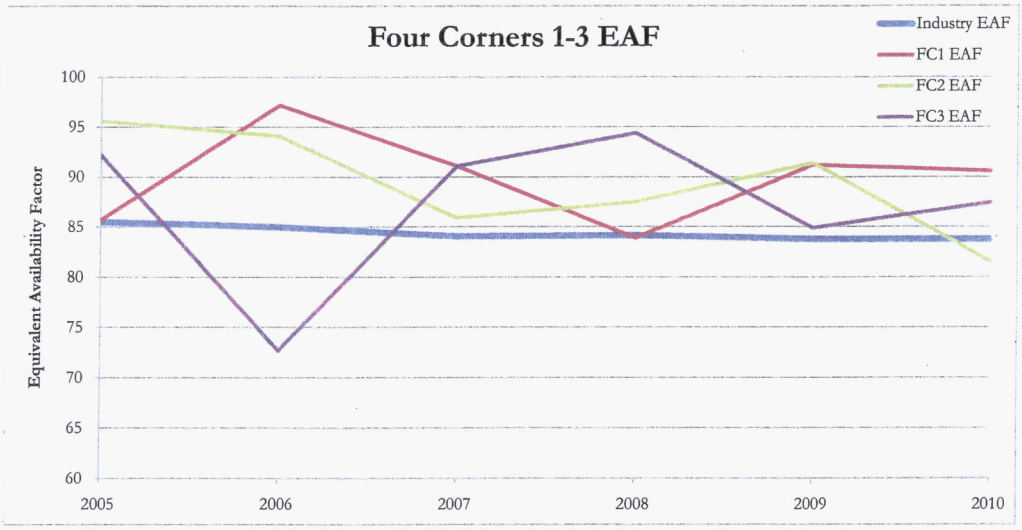
**Fossil Plant Metrics**

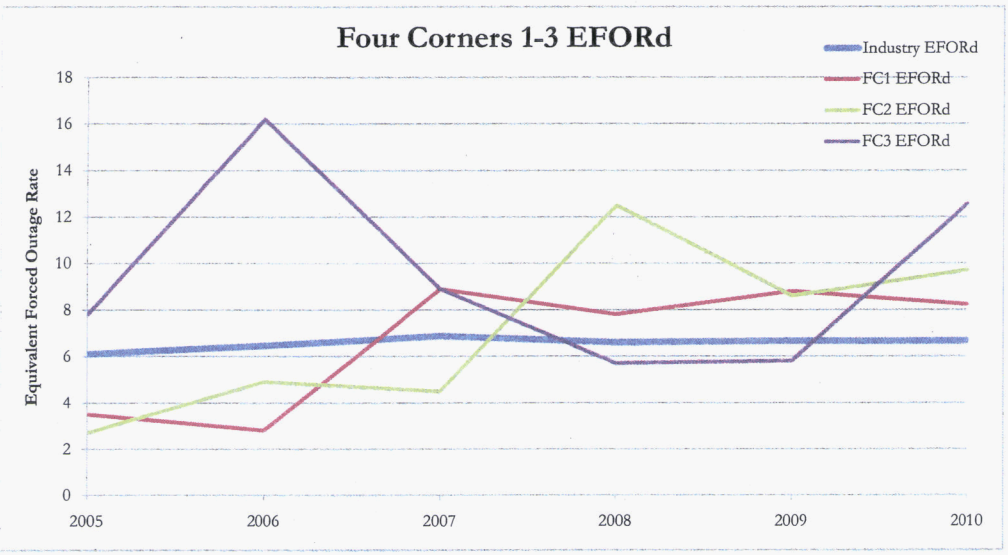


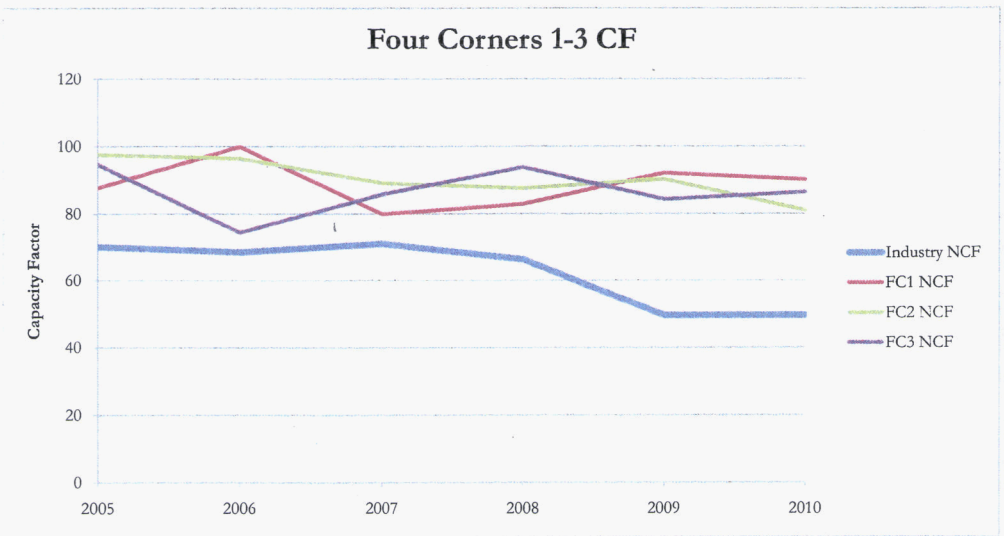



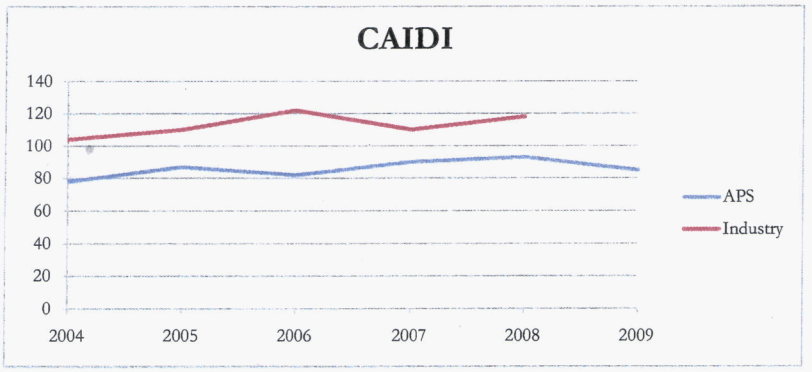
Fossil Plant Metrics

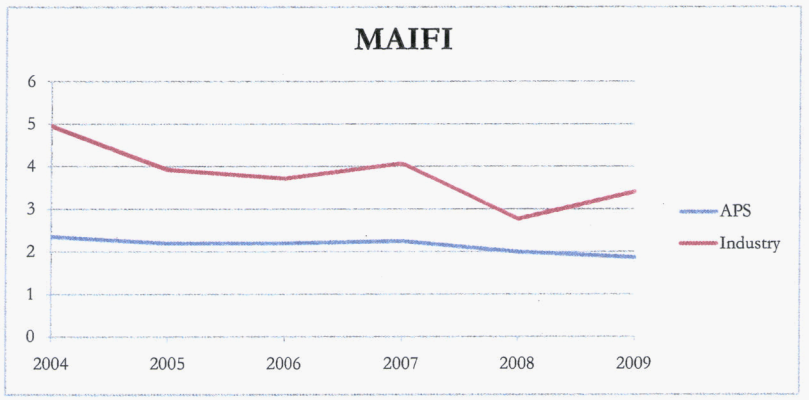


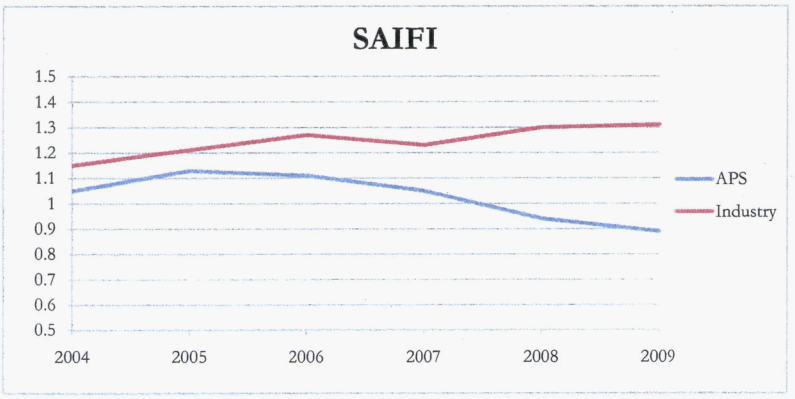



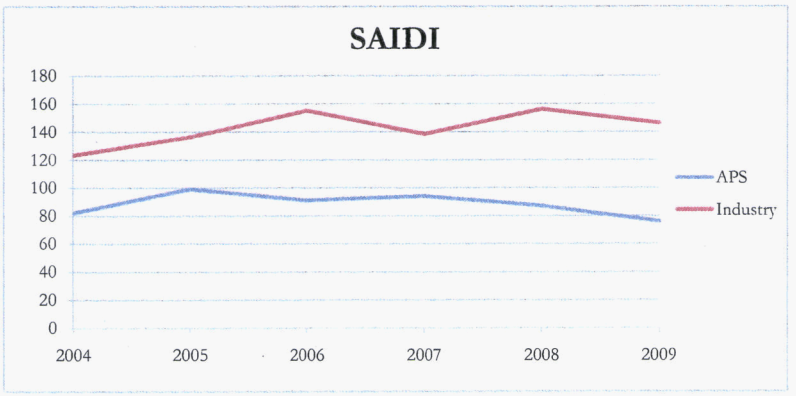



**Distribution System Reliability Metrics**

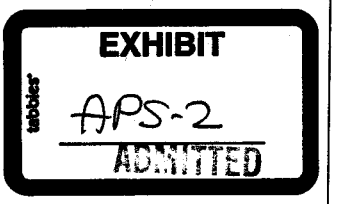


APS Exhibit 2




# DIRECT SETTLEMENT TESTIMONY OF JEFFREY B. GULDNER

**On Behalf of Arizona Public Service Company**

**Docket No. E-01345A-11-0224**

**January 18, 2012**

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**DIRECT SETTLEMENT TESTIMONY OF JEFFREY B. GULDNER**
**ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY**
**(Docket No. E-01345A-11-0224)**

I. INTRODUCTION

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

A. My name is Jeffrey B. Guldner. My business address is 400 N. 5th Street, Phoenix, Arizona, 85004. I am Vice President of Rates and Regulation for Arizona Public Service Company ("APS" or "Company"). In that role, I am responsible for rate, regulatory and regulatory compliance matters before the Arizona Corporation Commission ("Commission") and the Federal Energy Regulatory Commission ("FERC").

**Q. DID YOU SUBMIT DIRECT TESTIMONY IN THIS PROCEEDING THAT PROVIDES YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?**

A. Yes, in the Direct Testimony filed on June 1, 2011.

**Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

A. My Direct Settlement Testimony supports the Settlement Agreement ("Agreement" or "Settlement") that was filed with the Commission on January 6, 2012 and recommends that the Commission approve it. I discuss the settlement process, give an overview of the Agreement's key provisions, and explain why the Company believes the Agreement achieves a reasonable balance of the interests of all stakeholders in APS's rate case, results in just and reasonable rates, and is in the public interest. Details about some of the specific terms of the Agreement are also presented in the Direct Testimony of Leland Snook (Lost Fixed Cost Recovery Mechanism ("LFCR") and Environmental Improvement Surcharge ("EIS")) and Charles Miessner (Experimental Rate Schedule AG-1, other new rate offerings, and general rate design).

II. SUMMARY

**Q. PLEASE SUMMARIZE YOUR TESTIMONY.**

A. APS strongly supports the Settlement, which reflects thoughtful solutions that balance the many disparate interests at play in this rate case while preserving the Commission's critical role in setting energy policy. The Settlement will allow APS to continue to provide high quality service to customers, support the level of energy efficiency ("EE")[1] and distributed generation ("DG") authorized by the Commission, and contribute positively to the Arizona economy. Moreover, the fact that 22 of the 24 still active parties to these proceedings[2] champion the Settlement signals that Arizona's regulatory environment continues to be one that is collaborative, efficient, and focused on producing constructive outcomes for the State. Specifically, advocates for all of APS's customer classes support the Settlement (residential, commercial, industrial, and low income alike), as do the majority of other stakeholders, including the American Association of Retired Persons ("AARP"), merchant generators and competitive suppliers, individual large customers, Air Force and Marine Corps military bases, realtors, individual landowners, investors and labor unions. That the Settlement has such broad-reaching support strongly suggests that it is in the public interest.

Substantively, the Settlement proposes a total base rate increase of zero dollars, the components of which I later describe. The agreed-upon zero dollar base rate increase is significantly less than what APS originally sought, the same as what the Residential Utility Consumer Office ("RUCO") originally proposed, and only slightly more than what Staff initially recommended. It reflects a compromise

[1] Demand Side Management ("DSM") consists of both EE and demand response programs. For the purposes of my testimony, I will use the terms DSM and EE interchangeably.

[2] This number includes the Signatories and the parties who did not sign and have indicated an intent to file testimony regarding the Settlement on January 18. Absent from this group are Tucson Electric Power, the Arizona Schools Board Association, the Association of School Business Officials, Western Resource Advocates, Interwest Energy Alliance, the Town of Gilbert, and the Town of Wickenburg.

that, when balanced with all other provisions of the Agreement, was minimally adequate for APS to maintain its financial strength, support above-average levels of reliability and customer service, and make continued investments necessary for Arizona's energy future.

The average customer bill will go down, not up, on the rate effective date of this Settlement, and that impact will continue throughout 2012. The average residential customer's monthly bill, for example, will immediately decrease by about 1.0%. This customer benefit is caused by (1) APS receiving substantially less rate relief than it had originally requested; (2) a decline in fuel costs; and (3) the Company's agreement to delay the reset of the Power Supply Adjustor ("PSA") rate until February 2013, thus continuing the current PSA credit now applied to customer bills. I described the estimated bill impact of this Settlement in a letter filed in this Docket on January 9, 2012 and attached to this testimony as Attachment A.

In addition to proposing rate levels, the Agreement precludes APS from filing its next general rate case prior to May 31, 2015. New rates from any such filing could not take effect prior to July 1, 2016. This four-year stay out is intended to give continued structure and predictability to APS general rate cases. Other customer benefits include a buy-through rate for industrial and large commercial customers (discussed in detail in APS Witness Miessner's testimony), shareholder-funded bill assistance for additional low-income customers, additional rate options for residential and general service customers, and a process for simplifying the customer bill format.

From a policy perspective, the Settlement allows the Commission to retain its flexibility to set energy policy as it deems appropriate in the future. Unlike the

2009 APS Rate Case Settlement Agreement (Decision No. 71448 (December 30, 2009)), this Settlement was specifically designed to provide a rate structure that will allow APS to adapt to policy changes that may occur during the Settlement period (from the Settlement's rate effective date until July 1, 2016), without either constraining the Commission or producing economically untenable results for the Company.

For example, addressing highly divergent stakeholder positions, the Settlement resolves APS's original proposal for a comprehensive revenue per customer decoupling mechanism by proposing a LFCR mechanism with residential opt-out rates. The LFCR mechanism will enable APS to continue to offer a variety of DSM programs to help customers save money at the level or pace the Commission deems best for Arizona. The LFCR mechanism achieves this result by limiting lost fixed cost recovery only to revenues that are measurably lost because of DSM or DG, at whatever level the Commission authorizes in any year. The LFCR does not recover fixed costs lost because of other potential factors that could reduce energy sales, such as weather or general economic conditions. Nothing in the Settlement binds the Commission to any specific DSM or DG policy or standard. Rather, it both supports current EE and DG regulatory requirements and flexibly adapts to future changes in EE and DG policy.

While the LFCR is necessary to enable customers to have greater control over their energy use, the Settlement addresses more conceptual customer concerns about this type of mechanism by providing residential customers a choice to "opt out" of paying the LFCR and instead pay a slightly higher basic service charge ("BSC"). In addition, the Settlement addresses fixed cost recovery for large commercial customers through rate design rather than through the LFCR. APS

Witness Snook's Direct Settlement Testimony addresses the mechanics of the LFCR in greater detail.

The Settlement also enhances the Commission's flexibility with respect to the Renewable Energy Surcharge ("RES") and the Demand Side Management Adjustment Clause ("DSMAC"). As to the RES, it removes the requirement that RES charges and caps must be administered according to certain proportions; moves 15 months of utility-owned renewable resources from the RES to base rates; and, except with respect to the renewable energy-related capital investments made in compliance with Decision No. 71448, prevents the Company from continuing to recover capital carrying costs for APS-owned renewable energy projects through the RES adjustor. As to the DSMAC, among other things, it modifies the existing EE performance incentive; requires APS and stakeholders to develop and propose a new performance incentive structure for future DSM filings for the Commission's consideration; and, excluding DSM-related capital investments already authorized by the Commission, it prevents carrying costs for such investments to be recovered through the DSMAC. These provisions all give the Commission greater flexibility to manage the rate and customer bill impacts associated with the RES and DSMAC.

Certain financial terms are essential to sustain the four-year rate moratorium. Among them is constructive rate treatment for APS's requested purchase of the Southern California Edison ("SCE") share of Four Corners Units 4 and 5 were the acquisition to close and for the subsequent retirement of Units 1-3 – the "Four Corners Transaction," which is the subject of Docket No. E-01345A-10-0474 (the "Four Corners Docket"). While the Settlement would allow the Company to seek an adjustment rider related to the Four Corners Transaction, that rider cannot be implemented unless the Commission authorizes the Company to pursue the

transaction and the transaction thereafter closes. The Settlement does not presuppose either the outcome of the Four Corners Docket or a prudency-finding related to the Four Corners Transaction.

Other material provisions include eliminating the 90/10 sharing provision now in the PSA, coupled with the adoption of other prudent fuel and power procurement and use incentive devices; cost deferrals related to changes in APS's composite property tax rate; changes to the Transmission Cost Adjustment mechanism ("TCA") process; and modifications to the Company's EIS. I will discuss each of these provisions in greater detail.

In sum, the Settlement resolves the issues raised in the Company's Rate Application in a manner that produces customer benefits that would not result from litigation. This is true both because the litigation process is adversarial and because several of the Settlement's provisions are either unlikely to have been adopted or could not be mandated outside of a settlement.

While no Signatory, including APS, received all that it sought or would have sought in litigation, the Signatories agree that the Settlement is in the public interest. The Settlement preserves the Commission's flexibility with respect to energy policy; shields customers from a base rate increase in challenging economic times; supports APS financially during a four-year stay out period, allowing the Company to continue to provide high quality reliability and customer service; and resolves a complex and challenging rate case efficiently and to the satisfaction of the overwhelming majority of the parties. For all of these reasons, APS respectfully asks that the Commission promptly approve the Settlement and allow rates to take effect on July 1, 2012.

## III. THE SETTLEMENT PROCESS

**Q. PLEASE PROVIDE A BRIEF OVERVIEW OF THE SETTLEMENT PROCESS.**

A. This Settlement was the result of over four weeks of formal and informal negotiations among virtually all of the parties to this rate case. Settlement discussions began after the submission of Direct Testimony by Staff and other intervening parties, but before the submission of APS's rebuttal case. From the Company's perspective, the collaborative settlement process provided an opportunity to develop more creative solutions for the issues presented in the rate case than would have been possible through litigation.

Formal settlement discussions between all participants occurred regularly throughout the process, from the end of November 2011 until the Agreement was ultimately filed on January 6, 2012. A Term Sheet was filed on December 9, 2011 after the parties believed a settlement framework had been established, and that Term Sheet was generally discussed at an Open Meeting on December 16, 2011. From that date until January 6, 2012, the parties finalized the outstanding details and transformed the settlement framework into a definitive written agreement.

**Q. HOW WAS THE SETTLEMENT PROCESS CONDUCTED?**

A. The settlement process consisted of several weeks of arm's-length negotiations between more than 25 parties representing diverse interests. All parties to the Docket—not just those that actively participated in the settlement—were notified of settlement meetings, were invited to attend those meetings either in person or telephonically through a dial-in number, and were given the opportunity to fully participate in discussions regarding any issue raised in this case.

Meeting participants were provided with copies of all documents that were presented during the discussions. Hard copies of such documents were given to

the parties in attendance and electronic copies of documents were made available to all participating parties using a pre-established rate case Internet site. To permit and encourage openness and transparency, the parties agreed that the content of settlement discussions would be confidential, as they are generally in civil litigation under both state and federal Rules of Civil Procedure. Commission Staff led the negotiations, efficiently driving the discussions to a resolution that serves the public interest.

**Q. WHAT STANDARD SHOULD THE COMMISSION USE IN EVALUATING THE SETTLEMENT?**

A. The same general public policy supporting settlement of contested matters in civil litigation also applies to utility rate cases. However, a rate case settlement is not a resolution solely between private litigants. Rather, it must result in just and reasonable rates and the Commission must conclude that the settlement is in the public interest.

**Q. DO YOU BELIEVE THAT THE SETTLEMENT IS IN THE PUBLIC INTEREST?**

A. Absolutely. The Settlement contains many benefits for customers, described in Section 1.5 of the Settlement and reiterated below. A core interest for APS was that the Settlement needed to provide the Company with the minimum financial support required to sustain the four-year stay out and continue to provide high quality service for its customers. The Settlement's rate-related provisions are intended to permit the Company to retain its ability to attract capital, maintain reliability, and sustain growth—benefits that are important for the future of Arizona.

The interests of all rate case stakeholders were given equal and thoughtful consideration throughout negotiations. That is as true for the parties, like AARP and the ACPA, who ultimately signed the Settlement as it is for the energy

efficiency and environmental advocates who did not. Because the settlement process allows issues to be vetted outside a formal adversarial process, conflicting viewpoints were resolved efficiently, expediently, and creatively compared to how they might have been addressed in litigation. Even when it became apparent that a party may not sign the Settlement, the other parties continued to listen to that party's position and reflect certain of its suggestions within the agreement. In this way, the Settlement reflects input from all APS rate case stakeholders, not just Signatories.

In the end, the Settlement is a carefully crafted and cooperatively achieved balance of many important interests, not just those of APS. That balance, though, is a delicate one. Many aspects of the Settlement reflect the limits to which the Company was able or willing to agree. In many cases, APS's agreement to a provision depended upon the presence of certain other moderating provisions. I believe the same is true for the other Signatories. Taken as a whole, I strongly believe that the Settlement presented to the Commission is in the public interest and should be approved.

## IV. SETTLEMENT TERMS

**Q. DOES THE AGREEMENT REFLECT ANY UNDERLYING THEMES?**

A. Yes. A core theme of settlement negotiations was how to moderate the customer bill impact of this rate case, balancing customer interests in a difficult economy with the Company's financial needs. Towards that goal, as Section 1.5 describes, the Settlement shields all APS customers from a base rate increase and actually lowers customer bills in 2012; requires APS to agree to a four-year rate case stay out, during which time any additional customer bill impacts resulting from the Settlement will be more moderate and predictable; allows customers to benefit from EE programming and DG by proposing a narrow fixed cost recovery

mechanism that would support EE and DG at Commission-authorized levels; allows residential customers to subscribe to an opt-out rate if they do not want to participate in the LFCR; provides shareholder-funded bill assistance to additional low income customers; and provides commercial and industrial customers an innovative alternative generation buy-through rate option, Experimental Rate Schedule AG-1, as well as a new interruptible rate option.

Another important consideration was to ensure that nothing in the Settlement impaired the Commission's flexibility with respect to energy policy. The Settlement intentionally does not establish independent EE or DG policies or standards for APS. Instead, the Settlement enhances the Commission's flexibility with respect to the rate and customer bill impacts associated with the RES and DSMAC, as described in detail later.

A critical consideration for APS was to balance the zero dollar rate increase, the 10% authorized ROE (a full 100 basis points below the Company's current 11% authorized ROE), and the four-year stay out with related provisions that allow APS the financial wherewithal to be able to continue to provide superior service without another base rate increase before mid-2016. These other provisions include eliminating the 90/10 sharing provision in the PSA, implementing the LFCR, modifying the existing EIS, permitting the deferral of costs related to changes in the Company's composite property tax rate, changing the process related to the recovery of TCA revenues, and enabling APS to seek an adjustment rider to recover costs associated with the Four Corners transaction, if the Commission authorizes APS to pursue the acquisition and if the purchase closes. Even APS's ability to offer the buy-through alternative generation rate was balanced in part by provisions that will allow the Company to mitigate cost

recovery issues that could result if APS-owned capacity and energy is displaced by the AG-1 rate schedule.

APS believes that the Settlement in whole provides an ongoing structure of regulatory support that will maintain the Company financially and continue the way towards a sustainable energy future for Arizona.

**Q. YOU REFERRED TO SEVERAL OF THE SETTLEMENT'S PROVISIONS IN YOUR PREVIOUS ANSWER. PLEASE PROVIDE A BRIEF DESCRIPTION OF EACH.**

A. Certainly. I will discuss each of the provisions as they appear chronologically in the Settlement (bypassing the Recitals in Section I). Section II sets forth a "Rate Case Stability Provision," which precludes APS from filing another general rate case before May 31, 2015, and requires that any such filing be based on a test year end date no earlier than December 31, 2014. Under this provision, customers would not see another APS base rate increase before July 1, 2016—four years from the anticipated rate effective date in this case.

Section III describes the Settlement's agreed-upon rates. Importantly, APS base rates shall not increase above what they are today until at least mid-2016. Put another way, if the Settlement is approved, APS customers will not have had a base rate increase for at least six and a half years by the time the Company is next eligible for rate relief, a period measured from the January 2010 rate effective date of APS's last rate case until the end of this Settlement stay-out period. The zero dollar revenue requirement is comprised of a non-fuel base rate increase of $116.3 million, a base fuel rate decrease of $153.1 million, and a transfer of approximately $36.8 million of renewable energy projects from the RES to base rates. Recognizing the challenges posed by an unadjusted historical test year to APS's financial condition, the non-fuel increase includes consideration of post-

test year plant through March 31, 2012 ("Post Test Year Plant") – 15 months after the Test Year.

Section IV describes the customer bill impact that results from the Agreement. As stated previously, if the Commission approves the Settlement so that rates take effect on July 1, 2012 as requested, APS customers on average will see a small bill **decrease** during the remainder of 2012. Further detail relating to the estimated bill impact of this Settlement is provided in Attachment A to this testimony.

**Q. PLEASE DESCRIBE THE SETTLEMENT'S COST OF CAPITAL, DEPRECIATION/AMORTIZATION, AND DECOMMISSIONING PROVISIONS.**

A. For ratemaking purposes, the Signatories agreed to a capital structure of 46.06% debt and 53.94% of common equity, and adopted an embedded cost of debt of 6.38% and an authorized ROE of 10.0%. The 10% authorized ROE is a full 100 basis points below APS's existing 11% ROE, is the same ROE that RUCO proposed in its Direct Testimony, and is only 10 basis points above what Staff had originally proposed.

Consistent with Staff's initial proposals, the Agreement adopts the depreciation and amortization rates contained in the Direct Testimony of APS Witness Dr. Ronald White, but not the Company's proposed change to the depreciation rate for electronic, electro-mechanical, or AMI meters. The Signatories also agreed to a fair value rate of return of 6.09%, including a return on the Company's fair value rate base increment of 1.0%.

The Settlement adopts the annual decommissioning amounts that are contained in the Direct Testimony workpapers of APS Witness Jason LaBenz and attached to the Settlement as Attachment B. As Attachment B to the Settlement shows, APS

expects that Palo Verde Unit 2 will be fully funded by 2016. The Nuclear Decommissioning Trust Fund collects the costs required to decommission Palo Verde Unit 2 from customers through the SBC component of APS's base rates. To provide a benefit to customers prior to the Company's next general rate case, the Settlement requires APS to request a reduction of the SBC to reflect the full funding of Palo Verde 2 to be effective January 1, 2016. That early reduction in the SBC could not occur absent this Agreement.

**Q. PLEASE DESCRIBE THE SETTLEMENT'S FUEL AND PURCHASED POWER PROVISIONS, INCLUDING THOSE REGARDING THE 90/10 SHARING PROVISION IN THE PSA.**

A. With respect to fuel costs, the Settlement lowers the base cost of fuel and purchased power from $0.037571 per kWh to $0.032071 per kWh. This change occurs on the effective date of new rates, as provided in the PSA Plan of Administration. APS also agreed to withdraw its request to recover the cost of chemicals required for environmental compliance at APS's power plants and from raising the request again before its next general rate case.

To make APS's fuel adjustor consistent with the fuel adjustment clauses of all other Arizona electric utilities, the Settlement also eliminates the existing 90/10 sharing provision in the PSA. Although unnecessary from the Company's perspective, two provisions are tied to the elimination of the PSA, each intended to benefit customers and provide APS with continued incentive to prudently procure fuel and purchased power. The first such provision modifies the interest rates that apply to the PSA by requiring an asymmetrical interest charge to the annual PSA balance. Under Section 7.3, if the PSA has collected more money from customers than was spent by the end of the February to January PSA year, that over-collection will accrue interest at a rate equal to APS's authorized ROE or APS's then-existing short term borrowing rate, whichever is greater. If the

PSA has collected less money than needed to pay for PSA costs at the end of the PSA year, that under-collection will accrue interest at a rate equal to APS's authorized ROE or APS's then-existing short term borrowing rate, whichever is less. In either case, the total PSA year-end balance will be refunded to customers over the following 12 months.

So as to prevent any over-collection from occurring in the first place, the Settlement authorizes APS to request to reduce the PSA rate through the PSA's "Transition Component," and would permit such a request to become effective on the first billing cycle of the month following the request. On the other hand, any APS request to increase the PSA by way of the Transition Component would continue to require explicit Commission approval.

The second condition related to eliminating the 90/10 sharing provision is a requirement that APS be subject to periodic fuel and power procurement and use audits. The first such audit shall be for calendar year 2014 (the earliest test year permitted by the Settlement for APS's next general rate case). Commission Staff shall select the consultant to perform these audits, which shall be funded by APS in an amount not to exceed $100,000 each.

**Q. PLEASE DESCRIBE THE RENEWABLE ENERGY-RELATED PROVISIONS.**

A. Unlike the 2009 Settlement, the only renewable energy issues addressed in the Settlement now before the Commission relate to ratemaking, not energy policy. Most of these provisions relate to the mode of cost recovery associated with certain APS-owned renewable energy projects that the Company now collects through the RES. The first such provision, Section 8.1, directs that the portion of those APS-owned renewable projects that have been closed to plant in service as of March 31, 2012 shall be rate based and that the recovery of the associated

costs shall be accomplished through base rates rather than through the RES. This provision is consistent with the treatment of other Post Test Year Plant in this case. On the effective date of the new rates contained in the Settlement, the RES adjustor rate established for 2012 will be adjusted to reflect the removal of those projects.

In the proceeding underlying the Company's 2012 RES Implementation Plan (Docket No. E-01345A-11-0264), the Commission understood that APS had proposed in this rate case to transfer some of its renewable energy projects from the RES to base rates. The Commission also knew that no party's Direct Testimony in this case had entirely disputed that proposal. Seeking to reduce the adjustor rate approved for the 2012 RES Implementation Plan, the Commission moved $14 million worth of renewable-energy related purchased power agreement ("PPA") costs from the RES to the PSA as a temporary proxy for what the Commission expected to be the permanent removal of certain utility-owned projects from the RES to base rates in this rate case. Section 8.3 of the Settlement returns the renewable PPA costs that were moved from RES to the PSA back to the RES at the same time as the utility-owned projects identified in Section 8.1 are moved from the RES to base rates. On net, these provisions will have the effect of reducing the RES adjustor rate.

In addition, the Settlement recognizes that Decision No. 71448 authorized the Company to recover the capital carrying costs (a term defined in a footnote to Settlement Section 8.1) associated with any APS-owned renewable investments made to comply with that Decision through the RES. The Settlement does not change that prior Commission order. APS renewable investments made to comply with Decision No. 71448 will continue to receive that ratemaking treatment, unless and until the Commission authorizes the Company to recover

the associated costs through another adjustor or in base rates. However, once APS has fully complied with the renewable energy provisions of Decision No. 71448, APS will no longer be allowed to recover the capital carrying costs associated with renewable energy capital investments through the RES, at least until the conclusion of the Company's next general rate case.

Finally, Decision No. 67744 (April 7, 2005) established a requirement that any changes to RES charges and caps must be allocated between customer classes according to certain set proportions. The Settlement removes that requirement, for the express purpose of "provid[ing] the Commission with greater flexibility in setting RES adjustor rates and related caps."

**Q. PLEASE DESCRIBE THE PROVISIONS OF SECTION IX, RELATING TO ENERGY EFFICIENCY.**

A. Certainly. Sections 9.1 through 9.13 relate to the proposed LFCR mechanism. I will generally discuss those provisions from a policy perspective, but will leave details regarding the mechanics to the Direct Settlement Testimony of APS Witness Snook. As a matter of policy, the Settlement supports EE as a low cost resource and recognizes that, under APS's current rate structure, the Company will lose revenue as a result of effective EE programs. The Settlement does not adopt full revenue per customer decoupling, as APS had originally proposed. Rather, sensitive to the Commission's role in setting EE and DG policy, the Settlement proposes that the Commission adopt a LFCR mechanism that limits lost fixed cost recovery to revenues that are measurably lost because of EE or DG; it does not include the impact of other potential factors that may reduce energy sales, such as weather or general economic conditions. The amount of lost fixed costs recovered by the mechanism is limited to the amount of EE and DG that the Commission authorizes in any year so that APS is financially equipped to support these programs at whatever level or pace the Commission sets. In many

ways, the LFCR is a "middle ground" that addresses only the cost recovery issues associated with EE and DG without constraining the Commission's policy-setting flexibility or further impacting APS's customers, some of whom are still uncomfortable with the scope of a revenue per customer decoupling rate model.

The Settlement also provides residential customers a rate schedule choice to "opt out" of the LFCR if they would prefer not to have that charge on their bill. Large General Service customers taking service under rate schedules E-32L, E-32 L TOU, E-34, E-35, and E-36XL are excluded from the LFCR. To more fully address lost fixed cost recovery with respect to these large customers, the Settlement modifies their rate schedules to pick up a greater portion of fixed costs through the distribution demand component, with a corresponding adjustment to the energy charge. APS Witness Miessner describes these rate schedule changes in greater detail in his Direct Settlement Testimony. Although the exclusion of large customers from fixed cost recovery devices is not uncommon in the United States (particularly when tied to rate design changes that improve fixed cost recovery), the ability of residential customers to "opt out" of the LFCR mechanism appears to be unique.

To further mitigate the customer bill impact associated with the LFCR, the LFCR is subject to an annual year-over-year one percent rate cap. This means that the LFCR charge will never cause an increase in customer bills greater than one percent from one year to the next. The one percent cap provided in the Settlement is much smaller than the three percent cap that APS had proposed for revenue per customer decoupling. APS was able to agree to the lower cap for the LFCR partly because the LFCR excludes the effects of weather and the economy and recovers fewer dollars than would a full revenue per customer decoupling model, making a smaller cap possible at least in the early years of the LFCR's

implementation. The Signatories agreed, however, that the cap level set in the Settlement should be reassessed in the Company's next rate case.

**Q. YOU INDICATED THAT THE LFCR LIMITS LOST FIXED COST RECOVERY TO REVENUES THAT ARE MEASURABLY LOST BECAUSE OF EE OR DG. HOW ARE LOST ENERGY SALES VERIFIED?**

A. Sections 9.4 and 9.5 address this question. For DG, the Company will use statistical verification, output profile, or meter data for DG systems installed in APS's service territory to track the displaced energy sales until December 31, 2014. After that time, the Company will only be permitted to use meter data to calculate DG system savings.

For EE, the lost energy sales and unrecovered costs will be demonstrated by the Measurement, Evaluation, and Reporting ("MER") conducted for EE programs by an outside consultant in support of APS's annual DSM Implementation Plan filing. The Company's programs and the associated energy savings will be independently reviewed every five years by an evaluator selected by Staff and paid for by APS. *See* Section 9.14(e). The first such review will occur in APS's next general rate case, or within five years of a Commission order in this case, whichever is sooner. In addition, to help facilitate the MER process and LFCR analysis, Section 9.15 requires APS to compile and make available to all parties to this case a technical reference manual that documents program and measure savings assumptions and incremental costs. The first version of this reference manual will be distributed no later than December 31, 2013, and would be updated annually as part of the DSM Implementation Plan process.

**Q. HOW WILL APS EDUCATE CUSTOMERS ABOUT THE LFCR?**

A. APS understands the importance of customer outreach regarding the LFCR to help customers understand what to expect from the adjustor and why it is necessary. Over the past year, APS has reached out to several customer groups to

help explain the need for a fixed cost recovery mechanism and attempt to allay customer concerns. In addition, the Company has published a website, www.azenergyfuture.com, which explains APS's rate request and the Settlement (including both revenue per customer decoupling and the LFCR proposal) in easy-to-understand terms. Pursuant to Section 9.9, APS will seek stakeholder input regarding the development of an additional customer outreach program to continue to inform and educate customers regarding the LFCR and the voluntary Opt-Out rate option. APS will thereafter implement that program.

**Q. DOES THE SETTLEMENT ALLOW THE COMMISSION TO REVIEW THE LFCR?**

A. Yes. The Settlement provides two means by which the Commission will be able to monitor the progress of the LFCR. No later than January 15 each year, APS must file an application with the Commission to adjust the LFCR charge. *See* Section 9.6. That filing will include reports identifying, among other things, how the LFCR was calculated, whether the recoverable fixed cost revenues exceed the one percent cap and, if so, by how much. So that the Commission may compare the LFCR to a revenue per customer decoupling model, the reports contained in the LFCR filing will also include a comparison of the revenues that would have been recovered had the Company's full decoupling proposal been adopted. The annual LFCR adjustment will not be effective until the Commission approves it.

In addition, Section 9.11 expressly authorizes the Commission to review the LFCR at any time, and requires that such a review be undertaken in APS's next general rate case. At that time, through the annual LFCR filing, the Commission will have the benefit of being able to compare what revenue the LFCR collected over the four-year period to what a revenue per customer decoupling model would have collected, of having data to know whether the one percent cap is

appropriate, and of understanding whether any other issues exist with the LFCR that require correction.

The Settlement also contemplates that the Commission might choose to suspend, terminate, or materially modify the LFCR prior to APS's next general rate case. If the Commission did so and also provided APS with alternative relief that adequately addressed the lost fixed cost revenue erosion resulting from that decision, APS would remain bound by the Settlement's four year rate moratorium. If, however, the Commission chose to terminate, suspend, or materially modify the LFCR and did not provide APS with an alternative means of recovering at least the amount of lost fixed costs that the proposed LFCR would recover, APS would need to be granted relief from either the relevant EE and DG requirements or the financial impacts of EE and DG until the cost recovery issue is addressed. *See* Section 9.13. If the Commission chose not to provide APS with alternative relief that adequately addresses fixed cost revenue erosion, APS would no longer be bound by the Settlement's four year rate moratorium. *See* Section 9.11.

These latter provisions are critical to address the issues specifically called out in Section 9.1: that "under APS's current volumetric rate design, the Company recovers a significant portion of its fixed costs of service through kilowatt-hour ("kWh") sales" and that "Commission rules related to EE and DG require APS to sell fewer kWh, which, in turn, prevents the Company from being able to recover a portion of the fixed costs of service embedded in its energy rates." By law, APS must have an opportunity to recover those lost fixed costs. If the Commission chooses not to do it through the LFCR as the Signatories propose, the problem must be otherwise addressed.

**Q. PLEASE DESCRIBE THE SETTLEMENT'S OTHER ENERGY EFFICIENCY PROVISIONS.**

A. Like its renewable energy provisions, the Settlement addresses certain ratemaking issues associated with the Company's DSM Adjustment Clause (the "DSMAC") and the annual DSM Implementation Plan filing. The first is to prevent APS from continuing to recover capital carrying costs (as defined in Section 8.1) associated with the Company's DSM-related capital investments through the DSMAC, except to the extent such investments have already been authorized by the Commission. Under Section 9.14(a), this change will begin with APS's 2013 DSM Implementation Plan filing.

The Settlement also modifies APS's performance incentive for DSM programming. As the table set forth in Section 9.14(b) illustrates, from the effective date of this Settlement to the Commission's adoption of any new performance incentive structure recommended in Section 9.14(d), APS will no longer receive a performance incentive above 8% of EE Net Benefits. And that 8% maximum incentive will apply only if APS achieves 105% or more of the Commission's EE standard.

Section 9.14(d) requires APS to work with Staff and other stakeholders to devise and file an entirely new performance incentive structure by the end of 2012. This new performance incentive structure will be designed to "optimize[] the connection between energy efficiency, rates and utility business incentives" and "create a clear connection between the level of performance incentive and achievement of cost-effective energy savings." Section 9.14(d) also holds this rate case open for the single purpose of allowing the Commission to consider and approve including the new performance incentive structure as part of the DSMAC prior to APS's next general rate case. Section 9.14(d) does not require the Commission to adopt a new performance incentive structure, and allows the

Commission to determine the plan year to which any new performance incentive structure adopted should apply. Signatories to the Settlement, however, will recommend that the Commission apply any new performance incentive structure that the Commission might adopt to the first plan year after its adoption. That recommendation will permit the Company to design a DSM Implementation Plan knowing what the new incentive structure requires.

The Settlement also requires APS to use the inputs and methods that Staff uses to calculate the present value of benefits and costs for DSM as part of the Societal Costs tests. However, it also provides that Staff will regularly re-evaluate their inputs and methods, considering comments from other stakeholders including APS.

Finally, Decision No. 71448 raised the issue of whether the $10 million of DSM costs that are currently collected through base rates should be transferred to the DSMAC so that all DSM costs would be recovered through a single source. That Decision did not resolve the issue, but instead required that it be addressed in this case. Section 9.16 addresses this question and retains the $10 million of DSM costs in base rates.

**Q. WHAT OTHER FINANCIAL PROVISIONS SUPPORT THE FOUR YEAR RATE CASE STAY OUT?**

A. As I mentioned previously, the base rate increase contained in the Settlement was not itself sufficient to maintain APS's financial health between July 1, 2011 and the next permitted adjustment of base rates in mid-2016 or later. In an effort to balance the goal of keeping base rates as low as possible in a difficult economic climate with the Company's need to improve financial performance, the Settlement includes mechanisms in addition to the LFCR and others addressed above to sustain APS's financial condition during the stay out. These include a

rate adjustment rider related to the Four Corners transaction (if it closes), modifications to the EIS, and a cost deferral related to potential changes in the Company's property tax rate. Each of these provisions is material to APS's financial condition and needed to allow the Company to agree to a four-year rate moratorium. I will discuss each of these in turn.

**1. Rate Rider Adjustment for the Four Corners Transaction.**

Section 10 of the Settlement holds this rate case open for the purpose of allowing APS to seek an adjustment rider related to its proposed Four Corners transaction, if the Commission authorizes APS to pursue the transaction and if the transaction closes. As discussed in the Four Corners docket, the opportunity for APS to pursue the Four Corners transaction resulted from a combination of California environmental regulations that prompted SCE to withdraw as a participant in the Four Corners plant and from federal environmental regulations that would require significant costs for APS to continue to operate its own Four Corners Units. APS has shown in the Four Corners docket that the Four Corners transaction is a far less expensive option for customers over the long term compared to any reasonable alternative.

Even so, the non-fuel related revenue requirement associated with the Four Corners transaction is significant – roughly $70 million dollars per year. APS would not be able to absorb costs of that magnitude from the anticipated October 2012 closing date until the Four Corners transaction (if it closes) is reflected in rates in a rate case that concludes mid-2016. Although APS has requested a cost deferral related to the Four Corners transaction in the Four Corners docket, parties to the Four Corners docket have disputed whether almost half of the revenue requirement associated with the Four Corners transaction should be included in any cost deferral granted. The Settlement would allow APS to seek

timely rate relief associated with the transaction to help mitigate the impact of a partial deferral, thus facilitating the closing of the transaction. The Settlement would also lower the balance of the cost deferral that APS hopes will be granted in the Four Corners docket, which would be significantly higher were it carried over to the Company's next rate case.

Specifically, the Settlement allows APS to seek an adjustment rider to reflect the Four Corners transaction in rates, should the Commission allow the Company to pursue the transaction and should the transaction close. Any such application would need to be filed by no later than December 31, 2013, and would address only (1) whether to reflect in rates the rate base and expense effects associated with the acquisition of SCE's share of Four Corners Units 4 and 5, the rate base and expense effects associated with the retirement of Units 1-3, and any cost deferral authorized in the Four Corners proceeding (all of which would require a prudency finding), and (2) whether to allow APS to amend the PSA Plan of Administration to include in the PSA the post-acquisition O&M expense associated with Four Corners Units 1-3 as a cost of producing off-system sales until closure of Units 1-3, provided that those costs do not exceed off-system sales revenue in any given year. Boiled to its essence, the second issue will allow APS to continue to operate Units 1-3 if doing so would lower PSA costs to customers. The Settlement prevents the Four Corners rider, if implemented, from taking effect any earlier than July 1, 2013. If approved, the rider will apply on an equal percentage basis on base rates across all customer classes.

From a procedural standpoint, the schedules required by Section 10.3, modeled after those filed in water company Arsenic Cost Recovery Adjustor proceedings, require APS to update certain of its financial statements so that the Commission may ensure that the additional revenue generated by the rate rider does not result

in a return on fair value rate base (including the additional Four Corners plant) in excess of that authorized in this Settlement. The Settlement prevents Signatories from raising any issues in the Four Corners rate adjustment proceeding other than those identified above. It also requires Signatories to process the rate adjustment request within a reasonable time.

**Q. DOES THE SETTLEMENT PROVISION THAT ALLOWS FOR AN ADJUSTMENT RIDER FOR THE FOUR CORNERS TRANSACTION MEAN THAT APS NO LONGER REQUIRES AN ACCOUNTING DEFERRAL ORDER IN THE FOUR CORNERS DOCKET?**

A. No, it does not. The Settlement does not permit any Four Corners adjustment rider from taking effect until at least July 1, 2013. A deferral order that permits APS to defer all or part of the Four Corners revenue requirement until then is necessary if APS is to have any opportunity to earn the 10% authorized ROE provided in this Settlement. The deferral authorization thus remains critical to consummation of the Four Corners Transaction.

**2. Modifications to the EIS.**

**Q. EARLIER, YOU MENTIONED THAT THE PROPOSED MODIFICATIONS TO THE EIS WERE MATERIAL TO THE COMPANY. PLEASE EXPLAIN THOSE MODIFICATIONS.**

A. Section 11 modifies APS's existing EIS, a surcharge that collects customer dollars to offset the cost associated with government-mandated environmental controls. The electric utility industry as a whole is currently in a major build cycle to support environmental compliance, among other things. A recent EEI study noted that environmental spend alone could cost the industry up to $200 billion by 2015. As discussed in the Direct Testimony of Mark Schiavoni, APS's fossil fleet faces several environmental-related regulatory pressures from dozens of federal, state, and local regulators. The rules that these regulators promulgate place increasing environmental-related cost pressures on APS. One need only look to the hundreds of millions of dollars of capital investment that APS expects

to be required to make to install Selective Catalytic Reduction equipment at Four Corners Units 4 and 5 in the next few years to appreciate the magnitude of the issue.

The changes to the EIS take a small step towards helping APS defray the impact of these environment-related cost pressures. As amended, APS will no longer receive customer dollars through the EIS to pay for government-mandated environmental controls. But, when APS invests capital to fund any environmental controls, the EIS will recover the associated capital carrying costs (as defined in the footnote to Section 8.1), subject to a cap equal to the charge that is now in place for the EIS. APS will remain responsible for demonstrating that the environmental controls were government-mandated and represented a reasonable and prudent means of meeting the associated environmental requirements.

Importantly, the EIS is currently collecting roughly $5 million from customers annually. On the rate effective date of this Settlement, the existing EIS will be reset to zero. APS Witness Snook describes the mechanics of the EIS in his Direct Settlement Testimony.

### 3. Cost Deferral Related to Changes in the Company's Property Tax Rate.

**Q. PLEASE DESCRIBE THE SETTLEMENT TERM THAT PROVIDES THE COMPANY WITH A COST DEFERRAL RELATED TO CHANGES IN ITS PROPERTY TAX RATE.**

A. An important financial component needed to sustain the four-year rate case stay out is the authority provided APS in Section 12 to defer certain portions of the Company's Arizona-related property tax expense each year above or below the test year level caused solely by changes to the applicable Arizona composite property tax rate. The Settlement does not permit APS to defer changes in

property tax expense attributable to changes in the assessed value of APS property.

For most companies, the assessed value of property rises and falls with its market value. As values fall (as has been the case for several years), the state and local taxing entities raise rates in an attempt to maintain revenues. An increase in the tax rate to account for any lower assessed value would not necessarily change that non-utility taxpayer's tax payment. For APS, however, the assessed value of APS property is based on its book value – a value that in total is usually steady or rising. Thus, when a taxing entity increases or decreases its tax rate, APS's tax payment necessarily rises or falls accordingly.

APS is concerned that its property tax rate and related property tax expense could increase significantly during the course of the Settlement stay-out period, much like it has over the past few years. To maintain APS's financial condition from the rate effective date of this Settlement through the end of its next rate case, the Settlement allows APS to defer 25% of changes in tax expense above the test year level related to property tax rate increases in 2012 (prorated with an assumed July 1 rate effective date), 50% of such changes in 2013, and 75% of such changes in 2014 and all subsequent years. The Settlement does not allow APS to apply interest to the deferred balance. Beginning on the rate effective date of the Company's next rate case, any positive balance in the final property tax rate deferral will be recovered from customers over ten years; any negative balance will be refunded to customers over a shorter three year period.

**Q. PLEASE DESCRIBE THE SETTLEMENT TERMS RELATING TO THE TCA.**

A. The Settlement addresses APS's transmission costs in two ways. First, Section 13.1 rejects APS's proposal that the level of transmission costs now in base rates

be moved to the TCA. Rather, those costs will remain in base rates until further order of the Commission.

Second, Sections 13.2 and 13.3 modify the TCA implementation process, consistent with the Commission's suggestion in Decision No. 72430 (June 27, 2011). By federal law, the FERC has exclusive jurisdiction over APS's transmission rates to both retail and wholesale customers. Retail customers benefit through this Commission's active participation in FERC formula rate proceedings – something that the Commission has been diligent about since the FERC formula rate was implemented. It makes little sense for the Commission to be required to reflect in a separate order a decision already made by and under the exclusive jurisdiction of another agency. The Settlement changes that process and permits the annual TCA adjustment to become effective June 1 of each year without the need for affirmative Commission approval, unless Staff requests review or otherwise ordered by the Commission.

**Q. PLEASE BRIEFLY DESCRIBE THE SETTLEMENT PROVISIONS RELATING TO LOW INCOME CUSTOMERS.**

A. The Settlement contains two provisions relating to low income programs. The second (Section 14.2) is a matter of rate design, which is addressed by APS Witness Miessner in his Direct Settlement Testimony. The first, Section 14.1, extends from a commitment that APS made in Decision No. 71448. In that case, APS agreed to augment the bill assistance program approved in Decision No. 69663 by funding, at its own expense, $5 million to assist customers whose incomes exceed 150% of the Federal Poverty Income Guidelines but are less than or equal to 200% of those Guidelines. For a variety of reasons, little of that $5 million has been used today, notwithstanding the unfortunate state of the economy. So that additional low income customers may benefit from that $5 million contribution, the Settlement allows any funds remaining of that $5 million

funding commitment to be used to assist additional customers – those whose incomes fall below 150% of the Federal Poverty Income Guidelines.

**Q. DOES THE SETTLEMENT CONTAIN ANY PROVISIONS RELATING TO SERVICE SCHEDULE 3, CUSTOMER LINE EXTENSIONS?**

A. Yes. During 2011, APS and stakeholders in the Company's line extension policy worked together to resolve a significant dispute relating to changes that had been made to Service Schedule 3 in the Company's last two rate cases. A settlement of that dispute, reflected in Version 12 of Service Schedule 3, was approved by this Commission in Decision No. 72684. Version 12 cannot be implemented outside of a rate case. Section 15.1 of the Settlement requires Version 12 to become effective on the rate effective date of this rate case.

**Q. PLEASE ADDRESS THE SETTLEMENT PROVISION RELATING TO BILL PRESENTATION.**

A. Prior to filing the rate application underlying this Settlement, APS held a series of technical conferences with rate case stakeholders to discuss its anticipated filing and identify issues that the parties might seek to raise during the rate proceeding. The format of the Company's customer bill arose as one such issue, engendering a good deal of discussion and healthy debate about what type of information the bill should show, what items should be consolidated or differentiated, and whether there were any legal limits to how APS could change its bill format. In the end, the Signatories agreed that the issue should be resolved outside the context of this rate case.

The Settlement thus requires APS to initiate stakeholder meetings to address issues related to the APS bill presentation, with a goal of making the bill easier for customers to understand. APS will initiate those meetings within 90 days following approval of the Settlement, and must ultimately file an application with the Commission for whatever authorization is needed to modify its bill format.

That filing must also explain how the APS bill presentation proposal reflects the input of participants received during the stakeholder meetings.

**Q. THE AGREEMENT CONTAINS SEVERAL PROVISIONS RELATING TO EXPERIMENTAL RATE SCHEDULE AG-1 AND OTHER RATE MATTERS. PLEASE BRIEFLY DESCRIBE THOSE REGARDING RATE SCHEDULE AG-1.**

A. Experimental Rate Schedule AG-1 is a buy-through rate for commercial and industrial customers, detailed in Attachment J to the Settlement. The program spans a limited four year duration, with participation capped at 200 MW. APS Witness Miessner describes the mechanics of Experimental Rate Schedule AG-1 in detail in his Direct Settlement Testimony.

**Q. WHY DID APS PROPOSE EXPERIMENTAL RATE SCHEDULE AG-1?**

A. Because the Company thought that such a rate might make sense for some of our large customers, and it wanted to test the concept by offering a limited program that would allow APS to gather information regarding whether a rate of this type is operationally possible or economically feasible. APS currently has no way to know whether a buy-through rate will benefit the customer receiving the rate, or whether or how the displaced capacity resulting from such a rate may affect other APS customers. APS believes that this limited program will provide useful information regarding third-party participation in the generation and provision of electricity in Arizona. This rate schedule does not nor is it intended to address the subject of retail competition, nor does it circumvent in any way the Commission's role in evaluating that issue as a matter of policy.

**Q. DOES THE SETTLEMENT CONTAIN ANY OTHER RATE SCHEDULE MATTER PROVISIONS?**

A. Section XVII of the Agreement contains provisions for other rate schedule matters, which are detailed in Attachment K to the Settlement. Mr. Miessner elaborates on the rate design elements of the Settlement in his Direct Settlement Testimony.

V. CONCLUSION

**Q. DO YOU HAVE ANY CONCLUDING REMARKS?**

A. APS appreciates the dedication and commitment of all of the parties for their work in diligently and efficiently resolving a complex rate case that addresses a wide range of important ratemaking issues. The Settlement before the Commission is appealing from many perspectives, as I discussed in detail above. The widespread support for the Settlement by the many varied parties who spent weeks in detailed discussions over its terms is probably the best evidence that the Settlement is in the public interest. I believe that this Settlement, on balance, results in just and reasonable rates for our customers and should be approved.

**Q. DOES THIS CONCLUDE YOUR DIRECT SETTLEMENT TESTIMONY?**

A. Yes.

aps

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January 9, 2012

Docket Control
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

RE: Arizona Public Service Company 2011 Rate Case Settlement Agreement
E-01345A-11-0224

To whom it may concern:

The Signatories to the Arizona Public Service Company ("APS") Rate Case Settlement Agreement ("Settlement") filed in the above-captioned docket agreed that APS should file this letter to inform the Commission and the public about the customer bill impacts potentially associated with the Settlement, both on the rate effective date and afterwards. As described in greater detail below, several factors associated with the Settlement may impact customer bills, and several factors that are independent of the Settlement may also impact bills:

- First and most immediately, the Settlement results in a modest rate reduction across customer classes, generally around one percent, on the assumed rate effective date (July 1, 2012) and for the remainder of 2012.

- Second, the Settlement will defer resetting the existing Power Supply Adjustor ("PSA") to reflect the new base fuel rates established in the Settlement until early 2013. This will allow customers to continue to receive a credit for the PSA for the rest of this year, and the PSA bill will be reset as it normally is in February 2013.

- Third, the Settlement would allow APS to seek an adjustment rider related to its potential acquisition of Southern California Edison's ("SCE") interest in Four Corners Power Plant Units 4 and 5 and retirement of Units 1-3 (the "proposed Four Corners transaction"), if the Commission authorizes APS to pursue the acquisition and if the transaction closes. The "Four Corners" adjustment is itself composed of two parts, each dependent upon several contingencies. The first part is the impact of the Four Corners transaction on the 2013 PSA reset should the transaction close prior to December 31, 2012. The second part, which is subject to yet further contingencies, would largely center on the non-fuel costs associated with the Four Corners transaction and would take effect no earlier than July 1, 2013.

The potential customer bill impact associated with each of these changes is explained below and illustrated in detail in the attachment.

**1. Bill Impact on the Rate Effective Date.**

If the Commission approves the Settlement so that rates take effect on July 1, 2012 as requested, APS customers will see on average a slight bill *decrease* during the remainder of 2012. The average residential customer's monthly bill, for example, will go down by about 1.0%. This customer benefit is caused by (1) APS receiving less rate relief than it had originally requested; (2) a decline in fuel costs; and (3) the Company's agreement to delay the reset of the PSA rate until February 2013, thus continuing the current PSA credit as described below.

**2. Bill Impact Resulting from Existing Adjustment Mechanisms.**

Of the existing Commission-approved adjustors that affect customer bills between rate cases, only the PSA has a bill impact that is directly affected by the Settlement. There are two components to the PSA: a forward component that will reflect anticipated 2013 fuel costs and a historical component that will collect any under-collected 2012 fuel costs (or refund any over-collection). Although both the forward and historical components may be affected by changes in fuel costs, weather or economic conditions between now and February 2013, APS estimates that average residential customer bills will increase by 2.5% above what they had been just before Settlement rates took effect when the PSA rate is reset in February of 2013.[1] Importantly, although the PSA Plan of Administration would allow the PSA rate to be reset at the same time when new rates take effect, an annual reset occurs each February regardless of whether a rate case has been filed.

**3. Bill Impact Resulting from Potential Four Corners Acquisition.**

Finally, the Settlement contains a provision that would allow APS to seek an adjustment rider related to its proposed Four Corners transaction, if the Commission authorizes APS to pursue the transaction and if the transaction closes. Under the terms of the Settlement, such a rider, if implemented, may not become effective any earlier than July 1, 2013. Any bill impact associated with this adjustment is contingent on subsequent Commission actions and other future events that may or may not occur. The bill impact reflecting the Four Corners rider presented in the attached assumes, for example, that the Commission and other regulators (including the California Public Utilities Commission and the Federal Energy Regulatory Commission) allow the transaction to proceed, that all other conditions to closing are satisfied, and that the transaction is consummated in the fourth quarter of 2012. It further assumes that the Commission will grant the Company's request that it be allowed to operate Four Corners Units 1-3 through 2013 and recover the associated Operations and Maintenance expense through the PSA only and for so long as off-system sales from that additional capacity benefit customers more than the continued cost of operating those Units. None of these issues is specifically resolved in this Agreement.

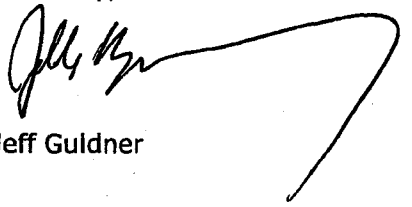
Completing the Four Corners transaction as described above could result in average residential customer bills increasing by slightly more than 3% after July 2013. Importantly, however, the rate treatment of Four Corners was not part of the bill impact analysis related to the Company's original rate case application. The

[1] Again, this analysis assumes that the Commission authorizes APS to pursue the proposed Four Corners transaction, the transaction closes prior to December 31, 2012, and also that Four Corners Units 1-3 continue to operate through the balance of 2013, which results in lower PSA costs.

opportunity for APS to pursue the Four Corners transaction resulted from a combination of California environmental regulations that prompted SCE to withdraw as a participant in the Four Corners plant and from federal environmental regulations that would require significant costs for APS to continue to operate its own Four Corners units. In the separate Four Corners docket, APS has shown that the Four Corners transaction is a far less expensive option for customers over the long term than any other alternative. The Settlement proposal would facilitate the timely closing of the transaction. It would also lower the balance of the cost deferral that APS has requested in the Four Corners docket, which would be significantly higher were it carried over to the Company's next rate case, causing a higher customer bill impact.

I hope this letter provides additional information regarding the potential customer bill impacts associated with this Settlement, and look forward to discussing this in more detail at the hearing. If you have any questions, or would like additional clarification or information, please let me know by way of a letter in this rate case docket, to which APS will promptly respond.

Sincerely,



Jeff Guldner

JBG/dk

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this 9th day of January, 2012 to:

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**ARIZONA PUBLIC SERVICE COMPANY**
**Estimated Annual Bill Impacts of Proposed and Settlement Rates**
**Includes PSA and RES Impacts**

| | Application | Rates on 6/30/2012 | Settlement 7/1/2012 |
|---|---|---|---|
| **Residential (Rate E-12)** | Annual Average Monthly Bill (1,2) | Annual Average Monthly Bill (2) | Annual Average Monthly Bill (3) |
| Average kWh per Month | 691 | 691 | 691 |
| Base Rates | $ 89.31 | $ 86.40 | $ 86.44 |
| PSA- Forward Component | (0.01) | (3.19) | (3.19) |
| PSA - Historical Component | (0.32) | 0.30 | 0.30 |
| 4 Corners | - | - | - |
| TCA | 1.48 | 2.91 | 2.91 |
| EIS | - | 0.11 | - |
| RES | 1.99 | 3.84 | 2.78 |
| DSMAC | 1.88 | 1.88 | 1.88 |
| Total | $ 94.33 | $ 92.25 | $ 91.12 |
| **Bill Impact** | **$ 4.33** | | **$ (1.13)** |
| Percent Bill Impact | **4.81%** | | **-1.22%** |

| | | | |
|---|---|---|---|
| **Residential (Average - All Rates)** | Annual Average Monthly Bill (1,2) | Annual Average Monthly Bill (2) | Annual Average Monthly Bill (3) |
| Average kWh per Month | 1,100 | 1,100 | 1,100 |
| Base Rates | $ 128.80 | $ 123.90 | $ 123.83 |
| PSA- Forward Component | (0.02) | (5.08) | (5.08) |
| PSA - Historical Component | (0.51) | 0.49 | 0.49 |
| 4 Corners | - | - | - |
| TCA | 2.36 | 4.63 | 4.63 |
| EIS | - | 0.18 | - |
| RES | 1.99 | 3.84 | 2.78 |
| DSMAC | 2.99 | 2.99 | 2.99 |
| Total | $ 135.61 | $ 130.95 | $ 129.64 |
| **Bill Impact** | **$ 8.36** | | **$ (1.31)** |
| Percent Bill Impact | **6.57%** | | **-1.00%** |

| | | | |
|---|---|---|---|
| **Commercial (Rate E-32, 0-20 kW)** | Annual Average Monthly Bill (1,2) | Annual Average Monthly Bill (2) | Annual Average Monthly Bill (3) |
| Average kWh per Month | 1,430 | 1,430 | 1,430 |
| Base Rates | $ 206.85 | $ 202.30 | $ 206.23 |
| PSA- Forward Component | (0.02) | (6.60) | (6.60) |
| PSA - Historical Component | (0.66) | 0.63 | 0.63 |
| 4 Corners | - | - | - |
| TCA | 2.29 | 3.53 | 3.53 |
| EIS | - | 0.23 | - |
| RES | 7.12 | 13.71 | 9.96 |
| DSMAC | 3.89 | 3.89 | 3.89 |
| Total | $ 219.47 | $ 217.69 | $ 217.64 |
| **Bill Impact** | **$ 4.37** | | **$ (0.05)** |
| Percent Bill Impact | **2.03%** | | **-0.02%** |

**ARIZONA PUBLIC SERVICE COMPANY**
**Estimated Annual Bill Impacts of Proposed and Settlement Rates**
**Includes PSA and RES Impacts**

| Commercial (Rate E-32, > 20 kW) | Application Annual Average Monthly Bill (1,2) | Rates on 6/30/2012 Annual Average Monthly Bill (2) | Settlement 7/1/2012 Annual Average Monthly Bill (3) |
|---|---|---|---|
| Average kWh per Month | 62,238 | 62,238 | 62,238 |
| Base Rates | $ 6,142.98 | $ 5,977.26 | $ 5,986.64 |
| PSA- Forward Component | (0.88) | (287.36) | (287.36) |
| PSA - Historical Component | (28.69) | 27.33 | 27.33 |
| 4 Corners | - | - | - |
| TCA | 144.81 | 163.78 | 163.78 |
| EIS | - | 9.96 | - |
| RES | 73.92 | 142.44 | 103.44 |
| DSMAC | 189.52 | 189.52 | 189.52 |
| Total | $ 6,521.66 | $ 6,222.93 | $ 6,183.35 |
| **Bill Impact** | **$ 401.72** | | **$ (39.58)** |
| Percent Bill Impact | **6.56%** | | **-0.64%** |

| Industrial (Rate E34/35) | Annual Average Monthly Bill (1,2) | Annual Average Monthly Bill (2) | Annual Average Monthly Bill (3) |
|---|---|---|---|
| Average kWh per Month | 3,581,412 | 3,581,412 | 3,581,412 |
| Base Rates | $ 257,184.98 | $ 249,125.86 | $ 244,035.16 |
| PSA- Forward Component | (50.14) | (16,535.38) | (16,535.38) |
| PSA - Historical Component | (1,651.03) | 1,572.24 | 1,572.24 |
| 4 Corners | - | - | - |
| TCA | 1,710.44 | 4,061.46 | 4,061.46 |
| EIS | - | 573.03 | - |
| RES | 221.77 | 427.33 | 310.33 |
| DSMAC | 6,395.98 | 6,395.98 | 6,395.98 |
| Total | $ 263,812.00 | $ 245,620.52 | $ 239,839.79 |
| **Bill Impact** | **$ 25,818.72** | | **$ (5,780.73)** |
| Percent Bill Impact | **10.85%** | | **-2.35%** |

Notes:
(1) From CAM-14 In Application
(2) Bill includes impact of proposed revised General Rate Case charges, and PSA and RES surcharges reset with implementation of new rates
Bill excludes regulatory assessment charge, taxes and fees. Adjustor levels in effect as of March 1, 2011
(3) 7/1/2012 - includes settlement rates, transfer from RES to base rates, and EIS set to zero. PSA based on 2/1/2012 rate

**ARIZONA PUBLIC SERVICE COMPANY**
**Estimated Annual Bill Impacts of Proposed and Settlement Rates**
**Includes PSA and RES Impacts**

**NOTE: PSA RESET OCCURS EACH FEBRUARY REGARDLESS OF WHETHER A RATE CASE HAS BEEN FILED**

| | Rates on 7/1/2012 | Potential Impact of PSA Reset in 2013 | |
|---|---|---|---|
| **Residential (Rate E-12)** | **Annual Average Monthly Bill (4,5)** | **Annual Average Monthly Bill (4,6)** | |
| Average kWh per Month | 691 | 691 | |
| Base Rates | $ 86.44 | $ 86.44 | |
| PSA- Forward Component | (3.19) | (2.12) | |
| PSA - Historical Component | 0.30 | 2.10 | |
| 4 Corners | - | - | |
| TCA | 2.91 | 2.91 | |
| EIS | - | - | |
| RES | 2.78 | 2.78 | |
| DSMAC | 1.88 | 1.88 | |
| Total | $ 91.12 | $ 93.99 | Equates to a 1.9% bill |
| **Bill Impact** | | **$ 2.87** | impact compared to |
| Percent Bill Impact | | **3.15%** | 6/30/2012 rates |

| | | | |
|---|---|---|---|
| **Residential (Average - All Rates)** | **Annual Average Monthly Bill (4,5)** | **Annual Average Monthly Bill (4,6)** | |
| Average kWh per Month | 1,100 | 1,100 | |
| Base Rates | $ 123.83 | $ 123.83 | |
| PSA- Forward Component | (5.08) | (3.37) | |
| PSA - Historical Component | 0.49 | 3.34 | |
| 4 Corners | - | - | |
| TCA | 4.63 | 4.63 | |
| EIS | - | - | |
| RES | 2.78 | 2.78 | |
| DSMAC | 2.99 | 2.99 | |
| Total | $ 129.64 | $ 134.20 | Equates to a 2.5% bill |
| **Bill Impact** | | **$ 4.56** | impact compared to |
| Percent Bill Impact | | **3.52%** | 6/30/2012 rates |

| | | |
|---|---|---|
| **Commercial (Rate E-32, 0-20 kW)** | **Annual Average Monthly Bill (4,5)** | **Annual Average Monthly Bill (4,6)** |
| Average kWh per Month | 1,430 | 1,430 |
| Base Rates | $ 206.23 | $ 206.23 |
| PSA- Forward Component | (6.60) | (4.38) |
| PSA - Historical Component | 0.63 | 4.34 |
| 4 Corners | - | - |
| TCA | 3.53 | 3.53 |
| EIS | - | - |
| RES | 9.96 | 9.96 |
| DSMAC | 3.89 | 3.89 |
| Total | $ 217.64 | $ 223.57 |
| **Bill Impact** | | **$ 5.93** |
| Percent Bill Impact | | **2.72%** |

**ARIZONA PUBLIC SERVICE COMPANY**
**Estimated Annual Bill Impacts of Proposed and Settlement Rates**
**Includes PSA and RES Impacts**

**NOTE: PSA RESET OCCURS EACH FEBRUARY REGARDLESS OF WHETHER A RATE CASE HAS BEEN FILED**

| Commercial (Rate E-32, > 20 kW) | Rates on 7/1/2012 Annual Average Monthly Bill (4,5) | Potential Impact of PSA Reset in 2013 Annual Average Monthly Bill (4,6) |
|---|---|---|
| Average kWh per Month | 62,238 | 62,238 |
| Base Rates | $ 5,986.64 | $ 5,986.64 |
| PSA- Forward Component | (287.36) | (190.39) |
| PSA - Historical Component | 27.33 | 188.77 |
| 4 Corners | - | - |
| TCA | 163.78 | 163.78 |
| EIS | - | - |
| RES | 103.44 | 103.44 |
| DSMAC | 189.52 | 189.52 |
| Total | $ 6,183.35 | $ 6,441.76 |
| **Bill Impact** | | **$ 258.41** |
| Percent Bill Impact | | **4.18%** |

| Industrial (Rate E34/35) | Annual Average Monthly Bill (4,5) | Annual Average Monthly Bill (4,6) |
|---|---|---|
| Average kWh per Month | 3,581,412 | 3,581,412 |
| Base Rates | $ 244,035.16 | $ 244,035.16 |
| PSA- Forward Component | (16,535.38) | (10,955.54) |
| PSA - Historical Component | 1,572.24 | 10,862.43 |
| 4 Corners | - | - |
| TCA | 4,061.46 | 4,061.46 |
| EIS | - | - |
| RES | 310.33 | 310.33 |
| DSMAC | 6,395.98 | 6,395.98 |
| Total | $ 239,839.79 | $ 254,709.82 |
| **Bill Impact** | | **$ 14,870.03** |
| Percent Bill Impact | | **6.20%** |

Notes:
(4) Bill excludes regulatory assessment charge, taxes and fees
(5) 7/1/2012 - Includes settlement rates, transfer from RES to base rates, and EIS set to zero. PSA based on 2/1/2012 rate
(6) 2/1/2013 - APS would have reset the PSA adjustor regardless of the current rate case. Projected PSA reset, under-collection in 2012 due to base fuel rate change in 7/1/12, FC 1-3 Off-system sales margin, and FC 4-5 base fuel rate change due to acquisition

**ARIZONA PUBLIC SERVICE COMPANY**
**Estimated Annual Bill Impacts of Proposed and Settlement Rates**
***Includes PSA and RES Impacts***

| | Bill Impact of PSA Reset in 2013 | Potential Impact of ACC Approval of FC |
|---|---|---|
| **Residential (Rate E-12)** | **Annual Average Monthly Bill (7,8)** | **Annual Average Monthly Bill (7,9)** |
| Average kWh per Month | 691 | 691 |
| Base Rates | $ 86.44 | $ 86.44 |
| PSA- Forward Component | (2.12) | (1.31) |
| PSA - Historical Component | 2.10 | 2.10 |
| 4 Corners | - | 2.08 |
| TCA | 2.91 | 2.91 |
| EIS | - | - |
| RES | 2.78 | 2.78 |
| DSMAC | 1.88 | 1.88 |
| Total | $ 93.99 | $ 96.88 |
| **Bill Impact** | | **$ 2.89** |
| Percent Bill Impact | | **3.07%** |

| | | |
|---|---|---|
| **Residential (Average - *All* Rates)** | **Annual Average Monthly Bill (7,8)** | **Annual Average Monthly Bill (7,9)** |
| Average kWh per Month | 1,100 | 1,100 |
| Base Rates | $ 123.83 | $ 123.83 |
| PSA- Forward Component | (3.37) | (2.09) |
| PSA - Historical Component | 3.34 | 3.34 |
| 4 Corners | - | 2.97 |
| TCA | 4.63 | 4.63 |
| EIS | - | - |
| RES | 2.78 | 2.78 |
| DSMAC | 2.99 | 2.99 |
| Total | $ 134.20 | $ 138.45 |
| **Bill Impact** | | **$ 4.25** |
| Percent Bill Impact | | **3.17%** |

| | | |
|---|---|---|
| **Commercial (Rate E-32, 0-20 kW)** | **Annual Average Monthly Bill (7,8)** | **Annual Average Monthly Bill (7,9)** |
| Average kWh per Month | 1,430 | 1,430 |
| Base Rates | $ 206.23 | $ 206.23 |
| PSA- Forward Component | (4.38) | (2.71) |
| PSA - Historical Component | 4.34 | 4.34 |
| 4 Corners | - | 4.95 |
| TCA | 3.53 | 3.53 |
| EIS | - | - |
| RES | 9.96 | 9.96 |
| DSMAC | 3.89 | 3.89 |
| Total | $ 223.57 | $ 230.19 |
| **Bill Impact** | | **$ 6.62** |
| Percent Bill Impact | | **2.96%** |

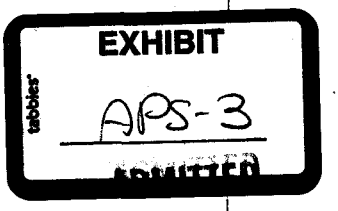
**ARIZONA PUBLIC SERVICE COMPANY**
**Estimated Annual Bill Impacts of Proposed and Settlement Rates**
**Includes PSA and RES Impacts**

| Commercial (Rate E-32, > 20 kW) | Bill Impact of PSA Reset in 2013 Annual Average Monthly Bill (7,8) | Potential Impact of ACC Approval of FC Annual Average Monthly Bill (7,9) |
|---|---|---|
| Average kWh per Month | 62,238 | 62,238 |
| Base Rates | $ 5,986.64 | $ 5,986.64 |
| PSA- Forward Component | (190.39) | (117.94) |
| PSA - Historical Component | 188.77 | 188.77 |
| 4 Corners | - | 143.68 |
| TCA | 163.78 | 163.78 |
| EIS | - | - |
| RES | 103.44 | 103.44 |
| DSMAC | 189.52 | 189.52 |
| Total | $ 6,441.76 | $ 6,657.89 |
| **Bill Impact** | | **$ 216.13** |
| Percent Bill Impact | | **3.36%** |

| Industrial (Rate E34/35) | Annual Average Monthly Bill (7,8) | Annual Average Monthly Bill (7,9) |
|---|---|---|
| Average kWh per Month | 3,581,412 | 3,581,412 |
| Base Rates | $ 244,035.16 | $ 244,035.16 |
| PSA- Forward Component | (10,955.54) | (6,786.78) |
| PSA - Historical Component | 10,862.43 | 10,862.43 |
| 4 Corners | - | 5,856.85 |
| TCA | 4,061.46 | 4,061.46 |
| EIS | - | - |
| RES | 310.33 | 310.33 |
| DSMAC | 6,395.98 | 6,395.98 |
| Total | $ 254,709.82 | $ 264,735.43 |
| **Bill Impact** | | **$ 10,025.61** |
| Percent Bill Impact | | **3.94%** |

Notes:
(7) Bill excludes regulatory assessment charge, taxes and fees. Adjustor levels in effect as of March 1, 2011
(8) 2/1/2013 - APS would have reset the PSA adjustor regardless of the current rate case. Projected PSA reset, under-collection in 2012 due to base fuel rate change in 7/1/12, FC 1-3 Off-system sales margin, and FC 4-5 base fuel rate change due to acquisition
(9) 7/1/2013 - FC 1-3 O&M base fuel rate transfer to PSA, and FC 4-5 non-fuel rate increase

APS Exhibit 3




# RESPONSIVE SETTLEMENT TESTIMONY OF JEFFREY B. GULDNER

**On Behalf of Arizona Public Service Company**

**Docket No. E-01345A-11-0224**

**January 25, 2012**

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**RESPONSIVE SETTLEMENT TESTIMONY OF JEFFREY B. GULDNER ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY (Docket No. E-01345A-11-0224)**

I. INTRODUCTION

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

A. My name is Jeffrey B. Guldner. My business address is 400 N. 5th Street, Phoenix, Arizona, 85004. I am Vice President of Rates and Regulation for Arizona Public Service Company ("APS" or "Company").

**Q. DID YOU SUBMIT TESTIMONY IN THIS PROCEEDING THAT PROVIDES YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?**

A. Yes, in the Direct Testimony filed on June 1, 2011 and the Direct Settlement Testimony filed on January 18, 2012.

**Q. WHAT IS THE PURPOSE OF YOUR RESPONSIVE SETTLEMENT TESTIMONY?**

A. My Direct Settlement Testimony supported the Settlement Agreement ("Settlement") that was filed with the Commission on January 6, 2012 and recommends that the Commission approve it. In this Responsive Settlement Testimony, it will not be my intent to take issue with every statement made or conclusion drawn by either the witnesses supporting the Settlement or those partially opposing the Settlement. Each of the Settling Parties, and for that matter the parties in partial opposition, view the Settlement and the issues resolved therein from their own perspective – a perspective that may or may not be shared by the Company. That also is something that should not be a surprise to anyone. Rather, my Responsive Settlement Testimony will focus on the testimonies of Ralph Cavanagh on behalf of the Natural Resources Defense Council ("NRDC") and Jeff Schlegel on behalf of Southwest Energy Efficiency Project ("SWEEP"), who are the only two witnesses registering even partial opposition to the Settlement.

II. SUMMARY

**Q. PLEASE SUMMARIZE YOUR RESPONSIVE SETTLEMENT TESTIMONY.**

A. Both NRDC witness Cavanagh and SWEEP witness Schlegel exaggerate what they perceive to be the deficiencies of the Lost Fixed Cost Recovery ("LFCR") mechanism adopted by the Settlement and fail to acknowledge the LFCR's benefits. APS needed an effective rate mechanism to allow it to pursue the level of demand-side management ("DSM") and distributed generation ("DG") authorized by the Commission. Customer groups and Staff wanted the protections they associated with a more limited and targeted mechanism than full revenue per customer decoupling ("Full Decoupling"). The Settlement strikes a balance between these interests while not limiting the Commission's authority to determine DSM and/or DG policy. Finally, the residential "opt-out" rate is an important, perhaps critical, feature of the Settlement to several of the Settling Parties representing consumer interests and does not affect the existing incentive of residential customers to manage their energy usage.

III. REBUTTAL TO NRDC AND SWEEP

A. *The Perfect is the Enemy of the Good*

**Q. NRDC AND SWEEP ARGUE THAT FULL DECOUPLING IS SUPERIOR TO THE LFCR. DO YOU AGREE?**

A. From the Company's perspective, the issue is one of balance. Obviously, APS proposed full decoupling in its Direct Testimony filed June 1, 2011, and thus I am not going to tell the Commission that Full Decoupling would not remove the current financial disincentive to the Company presented by energy efficiency and DG. However, the LFCR is also sufficient for that purpose at this time and represented a balanced mechanism that could garner the broad support necessary to reach a comprehensive Settlement.

**Q. COULD THERE HAVE BEEN A BROADLY SUPPORTED SETTLEMENT THAT INCLUDED FULL DECOUPLING**

A. In my opinion, the answer is clearly no. Indeed, it is precisely the narrower scope of the LFCR and the consequent ability to craft a reasonable residential "opt-out" rate that allowed the 22 Settling Parties to reach the consensus represented by the Settlement. For APS to insist on Full Decoupling would have been tantamount to saying the Company was unwilling to compromise with Staff and customer representatives such as RUCO, AARP, FEA, Kroger, Wal-Mart and AECC. Thus, whether or not Full Decoupling is regarded as the "perfect" solution to the problem of unrecovered fixed costs attributable to DSM and DG, the LFCR mechanism is clearly a good resolution to that problem which APS was not prepared to forego in this Docket.

**Q. IS THE LFCR INCONSISTENT WITH THE COMMISSION'S POLICY STATEMENT ON DECOUPLING?**

A. No. Although the Policy Statement did express a general preference for Full Decoupling, it clearly allowed for alternatives that fit the particular circumstances of the utility in question. *See* Policy Statement No. 3 at page 20. In this case, the particular circumstance for APS is the need to have a rate mechanism that has broad support from the very customers that will either be subject to the mechanism or have their rates restructured to account for lost fixed cost recovery due to DSM and DG. The Settlement in general and the LFCR in particular has precisely that broad support.

B. *NRDC and SWEEP have exaggerated the Perceived Deficiencies of the LFCR.*

**Q. SWEEP CONTENDS THAT THE SETTLEMENT SOMEHOW CONSTRAINS THE COMMISSION'S AUTHORITY RELATING TO DSM AND DG? (SETTLEMENT TESTIMONY OF JEFF SCHLEGEL AT 4.) IS THAT AN ACCURATE READING OF THE SETTLEMENT?**

A. No. Rather, the Settlement's proposed LFCR provides fixed cost recovery from whatever level of DSM and DG the Commission authorizes and at whatever pace

the Commission authorizes. The LFCR thus enhances the Commission's policy flexibility.

**Q. BUT DOES NOT THE SETTLEMENT LIMIT THE COMMISSION'S ABILITY TO CONSIDER FULL DECOUPLING IN THIS PROCEEDING? (SETTLEMENT TESTIMONY OF JEFF SCHLEGEL AT 4.)**

A. Absolutely not. Under terms of the Settlement, the Commission is not bound to make any particular resolution of the unrecovered fixed cost problem and could adopt Full Decoupling. *See* Settlement at §§9.13, 20.2 and 20.4. NRDC witness Cavanagh acknowledges that the Commission retains such an option. *See* Settlement Testimony of Ralph Cavanagh at 5. However, that could well result in several Signatories withdrawing their support for the Settlement. *See* Settlement at §20.5. A principal benefit of any settlement is the broad consensus it represents on a number of issues, of which unrecovered fixed costs is merely one.

**Q. DOES THE LFCR CREATE AN INCENTIVE FOR APS TO INFLATE THE SALES LOST TO DSM AND DG?**

A. I don't think so. The LFCR does not rely on the Company's estimates of lost sales, but on the measurement, evaluation and reporting ("MER") process conducted by an independent MER consultant on an after-the-fact basis (in the case of DSM) and on actual metered output (or its statistical equivalent) of DG installations. Moreover, the savings attributable to DSM will have a further independent review every five years, beginning with the Company's next general rate case. *See* Settlement at §§ 9.6 and 9.14(e).

**Q. IS APS CONCERNED THAT THE DETERMINATION OF LOST SALES ATTRIBUTABLE TO DSM AND DG UNDER THE LFCR WILL BE CONTROVERSIAL?**

A. This was originally a concern of the Company. However, the Settlement's determination that the already in place MER process for DSM programs and the metered output from DG are dispositive of the level of lost APS sales for

purposes of the LFCR alleviates that concern and is further evidence that APS cannot "game" the LFCR mechanism. *See* Settlement at §9.6.

C. *The Residential "Opt-Out" Rate Option does not Discourage Energy Efficiency.*

**Q. DOES THE RESIDENTIAL "OPT-OUT" RATE DISCOURAGE ENERGY EFFICIENCY" AS ALLEGED BY NRDC AND SWEEP? (SETTLEMENT TESTIMONIES OF RALPH CAVANAGH AND JEFF SCHLEGEL AT 6.)**

A. Absolutely not. This is essentially the same argument that opponents of Full Decoupling have made about the small annual adjustments to rates possible under that mechanism – an argument rejected by both NRDC and SWEEP in this and other proceedings. We are not talking about moving to a fixed/variable pricing regime for electricity, but rather a modest increase in one rate element. This small increase in the basic service charge in the residential "opt-out" is analogous to the price of gasoline dropping by about one percent per gallon. Who would seriously argue that such a small change would discourage consumers from buying fuel-efficient cars? Moreover, in this case there is, in fact, no decrease in the current per kWh charge in the residential "opt-out" rate, thus mooting even this already weak argument against the LFCR mechanism.

## IV. CONCLUSION

**Q. DO YOU HAVE ANY CONCLUDING REMARKS?**

A. APS strongly supports the Settlement. The Company was willing to compromise on the issue of Full Decoupling in the interest of reaching consensus on the LFCR and other critical issues. APS believes that the LFCR can allow the Commission to pursue the levels of DSM and DG that this Commission, as a matter of policy, finds appropriate during the term of the Settlement and urges that the Commission adopt this and other provisions of the Settlement as being in the public interest.

**Q. DOES THIS CONCLUDE YOUR RESPONSIVE SETTLEMENT TESTIMONY?**

Yes.

APS Exhibit 4

EXHIBIT
APS-4
ADMITTED

# TESTIMONY OF DONALD G. ROBINSON

**On Behalf of Arizona Public Service Company**

**Docket No. E-01345A-11-_____**

June 1, 2011

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**TESTIMONY OF DONALD G. ROBINSON**
**ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY**
**(Docket No. E-01345A-11-____)**

I. INTRODUCTION

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

A. My name is Donald G. Robinson. My business address is 400 North 5th Street, Phoenix, Arizona 85004. I am President and Chief Operating Officer of Arizona Public Service Company ("APS" or "Company"). In that capacity, I am responsible for all aspects of APS operations, including fossil generation, transmission, distribution, customer service, marketing and trading, resource planning, renewable resources, energy efficiency, and general administrative functions.

**Q. WHAT IS YOUR PROFESSIONAL BACKGROUND?**

A. I joined APS in 1978, in the Company's accounting department. In 1981, I became the Manager of Regulatory Affairs and in 1996, Director of Pricing, Rates, Regulation, and Planning. In 2001, I was named the Vice President of Regulation and Planning of Pinnacle West Capital Corporation, and was responsible for regulatory policies and activities before the Arizona Corporation Commission ("Commission") and the Federal Energy Regulatory Commission ("FERC"), as well as for corporate planning. I was thereafter named Senior Vice President of Administration and Planning of APS. I assumed my current role in 2009.

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

A. My testimony describes APS: the role we play in our Arizona communities, where we are headed as a leader in Arizona energy, and why approval of this rate filing is critical to getting us there.

II. SUMMARY

**Q. PLEASE SUMMARIZE YOUR TESTIMONY.**

A. This is a time of remarkable challenges and exceptional opportunities for both the electric power industry and APS. Technology improvements and cost efficiencies are making renewable resources a growing part of meeting electricity demand, but require changes to how we operate our electric system. Energy efficiency is being embraced in Arizona and around the country as an affordable resource, but is causing slower (and sometimes even negative) load growth – an impact that requires modern rate designs that will allow utilities to both maximize the anticipated benefits of efficiency and recover their fixed costs of service. An aggressive set of new pollution control regulations is poised to have a profound effect on our nation's power generation fleet. At a time when the electric industry needs to access large amounts of capital, credit ratings agencies are being subject to increasing government scrutiny and financial regulation, causing them to rate utility credit quality more conservatively than in the past. I see more changes affecting our industry today than at any time in my 30 years of experience.

We know that electricity is essential to our customers and that we must constructively address these many challenges. Doing so compels us to look to the future and plan for the long-term, recognizing that proactive planning requires investments in new resources, technology and infrastructure today. At the same time, we intend to maintain our proven track record of superior operating performance and explore new ways to serve customers reliably and efficiently.

APS is fully committed to the programs that have been established to achieve Arizona's energy goals, but we need the Commission's support to continue our progress. A sustainable energy future requires a long-term focus and constructive

regulatory support—such as that embodied in APS's 2009 rate case Settlement Agreement ("Settlement").[1] The Settlement set clear renewable energy and energy efficiency goals for APS, which we are meeting. The Settlement also recognized that the cost required to achieve these goals and provide reliable electric service must be adequately reflected in our prices. Towards that end, the Settlement took steps to modernize the ratemaking processes with a goal of making more gradual and predictable rate changes over time, rather than requiring sporadic and dramatic rate hikes. It put APS on a two-phase rate case filing plan that lasts until 2014 and funded the energy policy goals set in the Settlement through 2012. Recognizing that the Company would need additional funding thereafter to continue meeting Arizona's goals for energy efficiency, renewable energy and system reliability, the Settlement authorized a June 1, 2011 filing date for this rate case and provided that parties should work to resolve it by July 2012.

Working from that framework, this application proposes new tools that further adapt the Company's rate structures to meet today's needs and continue the work that started with the Commission and 22 Settlement signatories in 2009. Our proposals define a long-term strategy to continue to bring APS customers the high levels of reliability they expect, outstanding customer service, comprehensive energy efficiency and renewable energy programs, and needed upgrades to our electric system.[2] As proposed, these benefits would be funded through progressive rate mechanisms that will more gradually impact customer bills and bring more stability and predictability in the long run. If APS's requests are approved, customer bills would initially increase by about 6.6% on average.

[1] Approved in Decision No. 71448 (December 31, 2009).
[2] In his testimony, APS Vice President of Rates and Regulation Jeff Guldner describes the specifics of the Company's requests.

We are keenly aware of the challenges facing our customers and Arizona's economy. To that end, we have aggressively implemented cost management programs. Since the 2009 Settlement, we have achieved more than $37 million in cost-savings during the 2010 Test Year, thereby meaningfully reducing our rate request in this filing. Our operational expenses have remained virtually flat since the Settlement Agreement was approved and do not drive this rate request. We continue to look for new ways to manage costs and operate more efficiently without compromising reliability or customer service.

To lessen the bill impact of our rate application, we have also voluntarily excluded from our base rate calculation various portions of our cost of service that we have traditionally requested and are entitled to recover. Our filing also enables APS customers to benefit from significant energy efficiency offerings so that they may better manage their energy use and keep their bills down. Finally, our filing proposes a new rate offering specifically designed to promote cost-effective economic growth and development throughout the State.

The Commission's approval of the Settlement signaled a willingness to provide the support APS needs to achieve Arizona's energy goals and build a sustainable energy future for our State. Equally powerful was the demonstrated consensus among the Settlement's signatories that APS cannot accomplish this result unless Arizona's traditional regulatory framework adapts to keep pace with the fast-moving opportunities and challenges facing the electric industry today. That framework is widely viewed as a milestone that set the stage for positive developments in Arizona energy policy. This request seeks to continue that momentum and take further steps to make Arizona's energy landscape sustainable for the long term.

III. APS FUNDAMENTALS

**Q. PLEASE GIVE A BRIEF OVERVIEW OF APS.**

A. APS is Arizona's largest and longest serving electric utility, serving Arizona's growing population since 1886. APS has about 6,800 employees and serves more than 1.1 million retail and wholesale customers in all or part of 11 of Arizona's 15 counties – a service territory of approximately 35,000 square miles. APS owns more than 33,000 miles of transmission and distribution lines and underground cable to deliver this energy to our customers. We also co-own and operate the Palo Verde Nuclear Generating Station ("Palo Verde"), a primary source of electricity for the Southwest and the largest nuclear generation facility in the United States, as well as two coal-fired plants and six natural gas plants. At present, APS generates more than three percent of its electricity from renewable resources, a number that we expect to grow to 16% by 2025. By 2015, we expect to have a renewable portfolio of over 1200 MW, enough renewable energy to serve roughly 10% of our retail sales.

**Q. WHAT ECONOMIC IMPACT DOES APS HAVE ON ARIZONA?**

A. A significant one. With an extensive network of power plants, transmission and distribution lines, customer offices and support facilities, APS is the largest property taxpayer in the State by a significant margin, infusing approximately $128 million of property tax in 2010. This amount almost doubles the in-lieu-of tax payment of Salt River Project, Arizona's second largest taxpayer. Last year, the Company purchased from more than 6,000 Arizona suppliers and spent approximately $620 million on goods and services offered by Arizona businesses.

Due to the extensive construction of electric infrastructure necessary to maintain the Company's existing system and meet future demand, APS is among the State's largest construction companies. In 2010 alone, APS infused approximately $660 million into Arizona's economy as part of its ongoing

construction program. Next year, that number is projected to reach approximately $1 billion, and will likely be close to $20 billion through 2025. APS generates more jobs than most other Arizona corporations, providing employment to almost 6,800 Arizonans, directly creating jobs for thousands of contractors, and indirectly creating tens of thousands of additional jobs throughout the State. Roughly 2,000 of APS's employees and contractors are members of local unions. We are also one of the few S&P 500 companies with headquarters in Arizona. A Study prepared by the L. William Seidman Research Institute of the WP Carey School of Business discusses the Company's economic impact on Arizona in further detail, and is available on the APS website (aps.com).

**Q. WHAT DOES APS VIEW AS ITS CORE RESPONSIBILITIES?**

A. At APS, our mission is to "safely and efficiently generate and deliver reliable electric power and related services to our customers" – and we are recognized for performing that task well. In 2010, for example, APS's operational performance placed it in the top-quartile among its peers under each of the standard industry measures of distribution system reliability (such as outage frequency and average outage duration). As Liberty Consulting Group ("Liberty") observed in its recent benchmarking study that compared APS's operational performance to industry peers ("Liberty Benchmarking Study"), APS "rates far better than the industry average" on standard reliability metrics and "the favorable gap is growing with time."[3] APS also remains a consistent top-quartile industry performer in terms of outages per customer. In 2010, APS customers experienced an average of 0.90 outages per customer, compared to an industry median of 1.07.

APS also excels in terms of customer satisfaction. In July of 2010, J.D. Power and Associates ranked APS third of the 55 investor-owned utilities in its group for Residential Customer Satisfaction. In its associated webcast, J.D. Power

[3] *See* Liberty Benchmarking Study at 10.

featured APS as a top performer nationally, standing the Company apart from the other utilities in the mix. The Liberty Benchmarking Study concluded similarly, noting that – using factors such as price, billing and payment, power quality and reliability, and customer service as metrics– "APS ranks high in customer satisfaction," particularly vis-à-vis other investor owned utilities (where, Liberty finds, APS ranks 4 of 89).[4] Liberty also noted an upward trend in the Company's customer satisfaction scores, highlighting that APS "has risen to mid-top quartile from mid-second quartile just three years ago."[5]

While APS has always compared favorably to the industry generally in terms of safety,[6] 2010 marked APS's safest year on record – the third straight year of discernible improvements in the Company's recordable injuries. Our concerted emphasis on and employee commitment to safety has resulted in first-quartile safety performance. We expect that our continued focus on this value will result in improved safety performance going forward.

APS is also firmly committed to making our product and services cost-effective for customers. We do this in large part by intensely managing costs and operating efficiently. While APS has always focused on cost-management, we have intensified that effort in recent years through a cost management initiative that saved over $37 million of expenses in 2010 alone – an achievement that reduced the rate request made in this proceeding. In fact, the Company's aggressive focus on cost containment and operational efficiency has allowed us to keep our operational expenses relatively flat over the past several years. This is an impressive feat given the challenges and cost increases facing our industry today.

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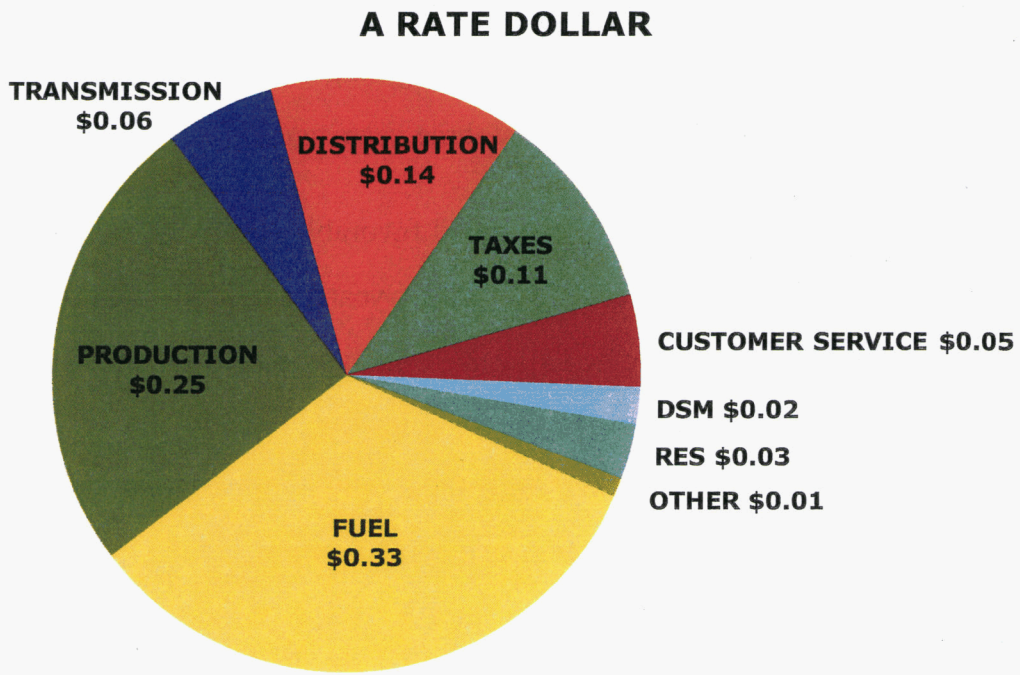
[4] *See* Liberty Benchmarking Study at 9.
[5] *See id.*
[6] See Liberty Benchmarking Study at 8.

These are but a few of several examples that demonstrate APS's commitment to getting the basics – our core responsibilities – right for our customers. And, as the following demonstrates, the overwhelming majority of every dollar that a customer spends on its APS bill pays for the costs required for us to do just that.




## IV. PROJECTS TODAY BENEFIT FOR THE LONG TERM.

**Q. YOU NOTED EARLIER THAT THE COMPANY STRIVES TO BUILD A SUSTAINABLE ENERGY FUTURE FOR ARIZONA. WHAT DOES THAT MEAN TO APS?**

A. At APS, sustainability means meeting Arizona's energy needs by implementing a business strategy that supports superior operating performance, efficiency, a healthy environment, a vibrant economy, and a strong community. When these goals compete, as they sometimes do, it means taking a long-term view to determine what path today best serves the generations of tomorrow. The Settlement took important steps down that path, which APS seeks to continue.

**Q. PLEASE PROVIDE SOME EXAMPLES OF WHAT APS IS DOING NOW TO MAKE ARIZONA'S ENERGY LANDSCAPE SUSTAINABLE.**

A. APS's focus on sustainability is demonstrated by the investments we make. Our distribution and generation upgrades improve system reliability; renewable energy and energy efficiency investments grow those resources' contribution to a balanced energy portfolio; and new tools enable customers to manage and understand better their energy use. In short, the programs and projects on which we spend capital dollars improve Arizona's energy landscape for the long term. APS's witnesses Daniel Froetscher (Vice President of Energy Delivery), Mark Schiavoni (Senior Vice President of Fossil Generation), and Randy Edington (Executive Vice President and Chief Nuclear Officer) will address the details of many of the Company's capital investments in their respective testimonies. I would like to highlight a few key examples here, all specific to the 2010 Test Year.

On the resource front, APS signed contracts to develop the first 83 MW of the 100 MW of utility-scale solar photovoltaic power plants authorized as part of the AZ Sun program. APS will finance and own these generating facilities, which are being designed and constructed by third party developers. Five contracts are now underway, and include a 17 MW Paloma solar plant in Gila Bend, a 17 MW Cotton Center solar plant in Gila Bend, a 16 MW Hyder solar plant east of Yuma, a 19 MW solar plant in Chino Valley, and a 14 MW solar plant at Luke Air Force Base. Collectively, these projects will produce enough solar energy to power roughly 20,750 homes, and will create roughly 625 temporary and permanent jobs in Arizona. Because of investments like these, APS estimates that 26% of customer growth through 2025 will be served by solar energy.

In line with our customer service focus, customers who participated in our energy efficiency programs during 2010 saved over $30 million on their electric bills.

These savings resulted from such Company programs as replacing incandescent lights with compact fluorescent lights, installing variable speed pool pump motors, recycling old inefficient refrigerators, and having their home's duct system inspected and repaired. Another interesting example: APS launched the "APS Outage Center" on Twitter on June 1, 2010, the Company's largest foray into social media. This tool allows APS to communicate directly to customers affected by outages about such things as the outage's size, areas affected, and restoration progress. In some cases, merely providing the update or reminding our "twittering" customers that APS crews were hard at work to restore their power put customers at ease.

As to energy delivery, no example better demonstrates the Company's commitment to delivery system reliability than does our response to the severe winter storms that lashed through the APS service territory early last year. Winds as high as 70 miles per hour drove heavy snow and torrential rain, downing power lines, snapping poles, and damaging towers throughout our system. APS crews responded rapidly and effectively to rebuild the system and restore power (crews even participated in a search and rescue effort to locate a missing family with young children). The vast majority of customers regained power within a few hours, although outages in some of the more remote locations lasted up to four days. Customers praised our crews for their dedication and professionalism despite the treacherous weather conditions.

On the generation reliability front, 2010 saw the last two of the new reactor vessel head installations needed on each of Palo Verde's three units, thus completing the power plant's major equipment upgrades. The new reactor vessel heads have specific qualities that make the equipment easier to maintain and will improve equipment performance. Replacing all three reactor heads at Palo Verde

is expected to increase the plant's reliability and improve its overall operating performance.

On the transmission side, a new 27 mile transmission line connecting the newly completed 230/500-kilovolt (kV) Morgan Substation to the newly-expanded Pinnacle Peak Substation was energized in December 2010. The $207 million construction project will provide needed transmission infrastructure to support growth in the north part of the Valley and improve the Company's overall transmission system reliability. As noted in the Company's Renewable Transmission Action Plan (approved by the Commission in 2010), this line will also facilitate the delivery of renewable energy to the Valley.

**Q. DO YOU HAVE ANY OTHER EXAMPLES OF APS'S COMMITMENT TO SUSTAINABILITY?**

A. Yes. As I described above, a key aspect of sustainability for APS is a strong dedication to our customers and the communities we serve. Although community outreach and economic development are not our core business, we strongly believe that it is our civic responsibility to do our part to engage with our communities and improve Arizona's economic condition.

Economic development is equally important to APS, particularly given our State's current economic climate. APS actively partners with several other economic development agencies (including, among others, the Greater Phoenix Economic Council, Central Arizona Regional Economic Development Foundation, and the Arizona Rural Development Council) in efforts to bring new companies to Arizona. Towards the same goal, this Application proposes a new economic development service schedule. If approved by the Commission, this new rate offering could promote new jobs and cost-effective business expansion for customers meeting defined eligibility criteria throughout our State. Mr. Charles Miessner describes this proposal in detail in his testimony.

APS is nationally recognized for our commitment to sustainability in these and other relevant areas. In March of this year, *Corporate Responsibility Magazine* ranked Pinnacle West Capital Corporation 15th overall on its annual list of "100 Best Corporate Citizens." The highest ranked of any utility, we received this prestigious honor because of APS's contributions in the areas of environment, climate change, employee relations, human rights, governance, and philanthropy. From our volunteers supporting children, education, the arts and culture; to our commitment to helping small and minority-owned businesses; to our encouragement of economic development, APS's strong dedication to corporate citizenship reflects its broader vision of supporting Arizona's future.

**Q. WHAT ELSE IS APS DOING TODAY TO STRENGTHEN ARIZONA'S ENERGY FUTURE?**

A. In a phrase, being proactive about our financial health. APS is Arizona's largest utility, and we must be financially strong so that we can continue to meet the State's energy goals cost-effectively. As Mr. Hatfield discusses, accessing the financial markets and securing financing on reasonable terms is by no means an easy feat, particularly in a tight economy. Like APS, utilities across the country are looking for the financing needed to upgrade their systems such that they will be less costly to maintain, more energy efficient and reliable, and more "green." The upward cost trend is more marked for Arizona utilities because, despite the current slow-down, Arizona remains a growth state. Thus, unlike many other utilities, APS must also invest in new plant and equipment to serve the new customers that join our system. Between now and 2025, we estimate that our customer base will grow by almost 550,000, rendering an overall customer count of close to 1.6 million. In total, APS's capital budget over the same period is close to $20 billion.

To finance these capital projects, APS must be able to compete effectively against the many other investor-owned utilities trying to do the same thing. Many of these utilities operate in regulatory jurisdictions that use future test years, allow automatic interim rate allowances, and use other mechanisms that reduce regulatory lag. As Mr. Hatfield discusses, the rates these utilities charge better track the utilities' pace of investment and reduce long-term customer prices, producing earned returns that are more attractive to potential investors compared to the returns generated when rates lag investment more significantly, such as under a historical test year regulatory model. To compete effectively against these utilities for capital, APS must be able to produce comparable returns.

The Settlement recognized this need and took steps to modernize APS rates as needed for APS to continue to serve customers reliably and finance Arizona's energy goals. Those steps were noticed by the financial world. As Mr. Hatfield notes, APS's bond rating may be upgraded if the ratings agencies perceive that the current trend of regulatory support will continue into the future.

**Q. HOW ELSE IS APS BEING PROACTIVE ABOUT ITS FINANCIAL HEALTH?**

A. As I earlier noted, APS has undertaken a significant cost management and operational efficiency initiative that has resulted in at least $37 million of cost savings in 2010.[7] We take this initiative seriously, as evidenced by our ability to keep operational expenses generally flat for the past several years – a remarkable accomplishment given the demands facing APS and the electric industry as a whole.

[7] APS identified the specific components of these cost-savings in a letter filed in Docket E-01345A-08-0172 on April 29, 2011.

Although cost management is critical, it is not enough to offset the need to invest in our system. Like everything, providing our customers with reliable electric power, reliable energy delivery, high levels of customer service, energy efficiency, and renewable energy comes at a price. As Mr. Hatfield explains, cost management simply cannot substitute for timely recovery of these costs. APS cannot continue to offer superior electric service and invest in the programs and projects that promote Arizona's energy policy without the rate relief requested in this Application.

## V. CONCLUSION.

**Q. DO YOU HAVE ANY CONCLUDING REMARKS?**

A. Yes. In the 2009 Settlement Agreement, APS came together with the Commission and many other parties to discuss Arizona's energy future. Participants included representatives of environmental organizations, business associations, community groups and other interested stakeholders. The result was a long-term energy plan that includes ambitious goals for renewable energy and energy efficiency, and funds continued investments in reliability. Today, APS is achieving those goals. Our service reliability and customer satisfaction rank in the top-performing quartile of our industry, and we are diligently managing our costs.

With this Application, we are asking the Commission to continue its support for the goals set forth in the 2009 Agreement. We are also asking the Commission to modernize our rate structure to reflect the importance of energy efficiency as a clean and cost-effective component of Arizona's resource portfolio and, when future electricity rate increases become necessary, to make them more predictable and gradual for customers.

The plan reflected in this Application is good for APS customers and good for Arizona. We are committed to providing our customers with electricity that is safe, reliable, efficient and environmentally responsible. We believe the Commission shares these objectives and we urge the Commission to approve the requests made in this Application.

**Q. DOES THIS CONCLUDE YOUR TESTIMONY?**

A. Yes.

# TESTIMONY OF JAMES R. HATFIELD

**On Behalf of Arizona Public Service Company**

**Docket No. E-01345A-11-____**

June 1, 2011

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**TESTIMONY OF JAMES R. HATFIELD**
**ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY**
**(Docket No. E-01345A-11-____)**

I. INTRODUCTION

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

A. My name is James R. Hatfield. My business address is 400 North 5th Street, Phoenix, Arizona, 85004. I am Senior Vice President and Chief Financial Officer of both Arizona Public Service Company ("APS" or "Company") and Pinnacle West Capital Corporation ("Pinnacle West"). I have executive management responsibility for the financial affairs of the Company, including all aspects relating to accounting, finance, taxes, budgeting and financial planning, supply chain, enterprise risk and investor relations.

**Q. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?**

A. I have a Bachelor of Science degree with a functional major in accounting from Central Missouri State University and an M.B.A. degree from the University of Missouri-Kansas City. I have 31 years of experience in the utility and energy business. I joined APS and Pinnacle West in my current capacity in July 2008. Immediately prior to that time, from August 1994 until July 2008, I worked at OGE Energy Corp. ("OGE"), the parent company of Oklahoma Gas and Electric Company. While at OGE, I served in various roles, including Treasurer from August 1994 until January 1996, Vice President and Treasurer from January 1996 until November 1999, and Senior Vice President and Chief Financial Officer from November 1999 until July 2008. Before OGE, I worked in various accounting and finance roles at UtiliCorp United Inc. of Kansas City, Missouri from 1980 through 1994, and served as UtiliCorp's Assistant Treasurer from 1988 to 1993. From January through August of 1994, I also held the position of Vice President, Investor Relations and Corporate Secretary for Aquila Gas

Pipeline Corporation of San Antonio, Texas, a publicly traded subsidiary of UtiliCorp United Inc.

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

A. My testimony will discuss the several benefits resulting from the regulatory framework established for APS by the 2009 Settlement Agreement ("Settlement" or "Settlement Agreement")[1], as well as explain why, because of the Settlement's financial design, APS is seeking a rate increase now. I also address APS's progress with respect to the "Settlement Term Action Plan" outlined in the Company's "Plan to Maintain Credit Ratings and Improve Financial Metrics" that APS filed on April 29, 2010 date in compliance with Section 8.4 of the Settlement. Finally, I sponsor the forecasted portions of Schedules A, D, and F that are included in the Company's rate application.

## II. SUMMARY

**Q. PLEASE SUMMARIZE YOUR TESTIMONY.**

A. This case offers the opportunity to further Arizona's energy policy objectives by continuing the positive momentum established in the Settlement Agreement to equip APS with the financial strength needed to provide safe and reliable service for APS customers during the second phase of the Settlement's five year plan term. The Settlement Agreement took an important step in the right direction for Arizona energy policy. It buttressed the Company's financial condition for the first of a two-phase Settlement period, and contained various provisions that began to modernize Arizona's historical regulatory structure as needed to put APS on a better financial standing with many investor-owned utilities throughout the country. These are companies against which APS competes for investment capital. Among other things, the Settlement Agreement placed APS on a rate case cycle, required important rate case process improvements aimed at

[1] Approved in Decision No. 71448 (December 30, 2009).

completing this and future cases in 12 months, and permitted the expedient collection of certain costs for APS-owned renewable projects. The Settlement led directly to a perceived improvement in APS' financial condition. The Company's bond ratings outlook improved and APS successfully completed a $253 million equity issuance last year on favorable terms, in a still tight economy.

But the Settlement Agreement was designed to support APS's financial metrics at agreed-upon levels through only the first phase of the 2010-2014 Settlement plan term ("Plan Term"). That initial phase is now coming to a close, and – as anticipated, and notwithstanding reductions in capital expenditures and operating costs made during and reflected in the Test Year at levels beyond what the Settlement requires – APS again faces Total Company projected returns on equity ("ROE") of 9.1% in 2012, 7.1% in 2013, and 6.7% in 2014. Returns like these are far below not only APS's 11% authorized ROE, but also the 10.6% average ROE actually earned in 2010 by other investor-owned utilities ("IOU") throughout the country. Without new rate relief that sustains APS's actual earned ROE at a reasonable level, APS will face challenges in raising the capital needed to invest in its system so as to provide safe and reliable electric service to APS customers and fulfill Arizona's efficiency, renewable energy, and other policy objectives.

My testimony also addresses the projected accounting data required by the Commission's SFRs to support the Company's rate case filing. Specifically, I sponsor the projected information presented on the following SFR Schedules:

- A-2 through A-5 – Summary Schedules
- D-1 through D-3 – Cost of Capital
- F-1 thru F-4 – Projected Financial Information

APS Witness Jason La Benz sponsors the historical and actual Test Year information required by those Schedules. APS Witness Zac Fryer jurisdictionalizes the Total Company data to isolate those items that fall within the Commission's regulatory jurisdiction.

## III. THE POSITIVE MOMENTUM GENERATED BY THE SETTLEMENT AGREEMENT

**Q. YOU INDICATED THAT THE SETTLEMENT AGREEMENT TOOK A STEP IN THE RIGHT DIRECTION FOR ARIZONA ENERGY POLICY. PLEASE EXPLAIN.**

A. A key benefit of the Settlement Agreement is its outline of a modernized regulatory framework that enables APS to continue its superior operating performance and make investments in projects driven by energy policy, while easing the resulting rate impacts on customers gradually over time. It achieves this result by way of regulatory measures that tackle the root of the Company's subpar financial performance: rates that have not kept pace with the Company's capital expenditures, due in large part to regulatory lag.

APS's financial pressure is not caused by too much debt, operational inefficiency, or poor cost management. Rather, the primary cause of APS's substandard financial performance is that the rate making process in Arizona has been lengthy (often taking, for APS, as much as 18-24 months to resolve) and is based on a historical test year – conditions resulting in persistent regulatory lag.[2] Under such a regulatory model, the rates set in APS rate cases have historically been based on costs as much as three to five years old. In other words, even though APS's costs – like most people's – rise over time, the Company has generally been required to pay those higher costs with a revenue stream that is several years outdated.

[2] *See, e.g.,* Liberty Study at 41; Concentric report attached to the Testimony of Jeff Guldner at Attachment JBG-2.

Such a regulatory model deprives APS of the ability to charge rates that reflect its true cost of service. Inadequate rates, in turn, cause APS to be weak financially. APS's actual earned ROE has consistently fallen well below that of others in the industry for almost a decade. That remains true today: APS's earned an ROE of 9.3% in 2010, while others in the industry performed materially better. To cite just a few examples, in 2010, Southern California Edison earned a 13.2% return, Florida Power & Light earned 10.4%, Alabama Power Company earned 13.2%, Georgia Power earned 11.1%, and Oklahoma Gas & Electric Company earned 10.3%. Investors have little incentive to entrust their capital to a utility that offers below average returns, thus making it more difficult for APS to raise the capital needed to upgrade and maintain its system and progress Arizona's energy objectives. Weak financial metrics also expose APS to potential credit downgrades – an issue that has dominated APS's last few rate cases. Indeed, APS's credit rating is about one and a half credit notches below that of its industry peers, and while "[e]lectric utilities have generally experienced improved ratings since 2006[,] APS has not."[3]

Relying primarily on historical data inevitably results in more frequent rate filings, deterioration over time in APS's financial condition and difficulty in attracting capital. The result for APS has been a constant string of rate cases – a pattern that consumes the scarce resources of the Commission and other interested parties, distracts from the Company's ability to focus on operational matters and execution of policies, makes financing the significant infrastructure expenditures needed for system reliability and energy policy more difficult and costly for customers, and results in "lumpy" and unpredictable rate increases for APS customers.

[3] Liberty Study at 42.

**Q. DID THE SETTLEMENT AGREEMENT ALLEVIATE THOSE CONSEQUENCES?**

A. Yes, it made material progress. Key changes occurred when the Commission approved the Settlement Agreement, which took several important steps towards establishing a more supportive, modern regulatory construct. First, the Settlement placed APS on a "Rate Case Filing Plan" that governs APS rate applications until December 31, 2014.[4] By design, the Settlement Agreement permits APS to file two general rate cases during the five year Plan Term to address plant additions and other rate matters: one on June 1, 2011 (this case), and a second on or after June 1, 2013. To mitigate the cash flow-eroding impact of regulatory lag, the Settlement encourages that each of these cases be resolved within 12 months of a sufficiency finding and requires certain process improvements intended to facilitate that goal. As APS Witness Jeff Guldner explains, APS has worked hard with the other signatories to the Settlement Agreement to give life to those provisions and other process improvements in this case.

To provide an added measure of rate stability for customers, the Settlement prohibits APS from charging new base rates to customers until July of 2012 – two and a half years after the Company's last base rate increase. To fund the first phase of the Rate Case Filing Plan, the Settlement approved several regulatory tools specifically designed to support APS's financial performance in between the anticipated rate increases without too high of an upfront bill impact to customers. For example, recognizing the significant capital expenditures that APS had made beyond the 2007 Test Year and would make before Settlement rates would take effect in January 2010, the Agreement allowed APS to include in rate base certain (but not all) plant additions that the Company had made through June of 2009 –

[4] *See* Agreement at § 2.1.

18 months after the Test Year. The resulting rates did not compensate the Company fully for all capital expenditures made up to the rate-effective date and included no post-Test Year operating costs, and thus did not completely resolve regulatory lag. In fact, since 2007, APS has placed $594 million of plant in service that was not included in the prior post-Test Year Plant adjustment. Even so, there is no question that the adjustment was a strong move in the right direction.

The Settlement Agreement also authorized several other "bridge" mechanisms, equally necessary for APS to sustain financially the first phase of the Plan Term while mitigating the customer bill impact. These included the revenue treatment of the Company's line extension policy, the deferral of certain pension and OPEB costs, a depreciation rate change reflecting an anticipated license extension at Palo Verde, and a means by which APS can expediently collect carrying costs related to the Company's renewable energy investments.[5] The Settlement also required APS to eliminate expenses by a total of $150 million over the term of the Agreement.[6] Each of these provisions combined to close the gap between the Company's financial needs for the first phase of the Filing Plan and the maximum base rate increase the Settling Parties were willing to accept during a recession. Without these key financial benefits, APS would have been forced to file a rate case immediately after the conclusion of the last.

In combination, the Settlement's progressive regulatory tools allowed APS to continue to provide customers with superior electric service, invest in the Settlement's energy policy projects, and earn closer to its allowed ROE than it had for nine years. In doing so, the Settlement endowed APS and its stakeholders with the hope of a stronger, more constructive regulatory future and sustained

[5] *See* Agreement at §§ IX, X, XI, and XV.
[6] *See* Agreement at § VII.

financial improvement – a story that allowed Pinnacle West to raise $253 million of net equity capital in April of last year, which was invested into APS.

**Q. PLEASE ELABORATE. HOW SPECIFICALLY DID THE FINANCIAL COMMUNITY REACT TO THE SETTLEMENT?**

A. The reaction from equity analysts and credit rating agencies to the Settlement Agreement has been positive. Of greatest significance, on June 28, 2010, Standard & Poors Ratings Services ("S&P"), revised the Company's 'BBB-' bond rating outlook upward to "positive" from "stable," and changed APS's "business profile" to "excellent" from "strong."[7] According to S&P, the positive outlook reflects what it views as APS's "progress in managing its regulatory agenda as well as expense containment, which provides a platform for higher ratings contingent upon financial prudency entering the post-recession economy." In explaining the positive outlook, S&P specifically cited the Settlement's mitigation of regulatory lag:

> The business profile also reflects the success that APS has shown in managing regulatory risk. High customer growth has necessitated that the company file regular general rate cases to recover its investments and operating costs. The use of a historical test year in Arizona, coupled with the 18- to 24- month completion time for fully litigated rate cases, previously made it difficult for APS to earn authorized returns, but interim rates and the recovery of certain post-test year costs and a higher equity return in the latest rate case have reduced regulatory lag and should enhance financial performance.[8]

As a result, S&P announced that it could upgrade the Company's bond rating if APS is able to demonstrate sustained financial performance – a task that, S&P notes, may require APS to do what it can to "minimize[s] rate lag and promote[s] stability in financial performance" going forward.[9]

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[7] *See* Research Update: Outlook on Pinnacle West Capital Corp. and Arizona Public Service Co. Ratings Revised to Positive; Ratings Affirmed, June 28, 2010.
[8] *Id.* at 3.
[9] *Id.* at 4.

Equity analysts similarly heralded the Settlement Agreement. Barclays, for example, described the Settlement as a "sea change" that "demonstrated a more constructive regulatory environment and significantly improved relationship with regulators."[10] Another analyst commented that "the regulatory/political environment in Arizona is beginning to better appreciate the damage that constant regulatory lag/attrition has inflicted on APS."[11]

Whether or not one agrees with these characterizations of Arizona's historical regulatory model, there is little doubt that the mechanisms approved with the Settlement made tangible progress toward a higher bond rating for APS. If APS is in fact upgraded – as we of course hope it will be – it will be because the rating agencies perceive Arizona as invested in the financial health of its largest utility and as willing to adapt its regulatory model to address the challenges that the Company, like the rest of the energy industry, faces today. With a 'BBB' credit rating, APS will have better access to capital at lower costs, will be able to continue to invest strongly in Arizona infrastructure and thereby promote job creation, and be more in step with the industry.

## IV. APS'S FINANCIAL CONDITION

**Q. GIVEN THE SUBSTANTIAL BENEFITS OF THE SETTLEMENT AGREEMENT, WHY DO YOU NEED A RATE INCREASE NOW?**

A. Simply put, because the regulatory mechanisms put in place in the Settlement Agreement were not designed to sustain APS beyond 2012. The Post-Test Year Plant provision, while productive, included in rates most of the capital projects that APS had placed in service as of only June 1, 2009, seven months before the Settlement rates went into effect. It did not, however, include $594 million worth of plant investment that is now serving customers. Nor did it include the

[10] "Raising Arizona," Barclays (Dan Ford), June 24, 2010.
[11] "Raising Rating, Target, Estimates," Wellington Shields and Company (Chris Ellinghaus), June 4, 2010.

additional $959 million of new plant that will be in service by the anticipated July 1, 2012 rate effective date.

Other of the Settlement's financially supportive provisions will also quickly expire. The Settlement provision that allows APS to defer, at most, $42.5 million of pension and OPEB costs in 2011 and 2012 terminates next year. The revenue treatment of line extension proceeds, which was lower than anticipated due to the slowdown in new growth in any event, also falls off at the earliest of the end of this rate case or the end of 2012. And although the Settlement allows APS to reduce its depreciation expense starting January 1, 2012 to reflect the license extension recently granted for Palo Verde on April 22, 2011, that benefit alone is insufficient to sustain the Company throughout the remainder of the Plan Term under present base rates.

In fact, notwithstanding substantial cost containment measures underway, the Company's actual earned ROE dips again during the second phase of the Settlement term to the mid-single digit ranges typical of pre-Settlement days. On a Total Company basis, APS expects to actually earn in 2011 an ROE of 8.8%, a number that grows to 9.1% in 2012 (the last year in which APS receives Settlement-related rate benefits), but then falls to 7.1% in 2013 and 6.7% in 2014 (the earliest year in which the second general rate case authorized by the Agreement would likely conclude). These returns fall off in the later years because of the material capital investments required. Without rate relief, the returns in the latter years are at levels similar to or below what APS was facing when this Commission authorized interim rate relief for the Company in 2009 – mid-range single digits described by the financial world as "abysmal."[12] APS's

[12] Credit Suisse, Equity Research, March 10, 2009.

FFO to Debt levels also deteriorate during this time, falling to 18.3% in 2013 (versus 2010's 21.4% levels).

Such metrics would eradicate any chance of S&P upgrading APS to a solid 'BBB' during the Settlement term. They would also limit APS's ability to secure the capital needed to invest in safety, reliability, customer service, efficiency, renewable, and other energy policy projects, and would make any such capital more expensive for customers. Further, with such metrics, the Company would not likely be able to raise the equity capital needed both to maintain a balanced capital structure and to meet sections 8.1 through 8.3 of the Settlement Agreement.[13] It was for these very reasons that the Settlement Agreement, recognizing that the Company would have incremental revenue needs in 2011, allowed APS to file a rate case at this time.

**Q. CAN THE COMPANY ACHIEVE ITS FINANCIAL NEEDS THROUGH FURTHER COST CUTTING?**

A. No. APS simply cannot cut enough costs to earn even close to its authorized rate of return without significantly sacrificing reliability and service quality. As described in the testimonies of APS President Don Robinson and others, APS has undertaken a significant cost management initiative, cutting more than $37 million in expenses during the Test Year. But despite these significant cost-management efforts, and taking full account of the additional expense reductions the Settlement requires, APS still has an annual ACC-jurisdictional revenue requirement deficiency of $129 million for 2012, $233 million for 2013, and $286 million for 2014. As shown in JRH-1, APS would have to reduce generation and distribution capital spend by more than $400 million per year

[13] Section 8.1 of the Agreement requires APS "to complete equity infusions of at least $700 million during the period from June 1, 2009 through December 31, 2014." Section 8.3 requires that APS "use its best efforts to improve its financial metrics and bond ratings, by completing timely equity infusions and taking other measures to strive to achieve a capital structure with no more than 52% debt/total capital as calculated by the ratings agencies, by December 31, 2012."

($1.6 billion for 2011 through 2014) in order to close this gap through capital reductions alone. Even if the Company were to reduce expenses by an additional $30 million per year beyond the Settlement's mandate (which it cannot do without a significant and inadvisable reduction in our current workforce, an act that would put into question APS's ability to maintain reliability and achieve a sustainable energy future), the Company would still have to cut capital expenditures by $350 million per year through 2014 to make up the deficiency. *See* JRH-2.

To address this deficiency on the expense side rather than the revenue side would mean eliminating projects that are vital to APS's basic service obligations, projects such as those described by APS Witnesses Randy Edington, Mark Schiavoni, and Daniel Froetscher. APS certainly would not want to risk sacrificing reliability in order to improve its financial condition, and highly doubts that its customers or the Commission would want it to do so either.

**Q. DOES THE COMPANY HAVE TOO MUCH DEBT ON ITS BALANCE SHEET? PLEASE EXPLAIN.**

A. No, it does not. APS's capital structure reflects an appropriate balance of debt and equity capital. In fact, as of the end of the 2010 Test Year, APS had less long-term debt on its balance sheet than was average for similar IOUs across the country. As Schedule D-1 reflects, in 2010, the Company's balance sheet long-term debt to total capitalization ratio was 46%. This metric compares favorably to an average 2010 long-term debt to total capitalization ratio of over 49% for similar investor owned utilities. Importantly, APS's net cash flow from operations to long-term debt was also below average: 21% for APS compared to 24% for the peer group. In other words, APS has less cash-flow available to service its debt than is average – a deficiency on the revenue side, not the debt side.

## V. PLAN TO MAINTAIN CREDIT RATINGS AND IMPROVE FINANCIAL METRICS

**Q. ON APRIL 29, 2010, APS FILED A "PLAN TO MAINTAIN CREDIT RATINGS AND IMPROVE FINANCIAL METRICS." IS APS ON TRACK WITH THAT PLAN?**

A. Yes. The "Settlement Term Action Plan," attached to my testimony as JRH-3, expressed three objectives as the Company's focus during the Settlement's plan term: (1) to maintain an earned ROE of around 9% in 2010 and 2011, and work to earn closer to its authorized 11% ROE in the subsequent years; (2) to manage its FFO/Debt ratio and capital structure to comply with the terms of Sections 8.2 and 8.3 of the Agreement; and (3) to continue to highlight to credit rating agencies the positive developments in Arizona's regulatory environment, which is the qualitative consideration that S&P declares "the most important factor in [its] analysis of a U.S. regulated, investor-owned utility's business risk."[14] To achieve those objectives, APS outlined five strategies: (1) maintain a balanced capital structure and infuse equity as appropriate; (2) mitigate negative impacts of debt imputation; (3) focus on cost management; (4) pursue rate-related strategies for timely cost recovery; and (5) support the capital markets' evolving perception of Arizona's regulatory environment and other qualitative factors.

The Company is on target with respect to each facet of its plan. As to the first strategy, APS generally aims to maintain a capital structure with a ratio of roughly 54% equity and 46% long-term debt, which we believe is an appropriate balance. This is also consistent with the capital structure filed in this case: APS's capital structure is composed of 46.06% debt and 53.94% equity. This ratio reflects the infusion of $253 million of equity into the Company by Pinnacle West in April/May of 2010, the first tranche of APS's commitment to receive a total of $700 million of equity infusions through December 31, 2014. APS has

[14] *See "Assessing U.S. Utility Regulatory Environments,"* Global Credit Portal, Ratings Direct (March 11, 2010).

issued no new debt since the execution of the Settlement Agreement, but will continue to raise debt capital to fund maturing debt and finance capital investment as market conditions permit and capital needs arise. APS plans to issue or obtain such new debt and equity financing to fund its capital requirements while maintaining a balanced capital structure throughout the Settlement Term.

With respect to the second strategy, APS is working hard to manage the impact of imputed debt on its credit metrics and achieve the 52% adjusted debt/adjusted total capital ratio that the Settlement encourages. *See* Agreement at § 8.3. For example, to mitigate the negative imputed debt impact of Purchase Power Agreements ("PPAs"), APS is actively pursuing ownership of renewable power plants so that it can meet the renewable energy requirements of the Settlement and avoid further PPA-related debt imputation. To date, APS has contracted for 83 megawatts of renewable energy under its AZ Sun program, and will balance investments in new utility-owned renewable generation resources and procurement through PPAs as appropriate to achieve our renewable energy commitments throughout the Plan Term.

In addition, because of a recent change in accounting standards (FAS 167), APS now reflects the debt and equity components of APS's Palo Verde Unit 2 sale leaseback obligations on its balance sheet, rather than as imputed debt. APS also made a voluntary contribution to its pension plan of $200 million in 2010, which improved the funded status of the plan and reduced the associated debt imputation. Because of these and other efforts, as of the end of the 2010 test year, APS's adjusted debt/adjusted total capitalization ratio was 54.4%, down from 57.2% as of the end of 2008, as calculated by the Company's approximation of S&P's bond benchmark methodology.

The third prong of APS's Plan to Maintain Credit Ratings and Improve Financial metrics is to focus on cost management. As previously indicated, APS has undertaken a significant cost management initiative, exceeding the minimum level for 2010 required by Section 7.1 of the Settlement. That Company-wide undertaking is described by Don Robinson in his testimony, and examples of savings by business unit are described in greater detail in the testimonies of Daniel Froetscher (for Energy Delivery), Mark Schiavoni (for Fossil Generation), and Randy Edington (for Nuclear Generation). APS's cost management focus is also detailed in a letter from Don Robinson to Docket Control filed with the Commission on April 29, 2011 in Docket No. E-01345A-08-0172.

Fourth, APS is actively pursuing rate-related strategies for timely cost recovery, as demonstrated by the present rate application. As described above, timely, adequate rate relief is critical for APS to achieve its financial objectives. Towards that end, and as APS Witness Jeff Guldner discusses in his testimony, APS has engaged its stakeholders and Commission Staff to develop a process that will allow the case to resolve with rates effective within 12 months of a sufficiency finding. In addition, and as noted previously in my testimony, APS requests in this filing various rate tools that will modernize the APS rate structure and reduce the detrimental financial impact of regulatory lag in a historical test year cost of service model.

The final piece of APS's Plan is to support the capital market's evolving perception of Arizona's regulatory environment and other qualitative factors. Our progress in this realm is in two parts: first, to pursue a regulatory construct that will be viewed as positive by the financial markets; and second, to communicate that story and show that Arizona supports the financial performance and credit quality of its utilities. Our success in this effort to date is exemplified

by the positive remarks contained in rating agency and equity analyst articles that have been published since the Settlement Agreement, virtually all of which focus on Arizona's marked demonstration of collaboration and commitment to processing rate cases faster with a more financially supportive result than has historically been the case. The Commission's policy statement on decoupling and support of the Company's AZ Sun projects were also positively received.

While the rating agencies have indicated their intent to keep a watchful eye on APS during this rate proceeding, the industry's expectations are high and the shift in the historical perception that Arizona is a "challenging" regulatory environment is a cautious one. Without timely and adequate rate relief from this case, that perception would instantly sour.

## VI. KEY FORECASTED FINANCIAL RESULTS AND CONCLUSION

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

A. With respect to the Company's SFR schedules, my testimony covers the forecasted accounting statements and financial results. The Total Company data is the same type of information that is disclosed directly or indirectly in both the APS and the consolidated Pinnacle West audited financial statements, each of which are included in filings made with the SEC for historical years. The forecasted information periodically is supplied to investors and filed with the SEC.

Additionally, all of the accounting projections provided in my testimony follow Generally Accepted Accounting Principles ("GAAP"). These are the principles that accounting professionals use to prepare financial statements. One major goal of GAAP is to make financial statements comparable from year to year, from industry to industry, and from jurisdiction to jurisdiction. In addition to GAAP,

APS's accounting practices comply with other applicable utility accounting standards, such as the FERC Uniform System of Accounts, which this Commission has adopted. *See* AAC R14-2-212(G).

The Direct Testimony of APS Witness Jay La Benz addresses the historical accounting statements and actual Test Year data used in the SFRs. Zac Fryer focuses on the jurisdictional allocation of APS revenues, costs and rate base items for the actual Test Year and all the pro forma adjustments.

*A. Summary Schedules*

**Q. PLEASE DESCRIBE THE PROJECTED INFORMATION ON SFR SCHEDULES A-2 THRU A-5.**

A. These summary schedules provide the "Summary Results of Operations," the "Summary Capital Structure," the "Construction Expenditures, Net Plant Placed in Service and Gross Utility Plant in Service," and the "Summary Changes in Financial Position" for the Test Year and the prior two calendar years. These schedules also include historical information. I am sponsoring the forecasted data for the Test Year and future calendar years. Mr. La Benz is sponsoring the historical information on these schedules. As Line 12 of Schedule A-2 shows, if the Company's rate request is granted effective July 1, 2012, Total Company average ROE will be 10.0% at December 31, 2012 (a year in which new rates will have been in effect for only six months) and 9.7% at 2013.

*B. Cost of Capital*

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

A. SFR Schedule D-1 is the summary of the Company's historical and projected cost of capital. I am sponsoring the forecasted data in this schedule. SFR Schedule D-2 presents supporting detail for the long-term debt summarized on SFR Schedule D-1. Again, I sponsor the projected data in this schedule. SFR Schedule D-3 addresses preferred stock. Although the Company did not have

any outstanding preferred stock as of the end of the Test Year, it has included Schedule D-3 nonetheless for the sake of completeness. SFR Schedule D-4 addresses the Company's cost of common equity, and is sponsored by Mr. La Benz.

*C. Projected Financial Information*

**Q. PLEASE DISCUSS THE INFORMATION THAT YOU ARE SPONSORING ON SFR SCHEDULES F-1 THROUGH F-4.**

A. SFR Schedule F-1 presents income statements for projected calendar years, and for actual Test Year results, at present and proposed rates. I sponsor the projected information contained on these schedules, while Mr. La Benz sponsors the historical and actual Test Year information.

As I have previously indicated, Schedule F-1, like Schedule A-2, shows key information relating to the Company's actual and projected ROE. As Schedule F-1 shows, under APS's present rates, the Company's ROE falls from 9.3% at the end of the Test Year to 8.8% at year end 2011, grows to 9.1% in 2012 (the last year in which we receive Settlement-related rate benefits), then falls to 7.1% 2013—well below any reasonable ROE required to maintain the financial health of APS and ensure access to capital necessary for a robust electric system. The Company's proposed rates would bring the Company's ROE to 10.0% in 2012 and 9.7% by year end 2013. As JRH-4 shows, the calculated ROE improves when considering only those items that fall within the Commission's regulatory jurisdiction, partly because the ACC-jurisdictional analysis removes all of the Company's below the line expenses.

SFR Schedule F-2 shows projected changes in the financial position of the Company for future calendar years and the Test Year, at present and proposed rates. SFR Schedule F-3 presents projected annual construction requirements, by property classification, for four years subsequent to the Test Year. I sponsor the

projected data on this schedule. Finally, SFR Schedule F-4 presents the key assumptions used in developing projections.

## VII. CONCLUSION

**Q. DO YOU HAVE ANY CONCLUDING REMARKS?**

A. Yes. APS hopes to continue working with the Commission and other stakeholders achieve a strong energy future for Arizona. However, it is quickly losing the financial support provided by the first phase of the Settlement term that allows it to do so. To continue down this path, APS will need rate relief adequate to compensate it for the significant amount of capital that has been and will be invested in the business. What is unique to APS and other Arizona utilities compared to others in the industry is the lower use of modernized rate tools that reduce the detrimental impact of regulatory lag and maintain the Company's financial condition in between rate cases. APS seeks the Commission's authorization to implement some of those tools in this Application, thus smoothing rate increases for customers and allowing APS and the Commission to avoid the distraction of a constant string of rate cases and to focus instead on refining important energy policies that will shape this State's future.

**Q. DOES THIS CONCLUDE YOUR TESTIMONY?**

A. Yes.

## Necessary Generation and Distribution Capital Reductions Needed to Correct Revenue Deficiency if Present ACC Base Rates Continue

($ in Millions)

| Line # | | 2011 | 2012 | 2013 | 2014 | Cumulative |
|---|---|---|---|---|---|---|
| | Projected revenue deficiency: | | | | | |
| 1 | Projected APS shareholder net income | $ 301.4 | $ 324.1 | $ 259.5 | $ 243.2 | |
| 2 | Projected year-end common equity | $ 3,154 | $ 3,427 | $ 3,408 | $ 3,555 | |
| 3 | Return on common equity | 9.6% | 9.5% | 7.6% | 6.8% | |
| 4 | Allowed ROE | 11.00% | 11.00% | 11.00% | 11.00% | |
| 5 | Net income at allowed ROE (line 2 x line 4) | 347 | 377 | 375 | 391 | |
| 6 | Net Income over / (under) allowed ROE (line 1 - line 5) | $ (46) | $ (53) | $ (116) | $ (148) | $ (363) |
| 7 | Revenue conversion factor | 1.6532 | 1.6532 | 1.6532 | 1.6532 | |
| 8 | Annual revenue deficiency excluding fair value | $ (76) | $ (88) | $ (192) | $ (245) | $ (601) |
| 9 | Fair value revenue requirement in 2010 test year | $ (41) | $ (41) | $ (41) | $ (41) | |
| 10 | Annual revenue deficiency including fair value | $ (117) | $ (129) | $ (233) | $ (286) | $ (765) |
| | Revenue requirement impacts of reducing capital expenditures: | | | | | |
| 11 | 2011 Capital expenditure reductions | (400) | (400) | (400) | (400) | |
| 12 | 2012 Capital expenditure reductions | | (400) | (400) | (400) | |
| 13 | 2013 Capital expenditure reductions | | | (400) | (400) | |
| 14 | 2014 Capital expenditure reductions | | | | (400) | |
| 15 | Total capital expenditure reductions | (400) | (800) | (1,200) | (1,600) | |
| 16 | Book depreciation savings | 3% | 3% | 3% | 3% | |
| 17 | Property tax savings | 1% | 1% | 1% | 1% | |
| 18 | Interest and equity return savings (1) | 9% | 9% | 9% | 9% | |
| 19 | Income tax savings (1) | 4% | 4% | 4% | 4% | |
| 20 | Revenue requirements savings as a % of capital expenditure reductions | 17% | 17% | 17% | 17% | |
| 21 | Annual revenue requirement reduction (line 15 x line 20) | (68) | (136) | (204) | (272) | (680) |
| 22 | Remaining annual revenue deficiency (line 10 - line 21) | $ (49) | $ 7 | $ (29) | $ (14) | $ (85) |

(1) Assuming the Company's proposed cost of capital with a 53.94% equity ratio and an 11% allowed return on common equity

**Necessary Generation and Distribution Capital Reductions Needed to Correct Revenue Deficiency if Present ACC Base Rates Continue and a Reduction of $30 Million in O&M is Required**

($ in Millions)

| Line # | | 2011 | 2012 | 2013 | 2014 | Cumulative |
|---|---|---|---|---|---|---|
| | Projected revenue deficiency: | | | | | |
| 1 | Projected APS shareholder net income | $ 301.4 | $ 324.1 | $ 259.5 | $ 243.2 | |
| 2 | Projected year-end common equity | $ 3,154 | $ 3,427 | $ 3,408 | $ 3,555 | |
| 3 | Return on common equity | 9.6% | 9.5% | 7.6% | 6.8% | |
| 4 | Allowed ROE | 11.00% | 11.00% | 11.00% | 11.00% | |
| 5 | Net income at allowed ROE (line 2 x line 4) | 347 | 377 | 375 | 391 | |
| 6 | Net Income over / (under) allowed ROE (line 1 - line 5) | $ (46) | $ (53) | $ (116) | $ (148) | $ (363) |
| 7 | Revenue conversion factor | 1.6532 | 1.6532 | 1.6532 | 1.6532 | |
| 8 | Annual revenue deficiency excluding fair value | $ (76) | $ (88) | $ (192) | $ (245) | $ (601) |
| 9 | Fair value revenue requirement in 2010 test year | $ (41) | $ (41) | $ (41) | $ (41) | |
| 10 | Annual revenue deficiency including fair value | $ (117) | $ (129) | $ (233) | $ (286) | $ (765) |
| 10a | Assume another $30m of required O&M reductions | $ 30 | $ 30 | $ 30 | $ 30 | $ 120 |
| 10b | Adjusted annual revenue deficiency | $ (87) | $ (99) | $ (203) | $ (256) | $ (645) |
| | Revenue requirement impacts of reducing capital expenditures: | | | | | |
| 11 | 2011 Capital expenditure reductions | (350) | (350) | (350) | (350) | |
| 12 | 2012 Capital expenditure reductions | | (350) | (350) | (350) | |
| 13 | 2013 Capital expenditure reductions | | | (350) | (350) | |
| 14 | 2014 Capital expenditure reductions | | | | (350) | |
| 15 | Total capital expenditure reductions | (350) | (700) | (1,050) | (1,400) | |
| 16 | Book depreciation savings | 3% | 3% | 3% | 3% | |
| 17 | Property tax savings | 1% | 1% | 1% | 1% | |
| 18 | Interest and equity return savings (1) | 9% | 9% | 9% | 9% | |
| 19 | Income tax savings (1) | 4% | 4% | 4% | 4% | |
| 20 | Revenue requirements savings as a % of capital expenditure reductions | 17% | 17% | 17% | 17% | |
| 21 | Annual revenue requirement reduction (line 15 x line 20) | (60) | (119) | (179) | (238) | (596) |
| 22 | Remaining annual revenue deficiency (line 10b - line 21) | $ (27) | $ 20 | $ (24) | $ (18) | $ (49) |

(1) Assuming the Company's proposed cost of capital with a 53.94% equity ratio and an 11% allowed return on common equity

APS ORIGINAL

ARIZONA PUBLIC SERVICE

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April 29, 2010

Docket Control
Arizona Corporation Commission
1200 W. Washington
Phoenix, AZ 85007

RE: Arizona Public Service Company 2008 Amended Rate Case
Plan to Maintain Credit Ratings and Improve Financial Metrics
E-01345A-08-0172, Decision No. 71448

Pursuant to Arizona Public Service Company's ("APS") Settlement Agreement approved in Decision No. 71448, APS was ordered to submit the following:

> Section 1.16(d): "a plan to be prepared by APS to maintain investment grade financial ratios and improve APS' financial metrics."
>
> Section 8.4: "prepare and submit to the [Arizona Corporation] Commission and Signatories within 120 days of approval of the Agreement, a plan detailing steps it intends to take to maintain and improve its financial ratings with the credit rating agencies."
>
> Section 13.2(g): "submit a plan to the Commission to maintain investment grade financial ratios and to improve financial metrics."

In fulfillment of each of these provisions, APS has prepared and hereby submits the following plan to maintain the Company's credit ratings and improve financial metrics.

If you have any questions regarding this information, please contact Zachary Fryer at (602) 250-4167.

Sincerely,

Susan Casady

Susan Casady

SC/sl
Attachment
cc: Steve Olea
Brian Bozzo
Barbara Keene
Terri Ford
Parties of Record

Arizona Corporation Commission
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AZ CORP COMMISSION
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# Arizona Public Service Company

# Plan to Maintain Credit Ratings and Improve Financial Metrics

## Compliance Filing, Decision No. 71448, Docket No. E-01345A-08-0172

## April 29, 2010

**Arizona Public Service Company**
**Plan to Maintain Credit Ratings and Improve Financial Metrics**

## Executive Summary

Arizona Public Service Company's ("APS" or "Company") current credit ratings are "BBB-" from Standard & Poor's ("S&P"), "Baa2" from Moody's Investors Service ("Moody's"), and "BBB" from Fitch Ratings ("Fitch"), all of which currently classify those ratings as "stable." The Company's ultimate credit rating objective is to improve or maintain its ratings to at least the mid-BBB level or its equivalent, if not better, at all three of the ratings agencies. Doing so would permit APS to borrow at more favorable interest rates and enhance its ability to reliably access the capital markets, while also providing greater protection from a non-investment grade rating – outcomes that benefit customers and APS alike. Such an improvement, however, will take time because the ratings agencies ultimately look for stability and predictability in credit quality – characteristics that can take several years to demonstrate.

A change to APS's credit rating can be accomplished by improving the Company's financial metrics, improving the underlying risk profile (what S&P calls "business position"), or a combination of both. APS's Plan to Maintain Credit Ratings and Improve Financial Metrics ("Plan") focuses on enhancing the Company's financial metrics (such as ROE and FFO/Debt) wherever practicable, and advocating that the ratings agencies recognize the improvements in our underlying risk profile.

The most critical qualitative factor that all the ratings agencies consider when rating investor-owned utilities is the extent to which the regulatory environment provides timely and full cost recovery. The Arizona Corporation Commission's ("Commission") approval of the Company's recent Settlement Agreement ("Agreement") provided a platform that improved APS's earned returns on equity and financial performance and established a rate case filing schedule with process improvements, and was thus viewed by the ratings agencies as a positive development in APS's regulatory environment. Other regulatory

decisions, such as the Commission's approval of APS's AZ Sun program and the Federal Energy Regulatory Commission's ("FERC") approval of transmission formula rates for APS, also provide positive support for this aspect of the ratings agencies' analysis.

Against this important backdrop, this Plan outlines APS's key strategies to maintain its credit ratings and improve its financial metrics: managing the capital structure, primarily through well-planned debt and equity issuances; taking measures to reduce negative effects of imputed debt; effectively managing costs across the Company; and advocating for recognition of a positive qualitative change in the Company's risk profile. Each is discussed in greater detail herein.

# Arizona Public Service Company
# Plan to Maintain Credit Ratings and Improve Financial Metrics

## Introduction

Section 8.4 of APS's Agreement, approved in Decision No. 71448 (December 30, 2009), requires APS to "prepare and submit to the [Arizona Corporation] Commission and Signatories within 120 days of approval of the Agreement, a plan detailing steps it intends to take to maintain and improve its financial ratings with the credit rating agencies." Section 13.2(g) similarly requires APS to "submit a plan to the Commission to maintain investment grade financial ratios and to improve [the Company's] financial metrics." In fulfillment of these provisions, APS has prepared and hereby submits the following Plan.

## Credit Ratings Objectives

APS's ultimate credit rating-related objective is to maintain mid-BBB level or better credit ratings that will enable the Company to finance needed investments at reasonable costs and avoid undue exposure to a potential for downgrade to non-investment grade levels. Given the financial commitments and rate case filing restrictions to which APS is bound, and the current macroeconomic environment, APS believes that an improvement to its current credit ratings is likely to take several years of sustained performance.[1] APS will work to improve its financial metrics and the qualitative factors within its control (which, as discussed below, are important elements within the ratings process), both of which could improve credit quality and better position the Company to achieve its ratings objectives.

[1] Moody's, for example, has indicated that "APS's rating is not likely to be revised upward in the near-to-medium term. Longer term, an upgrade could be possible if there is an increase in 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." Moody's Investors Service, Credit Opinion: Arizona Public Service Company (February 25, 2009).

The Agreement contains several provisions that APS intends to use as vehicles to facilitate eventual promotion to higher credit ratings. Of course, the rating agencies are independent arbiters of credit ratings and APS cannot control their analysis of all the underlying factors. For at least the period between now and December 31, 2014 (the "Settlement Term"), APS's objective is to maintain its current credit ratings at stable levels, improve the underlying financial metrics supporting those ratings, and build on the foundation to improved credit ratings paved by the Agreement.

**Ratings Process**

Credit rating agencies describe the ratings process as an art as much as a science. This process includes a quantitative assessment of a utility's key financial metrics and other factors, as well as a qualitative assessment of the utility's business position, including its regulatory environment. The evaluation of various key financial metrics such as Funds from Operations ("FFO") interest coverage, FFO/Debt, and Debt/Total Capital is a cornerstone of the quantitative aspect of the rating agencies' credit assessment. However, other factors such as accounting and financial governance policies and practices, cash flow adequacy, liquidity availability and access to capital are also critical quantitative factors.

Just as important as the *quantitative* analysis, however, is a *qualitative* assessment of various criteria that are core to credit quality and directly impact the predictability and sustainability of financial performance. Within the utility industry, these core areas include regulation and the utility's regulatory environment, markets, diversification, operations and management. Although specific ratings assessment approaches and relative weightings of credit factors may differ among the ratings agencies (along with the transparency of the analytical approaches), the concept, context and product are the same – rating

agencies undertake an analysis of key quantitative and qualitative factors driving credit quality and from this analysis they develop and assign ratings to an issuer.

**Settlement Term Action Plan**

To address the key quantitative and qualitative factors of this evaluation, APS intends to focus primarily on three objectives that address its ratings challenges.

First, the Company expects to earn a Return on Equity ("ROE") around 9% between now and the Company's next rate case, and work to earn closer to its authorized 11% ROE thereafter. Actually earning a ROE at these levels should provide APS with sufficient cash flow to result in a FFO/Debt ratio that supports the Company's present credit ratings. In addition to supporting FFO/Debt, improving the Company's ROE also encourages equity investment, which is necessary to finance capital projects and maintain a balanced capital structure, and is also critical given APS's equity funding commitments. Although rates charged and revenues received from customers are critical factors in earning a reasonable ROE, that metric can also be strengthened by reducing expenses. APS's Plan combines both to achieve its ROE objective.

Second, APS will manage its FFO/Debt ratio and capital structure to comply with the terms of Sections 8.2 and 8.3 of the Agreement, which require the Company to "use its best efforts to maintain investment grade financial ratios and a balanced capital structure that optimizes benefits to ratepayers" and "to strive to achieve a capital structure with no more than 52% debt/total capital, as calculated by the credit rating agencies, by December 12, 2012." Pinnacle West's recent equity issuance of $253 million (described in further detail herein) is an early step in this direction. The strategy to accomplish this objective also includes addressing negative effects of imputed debt.

Third, APS will continue to highlight to credit rating agencies the positive developments in Arizona's regulatory environment, which is the qualitative consideration that S&P deems to be "the most important factor in [its] analysis of a U.S. regulated, investor-owned utility's business risk."[2] In particular, APS intends to build on the momentum gained by the settlement and work with Commission Staff and interested parties on the process improvements discussed in the Agreement that credit rating agencies will view as additional enhancements to Arizona regulation.

To achieve these objectives, APS intends to:

1. **Maintain a Balanced Capital Structure and Infuse Equity as Appropriate.**

APS's capital programs and investment must be financed with an appropriate balance of debt and equity, and both are needed to maintain and strengthen APS's capital structure. APS cannot rely solely on debt to finance its significant capital spending program without damage to its financial metrics, but neither can or should it rely too heavily on equity capital, which is more expensive than debt and increases the Company's overall cost of capital and thus cost to customers.

For these reasons, the Agreement authorized Pinnacle West to infuse $700 million of equity into APS through December 31, 2014, and APS agreed to complete infusions of at least that amount by that date. *See* Agreement at § 8.1. APS completed the first tranche of this commitment through Pinnacle West's issuance of 6,900,000 shares of common stock in April 2010, which resulted in net proceeds to Pinnacle West of approximately $253 million. APS anticipates using these capital contributions to repay short-term indebtedness, to finance capital expenditures, and for other general corporate purposes. As a general matter, and subject to market conditions, the Company expects to issue or obtain new debt and

[2] *See "Assessing U.S. Utility Regulatory Environments,"* Global Credit Portal, Ratings Direct (March 11, 2010).

equity financing as needed to fund its requirements while maintaining a balanced capital structure throughout the Settlement Term.

**2. Mitigate Negative Impacts of Credit Rating Agency Debt Imputation.**

When calculating a company's debt levels and interest obligations for credit ratings purposes, credit rating agencies impute as debt certain obligations under long-term Purchased Power Agreements ("PPAs"), operating leases, or other contractual arrangements. Because of this practice, any utility that procures resources through PPAs or is a party to long-term operating lease agreements will be deemed effectively to have more debt on its balance sheet than it would without such contracts. Of particular concern is the level of subjectivity, variables, and assumptions at play in the rating agencies' calculation of the debt imputation amounts. These values are less certain and identifiable than balance sheet amounts representative of a debt and equity finance mix. APS, which has a significant portfolio of both renewable and conventional PPAs, is particularly vulnerable to the impact of debt imputation.

Critical to managing and mitigating that impact is investment in utility-owned resources, financed with an appropriate mix of debt and equity – the very type of investment recently approved for APS with AZ Sun for utility-scale renewable generation. The Agreement not only gives APS the key tools needed to make those investments, but requires APS to use those tools to reduce its imputed debt levels. Under Section 15 of the Agreement, APS must acquire significant amounts of renewable energy, such that renewable resources will be approximately 10% of APS's retail sales by 2015. This obligation requires significant financial commitments that – if procured solely through PPAs – could harm the Company's financial metrics and run contrary to APS's commitment to "strive to maintain a 52% debt/total capital ratio as calculated by the credit rating

agencies by December 31, 2012," which the Agreement also requires. *See* Agreement at § 8.3.

A similar option that APS may pursue is to purchase already constructed generation resources to replace PPA resources, assuming favorable pricing. Purchasing such resources, financed with an appropriate mix of debt and equity, would also eliminate the imputed debt impact associated with a PPA. Any such acquisition of a non-renewable generation plant could require a waiver by the Commission from the restrictions of APS's self-build moratorium, in effect until January 1, 2015.

Finally, APS is evaluating its leasehold interests, looking at several viable alternatives that will further mitigate negative impacts of imputed debt on the Company's balance sheet.

3. **Focus on Cost Management.**

An important component of maintaining a reasonable earned ROE between rate cases is disciplined cost management – having processes in place engineered to set budget and cost projections at appropriate levels and keep actual costs within those projected ranges. Maintaining an earned ROE closer to the authorized return, through a combination of the rate relief provided by the Commission and cost management, will support APS's financial metrics. During the Settlement Term, a cost management focus also is critical for APS to meet the Agreement's expense reduction requirement (whereby APS committed to reduce expenses by an average $30 million per year, for a total reduction of $150 million for the Settlement Term, *see* Section 7.1). Consistent with Section 7.3 of Agreement, APS will submit an annual report detailing the specific reductions made each year to meet the Agreement's expense reduction requirements. Pursuant to the Agreement, the first such report will be filed on April 29, 2011.

Some current examples of APS's cost management efforts include:

- APS held its operating budget for 2010 flat compared to 2009 budgeted levels, notwithstanding cost increases for materials and supplies, technology cost increases, maintenance cost increases, and increased maintenance levels required to maintain aging equipment. Doing so required virtually every area of the Company to reprioritize, rebalance, and reassess risk so that APS could hold flat its anticipated spend without jeopardizing the safety of employees or the reliability of service to customers. The same intense focus on cost management was also an important piece of our capital expenditure plan review for 2010.
- APS is restructuring its supply chain organization, transforming the processes by which goods and services are procured to become more efficient and cost-effective. This undertaking is significant. Supply chain management is one of the most important strategic aspects of any capital intensive business. Decisions must be made about how to coordinate the production of goods and services, how and where to store inventory, from whom to buy materials and under what terms, and how to distribute those materials in the most cost-effective, timely manner. Among other things, the supply chain initiative now underway will significantly reduce procurement costs by standardizing the Company's procurement practices and allowing APS to be more strategic about the payment and other contract terms used with vendors, thus obtaining the best value for the Company and its customers.
- APS has adopted and is now implementing a new operations model for its fossil plants that incorporates all aspects of how the Fossil Generation business unit operates. A critical component of the model is a movement to a one-fleet mindset, looking at all of the

Company's plants as one generation fleet that operates consistently and towards common goals. Fossil Generation is also making changes to implement best utility practices with respect to both staffing and processes. The model will drive the fleet towards improved consistency, economies of scale, implementation of best practices, resource and knowledge sharing, and cost management opportunities.

- APS is also implementing a power plant operations strategy to reduce environmental compliance cost exposure in the long-term and certain operational and maintenance ("O&M") expenses in the short run. For example, the Company is looking at various options to address the environmental matters at the Four Corners Power Plant and resolve ownership issues at Units 4 and 5 that may arise given Southern California Edison's indication that California legislation may prohibit it from investing any significant amount in those units going forward. While several complicating variables have yet to be resolved, APS hopes to achieve a result that, with the Commission's approval, will reduce APS's cost exposure under increasingly stringent federal EPA requirements and maintain an important baseload resource to support the Company's increasing acquisition of renewable resources.
- APS has launched an initiative in its Energy Delivery business unit to improve work processes, gain greater consistency in the execution of that work, and enhance the business unit's overall operational efficiency and performance. The Company's use of more modern technology, standardized work methods, and more streamlined processes will enhance its ability to plan, schedule, organize, execute

and monitor the work needed to manage the assets and equipment required to serve customers and reduce costs.

**4. Pursue Rate-Related Strategies for Timely Cost Recovery.**

As the foregoing describes, APS is focused on analyzing its operations and taking important steps to effectively and efficiently manage costs, finance with the right combination of debt and equity, and mitigate negative ratings impacts of imputed debt. But the sum total of these efforts does not eliminate the Company's need for appropriate rate relief. APS has a significant capital expenditure program devoted, among other things, to building infrastructure needed throughout the state, addressing environmental issues at its generation plants, and otherwise fostering an environmentally-friendly, sustainable, and efficient Arizona energy future. In combination with the other facets of this Plan, adequate and timely cost recovery is critical for APS to improve its ROE and other financial metrics.

In that regard, APS will:

- File a rate case on June 1, 2011, using a 2010 test year as permitted by Section 2.2 of the Agreement. Among other things, this rate filing will present the required information in a format that more transparently aligns the Company's revenue needs and its cost drivers.
- Work with the Settling Parties and Commission Staff to process the case within 12 months of a sufficiency filing, as contemplated by the Agreement. *See* Agreement at § 2.3. The 12 month turnaround provision is important to reducing the negative financial impact of regulatory lag and has been heralded by ratings analysts. APS will facilitate this processing time, both by filing the required 120 day notice of its intent to file, informally discussing issues relating to the rate filing with the parties well before that required notification, and

coordinating the logistics that will enable the parties to meet and confer about the anticipated rate filing, as the Agreement requires. *See* Agreement at § 2.4.

- Actively participate in the Commission's decoupling workshops and pursue a decoupling mechanism that supports the Company's ability to meet the aggressive energy efficiency levels set in the Commission's recent rulemaking without impairing APS's financial performance. S&P recently noted that, properly structured, decoupling "supports creditworthiness because it can lessen volatility in revenues and cash flow." Assurance of recovery of APS's fixed costs through decoupling will send a positive signal to the rating agencies that Arizona's regulatory environment is one that will support the Company's financial health while furthering important policy goals.
- Continue using FERC formula rates to recover costs for additional transmission investments, and pursue timely approval of the Company's Transmission Cost Adjustor applications each year.

**5. Support the Capital Markets' Evolving Perception of Arizona's Regulatory Environment and Other Qualitative Factors.**

Ratings agencies appropriately recognized the Agreement as a major milestone demarking what they believe to be an increasingly supportive regulatory environment. All three ratings agencies have described the Commission's approval of the Agreement as an indication of improving credit quality. S&P noted that "recent rate activity is evidence that the company's management of regulatory risk has improved" and that "interim rates and recovery of certain post-test year costs

have mitigated some risk in APS's latest case."[3] Moody's similarly affirmed APS's current rating after the Agreement was approved to reflect its view of APS's "continued financial and operating performance as well as recent decisions and recommendations of the Arizona Corporation Commission (ACC) and the ACC Staff respectively, which in our opinion appear to be somewhat more supportive than had historically been the case . . . . We believe the potential for rate settlements has increased, which could also potentially reduce regulatory lag."[4] Fitch also described the Agreement's approval as "supportive of APS's current credit ratings and a constructive development for APS fixed income investors."[5]

As a means of further improving this key qualitative aspect of the utility credit quality, APS plans to work with the Commission and other parties to capitalize on the momentum gained during the settlement. To that end, APS intends to:

- Pursue ratemaking mechanisms and processes that will allow APS to implement important state and federal policy objectives and move Arizona further into the evolving energy future without degradation to the Company's financial metrics;
- Work with the Commission and other interested parties to reach constructive agreements to settle future cases, if practicable, in order to conserve Commission resources and mutually promote shared goals.

Although credit ratings agencies deem "regulatory environment" to be the most important qualitative factor governing their assessment of investor-owned

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[3] Standard & Poor's, RatingsDirect, Arizona Public Service Company at 2 (December 22, 2009).

[4] Moody's Investors Service, Rating Action: Arizona Public Service Company (February 23, 2009).

[5] Fitch Ratings, Corporates, Global Power U.S. & Canada Credit Update: Arizona Public Service Company (December 30, 2009).

utility risk profiles, others are also considered, including market position, operational performance, and company management (looking at such things as a commitment to credit quality, operating efficiency and cost control). Many of the steps outlined in this Plan address these other qualitative considerations, as to which APS will continue to advocate its strong performance.

## Conclusion

The Agreement was an important step in the right direction towards stabilizing the Company's credit quality. Going forward, the Company will focus on maintaining a balanced capital structure and issuing equity and debt as appropriate; managing costs; and implementing strategies that mitigate negative impacts of imputed debt. Capitalizing on and furthering the momentum achieved during the settlement, APS also will work with the Commission and stakeholders as it pursues a decoupling mechanism and other forms of rate relief that are both timely and adequate to give APS a reasonable opportunity to earn its authorized rate of return. Collectively, these and other future efforts should improve APS's financial health and credit quality.

**ARIZONA PUBLIC SERVICE COMPANY**
**PROJECTED INCOME STATEMENTS**
**WITH PROPOSED RATE INCREASE EFFECTIVE JULY 1, 2012**
(Thousands of Dollars)

| Line No. | Description | Projected Year - Total Company Year Ended 12/31/2011 (A) | Year Ended 12/31/2012 (B) | Year Ended 12/31/2013 (C) | Projected Year - ACC Jurisdiction Year Ended 12/31/2011 (D) | Year Ended 12/31/2012 (E) | Year Ended 12/31/2013 (F) | Line No. |
|---|---|---|---|---|---|---|---|---|
| 1. | Electric operating revenues | $ 3,242,469 | $ 3,478,076 | $ 3,693,927 | $ 3,105,016 | $ 3,366,243 | $ 3,597,375 | 1. |
| 2. | Fuel and purchased power | 985,439 | 1,042,104 | 1,066,762 | 1,114,392 | 1,205,740 | 1,266,823 | 2. |
| 3. | Operating revenues less fuel and purchased power | 2,257,030 | 2,435,972 | 2,627,165 | 1,990,624 | 2,160,503 | 2,330,552 | 3. |
| | Other Operating Expenses: | | | | | | | |
| 4. | Operations and maintenance excluding fuel and purchased power * | 963,110 | 1,017,251 | 1,088,409 | 864,047 | 940,064 | 1,008,530 | 4. |
| 5. | Depreciations and Amortization | 421,726 | 404,136 | 440,345 | 373,804 | 350,955 | 380,136 | 5. |
| 6. | Income taxes | 192,641 | 253,878 | 273,496 | 176,711 | 222,980 | 240,683 | 6. |
| 7. | Other taxes | 153,869 | 174,953 | 194,124 | 130,732 | 148,610 | 164,894 | 7. |
| 8. | Operating income | 525,684 | 585,754 | 630,791 | 445,330 | 497,894 | 536,309 | 8. |
| | Other Income (Deductions): | | | | | | | |
| 9. | Income taxes | 4,410 | 8,272 | 11,385 | 107 | 429 | 894 | 9. |
| 10. | Allowance for equity funds used during construction | 26,691 | 24,490 | 23,276 | 22,447 | 20,840 | 17,923 | 10. |
| 11. | Other income | 5,036 | 2,094 | 1,367 | (270) | (1,086) | (2,263) | 11. |
| 12. | Other expenses | (15,664) | (16,973) | (19,693) | - | - | - | 12. |
| 13. | Total | 20,473 | 17,883 | 16,335 | 22,284 | 20,183 | 16,554 | 13. |
| 14. | Income Before Interest Deductions | 546,157 | 603,637 | 647,126 | 467,614 | 518,077 | 552,863 | 14. |
| | Interest Deductions | | | | | | | |
| 15. | Interest on long-term debt | 214,337 | 209,732 | 226,870 | 172,349 | 167,471 | 178,369 | 15. |
| 16. | Interest on short-term borrowings | 6,007 | 8,593 | 7,815 | 4,827 | 6,856 | 6,140 | 16. |
| 17. | Debt discount, premium and expense | 4,584 | 3,655 | 3,788 | 3,683 | 2,916 | 2,976 | 17. |
| 18. | Allowance for borrowed funds used during construction | (17,437) | (22,746) | (23,322) | (14,650) | (19,015) | (17,256) | 18. |
| 19. | Total | $ 207,491 | $ 199,234 | $ 215,151 | $ 166,209 | $ 158,228 | $ 170,229 | 19. |
| 20. | Net Income | $ 338,666 | $ 404,403 | $ 431,975 | $ 301,405 | $ 359,849 | $ 382,634 | 20. |
| 21. | Return on Year End Common Equity | 8.6% | 9.3% | 9.5% | 9.6% | 10.4% | 10.8% | 21. |
| 22. | Return on Average Common Equity | 8.8% | 10.0% | 9.7% | 9.7% | 10.9% | 11.0% | 22. |

Notes:
* Includes expenses related to Renewable Energy Standard and Demand Side Management programs.

# TESTIMONY OF MARK A. SCHIAVONI

**On Behalf of Arizona Public Service Company**

**Docket No. E-01345A-11-_____**

**June 1, 2011**

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**TESTIMONY OF MARK A. SCHIAVONI**
**ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY**
**(Docket No. E-01345A-11-____)**

I. INTRODUCTION

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

A. My name is Mark A. Schiavoni. I am the Senior Vice President of Fossil Generation at Arizona Public Service Company ("APS" or "Company"). In that capacity, I am responsible for overseeing all facets of the Company's non-nuclear generation plants, including operations of over 6,600 megawatts of fossil and renewable energy. This includes outage and work management, plant engineering and technical support, and operational oversight of co-owned facilities.

**Q. WHAT IS YOUR PROFESSIONAL BACKGROUND?**

A. I joined APS in 2009 from Exelon Corporation ("Exelon"), where I spent nine years, most recently as Senior Vice President of Exelon Generation and President of Exelon Power. I began work at Exelon in 2000 as a nuclear plant manager, after which time I assumed various senior executive positions overseeing Exelon's fossil, hydroelectric and renewable facilities, as well as the construction and integration of new generation assets. Before joining Exelon, I worked as a nuclear plant maintenance director for both Florida Power and Centerior Energy Corporation. Prior to that, I spent 22 years in the U.S. Navy's nuclear program.

**Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?**

A. Yes. I spoke at the Commission's November 18, 2010 Special Open Meeting on the topic of how an Environmental Protection Agency ("EPA") proposed rule impacts Four Corners power plant ("Four Corners"). I have also filed written testimony supporting APS's application to acquire SCE's portion of Four Corners Units 4-5 in Docket No. E-01345A-10-0474.

II. SUMMARY

**Q. PLEASE SUMMARIZE YOUR TESTIMONY.**

A. My testimony provides a general overview of APS's Fossil Generation business unit, and provides a high level picture of what is required to safely and reliably generate electricity at the Company's fossil plants. Specifically, I examine Fossil Generation's intense focus on safety, reliability, the environment, and cost management. I also identify the specific projects completed in the 2010 Test Year and through June 30, 2012, and isolate Fossil Generation's contribution to the Company's post-Test Year Plant Adjustment. Finally, I address certain recommendations made by Liberty Consulting Group ("Liberty") in its Benchmarking Study of APS.

III. INTRODUCTION TO FOSSIL GENERATION

A. *Overview of Fossil Generation*

**Q. TO WHAT DOES "FOSSIL GENERATION" REFER?**

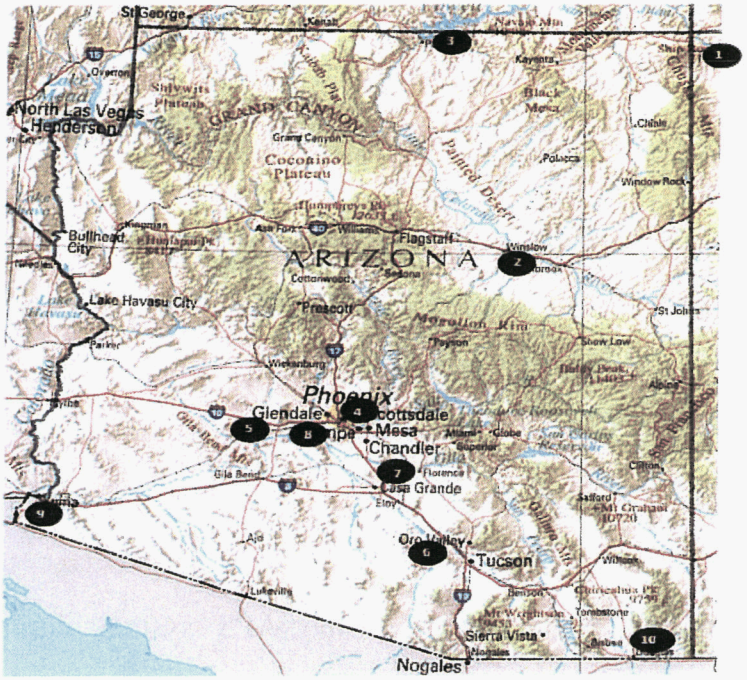
Fossil Generation is an APS business unit that operates a fleet of two coal-fired, six natural gas-fired, and one oil-fired generating station, which collectively provide over 6,600 megawatts of reliable capacity. APS also owns 14% of the Navajo Generating Station, operated by Salt River Project ("SRP"). In total, over 5,100 megawatts of the capacity generated by our fleet serve APS customers – meeting approximately two-thirds of our customers energy needs. Fossil Generation is also constructing several new utility-scale solar photovoltaic generation facilities that will join our generation fleet. At present, Fossil Generation has a workforce of about 960 employees. Our 2010 work plan required capital expenditures of $112.8 million and an operations and maintenance ("O&M") budget of $190.2 million.

Collectively, the APS plants within the Fossil Generation fleet have baseload, intermediate, and peaking capabilities that complement the power produced by

Palo Verde Nuclear Generating Station. The coal plants, with low fuel costs, provide base load power and have averaged capacity factors in the range of 80-85% over the past decade. APS's gas plants – and, soon, its solar facilities – serve as our intermediate and peaking resources.

**Q. PLEASE BRIEFLY DESCRIBE APS'S FOSSIL GENERATION FLEET.**

A. As the following map and corresponding table demonstrate, nine of the ten power plants within the APS Fossil Generation fleet are scattered throughout Arizona. Four Corners, the first plant listed below, is located in Farmington, New Mexico.



**Summary Table of Generating Capabilities**

| | PLANT | FUEL TYPE | UNITS | OWNED CAPACITY |
|---|---|---|---|---|
| ❶ | Four Corners | Coal | 5 | 791 |
| ❷ | Cholla | Coal | 3 | 647 |
| ❸ | Navajo | Coal | 3 | 315 |
| ❹ | Ocotillo | Natural Gas | 4 | 330 |
| ❺ | Redhawk | Natural Gas | 2 | 984 |
| ❻ | Saguaro | Natural Gas | 5 | 399 |
| ❼ | Sundance | Natural Gas | 10 | 420 |
| ❽ | West Phoenix | Natural Gas | 7 | 997 |
| ❾ | Yucca | Natural Gas | 6 | 243 |
| ❿ | Douglas | Oil | 1 | 16 |
| | Total Fleet | | 46 | 5,142 |

Allow me to elaborate a bit more on each of these plants:

- *Cholla:* The Cholla power plant ("Cholla") is a four-unit coal-fired plant located near Holbrook, Arizona. APS operates the plant and owns Units 1, 2 and 3, with a combined capacity of 647 megawatts. PacifiCorp owns Unit 4, with a 380 megawatt capacity. In addition, because APS and PacifiCorp have opposite periods of seasonal demand, we benefit from a seasonal power exchange agreement pursuant to which PacifiCorp receives electricity from the APS system during the winter when electricity demands are high in the Northwest, and APS receives an equivalent amount of power from PacifiCorp during the summer, our period of peak demand.

- *Four Corners:* The Four Corners power plant is a five-unit, 2,100 megawatt coal-fired plant located on the Navajo Nation, 24 miles west of Farmington, New Mexico. At present, APS owns Units 1, 2 and 3 and shares ownership of Units 4 and 5 with five other utilities. The units are

fueled by low-sulfur coal from the nearby Navajo mine (operated by BHP Billiton ("BHP")). As BHP mines the coal, it is transported to a reclamation pile by electric railroad. A conveyor belt system delivers coal from the reclamation piles to the unit's coal bunkers. Water is supplied by the San Juan River to Morgan Lake, located near the plant and containing over 1,200 surface acres of water. APS's current share of the plant's total production is 791 megawatts. APS has contracted to purchase an additional share of Units 4 and 5 from Southern California Edison, which acquisition is the subject of another docket.[1]

- *Navajo:* The Navajo power plant ("Navajo"), a three unit coal-fired facility operated by SRP, is located in northern Arizona on the Navajo Indian Reservation near Page. It has a total production capacity of 2,250 megawatts. The plant is jointly-owned with four other utilities and the U.S. Bureau of Reclamation, and APS has a 14% interest in the plant. The plant is fueled by low-sulfur coal from the nearby Peabody Kayenta Mine at Black Mesa. An electric railroad delivers coal to the plant from the mine, which is located on the Navajo and Hopi Indian Reservations.

- *Douglas:* APS's Douglas power plant (sometimes referred to as "Fairview"), is located in the town of Douglas in Southeastern Arizona. It is comprised of one 16-megawatt diesel-fueled combustion turbine ("CT") peaking unit installed in 1972, which normally operates only in emergencies. The plant has no full-time employees, but is operated and serviced by employees from APS's Sundance plant, near Casa Grande.

[1] *See* Docket No. E-01345A-10-0474.

- *Ocotillo:* APS owns and operates the Ocotillo natural gas power plant ("Ocotillo") located in Tempe, near Phoenix's center of customer demand and thus strategically important to summer reliability. The plant, served by the El Paso Natural Gas pipeline, has two steam-units and two CT units. The site has a total generating capacity of 330 megawatts.

- *Redhawk:* APS owns and operates the Redhawk power station ("Redhawk"), a natural gas plant comprised of two identical 492-megawatt combined-cycle units. Both the El Paso Natural Gas and Transwestern pipelines supply the facility. The plant is located 50 miles west of Phoenix. Because the facility is located in the desert without access to a reliable supply of surface water, the plant uses treated effluent purchased from Palo Verde to meet its cooling needs. To minimize cooling water use, Redhawk was designed as a zero liquid discharge site. In other words, the cooling process continually reclaims and reuses cooling water — no water is released into the environment.

- *Saguaro:* The natural gas-fueled Saguaro power plant, located north of Tucson, has two steam units and three combustion turbine units. The plant is served by the El Paso Natural Gas pipeline. APS owns and operates all five units, which have a combined capacity of about 399 megawatts. The site is managed by the Sundance leadership team.

- *Sundance:* The simple-cycle, natural gas-fueled Sundance Generating Station, located near Casa Grande, consists of 10 quick-start CT units that have a combined production capacity of 420 megawatts. The plant is served by both the El Paso and Transwestern pipelines, providing options for fuel delivery.

- *West Phoenix:* Located in Southwest Phoenix, the natural gas-fueled West Phoenix power plant has seven generating units, consisting of two CT units and five combined-cycle units. Like Ocotillo, West Phoenix is located near Phoenix's center of customer demand and is strategically important to summer reliability. The plant is served by El Paso Natural Gas pipeline. Operated and owned by APS, West Phoenix is capable of generating about 1,000 megawatts of electricity. Like Redhawk, West Phoenix uses zero liquid discharge technology for the Combined Cycle Units 4&5 for cooling to focus on water economy.

- *Yucca*: APS operates the natural gas-fueled Yucca Power Plant near Yuma. Yucca consists of six CT units that produce nearly 243 megawatts for APS customers, as well as a 75 megawatt steam unit and a 22 megawatt CT unit, both of which are owned by the Imperial Irrigation District ("IID"). Yucca CTs 1, 2 & 3 and the IID steam plant are served by the El Paso pipeline. In March of 2010, Yucca CTs 5&6 were connected to the North Baja natural gas pipeline. In March 2011, the IID steam unit was also connected to the North Baja pipeline. CT 4 and the IID CT both run on oil only, because historically there was insufficient gas transport for these units.

**Q. WHAT IS THE MISSION OF FOSSIL GENERATION?**

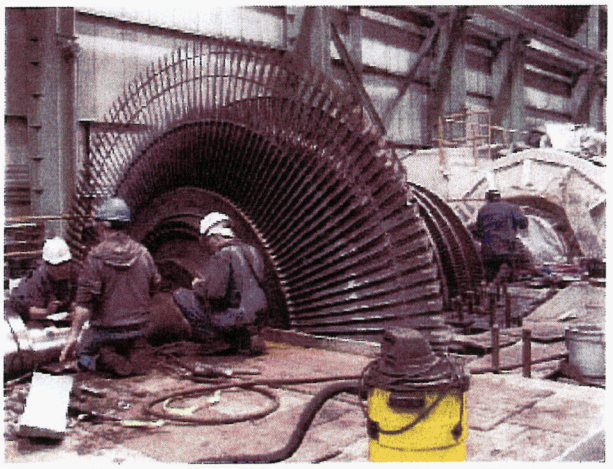
A. Fossil Generation's mission, simply put, is to be the best. We will deliver superior operational performance while instilling a strong safety culture and protecting our environment. Getting there is no easy task. Fossil Generation faces a variety of challenges, including an aging workforce and plants, preparing for and complying with continually-evolving environmental regulations and

policy developments that require significant cost investments, and operating in step with APS's aggressive corporate-wide focus on cost management.

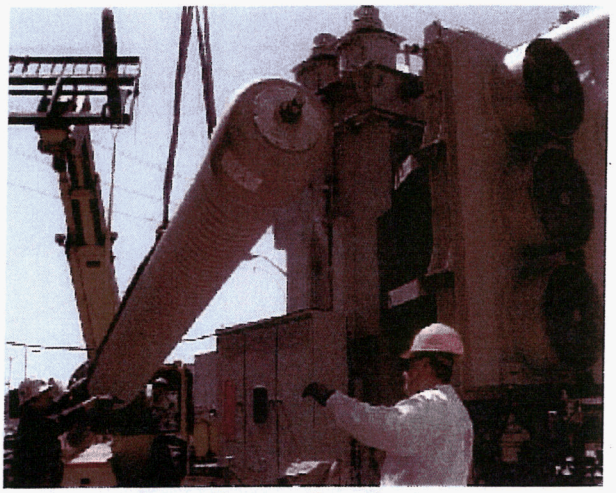
B. *Focus on Safety*

**Q. WHAT IS FOSSIL GENERATION DOING TO INSTILL A STRONG SAFETY CULTURE, AND AT WHAT COST?**

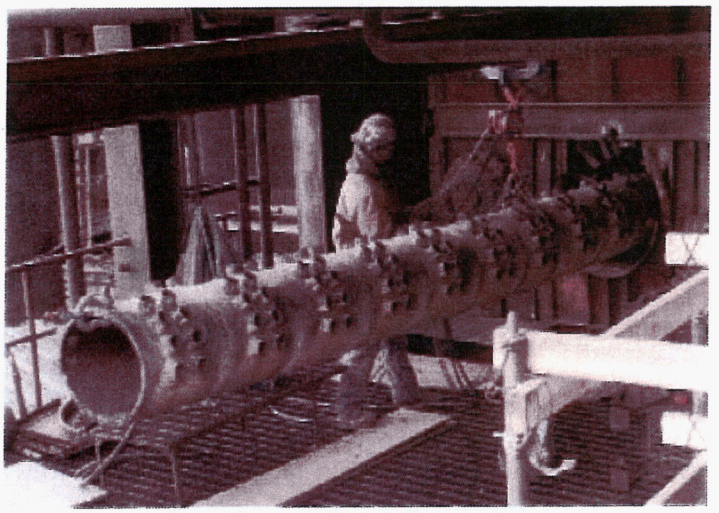
A. Safety is a core value at APS, and a key part of Fossil Generation's operating mission. Running a power plant is inherently hazardous, and the men and women who work at our plants generating power for customers throughout the Southwest face significant safety risks each and every day. Think of how a steam unit generates electricity: a fuel is burned in a huge boiler to create enough heat to turn water into steam. That steam is highly pressurized and carried through thick metal pipes to the turbine. The turbine rapidly spins a generator, which changes mechanical spinning energy into electricity. The following illustrate the types of machinery involved in the process:



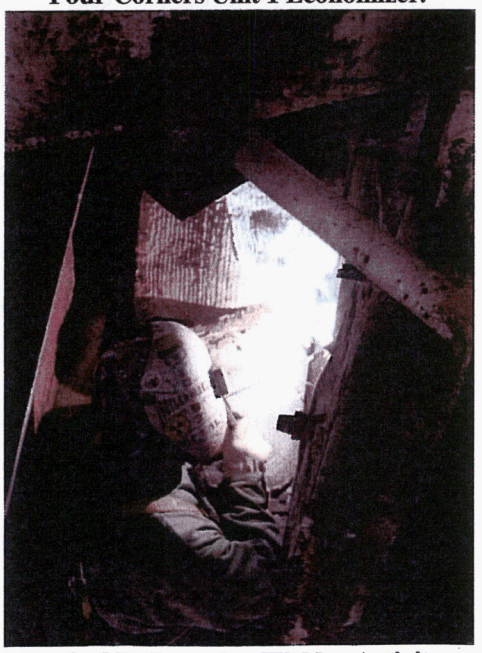
**Four Corners Unit 5 Low Pressure Rotor/Turbine.**



**Four Corners Transformer.**



**Four Corners Unit 1 Economizer.**



**Typical Boilermaker/Welder Activity.**

**Combustion Turbine Load Tunnel Inspection.**

This operation is replete with safety hazards. Power plant workers work with hazardous materials, high temperature and pressure piping, and rotating equipment every day. The innately dangerous working conditions at power plants require APS to make safety its first priority and insist that our employees and contractors do the same. That is the message behind the Company's "Got Safety – Get Zero!" campaign, and a critical focus for Fossil Generation. Safety is our #1 priority. I have often told the Fossil employees that there is no task so urgent that safety should be compromised.

Fossil's business plan for 2011 outlines a detailed approach to emphasize safety with our employees so as to eliminate "at risk" behavior (inappropriate actions on the part of our workers that increase risk) and achieve zero injuries. To reach this goal, Fossil Generation has designed a comprehensive safety management system to protect plant workers, visitors, and the public from safety hazards. As part of this program, we have developed, among other things, a standard set of safety protocol and training presentations, a procedure for conducting personal safety accountability meetings, and a safety assessment protocol. Our safety policies require all employees to regularly undergo standardized safety training, all

managers to start daily meetings with safety messages, all plants and equipment to undergo safety inspections and audits, and a quarterly fleet-wide "safety stand-down," in which every worker in every unit of APS's Fossil Generation fleet devotes a half-day to focus as a fleet on a variety of safety and related topics.

Most safety issues can and should be avoided if power plant workers are diligent about assessing how their behavior and attitudes contribute to safety incidents and other events (what we call "Human Performance"). For that reason, I repeatedly emphasize the need for our employees to keep cautious and vigilant so as to predict, manage and prevent error-likely situations; rely on organizational processes and values as a means of influencing individual behavior; understand the reasons that mistakes occur; and apply the lessons learned from past events to avoid similar incidents in the future. We aim to achieve these fundamental behaviors through encouragement and reinforcement, from the highest ranking positions in the business unit down.

For example, Fossil Generation implemented the Station Event Free Clock process in the fourth quarter of 2009 to encourage close attention to Human Performance. Each generating station installed a clock to measure the time passed since the last Human Performance-related incident. Each plant's progress in this regard is tracked on our internal website, and recognition is given to plants with positive results. In 2011, we will implement a similar "Event-Free Clock" process on a departmental level. Acknowledging and discussing the precursor events to safety incidents gives front-line supervisors and department managers opportunities to learn from events and ensure that employees understand their performance expectations. My team and I are working hard to make Fossil Generation a self critical and continuous learning organization. This, we believe, will drive sustainable and safe plant performance.

**Q. WHAT ELSE DOES FOSSIL GENERATION DO TO PROMOTE A SAFE WORKING ENVIRONMENT?**

A. Fossil Generation provides standardized personal protective equipment for all of its employees and others working at the plant, including safety shoes, protective eyewear, hearing protection, and hard hats. We also supply a variety of other equipment to protect employees from hazards associated with specific job assignments. This includes "spoggle" eyewear for areas of high wind and dust, hand protection for all types of tasks, and fire resistant and arc flash rated clothing. Our plants have also upgraded their safety equipment to include devices used to automatically open and close a circuit breaker from a remote location, thereby removing operations personnel from manual contact with the circuit breaker increasing personal protection from arc flash hazards; safety swing gates that automatically close on industrial ladders, protecting our workers from falls; and additional welding outlets to reduce the number of tripping hazards associated with welding equipment.

From a cost perspective, these and other safety-related measures required expenditures of more than $5.5 million in 2010, a number that will increase for 2011 and 2012. This figure does not include the cost of maintenance, described below, which is also important for safety. This is money very well spent. Indeed, we have already seen a marked improvement in our safety metrics: where Fossil Generation employees experienced 27 OSHA recordable injuries in 2009 (including one fatality), we had only 10 last year (and no fatalities) – an almost two-thirds reduction.

C. *Focus on reliability*

**Q. IS THE FOSSIL GENERATION FLEET RELIABLE?**

A. Yes, and it is becoming more so each day. As the Benchmarking Report published by Liberty Consulting Group found, when measured by capacity factor, "the performance of the APS units is at the top of the industry," "generally in the first quartile in their panels."[2] Our fossil plants overall also demonstrate above-average performance in terms of availability (measured by the "Equivalent Availability Factor").[3] Although some units have historically performed better than others, particularly with respect to forced outage rates, Fossil Generation is putting the mechanisms in place to drive improved reliability performance where opportunities exist to do so. Indeed, recent benchmarking studies indicate that current performance metrics trend in the right direction – a reflection of changes to our operations model.

**Q. PLEASE DESCRIBE GENERALLY WHAT FOSSIL GENERATION DOES TO MAINTAIN ITS FLEET TO BE SAFE AND RELIABLE.**

A. Keeping our fleet operating safely and reliably requires significant time and money. Imagine all of the various machines at work inside of a fossil power plant (boilers, generators, turbines, etc.), and all of the many components that make up those machines (metal pipes, coils, tubes, wires, and shafts, to name a few), with an average age of 42 years for our coal plants and 25 years for our Gas & Oil plants. Each of these components in all of the 46 units in our fleet must be inspected and maintained consistently if our plants are to provide safe and reliable power for our customers. Although Fossil Generation has always had policies in place towards that end, we have recently increased our rigor and focus on plant maintenance. The comprehensive set of standardized policies and procedures to which we adhere are designed to ensure that the fleet is working to

[2] *See* Liberty Benchmarking Report at 12.
[3] *See* Liberty Benchmarking Report at 12; Concentric report, attached to the Testimony of Jeff Guldner.

achieve continually improving reliability, measured not just by capacity factor but by ensuring the power is there when our customers need it.

Pursuant to these policies, our plants undergo regular preventative, predictive, and corrective maintenance, as well as planned overhaul outages. Fossil Generation's preventative maintenance program, for example, requires that specific routine maintenance work be done at each of the units at specified periods. As one would change the oil in his or her car on a regular basis, so do we maintain our generation equipment at regularly prescribed intervals. When conducting predictive maintenance, we carefully monitor a given piece of equipment and perform needed upkeep when conditions require (for example, when a component's temperature approaches an unacceptable range) rather than doing so on an arbitrarily set date. Predictive maintenance generally makes sense over preventative maintenance when the maintenance cost for a component is high, thus justifying more comprehensive monitoring. No matter how good our preventative and predictive maintenance programs are, parts can and do break. When they do, we perform "corrective maintenance" to fix them.

In addition, each of the units in the Fossil Generation fleet undergoes regular inspections that vary in depth and scope to identify equipment problems that may impact plant safety or reliability (such as corroded metal or stress on high pressure piping). Routine inspections assess how the machinery is performing without physically examining the inside of the equipment. At our coal plants, a more comprehensive analysis, "minor overhaul," is generally done every 3 years (or other period as dictated by the nature of the plant) and an even more comprehensive "major overhaul" is conducted every 6 years (or as otherwise appropriate). For our gas and oil fleet, minor overhauls are generally conducted every 3 to 4 years, and major overhauls occur every 8 to 9 years. These more

extensive analyses take place during planned plant outages, allowing our engineers and mechanics to actually get inside of the machines to physically examine them and better identify any potential problem areas. We also take advantage of these planned outages to repair or replace any components that are showing signs of stress.

Of course, all of our maintenance and inspection work must be carefully managed and monitored to ensure its completion. To that end, Fossil Generation is putting in place a comprehensive work management system that tracks all of the work that must be done on each of the units throughout the fleet and generates the work orders and manual tasks that our plant employees do daily.

**Q. DOES APS FACE ANY PARTICULAR ISSUES THAT MAKE ITS FLEET MORE COSTLY TO MAINTAIN?**

A. Yes. Six of the nine coal units in Fossil Generation's operated fleet are over 40 years old and require higher levels of capital investment to maintain relative to the newer units. Like a car or any other piece of equipment, the older the unit, the more likely the wear and degradation of its parts as well as obsolescence. Older facilities thus tend to need more maintenance and require more frequent component upgrades compared to newer ones. As I will describe in detail, that cost is compounded by the costs needed to install and operate emissions control equipment so as to meet environmental regulations. Issues with coal quality also impact plant operation and costs at the Four Corners Generating Station, as I later describe.

**Q. WHAT COST IS REQUIRED TO ENSURE RELIABLE PERFORMANCE OF THE FOSSIL GENERATION FLEET?**

A. The inspections and other activities described above require significant capital and O&M dollars. APS's share of the fleet's total reliability-related spend in the

2010 Test Year exceeded $175 million. These expenditures include the following:

- A major overhaul of the combustion and steam turbines at Unit 1 of APS's Redhawk's natural gas plant, the first such overhaul since Redhawk went into commercial service in 2002. This project required workers to disassemble, clean, inspect and replace/repair each of the components of these turbines to promote their continued reliability. The overhaul took 53 days to complete and cost over $40 million ($12 million in O&M costs and $28.7 million in capital).

- Replacement of the cooling towers motor control center and related parts at Units 1 and 2 of the Ocotillo natural gas plant. All thermal power plants produce waste heat energy as a byproduct of the useful electrical energy produced. Cooling towers remove the heat from the process water to improve power plant efficiency. As its name suggests, the cooling tower motor control center is a device that contains the switches and mechanisms that control the operation of the cooling tower motors. Replacing this device for Unit 1 and Unit 2 was necessary as a result of aging allowed for the continued operation of the cooling tower and cost $1.5 million.

Replacement of various portions of the boiler in Unit 2 of Cholla power plant, so as to reduce the possibility of a boiler tube leak. Were the boiler tube to leak, steam would escape into the boiler and would not be released into the turbine – an essential part of electricity generation. Tube leaks can result in a forced outage of three to six days for repairs. The boiler tubing had corroded beyond repair and needed to be replaced. Doing so supported the plant's continued reliability and cost $1.6 million.

**Q. PLEASE IDENTIFY THE RELIABILITY-RELATED CAPITAL PROJECTS THAT FOSSIL GENERATION WILL COMPLETE BY JUNE 30, 2012.**

A. A listing of all of the capital projects that Fossil Generation will place in service for customers by June 30, 2012 is attached to my testimony at MAS-1. These projects include the following:

- A major overhaul of the combustion and steam turbines at Unit 2 of APS's Redhawk natural gas plant, completed on April 2, 2011. This project is similar to that required for Unit 1 in 2010, requiring workers to disassemble, clean, and inspect each of the components of these turbines to promote their continued reliability. This overhaul took 56 days and required a capital cost of $39.6 million.

- Replacement of the "horizontal superheater" section of the boiler tubing and its support system at Unit 1 of Cholla power plant, so as to prevent equipment failure and reduce the possibility of tube leaks. The original superheater had been in service for more than 30 years and had degraded. This project will support the Unit's reliability, and was completed in April of 2011 at a cost to APS of $4.7 million.

- Replacement of the blades in the low pressure portion of the turbine at Unit 1 of Cholla power plant. The prior blades had suffered stress crack damage and needed to be replaced so that they did not break during operation and cause extensive and costly damage to other parts of the turbine. This reliability-related project was completed on April of 2011 and cost APS $3.1 million to complete.

- Replacement of the evaporative coolers at West Phoenix CC Unit 2 and Unit 3. Combined cycle units generate greater levels of electricity with

cool dense air than they do with hot, thin air. Evaporative coolers are used to cool the inlet air and increase its density during the hot summer time so that the units continue to generate reliable levels of power. The prior evaporative coolers had corroded over time and needed to be replaced. The upgrades were completed in April of 2011 at a cost to APS of $2.4 million.

D. *Focus on the Environment*

**Q. IS FOSSIL GENERATION FOCUSED ON PROTECTING THE ENVIRONMENT?**

A. Yes. Fossil Generation is committed to continually improving the environmental performance of our fleet – it is an integral part of our stated mission. Not only do we diligently comply with the increasing environmental regulations that apply to fossil plants, we also proactively plan for regulations that we expect will be implemented in the future and continuously look for new ways to minimize our environmental footprint in a manner that is cost-effective for our customers.

**Q. PLEASE DESCRIBE THE ENVIRONMENTAL CHALLENGES FACING FOSSIL GENERATION.**

A. APS, like other fossil-fueled electric generators, faces several environment-related regulatory pressures from federal, state, and local regulators. These include the federal Environmental Protection Agency ("EPA"), which regulates Four Corners Power Plant; Maricopa County Air Quality Department, which regulates the Maricopa County-based fossil plants (Redhawk, Ocotillo and West Phoenix); Pinal County Air Quality Control District, which regulates the Pinal County plants (including Saguaro and Sundance); and the Arizona Department of Environmental Quality, which regulates the non-Maricopa or Pinal County fossil plants (including Yucca and Cholla). Each agency has its own set of environmental rules and regulations that are at least as stringent as their federal counterparts. In some instances, local environmental regulations are more

stringent than the corresponding federal requirement, due to environmental circumstances unique to the locality.

The rules that these and other regulators promulgate place increasing environmental and cost pressures on our plants and require intense focus and planning to address cost-effectively. Such rules include, among others, an EPA rule that will require the installation of Best Available Retrofit Technology ("BART") at Four Corners and Cholla, a Coal Combustion Residuals ("CCR") rule that will govern ash disposal at Four Corners and Cholla, a rule that would regulate emissions of hazardous air pollutants from Four Corners and Cholla, a rule that would establish emissions performance standards for existing coal-fired power plants, and a Clean Water Act cooling water intake structures rule that would establish national standards applicable to Four Corners.

**Q. HOW DOES FOSSIL GENERATION MONITOR ITS COMPLIANCE WITH ENVIRONMENTAL REGULATIONS?**

A. While APS has always had mechanisms in place to monitor our fossil plants' compliance with environmental regulations, Fossil Generation increased this focus in 2010 by creating an environmental department specifically within the Fossil Generation business unit. This group is tasked with providing governance and oversight as well as interface with the communities in which we operate and the regulators on all environmental issues that may impact fossil operations. The department owns the detailed policies that govern Fossil Generation's environment-focused operations. Among other things, these policies require regular testing and monitoring of our plant equipment so as to ensure continued compliance with applicable laws and regulations.

To keep up-to-date on pending environmental issues, Fossil Generation's environmental team works regularly with various agencies on an ongoing basis.

We also actively participate in national utility and industry groups focused on air, water, waste, and other environmental issues. Cooperation with other affected utilities allows APS to identify key developments as they arise.

**Q. DOES FOSSIL GENERATION PLAN FOR FUTURE ENVIRONMENTAL REGULATIONS? IF SO, HOW?**

A. Absolutely. When we foresee that a new regulation may impact some portion of our fleet, Fossil Generation develops working teams that include members from each part of the Company whose perspective is needed to develop an integrated approach to cost-effectively address the issue. Our engineering department examines the options available to meet the potential rule early in rulemaking process so that these alternatives and their costs and schedules are available as we prepare comments to the proposed rule and for business planning purposes. Fossil Generation's environmental department drafts or amends policies and develops training as needed to provide guidance on the new rule and outline the steps required to become and remain compliant.

From a budgeting perspective, Fossil Generation keeps its leaders continuously informed of regulatory developments so that they may account for environmental concerns in the budgeting and operational planning process. When the pending regulation is sufficiently close to finalization, the working team assesses the likely timing for and cost of compliance, and – when appropriate – includes those costs in the Company's long range forecast to be considered in corporate financial projections. When it is cost effective to do so, Fossil Generation completes required environmental upgrades in advance of the rule. For example, APS began early the process of installing ash pond liners to comply with not-yet-final ash handling and management regulations because it made good business and environmental sense to do so.

Fossil Generation is also pursuing ISO 14001:2004 certification for its plants. ISO 14001 is governed by the International Organization for Standardization ("ISO") based in Geneva, Switzerland. The program is an internationally recognized Environmental Management System ("EMS") that helps organizations minimize how their operations negatively affect the environment, comply with applicable laws, regulations, and other environmentally oriented requirements, and continually improve their performance. The certification process ensures the conformance of a company's EMS against the international standard, as well as any organizational specific requirements that have been identified. Fossil Generation's business plan includes having the fleet ISO certified by the end of 2012.

**Q. DOES FOSSIL GENERATION DO ANYTHING BEYOND WHAT IS REQUIRED BY LAW TO MINIMIZE THE ENVIRONMENTAL IMPACT OF POWER PRODUCTION?**

A. Yes, we do. One of APS's critical areas of focus is environmental stewardship, and Fossil Generation supports that direction by doing what it can to cost-effectively minimize the environmental footprint of our fossil plants. For example, we have drafted a pollution prevention plan not directed toward any specific environmental requirement, have set goals for recycling and waste reduction, review our aging equipment to determine whether upgrades would cost-effectively improve efficiency, track emissions to ensure that our units are trending in the right direction, and evaluate our use and reuse of water resources to prevent waste. More globally, environmental awareness has been and continues to be integrated into all of Fossil Generation's operational processes and procedures so as to minimize the environmental impact of our operations. Fossil Generation's business model emphasizes continuous improvement, and we constantly look for new ways to operate cost-effectively in an environmentally-conscious manner.

**Q. WHAT WAS THE COST OF ENVIRONMENTAL COMPLIANCE DURING THE 2010 TEST YEAR?**

A. The regulatory compliance-related activities described above require significant capital and O&M dollars. APS's share of the fleet's total environmentally-driven spend during the 2010 Test Year was roughly $46 million. These expenditures include the following key items:

- Ash disposal projects at Four Corners power plant required to meet regulatory and other combustion by-product requirements governing the disposal of coal ash. Fly ash and bottom ash are by-products of the coal combustion process used to supply steam to the Four Corners turbines. These coal combustion by-products must be disposed of in accordance with regulatory requirements. These projects, part of a multi-year effort to achieve regulatory compliance, cost APS in excess of $4.7 million in 2010.

- Implementation of low nitrous oxide ("NOx") burners and separated overfire air systems at Navajo power plant. This pollution control equipment is the technology alternative to a Selective Catalytic Reduction ("SCR") system as a means of reducing NOx emissions to the levels required by the EPA. This project, required by environmental regulation, cost APS $2.2 million in 2010.

- High volumes of chemicals are required to operate the "scrubber systems" installed at the coal-fired power plants. A "scrubber system" is a very large pollution control device that removes the sulfur dioxide ("SO2") naturally produced during the combustion process. SO2, as well as various other pollutants, can be successfully "scrubbed" out of the flue gas stream using a process called lime scrubbing. Lime is a neutralizing agent that

reacts with the acid gasses in the gas stream, producing calcium salts (which can be used in cement manufacturing). In 2010, APS's chemical cost related to the Cholla power plant scrubbers was $5.8 million.

**Q. PLEASE IDENTIFY THE ENVIRONMENTALLY-DRIVEN CAPITAL PROJECTS THAT FOSSIL GENERATION WILL COMPLETE BY JUNE 30, 2012.**

A. As previously noted, a listing of all of the capital projects that Fossil Generation will place in service for customers by June 30, 2012 is attached to my testimony at MAS-1. These projects include the following:

- Continued ash disposal upgrades at Four Corners power plant, needed to meet EPA requirements governing the disposal of coal ash. These projects are part of the multi-year effort necessary to ensure that ash is disposed of in accordance with environmental regulations. The projects will be completed in the last quarter of 2011 and cost APS in excess of $11.7 million.

- Replacement of the SCR catalyst at Redhawk and West Phoenix natural gas plants. As indicated above, SCR is an emission control technology that uses a catalyst to convert NOx into diatomic nitrogen and water. A catalyst is a material that changes the rate of the chemical reaction; it is not consumed in the chemical reaction. However, catalysts do have an end of life and must be replaced. These projects replace the worn catalysts to achieve continued compliance with environmental permits. The projects will be completed in the second quarter of 2011 and cost APS a combined total of approximately $3.8 million.

E. *Focus on Cost Management*

**Q. IS FOSSIL GENERATION FOCUSED ON COST MANAGEMENT?**

A. Yes, cost management is a key part of Fossil Generation's business operations and an inherent result of the centralization efforts now underway. In mid-2009, shortly after I arrived at APS, I began the process of implementing a new operations model for the Fossil Generation business unit. Historically, the plants were run as individual entities, rather than as parts of a collective whole. The new fossil operations model (what we call the "FOM") moves to a one-fleet mindset, putting in place standardized policies and procedures designed to ensure that the fleet operates consistently, takes advantage of economies of scale and common resources, and works toward common goals. Much of the FOM reflects what we have determined to be best utility practices. This reorganization, now halfway complete, is improving the operational efficiency of the APS fossil fleet and providing cost management opportunities that benefit the business as a whole. In fact, these process changes resulted in a savings of at least $4.6 million in operational expenses during the 2010 Test Year.

**Q. PLEASE PROVIDE SOME SPECIFIC EXAMPLES OF HOW THE NEW OPERATIONS MODEL CREATES EFFICIENCIES AND MANAGES COSTS.**

A. A key aspect of the FOM is the use of benchmarking, metrics, and gap analysis. This process looks critically at what other fossil generators are doing in a given area so as to identify opportunities to improve our own operations, sets initiatives in place to drive process improvements, and establishes metrics used to measure performance. As part of this effort, in 2010, Fossil Generation took a critical look at its staffing and departmental structure and underwent an organizational redesign intended to improve operating efficiencies and implement a centralized fleet-focus. This reorganization resulted in, among other things:

- The creation of a new environmental operations department that centralized site environmental functions and created fleet-specific subject matter experts.

- The creation of an operations support department, which, among other things, centralized and standardized fleet-wide training programs and operational processes.

- A changed function for the engineering services department, from project design and management to plant operational and maintenance support.

- A transfer of the fuels department into the Fossil Generation business unit.

As a result of these and other organizational changes, the Company reduced its employee and consultant staffing levels by more than 10%.

Other process changes provide similar cost management opportunities. For example, in 2010, Fossil Generation implemented a capital project approval process, governed by a newly created Fossil Capital Approval Board (chaired by our Vice President of Fossil Operations). This process, modeled after a corresponding corporate process, sets forth guidelines intended to increase the transparency and scrutiny of project justification for Fossil Generation's capital spend, adopt a standardized approach to funding capital, incorporate a risk/opportunity analysis into capital spending decisions, and secure accountability for results. In addition, Fossil Generation's budgeting process for 2011 required a comprehensive review and detailed justification for all items proposed to be in the Fossil Operations budget, mandating approval of the proposed budget in its entirety rather than for increases from the prior budget year alone.

These examples are but a few that demonstrate Fossil Generation's contribution to the Company's aggressive focus on cost management.

**Q. DOES FOSSIL GENERATION FACE ANY OTHER CHALLENGES?**

A. Yes. APS, like other utilities and several other industries, is faced with the impact of an aging "baby boomer" workforce. Currently 34% of Fossil Generation's employees are eligible for retirement – a number that grows to almost 50% in 2014. With so many employees soon to retire, we have to plan now how to transfer knowledge to the continuing workforce. To address the potential knowledge gap, we have revitalized the Operations and Maintenance training program, started a summer internship for engineers, and implemented a Knowledge Transfer and Retention Procedure.

Another current challenge is managing our workforce through the changes that need to be made to transition to the current centralized organizational model. While we have seen improvements to areas of our operations as a result of this shift, we will not achieve our vision for operational excellence until those who work at our plants fully understand the need for and embrace the required change. Through focused communication, training, and demonstrated safety and operational improvements, we believe that all of our employees will support these policies and become champions of the new model.

## IV. TOTAL FOSSIL GENERATION OPERATIONS AND CAPITAL REQUIREMENTS

### A. *Total Capital Expenditures at the Fossil Plants.*

**Q. WHAT WERE FOSSIL GENERATION'S NET PLANT ADDITIONS DURING THE TEST YEAR?**

A. As illustrated in Standard Filing Requirement ("SFR") E-5, Fossil Generation added approximately $80 million in plant during the 2010 Test Year, bringing the business unit's total plant balance to approximately $3 billion.

**Q. WHAT LEVEL OF PLANT ADDITIONS DOES FOSSIL GENERATION EXPECT THROUGH JUNE 30, 2012?**

A. Attached to this testimony as MAS-1 is a detailed breakdown of the capital projects that will be in service as of June 30, 2012. As that exhibit shows, Fossil Generation expects to add a total of $156.3 million of plant by that date. These additions contribute $10.4 million to the Company's post-Test Year Plant adjustment, as detailed on SFR B-2, page 2, column 4. APS Witness Jason La Benz describes additional details of the adjustment, such as accumulated depreciation, accumulated deferred income taxes, depreciation expense, property taxes and interest expense.

## V. BENCHMARK STUDY RESULTS FOR THE FOSSIL PLANTS

**Q. EARLIER IN YOUR TESTIMONY YOU REFERENCED THE BENCHMARKING STUDY PREPARED BY LIBERTY CONSULTING GROUP. WOULD YOU LIKE TO ADDRESS ANY OF THAT REPORT'S RECOMMENDATIONS SPECIFIC TO THE FOSSIL PLANTS?**

A. Yes. Although I generally accept the conclusions that Liberty reached relating to Fossil Generation, there are several areas where the report did not reflect information that we had provided– information that gives context to the results and that I believe deserves greater attention. Most significantly, Fossil Generation was already taking many of the action items that Liberty recommends. For example, in Recommendation 4.1, Liberty suggested that "APS should consider the implementation of a continuing program for analysis of outage causes." We implemented such a program in 2011. As Liberty suggests in Recommendation 4.2, Fossil Generation is now aligning its reporting practices with NERC GADS definitions, including the classification of maintenance outages. With respect to Recommendation 4.3, Fossil Generation commissioned a study in 2010 that addressed each of the points that Liberty raised. That study made several recommendations to improve plant performance, all of which have

been incorporated into Fossil Generation's operations model or 2011 Business Plan.

With respect to the higher than average forced outage rates at Four Corners, one cannot discount the negative impact that the quality of the coal used to fuel that mine mouth plant has on plant operations. Obviously, when one constructs a mine mouth plant, the coal quality cannot be improved by switching to another source of coal. Instead, one must evaluate the trade-offs of higher forced outage rates with less expensive, locally-mined coal. This point is underscored and explained in greater detail by Concentric Group ("Concentric"), which performed a deeper analysis of many the issues that Liberty identified in its report. That is not to say that substandard coal is the sole cause of Four Corners' above average forced outage rate. But, to the extent other factors contribute, Fossil Generation's recent process improvements should gradually correct past operational issues and improve plant performance going forward. Indeed, as Concentric notes in its report, data from 2009 and 2010 shows that the trend is now moving in the right direction.

## VI. CONCLUSION

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

A. As I stated earlier, Fossil Generation's mission is to deliver superior operational performance while instilling a strong safety culture and protecting our environment. Although APS's fossil plants have performed well in the past, we are committed to operational excellence and have put in place the mechanisms that will drive future improvements where opportunities exist. Like other fossil-fueled generators in the industry, our fossil fleet faces significant challenges: among them, an aging workforce, aging assets, and ever-increasing laws and regulations that require expensive environmental upgrades. With a one-fleet

mindset, a standardized set of policies that reflect industry best practices, and a culture of continuous improvement and accountability, I firmly believe that we will navigate those challenges and continue to deliver cost-effective, reliable power to APS's customers and others throughout the Southwest.

**Q. DOES THAT CONCLUDE YOUR DIRECT TESTIMONY?**

A. Yes.

## Fossil Post-Test Year Plant Additions

| Line No. | WA# | Plant & Unit | Category | Project Description | Purpose | Project Cost to Date 12/31/2010 | Costs to Complete | Projected Closed Cost | Estimated In-Service Date |
|---|---|---|---|---|---|---|---|---|---|
| 1. | RHC0140 | Redhawk Unit 2 | Regulatory / Legislative / Contractual | GE LTSA CT Major Inspection | Scheduled overhauls are required to ensure reliable and safe operation of the gas turbine. | $ 29,016,657 | $ 671,308 | $ 29,687,965 | 3/29/2011 |
| 2. | FAC90173 | Four Corners Units 1, 2, 3 | Environmental Compliance | U1-3 5268 Lift Lined Ash Impoundment | The units must dispose of ash in order to operate. The embankments are raised in layers/lifts to minimize annual investment dollars. | $ 3,838,326 | $ 4,034,346 | $ 7,872,672 | 4/19/2011 |
| 3. | 60-0819A | Navajo Units 1, 2, 3 | Environmental Compliance | Low Nox Burners/Sep Overfired Air | Environmental / regulatory. NOx abatement modifications are being installed to meet presumptive Best Available Retrofit Technology (BART) levels of 0.22 lbs/mmBtu. | $ 5,259,081 | $ 1,505,728 | $ 6,764,809 | 4/3/2011 |
| 4. | 60-0609 | Navajo Units 1, 2, 3 | Reliability | Gen Step-Up Transformer Replacement | Industry experience suggests that these long-term lead transformers will experience a rapidly increasing failure rate starting around 2014. These transformers are more than 30 years old. Failure of these units could cause loss of power generation for an extended period. | $ 4,230,759 | $ 699,143 | $ 4,929,902 | 4/3/2011 |
| 5. | CHC0310 | Cholla Unit 1 | Reliability | Horizontal Superheat Replacement | This project is to prevent tube leaks caused by cracking of tube to tube attachment welds, ash erosion that has progressed deeper into the bundles into inaccessible areas and related pad weld failures. Tube material will be conformed to current OEM standards, which are also cheaper than original design material. The average length of outage is four days due to access and repair constraints. This also can increase as tube leaks occur deeper into the tube bundles. | $ 50,032 | $ 4,616,849 | $ 4,666,881 | 4/29/2011 |
| 6. | CHC0317 | Cholla Unit 3 | Reliability | Platen Superheater Replacement | The purpose of this project is to maintain unit reliability by avoiding weld failures at tube/clip interface and the effects of long term overheating of the T11 material. | $ 28,093 | $ 4,480,343 | $ 4,508,436 | 4/27/2012 |
| 7. | CHC0320 | Cholla Unit 3 | Reliability | Economizer Replacement | The purpose of this project is to maintain unit reliability by reducing the risk for tube failures based on external erosion. | $ 16,144 | $ 4,289,656 | $ 4,305,800 | 4/27/2012 |
| 8. | CHC0242 | Cholla Units 1, 2, 3 | Reliability | Computer Predictive Perf Tools | Maintain heat rate, fuel usage and emissions thru improved operation of furnace / boiler. | $ 3,456,414 | $ 159,930 | $ 3,616,344 | 6/30/2011 |
| 9. | CHC0290 | Cholla Unit 1 | Reliability | L-1 LP Turbine Blade Replacement | This project is to replace the L-1 LP blades. The replacement is required based on a inspection where stress cracking was identified on some blades. | $ 447,599 | $ 2,698,248 | $ 3,145,846 | 4/23/2011 |
| 10. | RHC0088 | Redhawk Unit 2 | Prevent Failure | IP Turbine Blade Replacement | Ensure continued steam turbine reliability through the replacement of the IP blades during the upcoming major overhaul. New IP turbine shims and blades are required due to steam turbine shim migration and 1st and 2nd stage blade impact damage as evidenced by a bore-scope inspection. | $ 2,148,128 | $ 931,784 | $ 3,079,912 | 3/29/2011 |
| 11. | WPC0114 | West Phoenix GT Units 1 & 2 | Prevent Failure | GSU Transformer Replacement (T1687) U1-4 | The GSU transformer is required to run the unit. T-777 was damaged during a synchronizing event on Unit 1 October 25, 2008, so it had to be replaced. With T-1483 in service there is no spare available. Lead time on a replacement transformer is approximately one year. | $ 2,760,092 | $ 256,229 | $ 3,016,321 | 5/10/2011 |
| 12. | RHC0104 | Redhawk Unit 2 | Safety / Security | 2A & 2B Reheat Outlet Header Replacement | The piping to be replaced has been exposed to off-design thermal transients associated with steam attemperator spray water control leading to significant plastic deformation in the headers. The scoped piping is in an open-access area leaving Plant personnel exposed to any risk of failure in these components making this a safety priority. | $ 569,021 | $ 2,134,369 | $ 2,703,390 | 3/29/2011 |
| 13. | CHC0327 | Cholla Unit 3 | Environmental Compliance | Cooling Tower Drift Elim Replacement | The existing drift eliminators have become brittle and plugged and can not be cleaned to function as intended to capture water droplets. If the water droplets carried over to the atmosphere exceeds that allowed by the plant air permit the carry over is a unpermitted discharge and is in violation of EPA air pollution discharge permit. | $ 3,237 | $ 2,623,989 | $ 2,627,226 | 4/27/2012 |

| Line No. | WA# | Plant & Unit | Category | Project Description | Purpose | Project Cost to Date 12/31/2010 | Costs to Complete | Projected Closed Cost | Estimated In-Service Date |
|---|---|---|---|---|---|---|---|---|---|
| 14. | RHC0127 | Redhawk Unit 2 | Reliability | Cooling Tower Cells D Thru I Wood Replacement | The purpose of this project is to maintain unit reliability. Continued deterioration of the tower would result in collapse and unit curtailment. Improper construction by the original Manufacturer requires premature replacement of Cooling Tower structure components. Failing film fill and casing will be replaced at the same time as structure to save additional labor cost. FRP offers improved corrosion and fire resistance properties compared to wood. The FRP does not contribute harmful constituents to the cooing water compared to wood which leaches preservatives. The life expectancy of the FRP is approximately 40 years as compared to wood life expectancy of 15- 20 years. Replacement of structural members in only three cells rather than entire Cooling Tower is required to maintain continuous operations. | $ - | $ 2,621,954 | $ 2,621,954 | 12/16/2011 |
| 15. | FAC90371 | Four Corners Units 1, 2, 3 | Environmental Compliance | Ash Pond Seepage Intercept | To intercept ash pond seepage. | $ 825,023 | $ 1,542,183 | $ 2,367,206 | 6/1/2011 |
| 16. | OCC0076 | Ocotillo Stm Unit 1 | Reliability | Cooling Tower Structure Improve | This project is to maintain the cooling tower structural integrity, preventing potential tower collapse and associated unit load curtailment. | $ - | $ 2,334,936 | $ 2,334,936 | 3/11/2012 |
| 17. | OCC0077 | Ocotillo Stm Unit 2 | Reliability | Cooling Tower Structure Improve | The purpose of this project is to maintain the cooling tower structural integrity. Structural wood framing members and cell divider walls are in need of replacement. | $ - | $ 2,334,936 | $ 2,334,936 | 3/16/2012 |
| 18. | WPC0117 | West Phoenix CC 1 | Reliability | Aux Cooling Water Piping Replacement | Pipe is corroding at an accelerated rate due to changes in cooling tower water chemistry. | $ 372,351 | $ 1,688,276 | $ 2,060,627 | 3/15/2012 |
| 19. | RHC0136 | Redhawk Unit 2 | Prevent Failure | Compressor Row Replacement | Excessive stator vane rock measured during the hot gas path inspection and confirmed during the 2009 borescope inspection places the compressor at risk of stator/blade liberation and failure. | $ 6,367 | $ 1,975,941 | $ 1,982,308 | 3/29/2011 |
| 20. | WPC0101 | West Phoenix GT 2 | Reliability | Inlet Cooler & Silencer Replacement | Inlet cooler and silencer are at end of life. Continued operation of existing equipment could result in cooler collapse and ingestion into the gas turbine causing damage. | $ - | $ 1,867,604 | $ 1,867,604 | 5/18/2012 |
| 21. | WPC0100 | West Phoenix GT 1 | Reliability | Inlet Cooler & Silencer Replacement | Continued operation of existing equipment could result in cooler collapse and potential ingestion of the cooler components in the gas turbine causing damage. | $ - | $ 1,838,809 | $ 1,838,809 | 2/9/2012 |
| 22. | CHC0298 | Cholla Unit 2 | Prevent Failure | Circ Water Line Steel Strand Replacement - In SVC 10/2010 | The steel strand reinforcement of the pipe has corroded and inspection by a third party has revealed the troubled areas for repair with Carbon Fiber Replacement. The Circulating Water lines are essential to cool the steam cycle of the turbine/generator. | $ 1,670,004 | $ 77,272 | $ 1,747,276 | 6/30/2011 |
| 23. | CHC0337 | Cholla Unit 2 | Reliability | SGS Transformer 23A Replacement | The startup and general services transformer is necessary to start Units 2 and 3 and provide power to the common equipment for Units 1,2,3,4. The spare transformer replaced a damaged transformer in Aug 2010. This purchase will restore a spare to the inventory. | $ 918,807 | $ 802,345 | $ 1,721,152 | 10/29/2011 |
| 24. | 60-0920M | Navajo Units 1 & 2 | Reliability | Main Steam Piping Replacement Navajo 1-2 | Metallurgical examination of the main steam piping concluded that a significant level of creep strain has occurred necessitating replacement of main steam piping from the crossover to the turbine connections during 2011 Major Overhaul. Generally, at 200,00 to 300,000 hours of operation, creep damage is to be expected at main steam conditions. NGS operating hours for Unit 1 is more than 250,000 hours to date. | $ 1,017,176 | $ 515,418 | $ 1,532,594 | 12/31/2011 |

| Line No. | WA# | Plant & Unit | Category | Project Description | Purpose | Project Cost to Date 12/31/2010 | Costs to Complete | Projected Closed Cost | Estimated In-Service Date |
|---|---|---|---|---|---|---|---|---|---|
| 25. | WPC0185 | West Phoenix CC 5 | Reliability | ZLD Vapor Washer | This project is to install a vapor washer down stream of the ZLD crystallizer body to eliminate safety related incidents and equipment down time. Currently, the ZLD operates below its designed operating level of 50% to stop foam from being carried over in the blower. The foam carryover has caused ZLD shutdowns and damage to the blower. If the ZLD system is abruptly shutdown, slurry begins to cool and solidifies in the piping. When this occurs, plant personnel are required to manually clear the semi-solidified slurry from the piping at elevated temperatures (225F). This has proven to be an unsafe operation leading to burn injuries. In addition, operating below the design level of 50% in the crystallizer has resulted in: Excessive wear on the circulation pump due to cavitation, a reduction in the retention time adversely affecting crystallization kinetics, finer crystals which are difficult to dewater, an increase in the Total Head (back pressure) TDH on the pump, reducing pump capacity, elevated temperatures in the heat exchanger that increases the rate of fouling. | $ - | $ 1,517,351 | $ 1,517,351 | 3/23/2012 |
| 26. | 60-0921 | Navajo Units 1, 2, 3 | Environmental Compliance | NE-1 Pond Refurbishment Nav 1-3 | Construct a smaller north east 1 (NE-1) pond within the existing pond and install a new lining. | $ 1,184,769 | $ 245,046 | $ 1,429,814 | 6/30/2011 |
| 27. | RHC0100 | Redhawk Units 1 & 2 | Reliability | Well Water Pipe Installation | Complete the conversion of Redhawk RO System makeup from Makeup Pond water to well water. The existing temporary piping used to validate the conversion from pond to well water make-up has served its purpose and must be replaced. The temporary piping is above ground and presents a risk to personnel, a source of frequent line leaks, and a deterrent to efficient and productive work flow and access around the cooling towers. Installing a permanent piping system underground will alleviate these concerns as well as provide a permanent source of RO makeup. | $ 136,739 | $ 1,281,694 | $ 1,418,433 | 3/23/2011 |
| 28. | WPC0106 | West Phoenix CC 5 | Reliability | HRSG Drain 5B Upgrade | This project is to reconfigure/redesign the drain lines from the Heat Recover Steam Generator to the condensate flash tank. Currently, the existing drain line configuration does not allow condensate to gravity flow to the condensate flash tank. This condition allows quenching of the superheater and reheater tubing sections. | $ 66,744 | $ 1,331,801 | $ 1,398,545 | 12/5/2011 |
| 29. | WPC0105 | West Phoenix CC 5 | Reliability | HRSG Drain 5A Upgrade | This project is to reconfigure/redesign the drain lines from the Heat Recover Steam Generator to the condensate flash tank. Currently, the existing drain line configuration does not allow condensate to gravity flow to the condensate flash tank. This condition allows quenching of the superheater and reheater tubing sections. | $ 73,873 | $ 1,294,795 | $ 1,368,668 | 12/5/2011 |
| 30. | CHC0294 | Cholla Unit 3 | Prevent Failure | Circulating Water Line Replacement | The inlet and discharge lines are in poor condition and will require either replacement or major repair effort. | $ - | $ 1,275,592 | $ 1,275,592 | 4/27/2012 |
| 31. | WPC0181 | West Phoenix CC 3 | Reliability | Evap Cooler Replacement | Extensive corrosion of the evaporative cooler and collection basins could allow water to leak from the contained area onto the ground which would not comply with the Aquifer Protection Permit. Corrosion has produced holes in the evaporative cooler enclosure which can allow debris to bypass the filtration and potentially enter the turbine. This debris would increase wear and decrease the life of the turbine components. | $ 23,514 | $ 1,217,203 | $ 1,240,717 | 4/15/2011 |
| 32. | CHC0289 | Cholla Unit 2 & 3 | Reliability | Acoustic Monitoring System | The system provides indication of small leaks that occur, so that the management of forced outage timing can be scheduled to minimize economic impact to the system. An additional advantage of this system is that it minimizes the probability of a forced outage occurring immediately following startup because all leaks can be identified going into an outage. | $ 166,078 | $ 1,060,760 | $ 1,226,838 | 7/1/2011 |
| 33. | RHC0091 | Redhawk Unit 2 | Environmental Compliance | HRSG SCR Catalyst Replacement | This project is to replace the SCR catalyst to ensure continued compliance with the Title V air permit requirements. Catalyst is replaced when the need is shown by testing. | $ 327,797 | $ 883,178 | $ 1,210,974 | 3/29/2011 |

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|---|---|---|---|---|---|---|---|---|---|
| 34. | WPC0167 | West Phoenix CC 2 | Reliability | CC2 - Evap Cooler Replacement | Extensive corrosion of the evaporative cooler and collection basins could allow water to leak from the contained area onto the ground which would not comply with the Aquifer Protection Permit. Corrosion has produced holes in the evaporative cooler enclosure which can allow debris to bypass the filtration and potentially enter the turbine. This debris would increase wear and decrease the life of the turbine components. | $ 396 | $ 1,185,061 | $ 1,185,457 | 3/25/2011 |
| 35. | WPC0151 | West Phoenix CC 3 | Prevent Failure | HRSG Economizer Replacement | Oxygen corrosion pitting caused by cyclic operation has compromised unit performance. Continued operation could damage the new SCR catalyst resulting in early replacement and increasing the number of forced outages due to tube leaks. | $ 698,541 | $ 474,900 | $ 1,173,441 | 4/15/2011 |
| 36. | SDC0049 | Sundance Units 1-10 | Reliability | Control System Upgrade | The purpose of this project is to replace the existing Turbine Flow and Speed Control System with an Enhanced Flow and Speed (EFS) Control System. This upgrade will maintain heat rate and power output, and optimize Sprint and NOX water control and upgrade the fuel core controls. | $ - | $ 1,120,556 | $ 1,120,556 | 12/16/2011 |
| 37. | WPC0187 | West Phoenix CC 5 | Reliability | 5A Rotor Air Cooler Replacement | The purpose of the project is to replace the rotor air cooler. The original rotor air cooler has experienced multiple tube failures and was eventually retubed. The original design for the rotor air cooler did not account for the high number of thermal cycles associated with cyclic operation and the tubesheet is showing signs of fatigue failure. | $ - | $ 1,080,521 | $ 1,080,521 | 3/23/2012 |
| 38. | CHC0308 | Cholla Common | Environmental Compliance | Mercury Vapor Lighting Replacement | Regulatory compliance requires all mercury vapor fixtures to be removed. | $ 701,187 | $ 370,833 | $ 1,072,019 | 2/26/2011 |
| 39. | RHC0147 | Redhawk Unit 1 | Environmental Compliance | Attemperator Replacement | The purpose of this project is to maintain safe operation of the unit by replacing the damaged hot reheat steam attemperators.<br>The inner liners of the attemperator piping have failed allowing quenching water to contact the pressure boundary, resulting in visible piping deformation. The attemperator assemblies will be replaced during the current Unit 1 outage and a piping health study will be conducted under the WA to find the root cause of the damaged piping. Solutions will be implemented based on the findings of the root cause investigation to prevent future attemperator and associated piping damage. | $ 996,610 | $ 46,114 | $ 1,042,724 | 6/30/2011 |
| 40. | CHC0325 | Cholla Unit 3 | Prevent Failure | Cooling Tower Upgrade | Replace wooden structure members in 3 cells with FRP structural member upgrades. This work does not include fan deck and hot deck which have already been upgraded to FRP. Repl distribution valves. | $ - | $ 1,018,580 | $ 1,018,580 | 4/27/2012 |
| 41. | WPC0131 | West Phoenix CC 5 | Prevent Failure | Condenser Modification Upgrade | The purpose of this project is to eliminate excessive water transport to the steam turbine L-0 blades during low load operating conditions. Excessive amount of water and water droplet size has caused accumulated trailing edge erosion on steam turbine L-0blades. This is based on an inspection done by Siemens and a study by Yuba condenser division. The condenser retrofit would be completed during the 2011 spring outage. Note: Siemens has installed new L-0 in the recent spring overhaul of 2010. The new blades will address tip cracking which is the subject of a warranty claim. However, Siemens is concerned with the amount of trailing edge erosion and has postulated that the condenser design could be causing the condition. | $ 118,932 | $ 878,287 | $ 997,219 | 1/29/2011 |
| 42. | WPC0155 | West Phoenix CC 5 | Environmental Compliance | CC5A SCR Catalyst | The purpose of this project is to replace the SCR catalyst to ensure continued compliance with the Title V air permit requirements. Catalyst must be replaced every 5 to 7 years in order to ensure proper performance. Lead time for catalyst is currently 12 months. This project must coincide with the gas turbine major overhaul. | $ 579,123 | $ 359,414 | $ 938,538 | 2/12/2011 |
| 43. | WPC0179 | West Phoenix CC 1 | Reliability | 1st Stage Bucket Replacement | The purpose of this project is to replace the first stage buckets in accordance with the OEM recommended maintenance schedule. | $ - | $ 921,116 | $ 921,116 | 3/15/2012 |
| 44. | WPC0178 | West Phoenix CC 2 | Reliability | 1st Stage Bucket Replacement | The purpose of this project is to replace the first stage buckets in accordance with the OEM recommended maintenance schedule. | $ - | $ 917,565 | $ 917,565 | 2/24/2012 |

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|---|---|---|---|---|---|---|---|---|---|
| 45. | CHC0356 | Cholla Common | Reliability | Cable Tray & Cable Replacement, Phase 5 | Purpose of this project is to maintain the integrity of this portion of the auxiliary power system. This is part of a long range plan to replace all critical 5KV feeder cables with cables contained in overhead cable tray. The underground cable for the 3A3 feeder faulted and is no longer useable. | $ - | $ 917,159 | $ 917,159 | 4/29/2011 |
| 46. | WPC0077 | West Phoenix CC 5 | Environmental Compliance | 5B SCR Catalyst | The purpose of this project is to replace the SCR catalyst to ensure continued compliance with the Title V air permit requirements. Catalyst must be replaced every 5 to 7 years in order to ensure proper performance. This project must coincide with the gas turbine major overhaul. | $ 586,254 | $ 313,286 | $ 899,541 | 1/28/2011 |
| 47. | WPC0180 | West Phoenix CC 1, 2, 3 | Safety / Security | Cooling Tower Fan Deck Replacement | The existing treated plywood deck has been inspected and needs to be replaced to ensure structural integrity of the tower structural diaphragm (fan deck) and provide a safe walking surface for plant personnel. | $ - | $ 889,330 | $ 889,330 | 12/15/2011 |
| 48. | WPC0198 | West Phoenix CC 1 | Reliability | 1st Stage Spare Nozzle | The purpose of this project is to replenish the critical (long lead) spare parts inventory. The warehouse spare 1st Stage Nozzle was recently installed in CC1. | $ - | $ 885,122 | $ 885,122 | 3/15/2012 |
| 49. | CHC0336 | Cholla Unit 2 | Reliability | Auxiliary Transformer Replacement | This project will enable operation of the unit without having to reduce load on Unit 3 when starting Unit 2, and reduce chance of overload of startup bus if Unit 3 trips when Unit 2 is operating, if Unit 2 auxiliaries are fed from the startup bus. | $ 368,743 | $ 504,293 | $ 873,036 | 4/23/2011 |
| 50. | WPC05916 | West Phoenix CC 2 | Reliability | Aux Cooling Water Piping Replacement | Pipe is corroding at an accelerated rate due to changes in cooling tower water chemistry. Piping system components were originally designed for two cycles of concentration. Plant is currently operated at seven cycles of concentration which results in a chloride level greater than what carbon steel can handle. | $ - | $ 841,439 | $ 841,439 | 2/24/2012 |
| 51. | RHC0128 | Redhawk Unit 2 | Reliability | Cooling Tower Drift Elim Cells D - I Replacement | This project is to redesign and replace the existing drift eliminators that are cracked and sagging. This will eliminate the potential of excessive drift and maintain compliance with regulations. | $ - | $ 841,201 | $ 841,201 | 12/16/2011 |
| 52. | RHC0106 | Redhawk Unit 1 | Reliability | Cooling Tower Drift Elim Cells D - | This project is to redesign and replace the existing drift eliminators that are cracked and sagging. This will eliminate the potential of excessive drift and maintain compliance with regulations. | $ 2,806 | $ 816,351 | $ 819,156 | 12/16/2011 |
| 53. | FBC90366 | Four Corners Units 4 & 5 | Environmental Compliance | Dry Fly Ash Disposal Area Phase 2 | Ash Disposal at Four Corners converted from mine disposal to an onsite area fill in 2006 to save hauling and operational expenses. The existing landfill may be over capacity in 2011. Initial expense includes the evaluation of onsite disposal alternatives to manage potential environmental issues associated with coal combustion products. | $ 333,343 | $ 464,159 | $ 797,502 | 10/4/2011 |

| Line No. | WA# | Plant & Unit | Category | Project Description | Purpose | Project Cost to Date 12/31/2010 | Costs to Complete | Projected Closed Cost | Estimated In-Service Date |
|---|---|---|---|---|---|---|---|---|---|
| 54. | FAC90382 | Four Corners Unit 2 | Reliability | Mill Bull Gear Replacement | This project is to replace the main ring gear and matching pinion gear to maintain Unit reliability. This bull gear has been in service since 1962. The Spring 2010 inspection found a severely damaged gear and pinion. The inspection report and the associated risk analysis both recommended replacement. | $ 1,649 | $ 794,874 | $ 796,522 | 10/8/2011 |
| 55. | FAC90377 | Four Corners Unit 1 | Reliability | Mill Bull Gear Replacement | This Bull Gear has been in service since 1962 and was reversed in 1988. The second side of the gear teeth are now worn and at end of life. | $ 7,072 | $ 780,093 | $ 787,165 | 12/16/2011 |
| 56. | 60-1059 | Navajo Units 1, 2, 3 | Reliability | Water Wall Repair-2 | NGS Unit 2 suffered a major furnace waterwall tube temperature excursion forced outage event in 2006. A waterwall tube inspection and condition assessment was performed during the 2007 minor overhaul. The inspection showed that the overheating event clearly induced a significant amount of permanent deformation as evidenced by buckling of the tube panels in both the transverse and longitudinal directions. This project will repair waterwall tubes damaged during the 2006 Unit 2 overheating event. | $ 748,382 | $ 34,628 | $ 783,010 | 6/30/2011 |
| 57. | FBC90405 | Four Corners Unit 4 | Reliability | Partial Economizer & Reheat Replacement | The high ash loading combined with the high gas velocity in the Unit 4 convection pass has resulted in erosion in parts of the Economizer and Horizontal Reheater. This project will replace the Economizer and Horizontal Reheater elements that are subjected to the worst erosion. A coating designed to reduce the ash erosion will be applied to portions of both the Economizer and Horizontal Reheater elements. | $ 700,032 | $ 32,391 | $ 732,423 | 6/30/2011 |
| 58. | WPC0119 | West Phoenix CC 4 | Environmental Compliance | CO Catalyst | The purpose of this project is to replace the CO catalyst to ensure continued compliance with the Title V air permit requirements. Catalyst is replaced based upon testing results. | $ - | $ 726,991 | $ 726,991 | 10/16/2011 |
| 59. | CHC0312 | Cholla Common | Reliability | Maximo Consolidation | A common structure will eliminate the need to migrate changes from one environment to the other two to support new requirements or resolve issues. Four Corners has committed to using Maximo to organize work flow. Upgrading will allow Four Corners to keep up with the Maximo long range strategy and minimize future upgrade expense. | $ 714,987 | $ 5,514 | $ 720,501 | 1/10/2011 |
| 60. | CHC0332 | Cholla Common | Environmental Compliance | Fly Ash Silo Vent Filter | The fly ash silo vent filters are to be resized to meet new ash flow requirements into the silo. The ash silo vent filters are essential to unit operation. | $ - | $ 712,473 | $ 712,473 | 4/20/2012 |
| 61. | YUC0064 | Yucca GT 1, 2, 3, 4 | Reliability | #4 Well Install (APS Share) 2011 | Ensure reliable raw water supply to the Yucca Power Plant, including IID's Yucca Unit 1. Existing well has been in service many years. The casing has corroded to extent that well reliability is difficult to ensure. | $ - | $ 711,464 | $ 711,464 | 12/9/2011 |
| 62. | WPC0074 | West Phoenix CC 3 | Environmental Compliance | SCR Catalyst Replacement | This project is to replace the SCR catalyst to ensure continued compliance with the Title V air permit requirements. Catalyst is replaced when the need is shown by testing. | $ - | $ 707,751 | $ 707,751 | 4/15/2011 |
| 63. | CHC0273 | Cholla Common | Safety / Security | Undgrnd Potable Water Pipe Replacement Ph | The purpose of this project is to maintain a reliable potable water supply to the Plant and outlying facilities. The existing supply mains were designed and installed with the Units in the 1970s. It is suspected that erosion/corrosion of the pipe wall is causing leakage in some areas. Additionally, users have been added to the system and an engineering study has shown that that the existing head tank cannot supply the pressure necessary for current system demands. Collectively, these conditions may create an unreliable and inadequate water supply. | $ 332,290 | $ 365,439 | $ 697,729 | 2/25/2011 |
| 64. | CHC0300 | Cholla Common | Environmental Compliance | BA East Monofill Expansion Ret Basi | To expand the existing monofill in order to continue Plant operations in compliance with the Aquifer Protection Permit (APP). | $ 50,362 | $ 645,666 | $ 696,028 | 12/15/2011 |
| 65. | WPC0135 | West Phoenix CC 5 | Safety / Security | Cooling Tower Fan Deck Replacement | The existing treated plywood deck is showing signs of deterioration and will need to be replaced to ensure structural integrity of the tower structural diaphragm (fan deck) and provide a safe walking surface for plant personnel. | $ - | $ 680,076 | $ 680,076 | 12/16/2011 |

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|---|---|---|---|---|---|---|---|---|---|
| 66. | SDC0048 | Sundance Units 1-10 | Reliability | Permanent Water Rights Purchase | Purchase of Central AZ Water Conservation District (CAWCD)(CAP) water rights from the Gila River Indian Community. Sundance is currently using CAP Excess water. If a shortage is declared on the Colorado River Sundance is in jeopardy of losing that water.APS needs a secure water supply to ensure Sundance can operate when called upon to do so. | $ - | $ 627,762 | $ 627,762 | 12/15/2011 |
| 67. | 60-0922 | Navajo Units 1, 2, 3 | Safety / Security | Coal Flame Scanners Navajo 1-3 | Purchase and install a new generation of coal flame scanners. | $ 433,069 | $ 162,396 | $ 595,464 | 3/4/2012 |
| 68. | FCC90393 | Four Corners Common | Prevent Failure | Coal Sample AB Surge Bin Cone Replacement | The existing surge bin has worn out. This project is to replace the coal sample A and B surge bin cones for Units 4 and 5, maintaining unit reliability. | $ - | $ 593,244 | $ 593,244 | 10/29/2011 |
| 69. | CHC0272 | Cholla Common | Reliability | Condensate Transfer System Upgrade | The purpose of this project is to provide flexibility to transfer condensate between Units 1-4 in order to prevent Unit load curtailments due to condensate contamination and loss of condensate resulting from underground pipe corrosion and failure. | $ 386,481 | $ 183,219 | $ 569,700 | 3/31/2011 |
| 70. | CHC06425 | Cholla Common | Regulatory / Legislative / Contractual | Flyash Slurry C Line Replacement | The purpose of this project is to ensure Unit availability through continued serviceability of the bottom ash pond. The "C" slurry pipe line is integral to maintaining the ash pond water level in that it transfers excess water from the bottom ash pond to he fly ash pond during the winter months when pond evaporation rates are diminished. Without the "C" slurry line in service, eventual shutdown of all Units would be required to remain in compliance with APP Permit requirements and ADWR Dam Safety Requirements. | $ - | $ 564,244 | $ 564,244 | 2/28/2011 |
| 71. | FAC90206 | Four Corners Unit 1 | Reliability | U1 Scrub Plumb Bob Shaft Dent Bowl | This project is to replace the existing 316L stainless steel shafts with 317L stainless steel, and to design and install a lateral support and Dentist Bowl. The scrubber plumb bob shafts are failing at the top of the shaft due to fatigue and near the unin of the shaft and the plumb bob due to stress corrosion cracking. 317L stainless steel has greater resistance to corrosion and a higher tensile strength which will reduce the chances of stress corrosion cracking and fatigue failure. The support will be installed into the scrubber vessel walls and restrain shaft oscillation. The support, coupled with the superior material properties of the 317L should effectively eliminate these types of failures. | $ 8,034 | $ 550,976 | $ 559,010 | 12/16/2011 |
| 72. | 60-1091 | Navajo Units 1, 2, 3 | Reliability | Long Lead Time Material Purchase-1 | Overhaul start dates have been moved forward to January. This creates a logistical problem for direct purchase materials. Maintenance personnel want the materials on-site well ahead of the outage, so they have the ability to react to any problems. Holidays affect NGS's ability to ship, receive, and pay for these materials. Overhaul materials have long lead times and need to be purchased ahead of the outage to ensure availability. NGS expects to purchase" between 30% and 50% of the materials required for the Unit 1 Major Overhaul to be delivered in 2010, prior to the scheduled outage. Specific materials identified because of known lead time issues include 1 st and 7th stage buckets for the main turbine ($0.7 million) and Platen Superheater pendent tube materials ($0.2 million). | $ 161,819 | $ 392,495 | $ 554,314 | 6/30/2011 |
| 73. | CHC0319 | Cholla Unit 2 & 3 | Reliability | Boiler, Turb Elev Controls Replacement | Make the Boiler and Turbine Bldg Elevators more reliable and avoid delays in productivity or return to service. Controls are to be replaced in compliance with ASME/ANSI A17.1 and 17.3, which require replacement rather than modification with non-OEM part. | $ - | $ 547,268 | $ 547,268 | 11/1/2011 |
| 74. | RHC0143 | Redhawk Common | Prevent Failure | RO Membrane Replacement - DELAYED | Expected life for 1st pass membranes is 3-5 years, second pass membranes need to be changed every 5-7 years. | $ - | $ 531,574 | $ 531,574 | 4/1/2012 |

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|---|---|---|---|---|---|---|---|---|---|
| 75. | CHC0299 | Cholla Common | Reliability | Plant Microwave System Upgrade | The existing system is experiencing reduced reliability and its bandwidth will be overloaded when all the security monitoring and control requirements are met throughout the existing system. The requirements to handle the critical control and data monitoring, security video information and business network communications will exceed the existing communications infrastructure capabilities. The Cholla switchyard is considered a high security area in alignment with the permanent Cyber Security Standard – Critical Infrastructure Protection Reliability Standards CIP-002-1 through CIP-009-1 which replaced the NERC 1200 Standard and was adopted in June 2006. | $ 34,206 | $ 478,660 | $ 512,866 | 7/12/2011 |
| 76. | RHC0135 | Redhawk Unit 2 | Reliability | Expansion Joint Replacements | To maintain unit reliability. | $ 8,996 | $ 496,174 | $ 505,170 | 3/29/2011 |
| 77. | CHC0297 | Cholla Common | Safety / Security | Plant Paving, South Rd,Entr Rd Replacement | The current roads have deteriorated. The paving needs be done after the environmental improvements have been completed. | $ 226,127 | $ 278,417 | $ 504,544 | 6/8/2011 |
| 78. | FCC90365 | Four Corners Common | Reliability | Maximo Consolidation | A common structure will eliminate the need to migrate changes from one environment to the other two to support new requirements or resolve issues. Four Corners has committed to using Maximo to organize work flow. Upgrading will allow Four Corners to keep up with the Maximo long range strategy and minimize future upgrade expense. | $ 455,658 | $ 48,350 | $ 504,008 | 1/11/2011 |
| 79. | WPC0141 | West Phoenix CC 3 | Prevent Failure | BFP Warehouse Spare | The purpose of this project is to provide a boiler feed pump, to be utilized as a warehouse spare in the event of a BFP failure and subsequent loss in Unit generation capacity. The existing OEM in-service BFP's are more than 30 years old, and each have experienced an increasing rate and extent of repairs over the last 15-years of service, increasing the risk of BFP failure. | $ 275,304 | $ 192,284 | $ 467,588 | 4/15/2011 |
| 80. | WPC0191 | West Phoenix CC 5 | Reliability | Cooling Tower Fan Purchase | This project is to replace the cooling tower fans with in-kind units to ensure reliable and safe operation of the cooling tower. Existing fans hubs are showing advanced signs of corrosion. | $ - | $ 464,236 | $ 464,236 | 10/7/2011 |
| 81. | RHC0093 | Redhawk Unit 2 | Prevent Failure | Perf Plates and Supports Replacement | The project is to eliminate the on going cyclic fatigue/failure of the existing perforated plates and supports within CC2 HRSG's. This will require having Vogt Engineering redesign the existing perforated plates and supports. The new replacements would be installed during the 2011 major outage. | $ 129,831 | $ 322,993 | $ 452,824 | 3/29/2011 |
| 82. | 60-0908 | Navajo Units 1, 2, 3 | Safety / Security | Main Turb Bearing-Underflr Fire Sup | Upgrade the main turbine and fire suppression system. Install heat detection and sprayers on the bearings. Install an underfloor wet pipe fire protection system. Upgrade the diesel fire pump. | $ 313,934 | $ 135,733 | $ 449,667 | 4/3/2011 |
| 83. | YUC0069 | Yucca GT 3 | Safety / Security | Cardox Tank Replacement | The purpose of this project is to replace the existing rusted Cardox tank with a new tank and controls. This is based on a recommendation by HSB during a fire inspection. | $ 11,080 | $ 436,327 | $ 447,407 | 2/18/2011 |
| 84. | 60-1115C | Navajo Common | Reliability | Op Emg,Cap Ex,Spare Pts Contingency | This budget item is to cover unforeseen capital expenditures which arise during 2011, and to comply with sections 15.2 and 17.1 of the Navajo Generating Station Operating Agreement. Examples of past expenditures from this line item include the purchase of an audiometer and a generator step-up transformer dissolved gas analyzer, and installing a ventilation system for the tool room. | $ - | $ 429,766 | $ 429,766 | 12/31/2011 |
| 85. | 60-1116C | Navajo Common | Reliability | Plant Tools Contingency | This budget item is to cover capital expenditures which arise during 2011. Examples of past expenditures from this line item include the purchase of hot water pressure washer, a breaker trip test kit, a pipe threader and Huck railroad tools. | $ - | $ 429,766 | $ 429,766 | 12/31/2011 |
| 86. | YUC0070 | Yucca GT 4 | Safety / Security | Cardox Tank Replacement | The purpose of this project is to replace the existing rusted Cardox tank with a new tank and controls. This is based on a recommendation by HSB during a fire inspection.. | $ 4,203 | $ 424,780 | $ 428,982 | 4/2/2011 |

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|---|---|---|---|---|---|---|---|---|---|
| 87. | WPC0190 | West Phoenix CC 5 | Safety / Security | Steam Turb Cond Flash Tank Replacement | This project is to replace the condensate flash tank. The current tank has significant deterioration and must be replaced. Without this tank in service the unit cannot operate. | $ - | $ 417,462 | $ 417,462 | 12/5/2011 |
| 88. | 60-1101M | Navajo Unit 1 | Reliability | Ash System - U1 Major Overhaul | To upgrade the Bottom Ash system to enable the continued operation of the collection and removal system. The unit cannot operate if the bottom ash is not removed from the boiler. | $ - | $ 417,095 | $ 417,095 | 4/3/2011 |
| 89. | CHC0324 | Cholla Unit 3 | Reliability | BFP Component Rotating Element Replacement | Restore worn pump, valve, fluid coupling, and piping to reliable operating condition. Replace check valve if necessary. | $ - | $ 416,886 | $ 416,886 | 4/20/2012 |
| 90. | CHC0306 | Cholla Common | Prevent Failure | Cathodic Protection Sys 9, 10, 11, | The depleted cathodic protection systems must be replaced to preserve underground assets, reduce maintenance costs, comply with government regulations, and preserve the environment. | $ 206,263 | $ 204,708 | $ 410,971 | 12/10/2011 |
| 91. | FAC90281 | Four Corners Unit 2 | Reliability | ID Fan Scroll Replacement | The purpose of this project is to ensure the continued full load reliability of Unit 2. Existing scrolls, including the cut off points ("bull nose") of the fans, are exposed to a harsh, corrosive service environment. The extent of damage to the existing scrolls and cut off points renders further interim repairs ineffective, therefore necessitating the need to replace the scroll. | $ 360,717 | $ 49,841 | $ 410,558 | 6/30/2011 |
| 92. | WPC0113 | West Phoenix Common | Safety / Security | Fire Alarm Panel Replacement | The purpose of this project is to reduce response time and alert personnel from entering unsafe locations. | $ 394,854 | $ 9,068 | $ 403,922 | 1/12/2011 |
| 93. | FCC90303 | Four Corners Common | Reliability | Local Area Network Switch Upgde | The purpose of this project is two fold: 1) to increased demand of the capture, storage and delivery of process systems data for systems like CEMS, Data Historians, Neural Networks and other business applications; 2) to increase performance to support more demanding applications including voice over IP communication and faster PC system demand. | $ 235,063 | $ 147,373 | $ 382,436 | 5/13/2011 |
| 94. | FCC90267 | Four Corners Common | Reliability | Plant Perimeter Security Upgde | The purpose of this project is to eliminate any unauthorized access to Plant equipment. | $ 350,684 | $ 29,465 | $ 380,149 | 3/9/2011 |
| 95. | 60-1154 | Navajo Unit 2 | Environmental Compliance | Sootblower Upgrade-2 | The 360 degree spray rotation and close proximity of the 29R and 30R sootblowers to the upper bullnose slope cause severe sootblower erosion and thinning of the water wall tube failures and forced outages. | $ 32,221 | $ 342,967 | $ 375,188 | 4/3/2011 |
| 96. | CHC0275 | Cholla Common | Safety / Security | Fire Water System Upgrade | This will prevent future leaks and control valve failures and the associated repair cost, as well as the loss of fire water supply. | $ 48,856 | $ 324,100 | $ 372,955 | 6/15/2011 |
| 97. | WPC06115 | West Phoenix CC 5 | Reliability | Cooling Twr Mech Equip Access Walkways | Allow safe access to fan assemblies mechanical equipment. | $ - | $ 369,222 | $ 369,222 | 3/23/2012 |
| 98. | FAC90324 | Four Corners Unit 1 | Reliability | 1st Stage Turbine Buckets Replacement | The purpose of this project is to mitigate lost generation and replacement power cost. The 1st stage high pressure buckets, installed in 1997, have a probability of damage when removed on critical path in 2011 to inspect and repair cracks in the axia face of the rotor dovetails. | $ 150,696 | $ 202,037 | $ 352,732 | 12/16/2011 |
| 99. | FBC90297 | Four Corners Units 4 & 5 | Environmental Compliance | 5268 Lift Lined Ash Impoundment | The units must dispose of ash and process water or they cannot operate. The embankments are raised in lifts to minimize annual investment dollars. | $ 213,333 | $ 121,770 | $ 335,103 | 4/19/2011 |
| 100. | YUC0062 | Yucca GT Units 1 & 2 | Reliability | AVR Replacement | The purpose of this project is to replace the old, original GE AVR with a new AVR and PSS. | $ - | $ 334,406 | $ 334,406 | 3/16/2012 |

| Line No. | WA# | Plant & Unit | Category | Project Description | Purpose | Project Cost to Date 12/31/2010 | Costs to Complete | Projected Closed Cost | Estimated In-Service Date |
|---|---|---|---|---|---|---|---|---|---|
| 101. | WPC0091 | West Phoenix CC 1, 2, 3 | Environmental Compliance | Lube Oil Mist Eliminator | The purpose of this project is to ensure continued operational compliance within the opacity limits defined in the Title V air permit. The current mist eliminators require replacement. This is an environmentally related project. | $ - | $ 315,014 | $ 315,014 | 3/11/2011 |
| 102. | WPC0177 | West Phoenix CC 1, 2, 3 | Reliability | Cooling Tower Drift Eliminators Replacement | Maintain environmental compliance with Plant air operating permit. | $ - | $ 313,881 | $ 313,881 | 12/15/2011 |
| 103. | OCC0078 | Ocotillo Common | Reliability | General Svcs Transformer T492 Replacement | Provide unit reliability. T492 has been deemed a critical transformer since it is the normal path to start up the steam units and provide aux power to the gas turbines. The present transformer is approaching the end of its useful life based on recent testing results. Gas-in-oil tests are in the normal range as of the kickoff date but several different gasses have shown elevated levels over the last three years. | $ - | $ 311,568 | $ 311,568 | 10/29/2011 |
| 104. | 60-1166M | Navajo Units 1, 2, 3 | Reliability | Plant Piping Replacement | Portions of the original above ground and underground piping is near the end of its service life in many areas of the plant. Since 1994, NGS has undertaken a systematic annual program to replace and move piping above ground. As of 2009, NGS replaced approximately 66,500 feet of pipe. Work is scheduled and completed based on condition. Past budgetary postponements of plant piping work due to overruns in other areas have resulted in steadily increasing maintenance in instrument air, cooling tower blow down, oily waste, and other lines that remain below the surface. This budget includes funding to continue work on firewater, oily water, potable water, service water, service air, and instrument air lines. Work will be performed on underground piping on the east side of the boilers. | $ - | $ 291,930 | $ 291,930 | 12/31/2011 |
| 105. | CHC0302 | Cholla Common | Reliability | Lime Swgr,Recvng Whse Bldg Roofs Re | The purpose of this project is to maintain unit reliability. | $ 14,221 | $ 276,516 | $ 290,737 | 6/1/2011 |
| 106. | WPC0211 | West Phoenix CC 5 | Safety / Security | Main Steam Flow Nozzle Replacement | The existing flow elements contain a dissimilar metal weld which is susceptible to cracking under cyclic operation. Service Bulletins have been released by the manufacturer and Alstom identifying the potential for personal injury and equipment damage. Approximately ten failures have been reported. | $ - | $ 272,042 | $ 272,042 | 12/5/2011 |
| 107. | RHC0139 | Redhawk Units 1 & 2 | Reliability | Lube Oil Varnish Mitigation | Redhawk has experienced servo valve failures due to oil varnish (sludge) contamination. The industry has alluded that diminished solubility of the now standard Group 2 oil has resulted in higher degradation of the oil additives. Ultimately, this becomes the main avenue for the formation of varnish within the system. This is especially a quality associated with the GE Frame 7 turbine which are subjected to high cycling operation. The varnish does not become an operating problem until the oil can no longer hold it in solution. Once this occurs, varnish begins to agglomerate throughout the lube oil system. It plates out on the reservoir, piping, and control valves and causes problems in operation. Technological advancements have allowed for the creation of Varnish Mitigation Technology that addresses the problem while in solution, preventing insoluble varnish from occurring. | $ 212,988 | $ 44,233 | $ 257,222 | 1/17/2011 |
| 108. | WPC0164 | West Phoenix Common | Reliability | Boiler Maint Tracking Software | The purpose of this project is to maintain good condition assessment and repair information on the HRSGs. | $ 168,373 | $ 81,618 | $ 249,990 | 1/31/2011 |
| 109. | FBC90369 | Four Corners Unit 5 | Reliability | DCS Pwr Supply & Amm Hardware Replacement | The purpose of this project is to restore ABB DCS hardware reliability in order to maintain Unit reliability. The parts are no longer available or supported by the original equipment manufacturer. Attempts to replace through third party sources have been unreliable. | $ 65,558 | $ 183,011 | $ 248,569 | 4/22/2011 |

| Line No. | WA# | Plant & Unit | Category | Project Description | Purpose | Project Cost to Date 12/31/2010 | Costs to Complete | Projected Closed Cost | Estimated In-Service Date |
|---|---|---|---|---|---|---|---|---|---|
| 110. | FBC90328 | Four Corners Unit 5 | Reliability | Aux Turbine Prot Upgrade | The purpose of this project is to improve the Auxiliary Turbines protection instrumentation, monitoring, and control system to maintain reliability, performance and protection. A new EHC oil system is needed along with new actuators to control the turbine seeds. The mechanical overspeed bolt will be replaced with triple redundant overspeed controls. New aux turbine supervisory instrumentation will be included for better monitoring and control of vibration, eccentricity, rotor positioning. | $ 97,776 | $ 148,797 | $ 246,572 | 4/15/2011 |
| 111. | CHC0276 | Cholla Common | Reliability | Service-Instrument Air Pipe Replacement | Plant personnel have had to repair and/or replace portions of the Service/Instrumentation Air system because of leaks that have occurred. | $ 131,292 | $ 114,508 | $ 245,800 | 2/25/2011 |
| 112. | CHC0291 | Cholla Units 1, 2, 3 | Environmental Compliance | Old Ash Pond Bank Stabilization | Stabilize ash pond bank. | $ 48,317 | $ 191,857 | $ 240,175 | 7/11/2011 |
| 113. | SDC0042 | Sundance Units 1-10 | Prevent Failure | RO Membrane Replacement | 1st pass membranes need to be replaced every 3 to five years and second pass membranes need to be replaced every 5 to 7 years. | $ 7,062 | $ 229,793 | $ 236,855 | 6/20/2012 |
| 114. | 60-0909 | Navajo Units 1, 2, 3 | Environmental Compliance | Scrubber Mist Eliminator Upgrade | The purpose of this project is to replace the existing mist eliminators with a more effective design made from a more durable material. | $ 146,416 | $ 84,410 | $ 230,826 | 4/3/2011 |
| 115. | WPC06113 | West Phoenix CC 1, 2, 3 | Reliability | Cooling Twr Mech Equip Access Walkways | Safely accessing cooling tower equipment, provide inspection, and decrease construction schedule. | $ - | $ 227,603 | $ 227,603 | 3/12/2012 |
| 116. | CHC0245 | Cholla Units 1, 2, 3 | Reliability | Boiler Maint Tracking Software | The purpose of this project is to maintain the frequency and length of boiler tube leak outages by maintaining good condition assessment and repair information on the boilers. | $ 217,308 | $ 10,055 | $ 227,363 | 6/30/2011 |
| 117. | WPC0205 | West Phoenix CC 1 | Prevent Failure | BFP Recirculation Piping Redesign | The purpose of this project is to redesign the Unit 1 boiler feed pump recirculation system to eliminate cavitation within the pump thereby reducing premature pump failure and maintaining unit reliability. | $ 27,600 | $ 197,692 | $ 225,292 | 3/25/2011 |
| 118. | OCC0072 | Ocotillo Stm Units 1 & 2 | Environmental Compliance | Circ Water Acid Tank Replacement | The purpose of this project is to replace the corroded steel acid storage tank with a corrosion resistant XLHDPE Double Wall tank. Wall thickness measurements taken in January 2010 indicate areas of serious thinning on the south side of the tank, tinning of the bottom, and significant buildup of corrosion products on the interior surface. Should a leak occur, there is the potential for a spill with associated safety issues due to the hazardous nature of Sulfuric acid. The tank is used to control the ph of the circulating water. | $ 21,305 | $ 196,086 | $ 217,391 | 3/31/2011 |
| 119. | CHC0318 | Cholla Unit 2 | Prevent Failure | Station Battery Charger Replacement | The purpose of this project is to maintain reliable source to charge unit batteries for the 125VDC distribution system. The battery chargers are plant original equipment (1981) and are at the end of life. | $ 142,409 | $ 73,599 | $ 216,008 | 3/4/2011 |
| 120. | WPC0175 | West Phoenix Common | Reliability | RO Membrane Replacement | To maintain quality water required for plant operations. | $ 186,644 | $ 28,543 | $ 215,187 | 1/18/2011 |

| Line No. | WA# | Plant & Unit | Category | Project Description | Purpose | Project Cost to Date 12/31/2010 | Costs to Complete | Projected Closed Cost | Estimated In-Service Date |
|---|---|---|---|---|---|---|---|---|---|
| 121. | 60-1066 | Navajo Units 1, 2, 3 | Reliability | Plant Piping Replacement-Com | The underground utility replacement project was started in 1993. The plant was broken up into 23 zones. The majority of these are outside the main power block area. Initially, pipe failures were occurring frequently in the out-lying areas around the Cooling towers and railroad. The piping replacement effort was concentrated in these areas first. As the failure rate of the remaining areas was relatively low, completing the rest of the work scope was delayed to allow the funds to be used to address other piping systems (fire water, service water, bearing cooling water) that were experiencing increasingly higher failure rates. As these other piping systems became critical, the allocated funds were directed at these systems or the budgeted funds were used to offset other plant expenses. In the last couple of years, the pipeline failure rates in the remaining areas have started to increase and these areas now have a higher priority to be replaced. The first 13 zones were mainly underground piping systems. The bulk of the remaining replacement will be above ground, which requires heat tracing, insulation, and lagging. In 2010, the project will focus on above ground piping systems that include the air preheater discharge headers, firewater, oily water, and service water. | $ 158,272 | $ 50,113 | $ 208,385 | 6/30/2011 |
| 122. | WPC0204 | West Phoenix CC 1 | Prevent Failure | BFP Recirculation Piping Redesign | The purpose of this project is to redesign the Unit 1 boiler feed pump recirculation system to eliminate cavitation within the pump thereby reducing pump failure and maintaining unit reliability. | $ 2,775 | $ 205,528 | $ 208,303 | 3/19/2011 |
| 123. | RHC0118 | Redhawk Units 1 & 2 | Prevent Failure | Cooling Tower XFMR Bus Protection | The purpose of this project is to protect the transformers and bus ducts from damage due to the ambient environment and cooling tower drift. During a recent storm, the bus duct was exposed to rain and faulted. Water intrusion was also found in the transformers. The new structure will provide protection from the weather and cooling tower drift that is deteriorating the transformers and bus duct. | $ 139,754 | $ 66,400 | $ 206,154 | 1/31/2011 |
| 124. | CHC0345 | Cholla Unit 2 | Reliability | Cable Tray & Cable Replacement, Phase 6A | Several of the cables installed underground have failed. This is a proactive attempt to replace cables before they cause a forced outage or load reduction, as well as to replace failed cables which have been repaired or replaced on a temporary basis. Cables are being replaced in overhead raceway to avoid the effects of submersed cables in manholes, conduits which have been damaged or deteriorated, and the safety difficulties of replacing cables in manholes with other energized circuits present. Specific pmps include Demister Water, Scrubber Recycle, and also includes Diesel Gen Swgr and Unit 2 MCC. | $ - | $ 204,627 | $ 204,627 | 6/24/2011 |
| 125. | SDC0044 | Sundance Common | Reliability | *Auxiliary Power Transfer* | The purpose of this project is to be able to maintain plant common auxiliary power during an outage on a power block. Present condition is that if the power block supplying the BOP auxiliary power has to be de-energized, the BOP system has to be shut down to transfer source of power to the second power block. During the transfer, power to common facilities is lost. The modification will allow power to common facilities to remain on. | $ - | $ 204,313 | $ 204,313 | 11/10/2011 |
| 126. | YUC0073 | Yucca GT Units 5 & 6 | Reliability | Chiller Bypass | The purpose of this project is to install a bypass around chiller 200A&B condenser and evaporators. This will allow isolation for either of the chiller. | $ - | $ 193,376 | $ 193,376 | 3/9/2012 |
| 127. | FBC90168 | Four Corners Units 4 & 5 | Reliability | U45 Absorber Module Blowdown Upgde | The components of the existing absorber module blow down system are worn out and cannot support the higher SO2 removal rates. As a result, waste slurry sump overflows, chloride excursions, and grit build up in the absorber modules are becoming frequent and are adversely affecting the scrubbing process increasing O&M cost. Project will result in reduced lime usage, maintained thickener performance/reliability, and enhanced TUT flow to the ash ponds. | $ 164,510 | $ 23,738 | $ 188,249 | 3/25/2011 |

| Line No. | WA# | Plant & Unit | Category | Project Description | Purpose | Project Cost to Date 12/31/2010 | Costs to Complete | Projected Closed Cost | Estimated In-Service Date |
|---|---|---|---|---|---|---|---|---|---|
| 128. | 60-0913 | Navajo Units 1, 2, 3 | Reliability | Service Building Refurbishment | Refurbish the west side of the Service Building. This refurbishment will include replacing the plumbing and HVAC systems, reconfiguring the restroom and shower facilities to match the gender of the current workforce and installing a room for large measure. | $ 184,355 | $ 1,422 | $ 185,776 | 1/31/2011 |
| 129. | FBC90390 | Four Corners Units 4 & 5 | Prevent Failure | Aux Transformer Spare | Auxiliary transformers are required to be able to operate Units 4 and 5 simultaneously. If an aux transformer is not available and that unit is operating on the reserve bus, the unit would have to be curtailed to be able to start up the other unit. If the unit with an auxiliary transformer were to trip, the reserve bus would have to carry both units' auxiliaries and would overload until the units' aux loads could be reduced. | $ - | $ 184,438 | $ 184,438 | 11/12/2011 |
| 130. | 60-1086 | Navajo Unit 2 | Reliability | Precipitator Deck Replacement-2 | The precipitator deck is a composite of concrete on top of corrugated steel that serves as the tension component of the deck. Cracks in the concrete have allowed moisture to seep in and corrode the corrugated steel. The load-carrying capacity of the deck has thus been reduced and may pose a risk of failure with the use of heavy equipment. The Unit 1 lower deck (the deck in the worst condition) was replaced in 2008 and the Unit 3 lower deck is scheduled for 2009. In 2010, the Unit 2 lower deck will be replaced. | $ 175,761 | $ 8,133 | $ 183,893 | 6/30/2011 |
| 131. | 60-1163 | Navajo Units 1, 2, 3 | Reliability | Circuit Breakers, Switchgear Repairs | NGS will replace the operating mechanism on the 4160V scrubber breakers. The scrubber type 5-VHK-2S0, model 20, ASS vacuum 4160V breakers have become a safety issue. Operating mechanism failures have resulted in arcing when Operations racks in these breakers. NGS will purchase two new breakers to allow cycling of the 40 scrubber breakers for repair. The spare breakers remaining after the repairs will be used for cycling breakers during future preventive maintenance cycles. The plan is to replace the operating mechanism every 10 years, with a 5 year PM cycle. | $ - | $ 177,385 | $ 177,385 | 12/31/2011 |
| 132. | 60-0811 | Navajo Units 1, 2, 3 | Reliability | Intelligent Sootblowing Breakout | Some areas of the Navajo boilers have soot blown too much, while other areas don't have it blown enough. Blowing too much erodes boiler tubes, and erosion is a major cause of tube failures, which results in Unit forced outages. | $ 157,155 | $ 14,588 | $ 171,743 | 4/3/2011 |
| 133. | OCC0071 | Ocotillo Common | Reliability | Security, CCTV Replacement | The purpose of this project is to improve plant and personnel security and safety. | $ 21,397 | $ 142,557 | $ 163,954 | 4/1/2011 |
| 134. | WPC0186 | West Phoenix CC 5 | Reliability | Boiler Feedwater Recirc Valve Replacement | Existing system design is not robust enough to handle cyclic unit operation. As a result the recirculation control valves must be rebuilt every year or two. | $ - | $ 163,913 | $ 163,913 | 3/23/2012 |
| 135. | WPC0156 | West Phoenix CC 1 | Prevent Failure | CC1 Battery Replacement | These are required to support unit functions during loss of AC power. | $ 125,586 | $ 34,264 | $ 159,851 | 3/19/2011 |
| 136. | SDC0026 | Sundance Common | Safety / Security | Lightning Prot & Grounding | The purpose of the project is to identify if a lower the ground resistance and associated arrestors are needed at the plant to make it safer during lightning storms and system faults. Then to make the changes as determined. | $ - | $ 159,390 | $ 159,390 | 6/25/2011 |
| 137. | RHC0099 | Redhawk Common | Prevent Failure | RO Membrane Replacement | The purpose of this project is to purchase replacement first pass RO membranes to ensure continued production of high purity water. | $ 151,990 | $ 7,033 | $ 159,023 | 6/30/2011 |
| 138. | FBC90080 | Four Corners Units 4 & 5 | Reliability | U4-5 Reserve Transf Breaker Addition | Install new breakers and associated equipment to individually isolate the Reserve Auxiliary Transformers. | $ 64,130 | $ 94,097 | $ 158,227 | 11/30/2011 |
| 139. | WPC0134 | West Phoenix CC 4 | Safety / Security | Cooling Tower Fan Deck Replacement | The existing treated plywood deck is showing signs of deterioration and will need to be replaced to ensure structural integrity of the tower support diaphragm (fan deck) and provide a safe walking surface for plant personnel. | $ - | $ 156,941 | $ 156,941 | 12/16/2011 |

| Line No. | WA# | Plant & Unit | Category | Project Description | Purpose | Project Cost to Date 12/31/2010 | Costs to Complete | Projected Closed Cost | Estimated In-Service Date |
|---|---|---|---|---|---|---|---|---|---|
| 140. | WPC0208 | West Phoenix CC 1, 2, 3 | Safety / Security | Cooling Twr Sodium Hypochlor Add Sys | The purpose of this project is to replace the existing Cooling Tower Sodium Hypochloride Injection Skids (pumps, instrumentation, and piping) with a gravity feed system. The existing system is prone to leaks and the pumps are prone to failure due to the nature of the material being pumped. Safety concern manually feeding chemicals because of weight of portable containers and excessive exposure to chemicals. | $ - | $ 156,362 | $ 156,362 | 11/30/2011 |
| 141. | WPC0210 | West Phoenix CC 5 | Safety / Security | Cooling Twr Sodium Hypochlor Add Sys | The purpose of this project is to replace the existing Cooling Tower Sodium Hypochloride Injection Skids (pumps, instrumentation, and piping) with a gravity feed system. The existing system is prone to leaks and the pumps are prone to failure due to the nature of the material being pumped. Safety concern manually feeding chemicals because of weight of portable containers and excessive exposure to chemicals. | $ - | $ 156,362 | $ 156,362 | 11/30/2011 |
| 142. | YUC0075 | Yucca Common | Reliability | Gas Storage Shelter (APS Share) | Currently the plant has limited gas storage. | $ 195,900 | $ (40,651) | $ 155,249 | 1/31/2011 |
| 143. | WPC0183 | West Phoenix CC 4 | Reliability | Cooling Tower Drift Eliminators Replacement | Maintain environmental compliance with Plant air operating permit. | $ - | $ 151,709 | $ 151,709 | 12/15/2011 |
| 144. | CHC0323 | Cholla Unit 3 | Prevent Failure | Station Battery Charger Replacement | The purpose of this project is to maintain reliable source to charge unit batteries for the 125VDC distribution system. The battery chargers are plant original equipment (1981). | $ 15,147 | $ 135,570 | $ 150,717 | 4/1/2011 |
| 145. | CHC0334 | Cholla Common | Reliability | Tools & Equipment - 2011 | Misc cap tool for projects including DC ground Fault Trouble shooting meter, Robot Control welder, Tube cutting/Prep mill tool, and Tube bending dies. | $ - | $ 149,109 | $ 149,109 | 12/15/2011 |
| 146. | 60-1170 | Navajo Units 1, 2, 3 | Reliability | Control System Replacement | Replace obsolete control systems as existing systems become unrepairable due to lack of availability of replacement parts. NGS maintains the existing DCS and PLC systems as components age from "Maturity" status to "Lifetime" status. "Maturity begins when the product is withdrawn from sales. "Lifetime" reflects the period when there is no guarantee the item can be supported; components are provided and maintained as long as parts are available, but they are no longer in production. The UNIX work stations are obsolete, and the Solaris operating system that is used on all three units' work stations is no longer supported as of January 2010. These systems will be replaced, starting with Unit 1 in 2011, using Windows-based work stations, control system peripherals, and the ItA Series System from Foxboro. | $ - | $ 146,038 | $ 146,038 | 12/31/2011 |
| 147. | CHC0222 | Cholla Unit 2 | Reliability | U2 Scrubber Elev Controls Replacement | Make the Scrubber Elevator more reliable and avoid delays in productivity or module return to service. Controls are to be replaced in compliance with ASME/ANSI A17.1 and 17.3, which require replacement rather than modification with non-OEM parts. | $ 16,604 | $ 129,403 | $ 146,007 | 1/1/2012 |

| Line No. | WA# | Plant & Unit | Category | Project Description | Purpose | Project Cost to Date 12/31/2010 | Costs to Complete | Projected Closed Cost | Estimated In-Service Date |
|---|---|---|---|---|---|---|---|---|---|
| 148. | 60-1173 | Navajo Units 1, 2, 3 | Reliability | DCS Field Devices | Improvements to field devices around the plant are necessary to optimize the control systems' capabilities for improved load following, run backs, and all systems controls. These improvements will allow the devices to be integrated with the control system. The following equipment will be addressed in 2011:<br>1) Feedwater Header Level Controls do not meet ASME recommendations for water induction prevention. The manufacturer of the current system, Masoneilan, discontinued sales of parts effective February of 2009. NGS's current Masoneilan level controllers use antiquated pneumatic technology. Related control valves are imprecise and heater levels fluctuate widely. Current conditions contribute to leaks and shell erosion. The project to replace the current Feedwater heater level controls with a DCS compatible Clark-Reliance/Jerguson control package will be completed in 2011.<br>2) The boiler Acoustic Leak Detection System (ALDS) is obsolete and no longer supported by the manufacturer. Parts are limited to stock on hand. A retrofit is available at a substantial savings vs. a complete replacement. NGS will replace the CE/Lintv"alve T6 ALDS with a LA 202 ALDS system on Unit 1 during the overhaul.<br>3) New REXA actuators will be installed on the Unit 1 SP and WD Valves to replace the CopesNulcan actuator and positioner that are failing due to the extreme heat in their location.<br>4) Obsolete and unsupported coal silo level devices will be replaced. Manufacturer parts are no longer available and NGS has depleted the spare parts inventory for the current devices.<br>5) The existing Stator Cooling System temperature, pressure and flow alarm devices are antiquated, inaccurate and difficult to replace. NGS will complete the replacement of redundant mercroid switches and thermo-bulb switches with existing Siemens' transmitters and 3-element J-type thermocouples on Unit 1 in 2011. | $ - | $ 145,745 | $ 145,745 | 12/31/2011 |
| 149. | 60-1060 | Navajo Units 1, 2, 3 | Environmental Compliance | Cathodic Protection Wells Replacement-Com | Inspection of the 56 existing cathodic protection wells found that only 13 were operational with no immediate maintenance needs. The Cathodic Protection Wells protect the underground piping system from corrosion. These wells are original plant equipment and have been collapsing. | $ 12,546 | $ 130,983 | $ 143,529 | 6/30/2011 |
| 150. | CHC0303 | Cholla Common | Reliability | Coal Handling Bldgs Roof Replacement | The purpose of this project is to replace the 28 year old leaking coal handling building roofs in order to protect control system and switchgear investments and the operation of the Cholla coal handling system. The condition of the roofs have deteriorated to the point that replacement is the practical solution. Replacement is recommended to protect the control room and switchgear equipment. | $ 15,068 | $ 125,864 | $ 140,932 | 6/1/2011 |
| 151. | SAC0062 | Saguaro Common | Reliability | Remote Start, CT 1-3 From Sundance | To enable remote control of all three Saguaro Combustion Turbines from Sundance. | $ 122,145 | $ 17,335 | $ 139,480 | 6/30/2011 |
| 152. | FCC90396 | Four Corners Common | Environmental Compliance | Off-Site Resin Regeneration | The purpose of this project is to eliminate on-site resin regeneration. The resin regeneration equipment in the Common "150-gpm" demineralizer system is to be demolished and replaced with a header designed to receive vendor supplied resin tanks. The vendor tanks are to be filled with resin that is regenerated at their facilities. | $ - | $ 138,754 | $ 138,754 | 12/23/2011 |
| 153. | WPC0158 | West Phoenix CC 3 | Prevent Failure | CC3 Battery Replacement | These are required to support unit functions during loss of AC power. | $ 96,636 | $ 32,428 | $ 129,064 | 4/15/2011 |
| 154. | 60-1019 | Navajo Units 1, 2, 3 | Reliability | Pulverizer Dynamic Analysis System | NGS recommends installation of a Dynamoc Analysis System on each (21) pulverizer, which would provide real-time predictive maintenance data on machines. | $ 124,538 | $ 3,842 | $ 128,380 | 4/30/2011 |

| Line No. | WA# | Plant & Unit | Category | Project Description | Purpose | Project Cost to Date 12/31/2010 | Costs to Complete | Projected Closed Cost | Estimated In-Service Date |
|---|---|---|---|---|---|---|---|---|---|
| 155. | 60-1073 | Navajo Units 1, 2, 3 | Reliability | DCS Field Devices-Com | Improvements to field devices around the plant are necessary to optimize the control systems' capabilities for improved load following, run backs, and all systems controls. These improvements will allow the devices to be integrated with the control system. The following equipment will be addressed in 2010 - 2011.<br>1) Feedwater Header Level Controls do not meet ASME recommendations for water induction prevention. The manufacturer of the current system, Masoneilan, discontinued sales of parts effective February of 2009. NGS's current Masoneilan level controllers use antiquated pneumatic technology. Related control valves are imprecise and heater levels fluctuate widely. Current conditions contribute to leaks and shell erosion. Feedwater heater level controls will be replaced with a DCS compatible Clark-Reliance/Jerguson control package.<br>2) The boiler Acoustic Leak Detection System (ALDS) is obsolete and no longer supported by the manufacturer. Parts are limited to stock on hand. A retrofit is available at a substantial savings vs. a complete replacement. NGS will replace the CE/Lintvalve T6 ALDS with a LA 202 ALDS system. This retrofit will allow NGS to utilize existing field wiring and relay room cabinetry.<br>3)- The existing Stator Cooling System temperature, pressure and flow alarm devices are antiquated, inaccurate and difficult to replace. Replacement of redundant mercroid switches and thermo-bulb switches with existing Siemens' transmitters and 3-element J-type thermocouples will increase accuracy and provide DCS compatibility. | $ 120,084 | $ 7,517 | $ 127,601 | 6/30/2011 |
| 156. | SAC0066 | Saguaro Common | Safety / Security | Cathodic Protection Sys #1, 3, 4 Replacement | Cathodic Protection provides protection against corrosion for all underground pipes at the Plant. The systems that must be replaced protect the oil tanks and natural gas lines at the Plant. | $ - | $ 125,552 | $ 125,552 | 12/2/2011 |
| 157. | WPC0182 | West Phoenix CC 4 | Reliability | Cooling Tower Fan Purchase | The purpose of this project is to replace the cooling tower fans to ensure safe, reliable operation. Cooling tower fan hubs are corroding as a result of failed coatings. | $ - | $ 124,627 | $ 124,627 | 10/7/2011 |
| 158. | 60-1004C | Navajo Units 1, 2, 3 | Reliability | Computer and Network Infrastructure | This project will replace personal computers (PC's) certain monitors, and various peripheral devices. NGS's desktop PC's are currently four years old. They are beginning to fail and their warranties have expired. PC monitors that are replaced will be used as terminal monitors, with the remainder kept as spares. Peripheral devices will be evaluated and replaced as required. | $ 64,345 | $ 58,336 | $ 122,681 | 4/30/2011 |
| 159. | YUC0051 | Yucca GT Units 1 & 2 | Prevent Failure | Auto Sync Relay Replacement | The purpose of this project is to restore the synchronizing protection to the combustion turbines. The electromechanical relays (2 relays on each of the two units at Yucca) require periodic calibration and repairs and provide protective functions to properly synchronize the units to the system. The original relays and parts are no longer available from the original manufacturer. | $ 42,685 | $ 77,321 | $ 120,006 | 1/15/2011 |
| 160. | WPC0172 | West Phoenix CC 4 | Reliability | Steam Turbine Coupling | The fasteners and spacer on the steam turbine coupling were replaced in 2005 after the coupling was exposed to a high load condition which caused it to fail. The reliability and performance of the coupling are uncertain and there is not a spare coupling on site. The lead time for a new coupling is 26 weeks. | $ 416 | $ 114,756 | $ 115,171 | 4/29/2011 |
| 161. | WPC0203 | West Phoenix CC 5 | Reliability | Distillate Tank Replacement | The purpose of this project is to replace ZLD Distillate Tank and piping to ensure operation of ZLD. The ZLD is required for operating CC5A, CC5B, CC5ST. Continued operation of ZLD under current conditions creates an unsafe work environment due to spraying hot water. | $ - | $ 115,090 | $ 115,090 | 12/5/2011 |
| 162. | WPC06114 | West Phoenix CC 4 | Reliability | Cooling Twr Mech Equip Access Walkways | Allow safe access to fan assemblies mechanical equipment. | $ - | $ 111,697 | $ 111,697 | 4/20/2012 |

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|---|---|---|---|---|---|---|---|---|---|
| 163. | 60-1181 | Navajo Units 1, 2, 3 | Reliability | Prot Relay Replacement | These devices ensure the protection and integrity of plant equipment and sub-systems vital to equipment availability. These devices will be replaced with more advanced digital technology for more reliable, quicker information after high current faults. This information will be used to insure proper protection and preventive maintenance of valuable equipment and systems. In 2011, NGS will focus on relay protection work on Unit 1 auxiliary equipment including; Induced Draft Fans, Primary Draft Fans, Circulating Water Pumps, Boiler Circulating Water Pumps and Unit Auxiliary Transformers. The protective relay modernization is designed to update antiquated relay hardware, which will positively impact long term maintenance and failure risk. | $ - | $ 111,616 | $ 111,616 | 12/31/2011 |
| 164. | WPC0157 | West Phoenix CC 2 | Prevent Failure | CC2 Battery Replacement | These are required to support unit functions during loss of AC power. | $ 92,509 | $ 18,600 | $ 111,110 | 3/25/2011 |
| 165. | FBC90378 | Four Corners Unit 5 | Safety / Security | Arc Flash Mitigation | The purpose of this project is to comply with NFPA 70E and Fossil Generation Managerial Policy S-15. | $ 1,814 | $ 107,699 | $ 109,514 | 5/1/2011 |
| 166. | FBC90172 | Four Corners Units 4 & 5 | Reliability | U45 Undergrnd Cooling Water Systems | The East flush water pump is currently leaking where the piping is above ground. Some of this piping has already had multiple repairs to it. Failure of any of these piping components will subject the auxiliary bay of Units 4&5 to flooding. In addition, a unit outage of 5 days will be required to repair this piping. | $ 78,792 | $ 29,794 | $ 108,586 | 5/2/2011 |
| 167. | OCC0065 | Ocotillo Stm Units 1 & 2 | Reliability | Boiler Maint Tracking Software | The purpose of this project is to maintain the frequency and length of boiler tube leak outages by maintaining good condition assessment and repair information on the boilers. | $ 91,089 | $ 14,693 | $ 105,782 | 6/30/2011 |
| 168. | WPC0159 | West Phoenix GT 1 | Prevent Failure | GT1 Battery Replacement | These are required to support unit functions during loss of AC power. | $ 99,229 | $ 6,431 | $ 105,660 | 1/27/2011 |
| 169. | OCC0083 | Ocotillo Stm Units 1 & 2 | Environmental Compliance | CEMS Upgrade | The current CEMS is antiquated and is causing low monitor availability. This project upgrades the system to state-of-the-art technology and should maintain the system availability. | $ - | $ 104,241 | $ 104,241 | 11/18/2011 |
| 170. | FBC90336 | Four Corners Unit 5 | Reliability | TSI Replacement | The purpose of this project is to replace the existing Turbine / Generator (T/G) supervisory instrumentation system (TSI) with a new vibration and critical monitoring system. The project will also integrate the new TSI system analog, alarm, and trip signals into the plant-wide Distributed Control System (DCS) and data historian. | $ 48,026 | $ 55,097 | $ 103,123 | 4/22/2011 |
| 171. | 60-1070 | Navajo Units 1, 2, 3 | Reliability | Control System Replacement-Com | Replace obsolete control systems as existing systems become unrepairable due to lack of availability of replacement parts. Maintain the existing DCS and PLC systems as components age from "Maturity" status to "Lifetime" status. "Maturity begins when the product is withdrawn from sales. "Lifetime" reflects the period when there is no guarantee the item can be supported; components are provided and maintained as long as parts are available, but they are no longer in production. The following equipment will be addressed. 1) The Servo positioners for both the Auxiliary and Main Turbines will be replaced. Current equipment is obsolete ant there are no compatible substitutes. Parts are limited to current onsite spares. Replacement will require a change to the turbine control system. 2) The COMM30 communication modules are no longer available from Foxboro. There are 26 modules on site that need to be replaced with current Foxboro equipment. 3) Unit 1 UNIX work stations are obsolete and the Solaris operating system that is used on all three units' work stations will no longer be supported after January 2010. These systems will be replaced with Windows based work stations from Foxboro. | $ 15,994 | $ 86,505 | $ 102,499 | 6/30/2011 |
| 172. | WPC0193 | West Phoenix Common | Prevent Failure | Cathodic Protection Replacement | Cathodic Protection of the natural gas and diesel pipelines is regulatory requirement audited by the ACC. | $ - | $ 101,928 | $ 101,928 | 5/31/2011 |

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|---|---|---|---|---|---|---|---|---|---|
| 173. | RHC0124 | Redhawk Unit 1 | Reliability | HRSG Feedwater Pump Motor Replacement | The purpose of this project is to replace the motor to reduce/eliminate vibration concers and provide reliable future operation of the Unit. The existing motor is experiencing abnormally high vibrations and poses a risk to generation. | $ 96,826 | $ 4,480 | $ 101,306 | 6/30/2011 |
| 174. | 60-0711 | Navajo Units 1, 2, 3 | Reliability | HVAC Air handler Replacement/Aux Bldgs | Major components of these air handling components (such as motors, cooling/heating coils, and fans) are beginning to fail, and direct replacements for these components are no longer available. Current fire protection requirements call for fire dampers an fan controls that are not easily added to the existing units. SRP has determined that the most cost effective long-term solution for maintaining reliable temperature controls for personnel and critical electrical components, and for providing an up-to-date level of fire protection, is replacement of these ten air handling units. | $ 50,291 | $ 44,165 | $ 94,457 | 12/31/2011 |
| 175. | OCC0080 | Ocotillo Common | Reliability | Tools - 2011 | Misc cap tool for projects including IR Camera. | $ - | $ 94,164 | $ 94,164 | 12/15/2011 |
| 176. | OCC0068 | Ocotillo Common | Reliability | Video Conf Equip Install | Project is to enhance the Generation Videoconferencing system providing continuity of use, additional capability & connectivity, and provide upgrades to older systems which not only allow additional function. | $ 87,917 | $ 4,068 | $ 91,985 | 6/30/2011 |
| 177. | SDC06353 | Sundance Units 1-10 | Reliability | CEMS UPS Power Supply | The purpose of this project is to power critical CEMS equipment from the PECC UPS System to allow for controlled shutdown of the CEMS equipment. The original CEMS System is equipped with a standalone, rack mount UPS/Battery system which needs to be replaced due to faulty batteries. | $ - | $ 86,966 | $ 86,966 | 6/11/2012 |
| 178. | 60-1081 | Navajo Units 1, 2, 3 | Reliability | Protection Relay Replacement-Com | These devices ensure the protection and integrity of plant equipment and sub-systems vital to equipment availability. These devices will be replaced with more advanced digital technology for more reliable, quicker information after high current faults. This information will be used to insure proper protection and preventive maintenance of valuable equipment and systems. In 2010, NGS will focus on relay protection work on Unit 2 auxiliary equipment including; Induced Draft Fans, Primary Draft Fans, Circ Water Pumps, Boiler Circulating Water Pumps and Unit Auxiliary Transformers. The protective relay modernization is designed to update antiquated relay hardware, which will positively impact long term maintenance and failure risk. | $ 81,598 | $ 5,048 | $ 86,646 | 6/30/2011 |
| 179. | FCC90363 | Four Corners Common | Environmental Compliance | Vacuumed Dust Disposal Upgrade | The purpose of this project is to control fugitive dust generated when vacuum trucks dump fly ash and other collected materials at the Dry Fly Ash Disposal Site. Spraying or foaming equipment will minimize the dust generated during the dumping operation. | $ 14,328 | $ 69,991 | $ 84,319 | 2/18/2011 |
| 180. | WPC0184 | West Phoenix CC 4 | Reliability | HP Drum Fill Valve | The existing HP drum level control valve is not designed for the high differential pressure associated with filling the unit or making up to the drum under cold conditions. The valve internals are damaged quickly under these operating conditions. | $ - | $ 81,865 | $ 81,865 | 4/20/2012 |
| 181. | WPC0075 | West Phoenix CC 1, 2, 3 | Prevent Failure | Zurn Coupling | The purpose of this project is to purchase a spare Zurn coupling to replace the warehouse spare that was recently installed in CC1. The Zurn coupling has a life expectancy of five years based on historical maintenance. Lead time on a replacement coupling is 26 - 28 weeks. For these reasons a spare coupling is necessary. | $ - | $ 80,934 | $ 80,934 | 2/28/2011 |
| 182. | FBC90370 | Four Corners Unit 5 | Reliability | Reheat Isolation Valves | The purpose of this project is to isolate the reheat section of the boiler during hydrostatic testing, allowing leaks to be located quickly and thereby reducing unit start-up time after overhaul. | $ 17,596 | $ 63,070 | $ 80,666 | 4/24/2011 |

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| 183. | NPA00558 | Navajo Units 1, 2, 3 | Safety / Security | Plant Wide Emerg Evac Notification System | Install a plant-wide emergency notification system that works in conjunction with the existing fire alarm panels. Notification will ne accomplished in general use areas of the plant with a multiOpattern sirent, and in high noise areas with horns and strobes. | $ - | $ 79,245 | $ 79,245 | 12/31/2011 |
| 184. | SAC0067 | Saguaro Common | Reliability | Remote HMIs for Saguaro at Sundance | To allow the Sundance Control operators to have more control capabilities over the Saguaro units. This also gives them access to all of the operating information for the units. | $ - | $ 78,181 | $ 78,181 | 11/18/2011 |
| 185. | WPC0209 | West Phoenix CC 4 | Safety / Security | Cooling Twr Sodium Hypochlor Add Sys | The purpose of this project is to replace the existing Cooling Tower Sodium Hypochloride injection Skids (pumps, instrumentation, and piping) with a gravity feed system. The existing system is prone to leaks and the pumps are prone to failure due to the nature of the material being pumped. Safety concern manually feeding chemicals because of weight of portable containers and excessive exposure to chemicals. | $ - | $ 78,181 | $ 78,181 | 11/30/2011 |
| 186. | RHC0126 | Redhawk Common | Safety / Security | Chemical Feed System | To improve safety with handling chemicals. | $ 12,996 | $ 64,892 | $ 77,889 | 4/1/2011 |
| 187. | CHC0315 | Cholla Common | Safety / Security | Lockout-Tagout System | Install the Lockout-Tagout (LOTO) system including software, four (4) PC stations, five (5) large printers, lock boxes and lock box accessories. | $ 73,974 | $ 3,423 | $ 77,397 | 6/30/2011 |
| 188. | FBC90388 | Four Corners Unit 4 | Reliability | Aux Steam Flow Control Valve Replacement | The purpose of this project is to ensure dependability of the Unit 4 auxiliary steam high demand flow control for Unit 4 normal full-load operation and Unit 5 start-up and shutdown auxiliary steam demand. The Unit 4 control valve and actuator have failed, preventing the valve from fully closing. | $ - | $ 74,932 | $ 74,932 | 10/27/2011 |
| 189. | WPC0173 | West Phoenix CC 1, 2, 3 | Prevent Failure | 4160V Breaker Reassignment | Facilitate safe maintenance practices without requiring complete shutdown of both power sources to switchgear. | $ 19,513 | $ 54,065 | $ 73,578 | 3/18/2011 |
| 190. | FBC90389 | Four Corners Unit 5 | Reliability | Aux Steam Flow Control Valve Replacement | The purpose of this project is to ensure dependability of the Unit 5 auxiliary steam high demand flow control for Unit 5 normal full-load operation and Unit 4 start-up and shutdown auxiliary steam demand. The Unit 4 control valve and actuator have failed, preventing the valve from fully closing. Currently Unit 4 auxiliary steam demand is being met by Unit 5 for start-up and shutdown purposes. | $ - | $ 73,541 | $ 73,541 | 5/21/2011 |
| 191. | NPA00557 | Navajo Common | Reliability | Exciter Breaker Replacement | The field breaker that protects the generator excitation system for NGS's unique exciter design is neither reliable nor repairable. Have a more robust breaker designed and install one on each unit. | $ - | $ 72,277 | $ 72,277 | 12/31/2011 |
| 192. | 60-1080 | Navajo Units 1, 2, 3 | Environmental Compliance | Coal Yard Dust Collector Sys-Com | The current dust collection system at NGS is outdated and many parts are obsolete. Maintaining this system is very time consuming and the results of this system's poor performance are creating safety and housekeeping issues throughout the coal handling areas. Combustible dust has become a priority following incidents in other facilities. | $ 67,279 | $ 3,113 | $ 70,392 | 6/30/2011 |
| 193. | FCC90398 | Four Corners Common | Reliability | Tools, New and Replacement, 2011 | Replacement and tools used for projects. Examples include a high speed handheld beveller, beveller for prepping pipe to 8-3/4", and a flange de-facing tool. | $ - | $ 70,383 | $ 70,383 | 12/15/2011 |
| 194. | 60-1010C | Navajo Units 1, 2, 3 | Reliability | Dissolved Gas Anlyzr MSS-RS-Main Tr | Replace the existing dissolved gas analyzers on the main auxiliary transformers (3) and the Maub Station Service transformers with Severon True Gas TM-8 monitors. | $ 39,301 | $ 28,391 | $ 67,692 | 12/31/2011 |

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| 195. | WPC0174 | West Phoenix Common | Safety / Security | Lockout-Tagout System | This project is required to standardize fleet production of lockout-tagout tags, and will reduce the risk of safety events due to human performance error. The Company has benchmarked other companies' best practices resulting in a complete re-write of the lockout-tagout process and procedure. This WA funds the purchase of software and equipment necessary to implement the new best practices for the lockout-tagout process and procedure. | $ 62,674 | $ 2,900 | $ 65,574 | 6/30/2011 |
| 196. | 60-1077 | Navajo Units 1, 2, 3 | Reliability | Facilities Maint-Roof Repairs-Com | Evaluation of the plant's roofing, floors and walls shows deterioration that requires repairs or replacement. NGS will make the following facilities repairs in 2010-2011:<br>1) Replace Water Treatment Building and Chlorine Building roof. Engineering inspections over the past several years found the water treatment building and Chlorine Building roofs to be in poor condition. The roofs on these buildings are original plant construction. Roof replacement will ensure these buildings will continue to provide shelter and protection to vital operations in this area of the plant.<br>2) Replace power block underground sanitary service and underground floor drain piping. NGS regularly experiences underground drain/sewer line plugs in the power block. In the past two years, each unit has required extensive contractor work to unplug drain lines. Recently, Unit experienced a sewer drain pipe failure that will require immediate repair. Based on inspection, NGS believes that the balance of the underground sewer piping in the power block area is at the end of its service life and requires replacement. | $ 29,805 | $ 33,295 | $ 63,101 | 6/30/2011 |
| 197. | 60-1005C | Navajo Units 1, 2, 3 | Reliability | Plant Historian Replacement | NGS's current plant historian is no longer reliable, is limited in functionality compared to what is available today, and will soon be out of sync with the rest of SRP. Lack of reliability was a major issue during the start-up and tuning of the low NOx burners on Unit 3. NGS recommends the purchase and installation of OSI PI software and its corresponding hardware. | $ 59,315 | $ 1,372 | $ 60,687 | 3/31/2011 |
| 198. | FCC90380 | Four Corners Common | Environmental Compliance | Ash Pond Seepage Intercept | To intercept ash pond seepage. | $ 952 | $ 57,217 | $ 58,169 | 6/1/2011 |
| 199. | FBC90335 | Four Corners Unit 5 | Reliability | Turbine HPU Heat Exchanger Replacement | The purpose of this project is to eliminate the possibility of water contamination of the turbine hydraulic oil system, thereby mitigating the risk of a forced outage, and to provide additional flow in the event one of the Air/Oil Heat Exchangers or one of the Kidney Pumps has to be taken out of service. | $ 16,093 | $ 37,733 | $ 53,827 | 4/22/2011 |
| 200. | YUC0063 | Yucca Common | Reliability | Tools - 2011 | Tools used for projects. Examples include vibration meter, megohm meter, thermocouple calibrator, mechanical shears, and track cutting machine. | $ - | $ 52,314 | $ 52,314 | 12/15/2011 |
| 201. | SDC0045 | Sundance Common | Reliability | Remote HMIs for Saguaro at Sundance | Misc cap tool for projects including instrument test bench. | $ - | $ 52,314 | $ 52,314 | 12/15/2011 |
| 202. | 60-1026 | Navajo Units 1, 2, 3 | Reliability | Performance Monitor Replacement | NGS's current performance monitor is obsolete and non-functional. Purchase a new performance monitor. | $ 50,419 | $ 1,555 | $ 51,974 | 4/30/2011 |
| 203. | WPC0170 | West Phoenix CC 1, 2, 3 | Prevent Failure | 480V Power Center Breaker Replacement | This switchgear provides power to the fuel oil unloading area. Without this MCC oil storage and customer load are out of service. The existing breakers are non-operational and the manufacturer no longer supports the replacement parts, so breakers with current technology will be installed as is being done throughout the fleet with breakers of this vintage. | $ 21,431 | $ 30,004 | $ 51,434 | 6/30/2011 |
| 204. | OCC0079 | Ocotillo Common | Prevent Failure | Cathodic Protection | The cathodic protection of our natural gas pipelines is a regulatory and safety requirement. CPS #1 being operational is required to protect the necessary cathodic protection. | $ - | $ 51,350 | $ 51,350 | 7/15/2011 |

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| 205. | FBC90392 | Four Corners Unit 5 | Reliability | Furnace Temperature Monitor | The purpose of this project is to maintain unit reliability by preventing superheat and reheat tube damage due to high startup flue gas temperatures. Damage occurs from overheating of the tubes which causes cracks and leaks. The new system will monitor the flue gas temperatures during startup. | $ - | $ 49,843 | $ 49,843 | 5/21/2011 |
| 206. | RHC0117 | Redhawk Units 1 & 2 | Reliability | Isophase Duct Protection | The purpose is to prevent rain water from entering the generator enclosure where the isophase ducts penetrate the roof. Due to the configuration of the ducts and location of the roof penetration, sealing the area against rain is difficult. | $ 47,238 | $ 2,186 | $ 49,423 | 6/30/2011 |
| 207. | RHC0137 | Redhawk Common | Safety / Security | Lockout-Tagout System | This project is required to standardize fleet production of lockout-tagout tags, and will reduce the risk of safety events due to human performance error. The Company has benchmarked other companies' best practices resulting in a complete re-write of the lockout-tagout process and procedure. This WA funds the purchase of software and equipment necessary to implement the new best practices for the lockout-tagout process and procedure. | $ 46,869 | $ 2,169 | $ 49,037 | 6/30/2011 |
| 208. | 60-1015C | Navajo Units 1, 2, 3 | Reliability | Op Emg-Cap Exp-Spare Parts Continge | This budget item is to cover capital expenditures to comply with sections 15.2 and 17.1 of the Navajo Generating Station Operating Agreement. Examples of past expenditures from this line item include the purchase of an audiometer and a generator step-up transformer dissolved gas analyzer, and installing a ventilation system for the tool room. | $ 47,318 | $ 730 | $ 48,048 | 2/28/2011 |
| 209. | FBC90391 | Four Corners Units 4 & 5 | Environmental Compliance | Off-Site Resin Regeneration | The purpose of this project is to eliminate on-site resin regeneration. The resin regeneration equipment in the Unit 4 & 5 "in-line" demineralizer system is to be demolished and replaced with a header designed to receive vendor supplied resin tanks. The vendor tanks are to be filled with resin that is regenerated at their facilities. | $ - | $ 47,867 | $ 47,867 | 12/23/2011 |
| 210. | 60-0915 | Navajo Units 1, 2, 3 | Reliability | Op Emgncy-Cap Exp-Spare Parts | Capital expenditures to comply with sections 15.2 and 17.1 of the Navajo Generating Station Operating Agreement. Examples of past expenditures from this line item include the purchase of an audiometer and a generator step-up transformer dissolved gas analyzer, and installing a ventilation system for the tool room. | $ 44,296 | $ 2,050 | $ 46,345 | 6/30/2011 |
| 211. | 60-1165 | Navajo Unit 2 | Environmental Compliance | Main Turbine TSI Diagnostic-2 | The Main Turbines and Auxiliary Turbines were originally provided with vibration probes (Shaft Riders) that provided vibration indications to the operators and engineers, balance data, and a method to take local readings with a portable device for balancing and diagnostics. The Shaft Rider vibration probes are now obsolete and replacements for the original probes cannot be purchased. In addition to replacing the probes, it will be necessary to replace the signal conditioning electronics (which are also original equipment) with updated equipment, compatible with the new probes. The Shaft Riders provide data that is complementary to the proximity probes on the Main Turbine, and are the only vibration indications for the Auxiliary Turbines. The majority of the historic balance data is from using the Shaft Riders and portable instruments. The Shaft Riders along with a portable device also allow measurement and comparison of bearing and coupling vibrations. In the past, balancing of the coupling was necessary and was difficult without the Shaft Rider comparison. NGS will replace the main turbine shaft riders during the 2011 major overhaul. | $ 22,094 | $ 22,574 | $ 44,668 | 4/3/2011 |
| 212. | 60-0925 | Navajo Units 1, 2, 3 | Environmental Compliance | Bottom Ash Level Monitoring System | The purpose of this project is to improve operation of the bottom ash system by adding fixed sonar ash level monitoring systems to the bottom ash hoppers to complement the nuclear ash density meters on the ash conveying pipe by showing if the hopper is empty or bridged when the density meter detects no ash. | $ 37,717 | $ 5,756 | $ 43,473 | 4/3/2011 |
| 213. | CHC0178 | Cholla Common | Reliability | CP Rectifier Remote Monitoring Delayed | Sustain the company's corrosion control program to preserve assets, reduce maintenance costs, comply with government regulations, and preserve the environment. | $ - | $ 41,206 | $ 41,206 | 1/1/2012 |

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| 214. | FBC90407 | Four Corners Units 4 & 5 | Reliability | 4N PA Fan Replacement | The purpose of this project is to maintain unit availability. | $ - | $ 38,734 | $ 38,734 | 1/11/2012 |
| 215. | 60-1063 | Navajo Units 1, 2, 3 | Reliability | Circuit Breaker-Switchgear Rep-Com | The 480V Air Interrupt Open Frame (AK) breakers in the GE Air Interrupt Open Frame Drawout (AKD) switchgear are original plant equipment. These breakers are used as contactors, and have accumulated a large number of operations. They are both mechanically and electrically worn out. The ITE medium voltage switchgear and circuit breakers are original plant equipment. All the old 1970's vintage breakers on plant site will be inspected to see if they can be reconditioned. Breakers that are too damaged will be replaced. The 13.8kV air circuit breakers also have lower terminal insulator issues which increases the costs to recondition them. Since the start of this project, all of the 230kV and 50kV oil circuit breakers have been reconditioned or replaced. This project will continue to recondition the 13.8kV, 4160V, and 480V air circuit breakers. | $ 17,765 | $ 19,421 | $ 37,186 | 6/30/2011 |
| 216. | 60-1055 | Navajo Units 1, 2, 3 | Reliability | Platen Superheater Pendant Sec Rpr | The 36 platen superheater pendant assemblies are requiring repairs to counter the aggressive sootblower erosion attack from four levels of retract sootblowers in the bottom 30-foot section of the pendant assembly. This section includes less than 5% of the pendent tubing, which has been repeatedly pad welded and repaired. This section of pendant tubing requires replacement to maintain boiler reliability. The bottom 30-foot tubing section will be replaced with upgraded stainless steel tubing to better resist the thinning effects that may cause forced tube leak outages from continual sootblower erosion. This job includes the installation of pendent assembly sections during the Unit 2 overhaul. | $ 35,229 | $ 1,630 | $ 36,860 | 6/30/2011 |
| 217. | 60-0924 | Navajo Units 1, 2, 3 | Environmental Compliance | Bottom Ash Motor Starters Nav 1-3 | Install sealed vacuum technology NEMA motor starters/controllers between the bottom ash conveying pump and hopper jet booster pump breakers and motors. | $ 32,843 | $ 3,481 | $ 36,324 | 6/30/2011 |
| 218. | CHC0304 | Cholla Common | Reliability | RO Unit Addition | The RO unit is essential to plant unit operation. The unit can be purchased at a significantly lower price than a new one and more economically than extending the lease. | $ 33,907 | $ 1,569 | $ 35,476 | 6/30/2011 |
| 219. | YUC0056 | Yucca Common | Safety / Security | Lockout-Tagout System | This project is required to standardize fleet production of lockout-tagout tags, and will reduce the risk of safety events due to human performance error. The Company has benchmarked other companies' best practices resulting in a complete re-write of the lockout-tagout process and procedure. This WA funds the purchase of software and equipment necessary to implement the new best practices for the lockout-tagout process and procedure. | $ 32,046 | $ 1,483 | $ 33,528 | 6/30/2011 |
| 220. | 60-1024 | Navajo Units 1, 2, 3 | Environmental Compliance | CEM Flow-Opacity Monitor Replace | NGS's Continuous Emissions Monitoring System (CEMS) flow and opacity monitors are obsolete and need to be replaced. Replace the existing flow and opacity monitors and the equipment required to calibrate them. | $ 30,862 | $ 1,428 | $ 32,290 | 6/30/2011 |
| 221. | 60-0907 | Navajo Units 1, 2, 3 | Safety / Security | Coal Hndling Fire Detection-Protect | Add fire detection and sprinkler piping and deluge nozzles at the appropriate locations. Develop a better zone system in the fire alarm panel program for troubleshooting problems. | $ 30,763 | $ 1,423 | $ 32,186 | 6/30/2011 |
| 222. | WPC0194 | West Phoenix Common | Reliability | Tools - 2011 | Misc cap tool for projects | $ - | $ 31,749 | $ 31,749 | 12/15/2011 |
| 223. | 60-1016C | Navajo Units 1, 2, 3 | Reliability | Plant Tools Contingency | This budget item is to cover capital expenditures. Examples of past expenditures from this line item include the purchase of hot water pressure washer, a breaker trip test kit, a pipe threader and Huck railroad tools. | $ 29,364 | $ 679 | $ 30,043 | 3/31/2011 |
| 224. | 60-1027 | Navajo Units 1, 2, 3 | Reliability | MSS Relay Replacement | NGS's current Main Station Service (MSS) relay is obsolete and has no redundancy. Recent NERC requirements require testing of this relay on a periodic basis. Compliance with other NERC requirements poses operational issues that preclude testing of the relay. Replace the existing relay with a system that includes two relays, adding redundancy which will allow testing to be done with the MSS transformer energized and in service. | $ 23,617 | $ 5,893 | $ 29,509 | 12/31/2011 |

| Line No. | WA# | Plant & Unit | Category | Project Description | Purpose | Project Cost to Date 12/31/2010 | Costs to Complete | Projected Closed Cost | Estimated In-Service Date |
|---|---|---|---|---|---|---|---|---|---|
| 225. | FBC90351 | Four Corners Unit 4 | Reliability | Furnace Temperature Monitor | The purpose of this project is to maintain unit reliability by preventing superheat and reheat tube damage due to high startup flue gas temperatures. Damage occurs from overheating of the tubes which causes cracks and leaks. The infrared based monitoring system will provide information to monitor the flue gas temperatures during startup. | $ 7,490 | $ 21,544 | $ 29,034 | 10/27/2011 |
| 226. | 60-0916 | Navajo Units 1, 2, 3 | Reliability | Plant Tools-Navajo 1-3 | Capital expenditures to comply with sections 15.2 and 17.1 of the Navajo Generating Station Operating Agreement. Examples of past expenditures from this line item include the purchase of hot water pressure washer, a breaker trip test kit, a pipe threader and Huck railroad tools. | $ 27,662 | $ 1,280 | $ 28,942 | 6/30/2011 |
| 227. | 60-1009C | Navajo Units 1, 2, 3 | Reliability | Coal Control Graphic Board Replacement | The Coal Control graphics panel, or switchboard, is original plant equipment. It is obsolete; parts are no longer available. The panel serves as the backup to an Allen Bradley PLC5 system, which is the primary method used to control the coal belt system. The panel is also the only way to control the feed rates. NGS will remove the graphics panel, purchase a second Allen Bradley PLC5 system to serve as the backup, and incorporate belt feed rate control into the PLC systems. | $ 26,109 | $ 2,013 | $ 28,123 | 10/31/2011 |
| 228. | 60-0917 | Navajo Units 1, 2, 3 | Environmental Compliance | Environmental Reg Requirements | Funding to comply, as necessary, with short lead time environmental regulatory requirements at NGS. Future requirements may include RATA testing equipment upgrades, opacity monitoring, particulate monitoring, precipitator controls upgrades, additional ambient air monitoring sites, and other unexpected corrective actions from audits by the EPA, NNEPA, ADEQ, ADHS, ARRA and OSHA. | $ 26,861 | $ 1,243 | $ 28,103 | 6/30/2011 |
| 229. | 60-0923 | Navajo Units 1, 2, 3 | Environmental Compliance | Potable Water Cartridge Filter | Install a cartridge filter system upstream of the sand filters to remove naturally occurring organic material to eliminate the formation of disinfection by-products. | $ 25,035 | $ 1,158 | $ 26,193 | 6/30/2011 |
| 230. | RHC0144 | Redhawk Common | Reliability | Tools - 2011 | Misc tools including : 500 Lb Positioner W/ 12 inch Chuck Price, Tungsten Grinder, Plasma Upgrade, Hole Borer, MS-2 Circuit Breaker and Overload Tester. | $ - | $ 26,157 | $ 26,157 | 12/15/2011 |
| 231. | OCC0074 | Ocotillo Common | Safety / Security | Lockout-Tagout System | This project is required to standardize fleet production of lockout-tagout tags, and will reduce the risk of safety events due to human performance error. The Company has benchmarked other companies' best practices resulting in a complete re-write of the lockout-tagout process and procedure. This WA funds the purchase of software and equipment necessary to implement the new best practices for the lockout-tagout process and procedure. | $ 23,560 | $ 1,090 | $ 24,650 | 6/30/2011 |
| 232. | 60-0914 | Navajo Units 1, 2, 3 | Reliability | Furniture and Office Equip Nav 1-3 | Purchase, as necessary, furniture and office equipment for NGS. As in past years, this budget line item will be used primarily for on-going replacements and upgrades of office computer systems. Example of past expenditures include the purchase of network storage devices, servers and printers. | $ 23,352 | $ 1,080 | $ 24,432 | 6/30/2011 |
| 233. | SDC0050 | Sundance Common | Reliability | Swgr Breaker Remote Racking, Closing | The remote racking and control will provide additional safety margin to rack in/out breakers and close/trip breakers, without having to de-energize the busses. ARC FLASH studies have shown the incident energy level to exceed level 4, so there is no PPE suitable for the existing incident energy level. | $ - | $ 23,495 | $ 23,495 | 3/30/2011 |
| 234. | SAC0063 | Saguaro Common | Safety / Security | Lockout-Tagout System | This project is required to standardize fleet production of lockout-tagout tags, and will reduce the risk of safety events due to human performance error. The Company has benchmarked other companies' best practices resulting in a complete re-write of the lockout-tagout process and procedure. This WA funds the purchase of software and equipment necessary to implement the new best practices for the lockout-tagout process and procedure. | $ 21,937 | $ 1,015 | $ 22,952 | 6/30/2011 |

| Line No. | WA# | Plant & Unit | Category | Project Description | Purpose | Project Cost to Date 12/31/2010 | Costs to Complete | Projected Closed Cost | Estimated In-Service Date |
|---|---|---|---|---|---|---|---|---|---|
| 235. | CHC0313 | Cholla Units 1, 2, 3 | Reliability | Video Conferencing Equipment Upgrade | Project is to enhance the Generation Videoconferencing system providing continuity of use, additional capability & connectivity, and provide upgrades to older systems which not only allow additional function. | $ 19,914 | $ 921 | $ 20,835 | 6/30/2011 |
| 236. | 60-1020 | Navajo Units 1, 2, 3 | Safety / Security | Locomotive Camera System-3 | Install an audio and video recording system that is tied to the event recorder on each of the three locomotives that are used as lead locomotives. | $ 19,101 | $ 884 | $ 19,985 | 6/30/2011 |
| 237. | WPC0154 | West Phoenix CC 4 | Prevent Failure | BOP Battery Replacement | The existing battery must be replaced to be able to operate the unit and provide emergency power for shutdown in the case of a AC power failure. | $ 18,078 | $ 836 | $ 18,914 | 6/30/2011 |
| 238. | 60-1053 | Navajo Units 1, 2, 3 | Reliability | Oil Gun Replacement-2 | The warm-up oil guns are critical to boiler start-up. Reliability and performance have eroded and maintenance efforts have not been successful. Current equipment uses obsolete technology and parts are costly and difficult to obtain. The retractable mechanism is prone to failure and results in improper atomization of combustion air and fuel oil causing costly delays and risk of fire during start-up. During a cold start, non-preheated combustion air, high excess air, and cold furnace walls that act as black body heat sinks for flame radiation make fuel light-off difficult with current equipment. Flames can be erratic and unstable when fuel is lit, resulting in unburned fuel escaping the flame envelope. This condition creates the risk of fire in the air preheater and electrostatic precipitator. A portion of the material purchases will take place in 2009 using the long lead time budget. Oil guns were replaced on Unit 1 and Unit 3 during the prior overhauls. | $ 17,589 | $ 814 | $ 18,402 | 6/30/2011 |
| 239. | 60-1062 | Navajo Units 1, 2, 3 | Reliability | Cable Replacement Com | The plant has adopted a policy of installing overhead cable rather than reusing underground raceways for power or control cables because:<br>• Extracting power cable is difficult as the pulling soap, generously applied during construction, has hardened. Efforts to soften the soap are time consuming, labor intensive, and not always successful.<br>• Water is entering electrical manholes and underground raceways, immersing the cable and resulting in degradation.<br>• Failure of the underground raceways is an issue. Borescope inspection of failed pulverizer control cable found the PVC duct joints separated due to continuous vibration. A contractor attempting to reuse underground duct bank for a 13.8kV power feed to Coal Control discovered sand in the duct bank that flushing did not clear.<br>In 2010, NGS will conduct an engineering life reassessment of critical cable feeds based on age, capacity, inspection and failures to determine which areas across the plant site need proactive cable replacement. The study will also determine cable specifications and quantity needed for situational repairs. | $ 16,700 | $ 773 | $ 17,473 | 6/30/2011 |
| 240. | 60-1014C | Navajo Units 1, 2, 3 | Reliability | Furniture and Office Equipment | Purchase, as necessary, furniture and office equipment for NGS. As in past years, this budget line item will be used primarily for on-going replacements and upgrades of office computer systems. Example of past expenditures include the purchase of network storage devices, servers and printers. | $ 15,975 | $ 739 | $ 16,714 | 6/30/2011 |
| 241. | 60-0906 | Navajo Units 1, 2, 3 | Reliability | Maintenance Training Equip Nav 1-3 | Purchase a group of learning systems and simulators that will allow maintenance employees to learn necessary skills in a laboratory setting. | $ 14,837 | $ 686 | $ 15,523 | 6/30/2011 |
| 242. | 60-1012 | Navajo Units 1, 2, 3 | Reliability | Spare Limestone Prep Ball Mil Motor | The scrubber ball mill motors have been unreliable since the scrubber was put in-service. These motors are sourced from outside the United States and have a long lead time. Implications from violating the Clean Air Act are such that NGS seeks to keep the scrubbers operational at all times. | $ 12,861 | $ 298 | $ 13,158 | 3/1/2011 |

| Line No. | WA# | Plant & Unit | Category | Project Description | Purpose | Project Cost to Date 12/31/2010 | Costs to Complete | Projected Closed Cost | Estimated In-Service Date |
|---|---|---|---|---|---|---|---|---|---|
| 243. | FCC90325 | Four Corners Units 4 & 5 | Reliability | Ash Flush Pump Motor Replacement | The purpose of this project is to maintain unit reliability. There are two motors, east and west, east motor has been rebuilt multiple times and is nearing the end of useful life. Repaired cracks in all four quadrants of the end housing makes future repairs questionable. A balancing analysis of the motor shows high vibration in both the inboard and outboard bearings and indicates that a balance-shot will most likely not decrease the vibrations. | $ - | $ 13,100 | $ 13,100 | 2/15/2011 |
| 244. | 60-1002C | Navajo Units 1, 2, 3 | Reliability | 900 CFM Air Compressor | Replace a 1993 Ingersoll Rand air compressor, NPG 621, with a new air compressor. | $ 11,325 | $ 524 | $ 11,849 | 6/30/2011 |
| 245. | 60-1017 | Navajo Units 1, 2, 3 | Environmental Compliance | Environmental Regulatory Contingency | Funding to comply, as necessary, with short lead time environmental regulatory requirements at NGS. Future requirements may include RATA testing equipment upgrades, opacity monitoring, particulate monitoring, precipitator controls upgrades, additional ambient air monitoring sites, and other unexpected corrective actions from audits by the EPA, NNEPA, ADEQ, ADHS, ARRA and OSHA. | $ 10,343 | $ 80 | $ 10,423 | 1/31/2011 |
| 246. | 60-1003 | Navajo Units 1, 2, 3 | Reliability | 10000 lb Forklift | Replace a 1997 Caterpillar 10,000 lb. forklift, NPG 667, with a new 10,000 lb. forklift. | $ 5,687 | $ 263 | $ 5,951 | 6/30/2011 |
| 247. | 60-0918 | Navajo Units 1, 2, 3 | Safety / Security | Coal Convey Emergency Light-Signage | Install emergency lighting and signage in coal conveying areas where this equipment is lacking. | $ 2,646 | $ 122 | $ 2,768 | 6/30/2011 |
| 248. | EIS Credits | Many Units | Environmental Compliance | Future EIS Credits - jobs not yet Designated | "Environmental Improvement Surcharge" is money to apply to jobs that qualify as environmental projects. Funds collected from the EIS surcharge are separately identified by APS and recorded as a liability. Use of these funds on qualified EIS improvement costs will reduce the regulatory liability and be recorded as Contributions in Aid of Construction ("CIAC") and applied against the capital costs of qualified EIS improvement projects during construction or upon acquisition, as appropriate. | $ - | $ (2,404,368) | $ (2,404,368) | 6/30/2012 |
| 249. | EIS Credits | Many Units | Environmental Compliance | Future EIS Credits - jobs not yet Designated | "Environmental Improvement Surcharge" is a bucket of money to apply to jobs that qualify as environmental projects. Funds collected from the EIS surcharge are separately identified by APS and recorded as a liability. Use of these funds on qualified EIS improvement costs will reduce the regulatory liability and be recorded as Contributions in Aid of Construction ("CIAC") and applied against the capital costs of qualified EIS improvement projects during construction or upon acquisition, as appropriate. | $ - | $ (4,332,312) | $ (4,332,312) | 12/31/2011 |
| 250. | 60-0819A EIS | Navajo Units 1, 2, 3 | Environmental Compliance | EIS Credit for Low Nox Burners | "Environmental Improvement Surcharge" is a bucket of money to apply to jobs that qualify as environmental projects. Funds collected from the EIS surcharge are separately identified by APS and recorded as a liability. Use of these funds on qualified EIS improvement costs will reduce the regulatory liability and be recorded as Contributions in Aid of Construction ("CIAC") and applied against the capital costs of qualified EIS improvement projects during construction or upon acquisition, as appropriate. | $ (5,259,081) | $ (203,053) | $ (5,462,134) | 4/3/2011 |
| 251. | CHC0335 | Cholla Unit 2 | Reliability | Insurance Reimbursement | Reimbursement for Cholla 2 Failure (2010). | $ - | $ (7,356,206) | $ (7,356,206) | 7/1/2011 |
| 252. | **Total Fossil Post-Test Year Plant Additions** | | | | | **$ 70,483,697** | **$ 85,785,565** | **$ 156,269,262** | |

# TESTIMONY OF RANDALL K. EDINGTON

**On Behalf of Arizona Public Service Company**

**Docket No. E-01345A-11-_____**

June 1, 2011

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**TESTIMONY OF RANDALL K. EDINGTON**
**ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY**
**(Docket No. E-01345A-11-_____)**

I. INTRODUCTION

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

A. Randall K. "Randy" Edington, Palo Verde Nuclear Generating Station, P.O. Box 52034, Station 7602, Arizona 85072-2034, Executive Vice President - Nuclear and Chief Nuclear Officer at Palo Verde Nuclear Generating Station ("Palo Verde," "the Station," or "the Plant").

**Q. WHAT IS YOUR PROFESSIONAL EXPERIENCE AND BACKGROUND?**

A. I have over 38 years of operational experience in the nuclear industry. My career began with 8 years of service in the Navy's nuclear submarine program. Following my discharge from the Navy in 1981, I joined Entergy's Arkansas Nuclear One ("ANO") where I obtained my Reactor Operator and Senior Reactor Operator licenses.

While working at ANO, I obtained a Bachelor of Science degree in physical science with an emphasis on nuclear physics from Arkansas Technical University and Master of Science degree in Operations Management from the University of Arkansas. From 1981 to 1998, I worked in various management positions of increasing responsibility, including Outage Manager, Operations Manager, Plant Manager, and Site General Manager.

In 1998, I left ANO and worked for Entergy at the executive level of several other nuclear power plants, all of which were experiencing performance issues, including River Bend, Indian Point, and Cooper nuclear stations.

In January 2007, I was hired by Arizona Public Service ("APS" or "the Company") as the Senior Vice President - Nuclear and Chief Nuclear Officer to

lead Palo Verde through performance improvement after the Station had experienced a decline in performance since the mid-2000s. I was promoted to Executive Vice President in November 2007.

**Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

A. My testimony provides general information regarding Palo Verde relating to the rate case, and supports APS's request to include the Company's share of Palo Verde capital expenditures in rate base and APS's share of Palo Verde's operations and maintenance ("O&M") expenses in its cost of service.

## II. SUMMARY

**Q. PLEASE SUMMARIZE YOUR TESTIMONY.**

A. The mission of Palo Verde is to SAFELY and efficiently *generate* electricity for the *long term*. Our responsibility as stewards of our customers' and other stakeholders' investment is shaped by one certainty: SAFETY. Our responsibility as the NRC's licensee for the operation of Palo Verde is to protect public health, safety, and the environment.

When I assembled my new management team in 2007, we committed ourselves – in writing – to the mission of SAFELY and efficiently *generating* electricity for the *long term*. Our first priority was then, is now, and will continue to be, SAFETY. My testimony will point out some of the unique attributes of Palo Verde, some of which provide advantages, some of which provide disadvantages. I will also point out how the Palo Verde team focused its activities over the past several years on recovering safety and regulatory margin by improving equipment and processes. We have moved at a controlled and deliberate pace to implement these improvements, and are shifting our emphasis to cost efficiency.

We believe these priorities were and are in keeping with the best interest of our customers and other stakeholders.

In my testimony, I also identify and discuss the major capital projects placed into service during 2010, as well as those to be placed in service during 2011 and the first two quarters of 2012, as reflected in the post-Test Year plant additions pro forma, as can be seen on Standard Filing Requirements Schedule B-2, page 2, column 5. APS's share of these capital improvements in the post-Test Year plant additions pro forma represents a nearly $120 million investment in greater safety, reliability and efficiency.

## III. INTRODUCTION TO NUCLEAR GENERATION.

**Q. PLEASE DESCRIBE NUCLEAR POWER GENERATION.**

A. All matter (natural and man-made) is comprised of elements that contain a distinct number of positively charged particles (protons) and neutrally charged particles (neutrons) in their nucleus. Negatively charged particles (electrons) orbit around the element's nucleus. Each element has an equal number of protons and electrons, but different forms of each element (isotopes) have different numbers of neutrons.

The presence or absence of neutrons may cause an isotope to become unstable and its nucleus will split (fission) in order to become more stable. The fission reaction produces a tremendous amount of energy relative to the size of the particle.

Nuclear power generation uses the energy produced upon the fission of the uranium 235 isotope ("$U_{235}$") to create steam, which subsequently turns a turbine and the attached electrical generator resulting in the production of electricity.

**Q. WHAT ARE BASE LOAD PLANTS AND WHAT MAKES NUCLEAR POWER BASE LOAD PLANTS UNIQUE?**

A. Base load electricity generating plants are the production facilities used to meet the steady and continuous needs of electricity to run our homes, businesses, hospitals, schools, military bases and other facilities. Nuclear power plants are ideal base load generating plants because their operations are predictable and reliable and they have the lowest operating costs and highest capacity of other traditional base load plants.

**Q. WHAT ARE OTHER UNIQUE ASPECTS OF NUCLEAR POWER PLANTS IN COMPARISON TO TRADITIONAL FOSSIL FUELED PLANTS?**

A. Nuclear power plants in the United States are regulated by the Nuclear Regulatory Commission ("NRC"). As a condition of its NRC license, each station is required to develop and maintain strict plant operating standards, plant designs, and technical specifications that must be complied with to meet the license requirements. If an anomalous situation occurs, technical specifications require that certain actions must be performed and conditions met within specific timeframes in order to continue to operate the unit. In some cases, when these prescribed actions cannot be met within predetermined timeframes, the technical specifications require that the unit be taken out of service. NRC regulations, radiological conditions, and prescriptive operating procedures require the unit to follow a specific process for shutdown, outages, and restart.

Nuclear power plants, especially those in the United States, are strictly regulated to assure their safety. The operating requirements are vastly different from those applicable to coal or gas-fired plants of similar size. For example, the radiological conditions of a nuclear plant are highly controlled and monitored, and access to specific areas is restricted during normal plant operations. When a nuclear plant is taken out of service, access to certain areas is restricted until

radiological, temperature, and other conditions are met. Despite Palo Verde's success in minimizing the effect of radiological conditions during outages, the ability of employees to work during outages is still more restricted than comparable maintenance or repair in a fossil fueled station.

Each U.S. nuclear station contains multiple systems as well as engineering practices and operational features that create redundancy – or multiple barriers – to ensure safe operations. Regulations and maintenance practices in nuclear stations are in place to replace, repair, and ensure the safety margin of the primary and secondary systems. This means that the unit may be down-powered or removed from service to repair a system that does not directly impact the operations or output of the plant but is done to ensure the safe operation of the back-up systems. Palo Verde has specific operations and maintenance procedures (and corresponding training for personnel) that control plant operation. These procedures cover not only normal plant operation, but a multitude of other conditions such as abnormal operations and emergencies. As a result, plant operators have extremely limited discretion in how the plant is to be operated in any specific condition. By contrast, fossil fueled units do not have strict technical specifications that require the unit to be taken out of service under such circumstances.

Additionally, from the time a nuclear unit is shut down for refueling, 100 hours are needed to ensure the decay heat from the reactor core has reached a point that it is safe to begin refueling operations. From shutdown conditions to returning to the grid takes about two days, and return to 100 percent power takes an additional one to two days. In contrast, to remove and return a gas or coal plant to service can be achieved in as little as, or less than, one day.

Finally, nuclear power plants do not rely on the combustion of carbon-based fossil fuels (such as coal and natural gas) that are utilized at other base load fossil fueled plants. Nuclear plants' heat source is the fission reaction of $U_{235}$. Therefore, nuclear plants do not produce green house gases or other air pollutant emissions such as sulfur dioxide, nitrogen oxides, or particulate matter during their operation. Since it started operation in 1986, the electricity generated by Palo Verde has enabled its Participant Owners to avoid the emission of 483.7 million tons of carbon dioxide, 253,481 tons of sulfur dioxide (which contributes to acid rain), and 618,000 tons of nitrogen oxides (which contributes to the formation of ground level smog).

**Q. WHAT IS UNIQUE ABOUT THE PALO VERDE NUCLEAR GENERATING STATION?**

A. Palo Verde has a number of unique attributes, some of which provide advantages while others provide disadvantages.

**FOOTPRINT.** Palo Verde is located on a 4,286 acre site approximately 55 miles west of Phoenix, and consists of three separate standardized nuclear generating units, a water reclamation facility, and a variety of common support facilities. Palo Verde is the largest nuclear power plant in the U.S. and is capable of generating over 4,000 megawatts of electricity ("MWe"). Furthermore, it is the first and only power plant in the country (of any fuel source) to produce more than 31 million megawatt-hours ("MWh") in one year. Indeed, Palo Verde Unit 1 generated more electricity than any single nuclear unit in the world in 2009 (11,589,723 MWh) followed by Palo Verde's Unit 2 world leading production in 2010 (11,652,972 MWh).

Unfortunately, Palo Verde's large footprint also gives it a disadvantage relative to the country's three other three-unit nuclear power plants (which cover 840, 700

and 510 acres). The sheer size requires larger physical security systems and a greater number of security guards in order to meet operational and regulatory requirements.

**NUCLEAR STEAM SUPPLY SYSTEM**. The three Palo Verde generating units are virtually identical Combustion Engineering System 80 ("CE System 80") pressurized water reactors ("PWR").

The three virtually identical units provide an advantage with respect to operational economies of scale. Although each unit has its own NRC operating license, there is a common design and licensing basis for the three units. Therefore, there are efficiencies associated with the design, engineering, and implementation of modifications to the three units, as well as a common set of operations and maintenance procedures for the three units. As such, the development and maintenance of procedures can be centralized into one organization and training of operations and maintenance crews can be conducted on a Station-wide basis rather than a unitized basis.

Nevertheless, the risks associated with operating any three units of virtually identical design provide disadvantages. Specifically, a degraded or non-conforming condition in any one unit must immediately be analyzed in the other two units to determine the extent of that condition (if one exists) in the other units. Therefore, a design or maintenance issue in any unit can be transportable to all units and consequently increase the risk of a three-unit shutdown. Additionally, while the CE System 80 was designed to maximize reliability and performance, the units each have approximately 9,500 more components than typical PWRs. These additional components require the conduct of more

operations and maintenance, the purchase of more components, and the stocking and storing of those components in the warehouse.

Moreover, Palo Verde's CE System 80 reactor core is designed for refueling every eighteen months. Therefore, Palo Verde requires two refueling outages every year. This condition places as much emphasis on outage performance at Palo Verde as operational performance – making Palo Verde "in the outage business."

In addition, Palo Verde is the only nuclear plant in the U.S. with its ultimate nuclear safety heat sink (the spray ponds) located immediately next to the units within the protected area. This requires additional monitoring and staging and logistics of equipment stored in the protected area.

Finally, each of the units has its own control room and chemistry laboratory. Therefore, staffing those positions to meet regulatory and operational requirements demands greater human resources than employed at most two-unit nuclear plants, which often share a control room or chemistry laboratory.

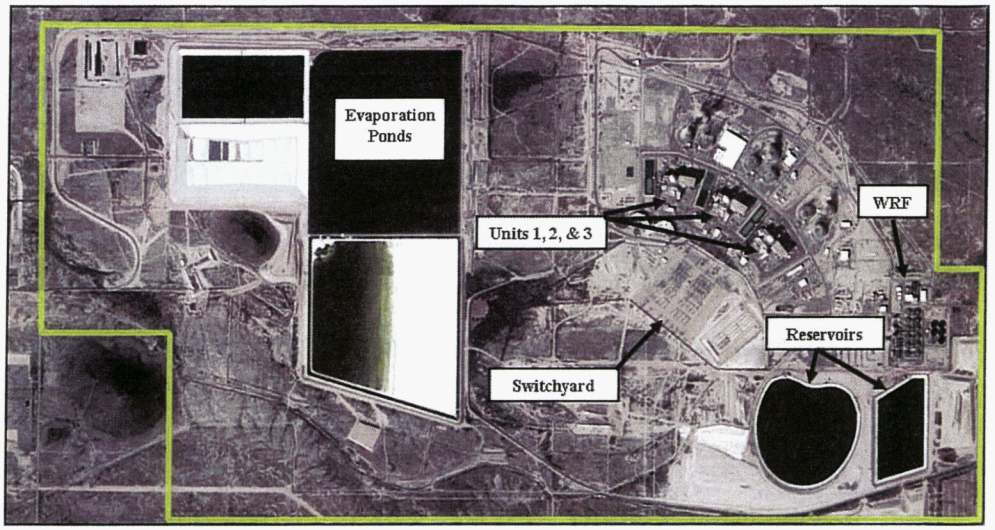
**WATER RECLAMATION FACILITY**. One aspect of Palo Verde that distinguishes it from any other nuclear power plant in the world is that it is not located on or near a large body of water. Therefore, it must obtain water from other sources and must discharge any waste water to a system that will not adversely impact surface or underground water supplies. This unique aspect of Palo Verde is a necessary cost of doing business that is not incurred at any one of the world's nuclear power plants.

Palo Verde purchases its cooling water from the waste water treatment plants of the Valley (Glendale, Mesa, Phoenix, Scottsdale, and Tempe (the Subregional

Operating Group ("SROG"), and Tolleson). The SROG and Tolleson waste water treatment plants' effluent gravity flows 28 miles to the Hassayampa River basin due to the natural decrease in elevation from 91st Avenue to the Hassayampa River. From the Hassayampa River, it is then pumped eight miles to Palo Verde due to the natural increase in elevation from the Hassayampa River to Palo Verde.

Once received at Palo Verde, the effluent is treated at the Palo Verde Water Reclamation Facility ("WRF") to remove ammonia and minerals that would otherwise damage or cause scaling on vital plant cooling components. After being treated, the water is stored in either one of the Station's on-site 45 acre or 85 acre reservoirs. When cooling water is needed, it is pumped to the cooling towers where it is cycled more than 20 times before a small amount (less than 5%) is discharged to one of the Station's three evaporation ponds.

The WRF operations described above require a separate physical plant with a staff of approximately 140 people which, along with chemicals, materials and supplies, increases Palo Verde's operating costs by more than $1.00 per MWh above all other nuclear plant in the world. Additionally, as a zero liquid discharge plant, Palo Verde must also operate and maintain three very large evaporation ponds (covering 250, 220, and 180 acres, respectively) for the life of the Plant until all standing water evaporates. An aerial photo of Palo Verde is provided below:




**Q. COULD YOU PLEASE EXPLAIN APS'S ROLE IN OPERATING PALO VERDE?**

A. Palo Verde is owned by seven southwest region electric utilities ("Participant Owners") with various ownership interests: APS (29.1%), Salt River Project (17.49%), El Paso Electric Company (15.8%), Southern California Edison Company (15.8%), Public Service Company of New Mexico (10.2%), Southern California Public Power Authority (5.91%), and Los Angeles Department of Water and Power (5.7%). Pursuant to the contract between and among the Palo Verde owners (referred to as the Arizona Nuclear Power Project Participation Agreement), APS is the NRC operating license holder and operating agent of Palo Verde. In this regard, APS manages the employees and contractors working at Palo Verde, and makes all decisions with regard to the safe and reliable operation of the Station such as scheduling maintenance and refueling outages, shutting a unit down for an outage when an issue arises, and restarting a unit after an outage. APS confers with, and receives approval from, the Participant Owners on a number of things, including all major capital projects. The involvement of the Participant Owners in Palo Verde operations is facilitated by several committees, including the Administrative Committee, which is comprised of

Participant Owner senior executives, and of which I am the Chairman, and the Engineering and Operating Committee.

As I mentioned earlier in my testimony, certain aspects of nuclear power plant operations are affected by regulations promulgated by the NRC. As has been demonstrated by the tragic earthquake and tsunami in Japan, and their impact on the Fukushima Daiichi nuclear power plant, the operation and management of a nuclear power plant demands a high level of expertise and a healthy respect for the special and unique nature of nuclear technology. As the NRC operating license holder, APS is given tremendous responsibility – and the corresponding accountability – to operate Palo Verde in a manner that does not adversely impact or threaten to adversely impact public health and safety, and the environment.

**Q. WHAT ARE CURRENT TERMS OF THE PALO VERDE NRC OPERATING LICENSE?**

A. The Unit 1 operating license was approved by the Nuclear Regulatory Commission ("NRC"), on May 30, 1985. In 2006, the Unit 1 design electrical rating was increased by 68 MWe (from 1,265 MWe to 1,333 MWe) as a result of the 2005 steam generator and low pressure turbine replacements.

The Unit 2 operating license was approved by the NRC, on April 23, 1986. In 2004, the design electrical rating of Unit 2 was increased by 71 MWe (from 1,265 MWe to 1336 MWe) as a result of the 2003 steam generator and low pressure turbine replacements.

The Unit 3 operating license was approved by the NRC on November 25, 1987. In 2008, the design electrical rating of Unit 3 was increased by 65 MWe (from 1,269 MWe to 1,334 MWe) as a result of the steam generator and low pressure turbine replacements in 2007.

On December 11, 2008, APS submitted an application to the NRC to renew the operating licenses of each unit in order to extend the licenses of each unit for an additional 20 years. The NRC approved the license renewal application on April 21, 2011. The new expiration dates for the NRC operating licenses for the three Palo Verde Units are June 1, 2045, April 24, 2046, and November 25, 2047.

**Q. WHAT OPERATING PHILOSOPHY AND ASSOCIATED PLANS AND PROGRAMS DOES APS HAVE IN PLACE TO MEET ITS RESPONSIBILITIES AS THE NRC LICENSEE OF PALO VERDE?**

A. APS is a values driven organization. Our values are Safety, Integrity and Trust, Respect, and Accountability. These values influence our behaviors and are revealed through the way we act. Values guide us to do the right thing. At Palo Verde, we believe how we get the job done is as important as getting the job done. Ultimately, our values and our behaviors define our culture and have a fundamental influence on how and why we make decisions and how we work together at Palo Verde.

When faced with an issue, we ask ourselves: What is the right thing to do? We discuss our points of view professionally and respectfully to determine the right course of action by making conscious, informed decisions. Furthermore, we have an obligation to protect the assets of the organization, and we achieve this by living our values each day with each decision we make. Achieving excellence benefits us, our owners, all of our stakeholders, and our community.

We recognize that nuclear technology is special and unique and accept the significant responsibility in operating a nuclear power station. As such, our values and mission statement - to SAFELY and efficiently *generate* electricity for the *long term* - drive the operation.

To effectively accomplish its mission, Palo Verde management utilizes a Leadership Model that describes the characteristics and behaviors each employee should demonstrate. It describes our values, fundamental behaviors, key program areas, and how we measure and monitor success. Moreover, every employee is a leader regardless of title or position. To effectively accomplish its mission, Palo Verde management utilizes strategic planning, long range planning, and business planning processes.

Additionally, Palo Verde's business planning processes consist of a building block approach in which areas of emphasis (SAFETY, Operational Focus, Generation, and Cost) support effective mission accomplishment. An illustration of the Palo Verde Business Plan is provided below.

**SAFETY** is one of APS's core values and is essential to Palo Verde's mission.[1] To SAFELY and efficiently *generate* electricity for the *long term* is the common denominator that links every employee and every department at Palo Verde. Indeed, Station and individual alignment to the mission are key to the Station's long-term success. There are four elements of SAFETY that are embraced at Palo Verde: Nuclear Safety, Industrial Safety, Radiological Safety, and Safety

[1] Because safety is of the utmost importance to the Company, and is addressed in its Values and various levels of the Leadership Model, the competency detail will be addressed primarily in this section to avoid redundancy.

Culture. Our employees embrace SAFETY and make personal and conscious decisions to ensure the safety of themselves, their co-workers, APS's customers, and the public at large.

**NUCLEAR SAFETY**. Personnel at the Station exhibit the right behaviors and are committed to keeping employees and the public free from danger, injury, or undue risk from the operation of Palo Verde. Employees at Palo Verde:

- Understand their role with Station probabilistic risk;
- Maintain a questioning attitude;
- Challenge assumptions and beliefs and involve others;
- Understand the potential consequences of actions before they are taken;
- Identify and promptly report problems through initiation of a Palo Verde Action Request ("PVAR") and take immediate action when appropriate;
- Use conservative decision making;
- Model organizational values and adhere to the highest standards that support nuclear safety;
- Follow procedures, work instructions, and plant postings;
- Ensure that component manipulations are performed using procedures or work instructions; and
- Ensure that reported problems are properly reviewed, prioritized, and resolved.

**INDUSTRIAL SAFETY**. Every employee is involved in activities and decisions that impact their safety and health. We take individual accountability for our own health and safety and the health and safety of others. At Palo Verde we work safely and reliably by following proper industrial safety work practices and rules. We challenge unsafe behavior and maintain a safe work area. Employees at Palo Verde:

- Understand steps to take for accident prevention;
- Recognize, report, and correct unsafe conditions;
- Assess conditions at the beginning and throughout an activity;
- Identify existing and potential hazards;
- Eliminate (preferred) or manage/mitigate hazards;
- Ensure tagging boundaries are appropriate for work being performed;
- Use appropriate Personnel Protective Equipment ("PPE");
- Ensure that safety briefings are conducted;
- Frequently conduct safety observations;
- Recognize individuals that reinforce safe behaviors;
- Correct inappropriate behaviors;
- Use operating experience; and
- Conduct prompt thorough, detailed accident investigations.

**RADIOLOGICAL SAFETY**. At Palo Verde we are aware of and follow proper radiation work practices to protect our employees and the public from the hazards of radiation. Employees at Palo Verde:

- Understand and maintain strict compliance with Radiation Exposure Permits;
- Minimize the spread of contamination during work activities;
- Practice maintaining dose As Low As Reasonably Achievable ("ALARA") using time, distance and shielding;
- Adhere to radiological boundaries and postings;
- Anticipate potential changes in radiological conditions;

- Ensure radiological briefings are conducted and actively participate in radiological briefings;
- Respond properly to dosimeter and area alarms;
- Identify dose-reduction activities proactively;
- Exercise "stop work" if radiological conditions change and get additional management involvement;
- Support changes in processes to reduce dose; and
- Implement emergency plan controls to protect employees and the public.

**SAFETY CULTURE**. As defined by the Institute of Nuclear Power Operations ("INPO") nuclear safety is, "an organization's shared values and behaviors - modeled by its leaders and internalized by its members - that serve to make nuclear safety the overriding priority." Moreover, "a safety-conscious work environment (freedom to raise concerns without fear of retribution) is but one (albeit important) element of a strong nuclear safety culture." A strong safety culture is critical to achieving Palo Verde's mission. With broad industry input, INPO developed the following eight safety culture principles:

- Everyone is personally responsible for nuclear safety;
- Leaders demonstrate commitment to safety;
- Trust permeates the organization;
- Decision making reflects safety first;
- Nuclear technology is recognized as special and unique;
- A questioning attitude is cultivated;
- Organizational learning is embraced; and
- Nuclear safety undergoes constant examination.

Palo Verde makes nuclear safety the overriding priority by modeling the safety culture principles during our daily activities, which provides a solid foundation for nuclear safety.

**OPERATIONAL FOCUS**. For the Plant to remain in excellent material condition, Palo Verde embraces a culture of common goals and priorities. Excellence in Operational Focus requires that the Station concentrate on SAFETY, exercise sound decision making and judgment, and maintain a proper operational alignment. Palo Verde exhibits the highest level of craftsmanship, enhancing equipment reliability and system integrity. To this end, we minimize rework and place a high degree of importance on our preventive maintenance and foreign material exclusion programs. Establishing an environment where craftsmanship can thrive and grow plays a key role in the Station's continued journey to excellence.

INPO maintains a document titled *The Principles for a Strong Plant Operational Focus*, which outlines five areas of focus to achieve operational excellence. Palo Verde places high emphasis on the model and has incorporated the principles into the Station's Business Plan. The five focus areas are:

- High levels of reliability and ample operating margins are relentlessly pursued for equipment that is needed to monitor and control the Plant;
- Equipment removed from service for planned evolutions is scheduled and degraded Plant conditions are managed such that the risk of operational transients and the burden to those operating the Plant are maintained low;

- Plant activities are performed in a manner that prevents unexpected operational events, misalignment of Plant equipment, and impediments to responding to events by those controlling the Plant;

- Organizational roles, responsibilities, processes, procedures or infrastructure are established such that unexpected operational conditions can be promptly and adequately managed; and

- The concepts of Plant operational focus are understood by all levels in the organization.

**LONG-TERM GENERATION[2] AND COST EFFECTIVENESS.**

To continue SAFELY and efficiently *generating* electricity for the *long term*, Palo Verde takes a strategic view of operational costs. We invest in our people and the Plant to maintain excellent material condition, while remaining cognizant of our budget and resources. Although cost-effective is not synonymous with cheap or least-expensive, the Station does operate as a low-cost generator of electricity without compromising effectiveness and quality. Moreover, as a multi-unit, compact fleet, it is prudent to maintain appropriate levels of resources with adequate margins to ensure continuous SAFETY and effectiveness. Station personnel strive for the simplest solutions at the appropriate cost. Nevertheless, Palo Verde requires high quality reliable equipment and it cannot compromise SAFETY, effectiveness, and quality for cost because the end result will be a reduction in the generation of power.

**Q. WHAT IS MANAGEMENT DOING TO IMPROVE PERFORMANCE?**

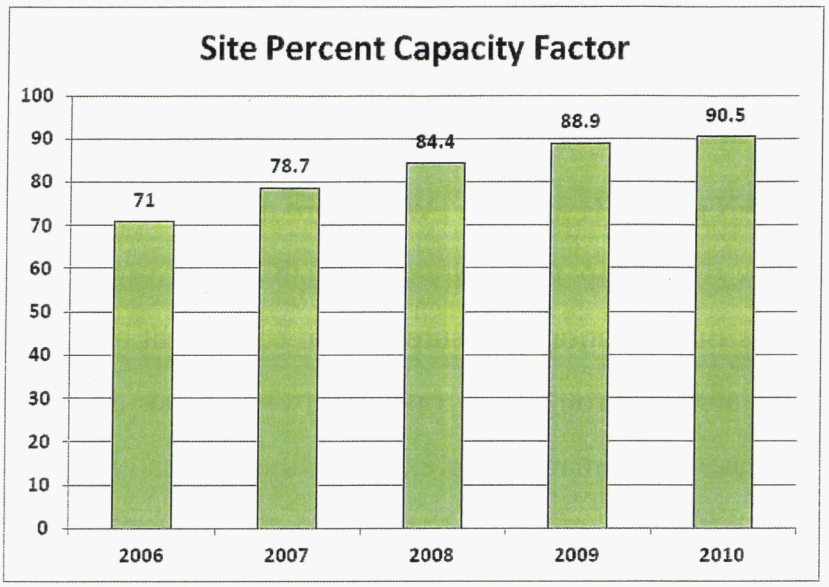
A. The Business Plan serves as an anchor to Station improvement efforts. Its five core building blocks are depicted in red because they are critical elements that we

[2] Generation, in particular base load generation, was addressed in detail above.

continue to focus on. The areas of emphasis are Equipment, People, Problem Identification and Resolution, SAFETY, and Knowledge and Training.

**PLANT EQUIPMENT**. We are intolerant of equipment failures and everyone takes ownership for equipment reliability. Everyone proactively monitors and takes timely action to ensure Station equipment operates reliably with maximum availability through the operating cycle and that standby safety equipment operates on demand. For example, the Station enlists committees to focus staff on sustained equipment performance improvement, including Equipment Reliability, Long Range Planning, Top 10, and Plant Health Committees to address the life cycle of equipment and long range planning needs. With funding from operations and maintenance ("O&M") and capital budgets now suitably established and focused project management processes, the Station has improved equipment performance and is now achieving higher capacity factors. For example, a modification was recently implemented to allow for the cross connection of the air supply used for instrumentation with the air supply for general services. This modification allowed the Station to avoid a Unit 2 short notice outage in 2010, which directly contributed to that unit's exceptional annual capacity factor. Additionally, the Station recently implemented a modification of the refueling water tank instrumentation. This modification replaced valves with more reliable components, which directly contributed to increased nuclear safety system reliability.

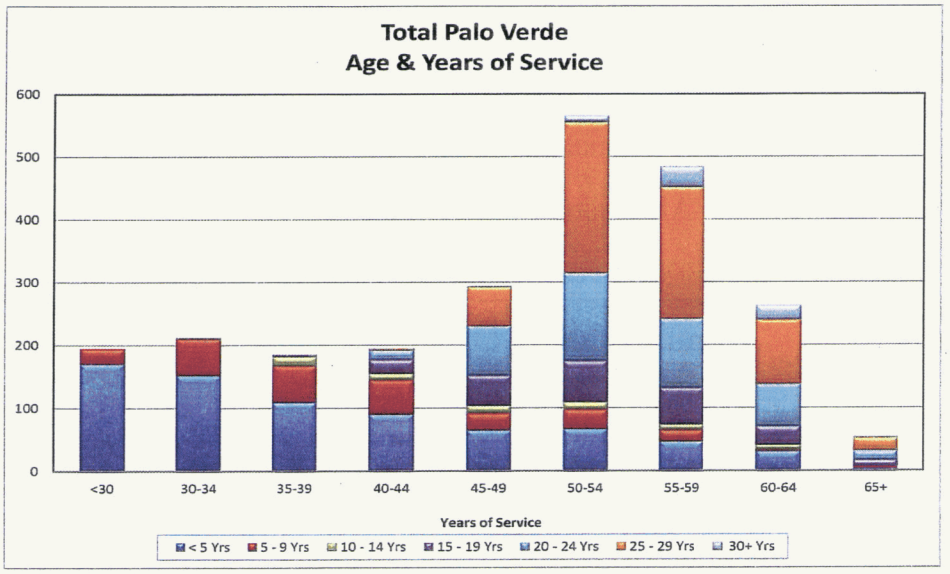
Although Palo Verde's performance is improving and is moving into the top half of the industry, continued success is dependent on uncompromising goals regarding long term performance. A graph of capacity factor performance is provided below:




**PEOPLE**. People are Palo Verde's most valuable asset. They define who we are and make the difference in Palo Verde's success. Given the complexity of the equipment and technology required to operate a nuclear power plant, the Station requires a motivated, highly skilled, and reasonably compensated work force. Palo Verde is committed to driving excellent performance with comprehensive hiring and talent management strategies for long-term development of skills, knowledge, and retention of Station personnel. To achieve long term results and ensure leadership effectiveness and continuity, the Business Plan requires adequate resources to define and assess performance standards, recruit diverse talent, continuously develop our workforce, and carry out knowledge transfer efforts. Palo Verde recognizes and rewards excelling performance and behavior which ultimately results in increased plant performance and reduced costs.

Since 2006 a total of 631 employees have left Palo Verde for retirement and various other reasons. As of December 2010, 889 employees of the 2,400 employed at Palo Verde are over 55 and of that number, 700 have 20+ years with the Company. Furthermore, within five years an additional 410 employees will reach age 55 and have 20 years of service. To further the dilemma, the nuclear

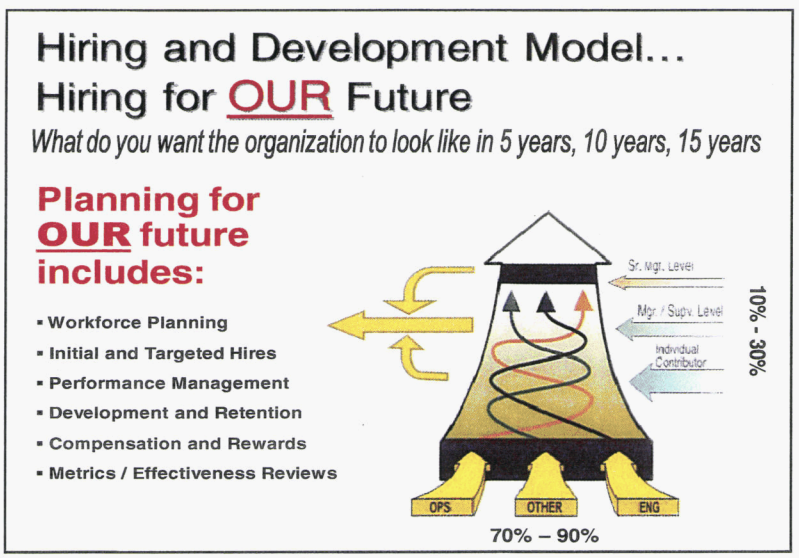
industry as a whole will lose 35% of its workforce to retirement within the next five years. As such, recruiting high-quality candidates will be increasingly competitive. Although the number of enrolled students in nuclear engineering programs has increased from 500 in 1998 to 4,700 in 2010, there still remains a critical shortage of skilled workers to operate the Plant.[3] A chart illustrating the age demographics at Palo Verde is provided below.




Nevertheless, an aggressive new hire initiative is under way to sustain Palo Verde's long-term health and productivity. To address the number of expected retirements in the next five years and to ensure that key areas of the organization are staffed appropriately, strong recruiting efforts are essential. Targeted hiring includes recruiting top sources of diverse talent with a focus on quality. Succession planning begins with the hiring process. Moreover, extensive training to develop knowledge and experience is required to ensure the Station continues to operate SAFELY and efficiently for the *long term*.

[3] *Nuclear Energy – Just the Facts*. Nuclear Energy Institute, June 2010.

For example, the typical timeframe for an individual to stand shift as a Senior Reactor Operator is eight years, including formal training and job experience. This time period includes three months of nuclear generic fundamentals training, five months of non-licensed operator systems training, and over two years of time on-shift to complete the requirements to be a fully qualified non-licensed operator. Once selected for the license training class, a candidate is required to complete fifteen months of formal training to become a Reactor Operator and, when selected for upgrade, another 15 months of formal training to become a Senior Reactor Operator. In total, a Senior Reactor Operator undergoes almost 40 months of formal training as well as many years of on-shift training and experience. An illustration of the hiring model is provided below.




**PROBLEM IDENTIFICATION AND RESOLUTION.** This focus area is the heart of the Station's continuous improvement effort. It drives the way the Station identifies issues, evaluates and trends problems, and develops and implements appropriate actions to correct current problems and prevent future issues. Leaders promote problem identification, timely and thorough evaluation of conditions and development and implementation of timely corrective actions.

Effective problem identification and resolution drives down costs by identifying problems before they become material issues and require significant financial resources to correct. Employees live the Operating Experience model, "The right Information to the right People in time to make a Difference!"

**SAFETY**. As discussed in detail above, SAFETY is key to Palo Verde's success. The culture is such that employees own nuclear, industrial, and radiological safety. Employees value SAFETY and recognize the benefit of a strong nuclear safety culture and safe work behaviors. Indeed, they help each other to achieve an injury-free workplace.

In our drive to achieve an injury-free workplace, we have established a goal to achieve the Occupational Safety and Health Administration ("OSHA") Voluntary Protection Program ("VPP") Safety Through Accountability and Recognition ("STAR") recognition, the highest level of VPP status. In practice, VPP sets performance-based criteria for a managed safety and health system, invites companies to apply, and then assesses applicants against the program's criteria. The program is designed to encourage employers and employees to go above and beyond industry standards and improve existing safety programs.

Palo Verde has established a core team and is in the process of preparing the application for VPP STAR status. Approval as a VPP STAR site is OSHA's official recognition of the outstanding efforts exhibited by employers and employees to achieve exemplary occupational safety and health performance. Moreover, it is validation that a safe plant is a cost effective plant in that injuries and associated time off from work are minimized.

**KNOWLEDGE AND TRAINING**. The Station operates on the premise that knowledge is the foundation upon which we build. Personnel are encouraged to

increase their knowledge on a daily basis. Indeed, knowledge and training are key strategic tools to develop the workforce and improve overall Station performance in a safe and reliable manner. The self-assessment and corrective action processes are used to identify training solutions that can enhance safe and reliable Plant operations. We have a passion for the pursuit of knowledge and recognize this goes beyond the classroom, laboratory, or other formal training – learning opportunities exist with every task we do. We look for these opportunities across organizational boundaries and seek ways to transfer knowledge from each other and the industry. Furthermore, as I previously stated, recruiting and training new hires are of the utmost importance to Palo Verde given the potential future loss of nearly one-third of the Palo Verde's workforce by the year 2015.

Finally, Station management has a goal of leading the industry in SAFETY, Knowledge and Training, Craftsmanship and Field Focus, which have long term benefits to ensure Palo Verde's continued success. We are also promoting leadership by encouraging personnel to volunteer on committees outside the Plant, whether they are industry affiliations or non-profit organizations. For example, I am Chairman of INPO's Executive Advisory Group, Vice Chair of the PWR Owner's Group, Chairman of the Nuclear Energy Institute ("NEI") Workforce Working Group, and a member of the NEI Nuclear Strategic Issues Advisory Committee Steering Group.

**Q. PLEASE DISCUSS THE ARIZONA CORPORATION COMMISSION PERFORMANCE STANDARD AND COMPARE IT TO PALO VERDE'S PERFORMANCE.**

A. In 2010, Palo Verde performed well, achieving its best production year ever, generating over 31 million megawatt-hours ("MWh"), which yielded an overall Station capacity factor of 90.5%. At the Station level, this performance would have ordinarily brought Palo Verde within the first tier classification used in the

APS Nuclear Performance Reporting Standard ("NPRS"). Indeed, Unit 2 had a record year, generating more than 11.6 million MWh and achieving a capacity factor of 101.2%. Furthermore, despite Unit 3's planned refueling outage, it achieved a capacity factor of 89.1%, generating 10.2 million MWh.

Even so, the rigor of the NPRS is such that, notwithstanding the high performance of Units 2 and 3, APS still reported unit performance at the more detailed second tier NPRS level because Unit 1 missed the 82% capacity factor forecast provided in the 2010 NPRS report by one percentage point. Unit 1 generated 9.3 million MWh, resulting in a capacity factor of 81%, due primarily to the planned refueling outage and two short forced outages.

The Unit 1 and Unit 3 refueling outages included major equipment capital projects, which will be described in more detail in the portion of my testimony below that describes major capital projects. Briefly stated, two of these projects were installation of new Reactor Vessel Heads and installation of new Simplified Head Assemblies.[4] In addition to the SAFETY improvements recognized by these projects, completion of these projects will lead to higher equipment reliability and shorter outages.

Beginning in 2007 when I assembled my new management team, we committed ourselves – in writing – to the mission of SAFELY and efficiently *generating* electricity for the *long term*. Our first priority was then, is now, and will continue to be, SAFETY. As we developed our recovery plans, our emphasis was on restoring safety margins in our equipment and processes. The emphasis on restoring safety margins also helped restore the confidence that our nuclear safety regulator, the NRC, has in the Station. Cost efficiency was clearly a

[4] Even though we installed new Reactor Vessel Heads and new Simplified Head Assemblies in the fall 2010 Unit 3 outage (3R15), this outage was completed in one day less than the U.S. industry average.

consideration during this period of recovery, but we made a conscious decision to manage our activities towards longer term cost goals.

As we entered a period of transition from recovery of safety margin and regulatory margin to more routine operations, we continued to develop and refine cost and outage improvement goals. The Reactor Vessel Head and Simplified Head Assembly projects that I highlighted above, which significantly increased safety margins, will also help reduce outage duration and result in higher capacity factors.

Therefore, while we recognize Liberty's recommendation that "APS should establish a more aggressive goal of achieving at least industry median capacity factors,"[5] these goals were in place as early as the beginning of 2007, have been developed and refined through 2011, and are expected to drive the Station well above industry median performance by 2013. As noted in the Liberty Report, the Station has experienced operational delays pursuant to material projects that have been in process since the 2003 outages: "There was a period of under-performance, starting perhaps in 2003 [but] there are signs that the plant has indeed entered a new period of improved performance. Our review did verify that there are good things happening."[6] Again, large equipment replacements (Steam Generators, Reactor Vessel Heads, and Simplified Head Assemblies) have been completed and the Plant is now in a position to take advantage of the efficiencies provided by these capital expenditures and execute outage schedules that are more aligned with industry median.

[5] Benchmarking Study of Arizona Public Service Company's Operations, Cost, and Financial Performance Docket No. E-01345A-08-0172, FINAL REPORT Presented to the Arizona Corporation Commission, Utilities Division, by the Liberty Consulting Group, February 28, 2011 (the "Liberty Report") at Page 17.

[6] Liberty Report at 16.

In addition to the large equipment replacements, we have also been focusing on facility and process improvements that will make our outage work flow more efficient. As a Station that "is in the outage business" two times per year and that will be completing two outages per year for the next 30+ years, we will continue to look at ways to learn from the industry through benchmarking, and learn from our own experience. On May 6, 2011, we completed the Unit 2 spring outage ("2R16") in 34 days. This duration is well shorter than industry median. While we recognize that one success does not mean that we have remediated all of our prior performance challenges, we are confident that we can build on the successes of 2R16 in the future and will continue the drive to consistently complete routine refueling outages in less than 30 days.

## IV. COST EFFICIENCIES AT THE NUCLEAR PLANT.

**Q. WHAT IS THE PALO VERDE APPROACH TO EFFICIENT COST MANAGEMENT?**

A. The goal of cost efficiency, as stated in the Station mission statement, focuses on SAFELY and efficiently *generating* electricity for the *long term*. Cost analysis is taken very seriously to ensure that the Plant continues to operate safely while associated expenditures (capital projects and budget forecasting) are managed appropriately. The Liberty Report recognizes our position wherein the consultants state "[w]e have considerable experience in cost management approaches, particularly at nuclear plants, and we found the Palo Verde material...to be as good as we have seen[;] the recent cost decreases suggest something positive is underway."[7]

Palo Verde utilizes a variety of measures to ensure costs are managed appropriately, including benchmarking peer nuclear facilities, developing our

[7] Liberty Report at 20.

leaders' business acumen, and using strategic methods such as Top 10 and Long Range Planning processes to prioritize capital projects. For example, the Long Range Planning program provides guidelines to systematically plan for major projects including Plant modifications, major maintenance activities and projects. This allows the Station to anticipate and schedule the required work and related activities to reduce cost. Effective long range planning increases equipment reliability, tracks major projects and component replacements, improves outage performance and manages future budgets and resources which provide a planned response to technical issues before they occur. Variance reports are prepared each month and are reviewed by Palo Verde management and the owners. During outages Palo Verde holds daily budget review meetings with leaders to monitor expenses.

In addition, capital projects are vetted through a multi-tiered process with approvals being required internally at the Station and unanimously by the Participant Owners. First, a project's justification is documented in a business case or work authorization. The process of review and approval of capital modifications is designed to ensure that proposed projects undergo several layers of scrutiny and review to demonstrate they are necessary and reasonable. Plant modifications that will gain safety margin and increase plant reliability, such as the high pressure safety injection and the instrument air modifications, are prioritized to support SAFE and efficient *generation* for the *long term*. Review and approval of capital projects is required by both management and all Participant Owners to ensure that capital improvements at Palo Verde are consistent with the needs of all the Owners and are in the interest of their customers. Lower cost work authorizations are approved by the Engineering and Operating Committee, whose Chair is the Palo Verde Senior Vice President of

Operations, while higher cost work authorizations require Administrative Committee approval, of which I am the Chair.

Cost effectiveness efforts also focus on budget development and control. Budget assumptions, such as staffing, timing, and duration of outages, are established by the Business Operations Department after working with other key groups at the Station. This allows individual functional areas to identify necessary work and begin the process of assembling their budgets. Thereafter, a series of meetings are held by leaders and executives to review the scope and proposed budget amounts and then they are submitted to the Participant Owners.

Once the budget is unanimously approved by the Participant Owners, status is managed by Station leaders and the Business Operations Department. Furthermore, to remain current on status and emergent work, Business Operations analysts regularly interface with functional leaders to monitor and assist in the oversight of costs throughout the year. This oversight includes a review and challenge of costs, cost accruals, cash flow forecasts, contract services, contract labor, staffing, and overtime. The leaders and analysts also meet with senior management to address further challenges, trends, and goals, including where budget under runs can be shared to offset budget overages from one Department to the next.

Monthly Executive Cost Reports are provided to the Participant Owners detailing all aspects of the budget. Furthermore, during outages, Business Operations personnel monitor and challenge costs with Daily Status Reports that are shared with and reviewed by department leaders.

**Q. PLEASE EXPLAIN THE COST TO GENERATE NUCLEAR POWER.**

A. The cost of electricity generation consists of several components: operations and maintenance costs (such as labor, contractor services, licensing fees, security, materials and supplies, and planned maintenance), and construction costs (procurement and installation of capital equipment). Fuel is also a cost incurred in generation of electricity, but is not included in this testimony because it is included in the Power Supply Adjustor testimony (addressed by APS witness Peter Ewen).

**OPERATIONS & MAINTENANCE COSTS.** O&M expenses represent the costs required to operate equipment or facilities from day-to-day or maintain equipment and facilities in good operating condition. Palo Verde manages O&M costs through a variety of initiatives. Examples of those initiatives are:

- The Station is utilizing strategic alliances when selecting vendors for contracting services and material purchases (e.g., the Strategic Teaming and Resource Sharing ("STARS") alliance). Membership in STARS provides a fleet-like advantage to seven independently operated nuclear power plants located in the western United States. The result of the alliance is reduced costs and improved performance.

- The Station is also focusing on achieving shorter refueling outages, which reduces the amount of time that outage contractors are needed and increases net generation.

- Palo Verde also implemented a new company wide APS overtime policy on January 1, 2011 to manage exempt employee overtime and reduce expenses.

The Liberty report states that "APS should incorporate into its cost management program, an ongoing analysis of its cost performance versus other [Electric Utility Cost Group] companies,"[8] Palo Verde's long term view since early 2007 has been to reach well into the second quartile and strive to reach first quartile of Electric Utility Cost Group plants. We will continue to use benchmarking as a means to continuously improve performance, in all areas, including cost management. Of course, that needs to be balanced with the primary focus on maintaining a wide safety margin. The Palo Verde 2010 O&M Expenses are described below.

**LABOR**. Labor costs include both direct and contract employee expenditures to support and balance Plant requirements, overtime, and other related spend such as payroll taxes, benefits, and pensions. Furthermore, and as already addressed, Palo Verde is faced with an aging workforce, which presents additional costs associated with recruiting, hiring, and training replacement employees. To address the costs associated with the engagement of contractors, Palo Verde is implementing a rigorous contractor management system.

**MATERIALS AND SUPPLIES**. Material costs include items such as Plant equipment, tools, chemicals, protective clothing, and office expenditures. The most significant impact on Palo Verde's budget in this area has been the increasing commodity prices associated with the chemicals needed for water production at the Station. The spike in cost is due to the increase in oil prices used in the production of these products as well as for transportation and delivery of the materials to the Plant. Other material costs have been impacted by the Plant's aging equipment, facilities, and infrastructure as Palo Verde is in

[8] Liberty Report at 22.

its twenty-fifth year of operation. Palo Verde has initiated a Station wide focus to develop synergies with the APS corporate and STARS supply chains. Performance teams and a multi-organizational task force have been established and long range planning and life cycle management is under evaluation to identify material and supplies and when they will be needed.

Finally, as already discussed, Palo Verde is the only nuclear power plants in the United States that that has its own Water Reclamation Facility.. Operation of the WRF represents approximately $43 million in annual O&M costs and long-term capital additions and improvements that are not incurred by other nuclear power plants.

**FUEL MANAGEMENT AND DECOMMISSIONING COSTS.**

**REFUELING OUTAGES**. The most significant capital spending costs incurred by a nuclear power plant are those affiliated with outages. While refueling outages represent a significant opportunity to boost performance and play a major role in nuclear fleet economics, INPO ratings, and ALARA levels, the cost is substantial. Indeed, outages absorb approximately 8.8% of the total O&M budget and the direct costs can exceed $600,000 per day with additional lost margins for time off-line exceeding $900,000 per day.

During a typical refueling, approximately one-third of the fuel (approximately 100 fuel assemblies) is replaced with fresh unirradiated fuel. In addition, major projects, routine maintenance, testing, and inspections are performed during the outage.

Palo Verde conducts a refueling outage every six months and will continue to do so throughout the life of the Plant. We stress the importance of schedule

adherence since it can significantly affect risk, nuclear safety, and production. Since refueling outages are such an important element of our business, we must achieve excellence in refueling outage performance and the key to outage execution is preparation. At Palo Verde, every employee has three jobs: a day-to-day job, an outage job, and an emergency preparedness job. We approach our outage role with even more skill and care than our day-to-day job because refueling outages are intense. As such, we are shortening the length of outages. As an example, the Reactor Vessel Head replacement outages completed in Unit 2 in 2009 and Units 1 and 3 in 2010 saw a reduction of 20% and 28% respectively from one identical outage to the next.

**Q. HOW DOES PALO VERDE PLAN TO MANAGE COSTS GOING FORWARD?**

A. Palo Verde will maintain equipment in excellent condition for the long term. Furthermore, we will continue to take a strategic view of costs and invest in people and the Plant to maintain knowledge, performance, and excellent material condition. Although Palo Verde is a low-cost generator of electricity, as a multi-unit fleet, the Station must maintain appropriate levels of resources with adequate margins to ensure excellent and efficient Station operation for the long term.

**Q. WHAT ARE THE MOST SIGNIFICANT RISKS CURRENTLY FACING THE PALO VERDE NUCLEAR GENERATING STATION?**

A. Absolute standards of SAFETY are sought by not only Palo Verde, but the nuclear industry at large. The setting and enforcement of acceptable risk levels is a matter of public policy and is mandated by various regulatory agencies. Key risks facing Palo Verde include Personnel, Security, Technical Issues, Owner Nuclear Acumen, Public Confidence, and Regulation.

**PERSONNEL**. The first risk is the loss of knowledge and experience due to retirement or job opportunities at other nuclear utilities, including domestic and

international plants. In response to this challenge, Palo Verde is working to recruit and develop talent, drive performance excellence and model attitudes and behaviors for success. Comprehensive hiring and talent management strategies are being implemented for long-term retention and growth. The hiring model discussed previously reflects the Station's acknowledgement that turnover will occur and efforts to enlist the right people at the right levels of the organization is an immediate necessity.

**SECURITY**. The second risk is an international or domestic event related to security (physical or cyber) that would impact public confidence and result in additional regulations, ultimately requiring additional funding to enhance security measures. Furthermore, as additional international nuclear plants are constructed, the associated risk of a significant event that could impact Palo Verde grows. Costs in this area are projected to increase as Palo Verde responds to additional NRC mandated security regulations to strengthen the Station's security.

**TECHNICAL ISSUES**. The third risk is the identification of technical issues that would require additional funding to comply with regulations. Some examples are listed below:

- An equipment/system issue found in one unit that is "transportable" could impact operation of all three units. Sufficient margin is needed to minimize this risk. The equipment reliability program addresses this issue with identification of equipment that could lead to the single point of failure (shut down the plant if it failed) and adjusting preventive maintenance schedules to ensure it remains operable.

- Aging/obsolescent equipment that could impact Plant operation if equipment failed and a replacement could not be located expeditiously

because it is obsolete. Nevertheless, the Plant addresses this issue prior to the equipment failure and/or it becoming antiquated.

- Underground/buried piping is a recent area of regulatory emphasis for Palo Verde and the industry. Industry events at the Vermont Yankee, Oyster Creek, Indian Point, Braidwood, Salem, and other nuclear plants have significantly heightened NRC concerns on buried piping. The Nuclear Energy Institute and the NRC have embarked on a comprehensive buried piping initiative to address these concerns. During the summer of 2010, Palo Verde implemented a new underground piping program that will be fully implemented by the end of 2013.

- International growth and the availability of key spare equipment is another issue facing Palo Verde and the industry. There are a limited number of nuclear industry vendors and their capacity to respond to requests for key spare equipment could be challenged by the demands of the growing international nuclear industry. Again, Palo Verde takes a proactive approach to this issue by identifying key equipment and working with suppliers to ensure its availability prior to equipment failure.

Furthermore, the recent tragic natural disasters in Japan and their impact on the Fukushima Daiichi nuclear plant are not yet fully understood. Palo Verde and the U.S. nuclear industry have taken prompt aggressive actions to evaluate the events at Fukushima Daiichi for potential consequence at Palo Verde and the U.S. nuclear industry, respectively. I can not speculate on the long term impact of those events on the U.S. nuclear power industry but I do expect that regulatory changes to address beyond design basis events may occur in the next few years.

**OWNER NUCLEAR ACUMEN**. The fourth risk is nuclear acumen of the Participant Owners, which could ultimately impact decision making on necessary improvements that have a financial impact on them. Actions taken to address this issue include development of corporate/owner training programs and additional regular updates by me or the Station Vice Presidents.

**PUBLIC CONFIDENCE**. The fifth risk is the potential for public confidence issues resulting from an international or domestic event at a nuclear power plant. Again, the natural disaster at the Fukushima Daiichi nuclear power plant is a prime example. Actions taken to address this issue include education of the public, media outreach, and rigorous communication. In 2010, Palo Verde escorted more than 1,500 people through the Plant, including U.S. Senator John McCain, U.S. Representative Trent Franks, NRC Executive Director of Operations R. William Borchardt, Environmental Protection Agency Regional Administrator Jared Blumenfeld, and other local stakeholders. We also assist with community and educational outreach programs focused on raising awareness of the benefits of nuclear power technology.

**REGULATORY**. Regulatory issues, the sixth risk, could ensue if the Station has degraded performance that impacts regulatory margin or Reactor Oversight Process ranking. Of course, the regulatory mandates would drive additional expenses. Actions taken to address this risk include participation in industry organizations, leader training on the regulatory process, employing key Station personnel who have credibility with the regulatory agencies, use of Station oversight groups with extensive regulatory knowledge, and maintaining formal, informal, and repetitive communications with regulatory agencies.

**Q. WHAT MAJOR CAPITAL PROJECTS WERE PLACED INTO SERVICE DURING THE TEST YEAR (2010)?**

A. The Station has focused on long term performance and replaced aging Plant components to ensure it continues to can run SAFELY and reliably for the *long term*. In 2010, the total plant capital projects that were placed in service cost approximately $235.7 million. Those projects with a total cost of $10 million or greater, some of which were mandated by regulatory agencies, include the following:

| Project ID | Title | Actual In-Service Date | Total PVNGS In Service in 2010 (in thousands) | APS Share In Service in 2010 Estimate (in thousands) |
|---|---|---|---|---|
| 070075 | Simplified Head Assembly U-1 | 5/23/2010 | $32,995 | $9,602 |
| 070077 | Simplified Head Assembly U-3 | 11/10/2010 | $30,202 | $8,789 |
| 050081 | Rx Vessel Head Repl., U3 | 11/10/2010 | $28,603 | $8,324 |
| 050080 | Rx Vessel Head Repl., U1 | 5/23/2010 | $22,887 | $6,660 |
| 100112 | Circulating Water Tie-In U3 | 11/10/2010 | $11,975 | $3,485 |
| 090210 | Security Prescreening Facility (PASE) | 11/29/2010 | $10,601 | $3,085 |

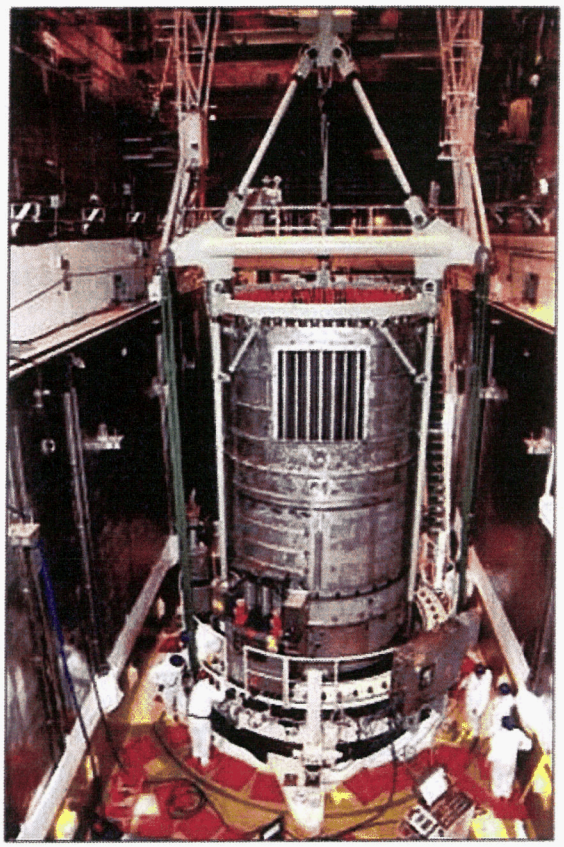
Replacement of the Reactor Vessel Heads and installation of Simplified Head Assemblies were successfully completed on Unit 2 in 2009 and Units 1 and 3 in 2010. Initially, the industry used Reactor Vessel Heads with the alloy Inconel 600; however, in recent years the Inconel 690 alloy, which is more resistant to stress corrosion cracking, has become the material of choice for applications susceptible to stress corrosion cracking. The Station installed Reactor Vessel Heads containing Inconel 690, which has improved the nuclear safety margin, eliminated Inconel 600 material welds and nozzles, and will ultimately reduce outage costs associated with the aging Reactor Vessel Heads. Additionally, the new Reactor Vessel Heads will also provide a single failure proof Reactor Vessel Head lift rig that will reduce the time to complete outage destack and restack.

Shorter outages translate into higher capacity factors for the Station and lower cost for the ratepayer. Photos of Reactor Vessel Head work are provided below.

**ARRIVAL OF NEW REACTOR VESSEL HEAD AT THE STATION**

**LIFT OF REACTOR VESSEL HEAD INTO CONTAINMENT**

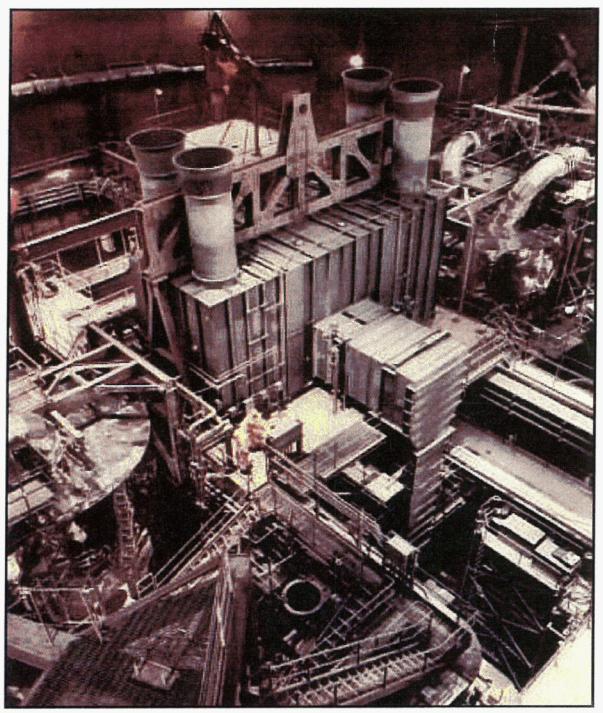
## REACTOR VESSEL HEAD SET ON REACTOR VESSEL



Simplified Head Assemblies that were installed during the 2009 and 2010 outages will provide significant improvements in safety margins. With respect to nuclear safety, the new Simplified Head Assemblies reduce utilization for the polar crane from approximately 24 manipulations to 6 manipulations. Therefore, fewer and shorter lifts of heavy components over the reactor vessel reduces the potential for an accident that might damage the reactor core. The reduced number of lifts also minimizes the amount of manual labor by maintenance personnel, therefore resulting in reduced potential for industrial safety incidents. The Simplified Head Assemblies also contain permanent upper and lower Reactor Vessel Head radiation shielding shrouds, thus eliminating the requirement to install and remove Reactor Vessel Head temporary shielding during refueling outages, which reduces potential worker exposure to high

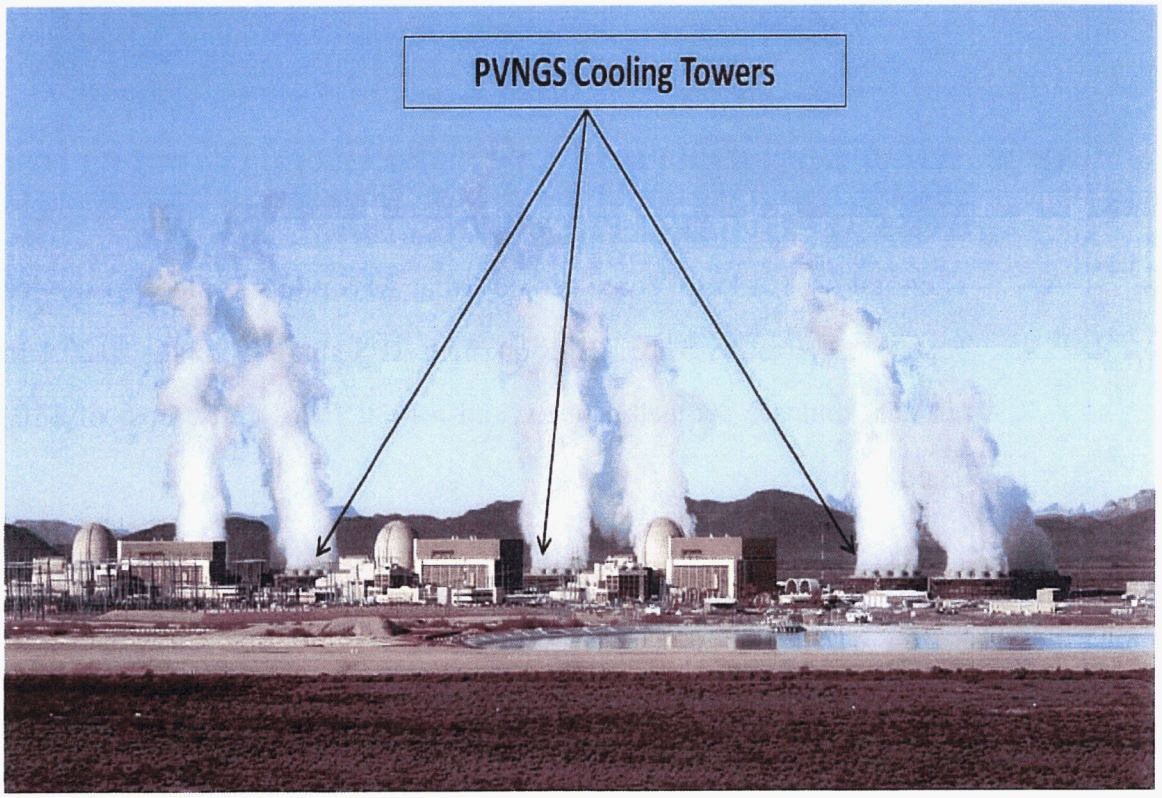
radiation environments and maintaining exposure ALARA. Photos of Simplified Head Assembly work are provided below.

**ORIGINAL REACTOR VESSEL HEAD ASSEMBLY**

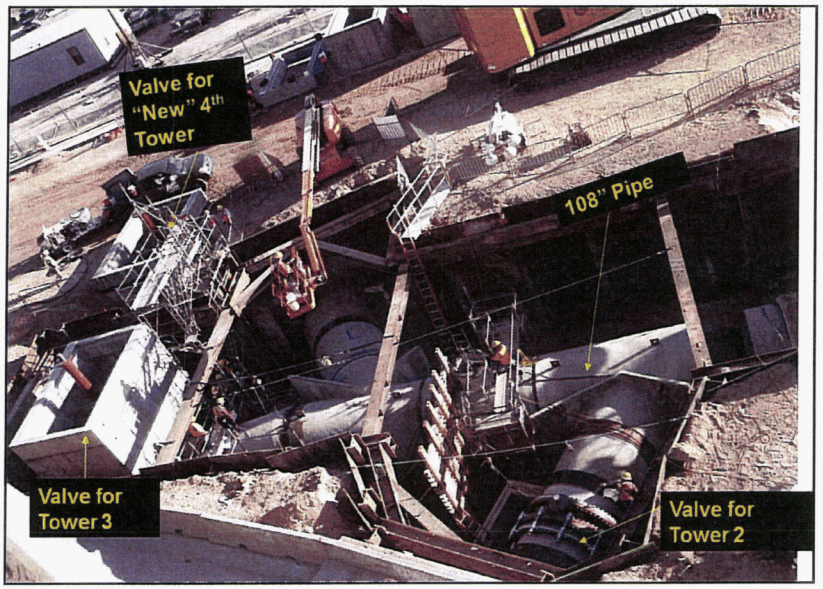


**NEW SIMPLIFIED HEAD ASSEMBLY**

In the table above that lists those projects with a total cost of $10 million or greater that were placed into service in 2010, we identified cooling tower replacement tie-ins for Units 1 and 3. The cooling tower tie-in project involved the installation of a branch connection and butterfly valves into the piping that returns water from the unit condensers to the cooling towers. The tie-in provides the option of isolating a tower and keeping the other two towers in operation if repairs are needed or if cooling tower replacement is necessary. Photos of the cooling tower tie-in work are provided below.



## COOLING TOWER TIE-IN WORK




**Q. WHAT NUCLEAR PROJECTS DOES APS PLAN ON PUTTING IN SERVICE BETWEEN THE END OF TEST YEAR 2010 AND JULY 1, 2012 (POST TEST YEAR)? PLEASE INCLUDE THE COST.**

A. The total cost of Palo Verde projects that APS plans to place in service in the Post Test Year period is $412.7 million. The APS share of this is $120.1 million. The projects that are projected to exceed a total Palo Verde cost of $10 million are listed below.

| Projects Projected In Service from January 1, 2011 through June 30, 2012 | | | |
|---|---|---|---|
| **Project ID** | **Post Test Year Project Titles** | **Palo Verde Projected Cost (in thousands)** | **APS Projected Closed Cost (in thousands)** |
| 070005 | WRF Evap. Pond #2 Liner Replacement | $89,127 | $25,936 |
| 060066 | Component Design Basis Review | $41,174 | $11,982 |
| 080080 | Outage Support Facility | $31,627 | $9,204 |
| 040051 | Plant Aging Management Project | $25,468 | $7,411 |
| 100040 | Emergency Operations Facility | $16,490 | $4,799 |
| 090076 | Security Fence Extension Plant West | $13,862 | $4,034 |
| 090075 | Power Expansion Plant West | $12,540 | $3,649 |
| 080153 | North Annex Building Upgrades | $12,010 | $3,495 |
| 090126 | Upgrade Ingress/Egress Road | $10,849 | $3,157 |
| 100087 | TF/FC Sump Life Extensions | $10,468 | $3,046 |

**Q. BRIEFLY DESCRIBE THE PROJECTS DESRBED IN THE PRECEDING TABLE.**

A. The following contains information regarding the individual projects discussed above.

- **WRF Evaporation Pond #2 Liner Replacement.** The purpose of this project is design and construction of replacement embankments for Evaporation Pond #2, as well as replacement of the pond's liner. The existing liner system has reached the end of its useful life and is experiencing increased degradation. The embankments need to be rebuilt because they have experienced cracking. The evaporation ponds are a critical component of the site's water management system.

- **Component Design Basis Review.** This project will review and replace inaccurate components of the Component Design Basis Manual ("CDBM"). The CDBM includes drawings and calculations, and other plant specifications relating to the various systems within the plant. It is critical that this information be correct as it is used by the NRC to ensure that the plant is operating within design specifications. The site made a commitment to the NRC that it would review all of the documents and revise them to accurately reflect design basis requirements.

- **Outage Support Facility**. This project will consolidate all of the outage related functions into one area to improve the efficiency of both outage planning and execution. Currently outage planning and preparation activities are performed in various areas of the plant and must often compete with on-going operational activities for use of space and equipment. Completion of this project will result in better communication

and coordination among the groups responsible for the outage, more efficiently run outages and reduced cost.

- **Plant Aging Management Project**. The purpose of this project is to conduct engineering reviews necessary to identify equipment aging management issues across the site and to support activities necessary to submit the site's license renewal application. Successful completion of this project will result in an extension of the site's operating license from the NRC for an additional 20 years of operation from 2026 to 2046.

- **Emergency Operations Facility**. This project involves the construction of an off-site emergency operations facility to be used as a "nerve center" for site operations in case of an emergency situation. Pending NRC 10CFR50.47 rule changes require licensees to maintain an offsite facility capable of performing functions required to respond to an event. The functions specified in Federal Register Vol. 74, No 94 include classification, notification, and issuance of protective action recommendations and development of mitigation strategies using plant computer system information. This requires replacement of the existing facility outside a 10 mile but within a 25 mile range of the site. The State of Arizona currently owns the Joint Information Center. Co-locating the JIC and the EOF restores control of the JIC to Palo Verde which, in turn, will ensure compliance with regulatory requirements.

- **Security Fence Extension Plant West**. This project is to construct a fence to incorporate the expanded west side of the site into the Protected Area (PA). The site is constructing several new facilities on the west side of the plant in an area currently not encompassed by the Protected Area fence.

After these facilities are completed, the fence will be extended to include them in the Protected area to improve plant safety and security as well as efficiency. The facilities to be incorporated into the new PA are the Outage Support Facility, the new Warehouse inside the PA, the Vehicle Minor Maintenance Facility and the Fuel Depot.

- **Power Expansion Plant West**. This project will install a new 100 MVA transformer to provide site-generated power to the planned west side expansion of the site. The site is planning to expand the Protected Area to the plant west of the existing PA. This expanded area will house the new Outage Support Facility and the new Warehouse inside the PA as well as several other new installations planned for the next several years. Sufficient metered power is not available at present to power the new installations. Economic analysis of options demonstrates that using site-power for these loads is the superior economic choice. Site-power is also preferable from a reliability perspective.

- **North Annex Builiding Upgrades**. This project is to renovate an existing administrative building on site to resolve numerous building code violations and to make the space more efficient for continued use. The building is original to the site and has not been upgraded in 30 years. This building is critical to the Site Master Facility Plan execution as it is planned for swing space as other areas on site are remodeled to increase their efficient use of space. The option of remodeling is approximately 2/3 the cost of construction of a new building and is, therefore, the more financially feasible solution.

- **Upgrade Ingress/Egress Road**. The purpose of this project is to construct a new ingress/egress road, expand the parking lot "C", and reconfigure the Security Owner Controlled Area (SOCA). These improvements will significantly reduce, if not eliminate, traffic backing up into Wintersburg Road, especially during outages when there are a large number of contractors entering the site which will improve safety for both drivers entering the plant and other traffic on Wintersburg Road. The SOCA reconfiguration will improve site safety and security by eliminating parking for personal vehicles inside the SOCA. Personnel will park in Lot "C" and enter through a security entrance where biometric scanners will permit only those persons with authorized access to enter. The project will result in a reduction of required Security Officers. An economic analysis of the project returned a positive net present value and an internal rate of return of 13%.

- **TF/FC Sump Life Extensions**. This project replaces sections of degraded concrete and reinforcing steel of the large sump structure that takes in water from the trickling filters and clarifier filters. All water flowing into the water reclamation facility goes through this structure which has degraded due to corrosion of the concrete and reinforcing steel from chloride attack from the influent.

**Q. WHICH OF THESE PROJECTS DOES APS REQUEST TO BE INCLUDED AS PRO FORMA ADJUSTMENTS TO THE TEST YEAR? ALSO, DOES APS SEEK TO INCLUDE ANY OTHER PRO FORMA ADJUSTMENTS TO THE TEST YEAR RELATING TO PALO VERDE?**

A. APS requests that all of the projects be included as pro forma adjustments. However, after considering higher levels of depreciation reserves and accumulated deferred taxes, there will be a net reduction of $5.2 million to APS's Total Company cost rate base attributable to Palo Verde. This adjustment can be

found on SFR Schedule B-2, page 2, column 5. APS witness Jason La Benz speaks to the details of this adjustment, including the related impacts of property taxes, depreciation and interest.

**Q. WHAT TOTAL ADJUSTMENT TO THE TEST YEAR IS APS PROPOSING TO INCLUDE FOR CAPITAL EXPENDITURES RELATED TO PALO VERDE?**

A. The gross plant adjustment for APS is $120.1 million. This is the projected total related to work orders that will be placed in service from January 1, 2011 to June 30, 2012. Please see Attachment RKE-1 for a complete listing of the projects included in the adjustment.

**Q. IS THERE ADDITIONAL INFORMATION YOU WOULD LIKE TO ADD ABOUT PALO VERDE?**

A. Yes. In the middle of 2010, Palo Verde released the results of an economic impact study (the "Applied Economics" report) that it had performed to evaluate the impact of Palo Verde on the regional economy. The Applied Economic report concluded that Palo Verde creates an annual economic impact of approximately $1.8 billion on the Arizona economy. In total, Palo Verde directly and indirectly supports an estimated 8,800 jobs and $508.8 million in annual payroll in Arizona. Palo Verde directly provided about 2,900 "recession-resistant" jobs for employees and contractors with a combined payroll of $255.1 million annually in 2009. An additional 5,800 jobs and $253.7 million in payroll are supported annually at other businesses throughout the state through the economic multiplier effect. Included in the economic impact cited above is a twice-per-year "surge" of several hundred non-local temporary workers who spend substantial sums on lodging and food while in the area to support Palo Verde's 30- to 60-day refueling outages. Due to the transient nature of these non-

local contractors, a substantial number of them reside in local hotels, eat at local restaurants, and utilize other local service industry businesses.

Annual property tax revenues from Palo Verde are estimated at $50 million per year, and state, county and city sales taxes are estimated at an average of $54.7 million per year. Palo Verde also generates substantial indirect property, sales and income tax revenues in Arizona through employee spending and property ownership. Indirect revenues are estimated at an average of $13.8 million per year.

The Station made an estimated $223.8 million in local purchases for various equipment, supplies and services in 2009. Based on the share of vendor purchases that are made locally, the annual economic impact on the state was estimated at $399.4 million in 2009.

When Palo Verde workers retire, the majority remain in the area. They provide a positive economic impact of $4.7 million annually, and an increasing number of workers at Palo Verde will reach retirement age over the next three to five years.

A number of national nuclear utility vendor companies have established offices in the West Valley as a direct result of their relationship with Palo Verde — and others are being actively encouraged to establish local branch offices here. While these offices were initially established to serve Palo Verde and the STARS alliance, some are now serving other local and non-local customers — and some have plans for expansion. The economic impact of expansions related to companies growing their customer base is in addition to the positive economic impacts detailed in the Applied Economics report.

The economic impact study did not consider the economic impact of the reliable and affordable energy produced by Palo Verde. In other words, the economic impact study did not take into account the affordably-priced electricity produced at Palo Verde that may entice an expanding business to move its operations to Arizona or encourage a potential homeowner looking for place to settle to consider Arizona as the residence destination of choice.

The impact of rates on APS's customers certainly is an important consideration. But it is also important to recognize that Palo Verde has broader impacts that are not reflected in rates as it is a significant and substantial economic engine for the state of Arizona. And, given the joint ownership model, much of that impact to Arizona results from rates paid by customers in California, New Mexico and Texas.

## V. CONCLUSION

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

A. As I stated at the outset of my testimony, the mission of Palo Verde is to SAFELY and efficiently *generate* electricity for the *long term*. Our responsibility as stewards of the ratepayers' and other stakeholders' investment is shaped by one certainty: SAFETY. Our responsibility as the NRC's licensee for the operation of Palo Verde is to protect public health, safety, and the environment. I demand the overriding SAFETY priority from every employee.

While SAFELY and efficiently *generating* electricity at Palo Verde over the past several years, we have had some notable achievements:

- Not only was Palo Verde the first and only generating site in the United States to ever produce more than 31 million megawatt-hours in a single

year, the Station has exceeded 30 million megawatt-hours in a single year on six occasions. Furthermore, no other U.S. generating station (of any fuel type) has ever produced 30 million megawatt-hours.

- Unit 2 was the world's top electricity generator in 2010 and Unit 1 was the top generator in 2009.

- All three units at Palo Verde operated simultaneously throughout the 2010 summer until the Unit 3 fall outage. Moreover, for three straight years, the three units have operated continuously for at least 100 days during triple-digit temperatures throughout the summer providing safe reliable power to APS customers.

- In 2009, our operations had an overall economic impact on Arizona of $1.8 billion and our annual projections show similar impacts through 2013.

With the major equipment upgrades completed over the past few years, the completion of a long-term cooling water agreement, and NRC's recent approval of Palo Verde's license renewal application, Palo Verde is positioned to provide safe, reliable and efficient production of electricity and continue to be an economic engine for Arizona through the middle of this century.

**Q. DOES THAT CONCLUDE YOUR DIRECT TESTIMONY?**

A. Yes.

## Nuclear Generation Post-Test Year Plant Additions

| Line No. | WA # | Project Description | Purpose | Project Cost to Date 12/31/2010 | Cost to Complete | Projected Closed Cost | Estimated In-Service Date |
|---|---|---|---|---|---|---|---|
| 1. | 070005 | WRF Evap Pond #2 Liner Replacement | The purpose of this project is design and construction of replacement embankments for Evaporation Pond #2, as well as replacement of the pond's liner. The existing liner system has reached the end of its useful life and is experiencing increased degradation. The embankments need to be rebuilt because they have experienced cracking. The evaporation ponds are a critical component of the site's water management system. | $ 21,030,283 | $ 4,905,782 | $ 25,936,065 | 1/31/2012 |
| 2. | 060066 | Component Design Basis Review | The purpose of this project is to review and replace inaccurate components of the Component Design Basis Manual (CDBM). The CDBM includes drawings and calculations, and other plant specifications relating to the various systems within the plant. It is critical that this information be correct as it is used by the NRC to ensure that the plant is operating within design specifications. The site made a commitment to the NRC that it would review all of the documents and revise them to accurately reflect design basis requirements. | $ 9,967,411 | $ 2,014,206 | $ 11,981,617 | 12/30/2011 |
| 3. | 080080 | Outage Support Facility | The purpose of this project is to consolidate all of the outage related functions into one area to improve the efficiency of both outage planning and execution. Currently outage planning and preparation activities are performed in various areas of the plant and must often compete with on-going operational activities for use of space and equipment. Completion of this project will result in better communication and coordination among the groups responsible for the outage, more efficiently run outages and reduced cost. | $ 2,353,797 | $ 6,849,743 | $ 9,203,540 | 4/30/2012 |
| 4. | 040051 | Plant Aging Management Project | The purpose of this project is to conduct engineering reviews necessary to identify equipment aging management issues across the site and to support activities necessary to submit the site's license renewal application. Successful completion of this project will result in an extension of the site's operating license from the NRC for an additional 20 years of operation from 2026 to 2046. | $ 6,882,835 | $ 528,385 | $ 7,411,220 | 4/30/2011 |
| 5. | 100040 | Emergency Operations Facility | The purpose of this project is to construct an off-site emergency operations facility to be used as a "nerve center" for site operations in case of an emergency situation. Pending NRC 10CFR50.47 rule changes require licensees to maintain an *offsite facility capable of* performing functions required to respond to an event. The functions specified in Federal Register Vol. 74, No 94 include classification, notification, and issuance of protective action recommendations and development of mitigation strategies using plant computer system information. This requires replacement of the existing facility outside a 10 mile but within a 25 mile range of the site. The State of Arizona currently owns the Joint Information Center. Co-locating the JIC and the EOF restores control of the JIC to Palo Verde which, in turn, will ensure compliance with regulatory requirements. | $ 3,537,854 | $ 1,260,652 | $ 4,798,506 | 6/15/2011 |
| 6. | 090076 | Security Fence Extension Plant West | The purpose of this project is to construct a fence to incorporate the expanded west side of the site into the Protected Area (PA). The site is constructing several new facilities on the west side of the plant in an area currently not encompassed by the Protected Area fence. After these facilities are completed, the fence will be extended to include them in the Protected area to improve plant safety and security as well as efficiency. The facilities to be incorporated into the new PA are the Outage Support Facility, the new Warehouse inside the PA, the Vehicle Minor Maintenance Facility and the Fuel Depot. | $ 368,277 | $ 3,665,596 | $ 4,033,873 | 3/12/2012 |

## Nuclear Generation Post-Test Year Plant Additions

| Line No. | WA # | Project Description | Purpose | Project Cost to Date 12/31/2010 | Cost to Complete | Projected Closed Cost | Estimated In-Service Date |
|---|---|---|---|---|---|---|---|
| 7. | 090075 | Power Expansion Plant West | The purpose of this project is to install a new 100 MVA transformer to provide site-generated power to the planned west side expansion of the site. The site is planning to expand the Protected Area to the plant west of the existing PA. This expanded area will house the new Outage Support Facility and the new Warehouse inside the PA as well as several other new installations planned for the next several years. Sufficient metered power is not available at present to power the new installations. Economic analysis of options demonstrates that using site-power for these loads is the superior economic choice. Site-power is also preferable from a reliability perspective. | $ 2,904,709 | $ 744,499 | $ 3,649,208 | 6/30/2011 |
| 8. | 080153 | North Annex Building Upgrades | The purpose of this project is to renovate an existing administrative building on site to resolve numerous building code violations and to make the space more efficient for continued use. The building is original to the site and has not been upgraded in 30 years. This building is critical to the Site Master Facility Plan execution as it is planned for swing space as other areas on site are remodeled to increase their efficient use of space. The option of remodeling is approximately 2/3 the cost of construction of a new building and is, therefore, the more financially feasible solution. | $ 158,678 | $ 3,335,974 | $ 3,494,652 | 12/31/2011 |
| 9. | 090126 | Upgrade Ingress/Egress Road | The purpose of this project is to construct a new ingress/egress road, expand the parking lot "C", and reconfigure the Security Owner Controlled Area (SOCA). These improvements will significantly reduce, if not eliminate, traffic backing up into Wintersburg Rd., especially during outages when there are a large number of contractors entering the site which will improve safety for both drivers entering the plant and other traffic on Wintersburg Rd. The SOCA reconfiguration will improve site safety and security by eliminating parking for personal vehicles inside the SOCA. Personnel will park in Lot "C" and enter through a security entrance where biometric scanners will permit only those persons with authorized access to enter. The project will result in a reduction of required Security Officers. An economic analysis of the project returned a positive net present value and an internal rate of return of 13%. | $ 537,683 | $ 2,619,439 | $ 3,157,122 | 9/15/2011 |
| 10. | 100087 | TF/FC Sump Life Extension | The purpose of this project is to replace sections of degraded concrete and reinforcing steel of the large sump structure that takes in water from the trickling filters and clarifier filters. All water flowing into the water reclamation facility goes through this structure which has degraded due to corrosion of the concrete and reinforcing steel from chloride attack from the influent. | $ 1,493,160 | $ 1,552,908 | $ 3,046,068 | 11/1/2011 |
| 11. | 120016 | CT Life Extension U3 2012 | The purpose of this project is replacement of Unit 3 cooling tower structural components (distribution deck sections and fill support beams), fill material, and fan assemblies in the cooling towers to improve their operational efficiency and structural integrity. This work is necessary because the cooling towers are continuously exposed to aggressive chemicals in circulating water, degrading concrete components due to corrosion of the reinforcing steel. This work will extend the useful lives of the cooling towers. | $ - | $ 2,881,064 | $ 2,881,064 | 4/1/2012 |

## Nuclear Generation Post-Test Year Plant Additions

| Line No. | WA # | Project Description | Purpose | Project Cost to Date 12/31/2010 | Cost to Complete | Projected Closed Cost | Estimated In-Service Date |
|---|---|---|---|---|---|---|---|
| 12. | 070008 | TF Rehabilitation | The purpose of this project is to rebuild one of the site's six trickling filters (TFs) that are used in the process of purifying the influent piped into the plant for the cooling water used to remove excess heat from the Units . The TFs remove ammonia from the influent, reducing the amount of chemicals used in the downstream treatment process. Over time, the structure, machinery & equipment, and plastic media of the TFs have been degraded due to the corrosive action of the influent. Included in the work scope is replacement of fiberglass side walls and the plastic media, as well as refurbishment of machinery and concrete structural components. | $ 2,735,074 | $ 42,184 | $ 2,777,258 | 2/11/2011 |
| 13. | 110021 | CT Life Extension U2 2011 | The purpose of this project is replacement of Unit 2 cooling tower structural components (distribution deck sections and fill support beams), fill material, and fan assemblies in the cooling towers to improve their operational efficiency and structural integrity. This work is necessary because the cooling towers are continuously exposed to aggressive chemicals in circulating water, degrading concrete components due to corrosion of the reinforcing steel. This work will extend the useful lives of the cooling towers. | $ - | $ 2,708,648 | $ 2,708,648 | 5/31/2011 |
| 14. | 110020 | CT Life Extension U1 2011 | The purpose of this project is replacement of Unit 1 cooling tower structural components (distribution deck sections and fill support beams), fill material, and fan assemblies in the cooling towers to improve their operational efficiency and structural integrity. This work is necessary because the cooling towers are continuously exposed to aggressive chemicals in circulating water, degrading concrete components due to corrosion of the reinforcing steel. This work will extend the useful lives of the cooling towers. | $ - | $ 2,442,238 | $ 2,442,238 | 11/15/2011 |
| 15. | 090011 | PBX Replacement | The purpose of this project is replacement of the site's PBX switches and associated telephone network hardware and software. Being replaced with two modern PBX switches and associated software are three old PBX switches installed before 1990 that are obsolete and are no longer supported by the original vendor. The project incorporates recommendations from a comprehensive study performed in 2008 that evaluated all of the PV's communication infrastructure, including: 1) migration from analog telephones to digital telephones using Voice over Internet Protocol (VoIP) for all office environments at the site, and 2) migration from an obsolete, unstable Octel voicemail system to a state-of-the-art Cisco unified voicemail messaging system. | $ 1,356,705 | $ 562,856 | $ 1,919,561 | 8/31/2011 |
| 16. | 090217 | 2009 Security Fencing | The purpose of this project is to address site defense vulnerabilities identified in self-assessments performed prior to the 2010 Nuclear Regulatory Commission Force-on-Force evaluation and subsequently in response to the evaluation. Additional, more detailed information is considered Safeguards. | $ 1,866,022 | $ 47,695 | $ 1,913,717 | 3/15/2011 |
| 17. | 070024 | Main Generator Rotor Rewind U1 | The purpose of this project is to install the refurbished Main Generator Rotor into Unit 1 as part of the Long Range Plan (LRP). A Main Generator LRP has been developed to systematically refurbish / rewind the three Main Generator Rotors to address aging electrical insulating condition, and promote reliable operation. | $ 1,626,345 | $ 176,671 | $ 1,803,016 | 5/15/2011 |

## Nuclear Generation Post-Test Year Plant Additions

| Line No. | WA # | Project Description | Purpose | Project Cost to Date 12/31/2010 | Cost to Complete | Projected Closed Cost | Estimated In-Service Date |
|---|---|---|---|---|---|---|---|
| 18. | 080092 | Main Transformer Rewind (from U1R14) | The purpose of this WA is the rebuild of the main transformer as part of the LRP, including the complete rewind of the phase using copper conductor and insulating material. All internal wiring will be inspected and replaced as necessary. The expected end of life for a main transformer is 30-40 years. A Large Power Transformer LRP has been developed to systematically replace and refurbish PVNGS' Generator Step Up transformer to address aging electrical insulating condition, and promote reliable operation. | $ 1,419,039 | $ 181,820 | $ 1,600,859 | 3/28/2011 |
| 19. | 110107 | WRSS Pipeline - 2011 Scope | The purpose of this project is continuation of the pipe rebuilding program started in 1999 to deal with widespread corrosion on the water reclamation supply system (WRSS) pipeline that runs from the Phoenix sewage treatment facility to the WRF. The concrete pipe spools in the 39 mile underground line are under attack from the chemicals in the influent from the sewage treatment facility. Failures of the WRSS pipeline could severely impact operations of all three PVNGS units and could have an adverse impact on the environment and regulatory margin. Therefore, rebuilding of the degraded spools is necessary for continuous, event-free operation of the plant. | $ - | $ 1,398,894 | $ 1,398,894 | 11/15/2011 |
| 20. | 090148 | Main Transformer Rewind "C" U2R15 | The purpose of this project is to rewind the Unit 2 "C" transformer. The expected end of life for a main transformer is 30-40 years. A Large Power Transformer Long Range Plan has been developed to systematically replace and refurbish PVNGS' Generator Step Up transformer to address aging electrical insulating condition, and promote reliable operation. | $ 334,149 | $ 1,003,904 | $ 1,338,053 | 9/15/2011 |
| 21. | 100239 | TB "A" Blowdown Line Pipe replacement | The purpose of this project is replacement of degraded pipes, valves, pipe supports, concrete berms, instrumentation and controls from the 8" nozzle on the circulating water return header in all three units to the evaporation pond inlet valve structure. Also included is excavation of Circulating Water (CW) return line, installation of a new stainless steel riser and installation of an isolation valve above ground with associated support. | $ 135,282 | $ 972,305 | $ 1,107,587 | 4/30/2012 |
| 22. | 090027 | Circ Water Pipeline Replacement, Phse III, U2 | The scope of this project includes identification and rebuilding of up to 10 sections in each of the Unit 1, Unit 2 and Unit 3 Circulating Water System pipe sections, due to their degraded condition. This water line provides critical water to the plant for operations and degraded pipe impairs the reliability of the water source. | $ - | $ 818,235 | $ 818,235 | 12/31/2011 |
| 23. | 090131 | Cask Load Pit Leak Detection U1 | The purpose of this project is to install both a leak detection system and a water level indicator in the cask load pit (CLP) for each unit. These are required to bring the CLPs into compliance with 10CFR50 Appendix A, General Design Criteria 60 & 64, which mandate that the site provides the means to control the release of radioactive materials and monitor such releases. From the plant's inception it has been assumed that the CLPs would not be full often enough to present a risk of leaks and potential radiation exposure. However, due to fuel movements and inspections, reactor loading during outages, and dry storage campaigns, the CLPs are full more than originally anticipated. Therefore, to increase control and monitoring, leak detection systems and water level indicators are being installed in the CLPs. | $ 195,802 | $ 601,245 | $ 797,047 | 4/15/2011 |
| 24. | 080042 | 2009 PA Evacuation System | The purpose of this project is to replace public address and evacuation system components which are over 21 years old and are experiencing an increasing component failure rate. These systems are required to give instructions to individuals in and around the site in case of an emergency. | $ 764,179 | $ 29,813 | $ 793,992 | 2/15/2011 |

## Nuclear Generation Post-Test Year Plant Additions

| Line No. | WA # | Project Description | Purpose | Project Cost to Date 12/31/2010 | Cost to Complete | Projected Closed Cost | Estimated In-Service Date |
|---|---|---|---|---|---|---|---|
| 25. | 090091 | Hydrazine Injection Mod - Unit 2 | The purpose of this project is to modify the Hydrazine Chemical Addition system to address industry-wide issues related to pump failures. Hydrazine is a chemical which removes dissolved oxygen gas to prolong the life of the steam generators and system piping. Failure to maintain the hydrazine levels results in corrosion and corrosion product transport to steam generators. | $ 321,269 | $ 413,534 | $ 734,803 | 5/15/2011 |
| 26. | 100088 | GF/Clearwell Life Extension | The purpose of this project is rebuilding of the Water Reclamation Facility (WRF) gravity filter (GF) clearwell. This concrete and steel structure is substantially degraded from contact with corrosive chemicals in the water. It requires rebuilding and resurfacing to restore structural integrity, to permit continued safe operation, and to extend its life. The Clearwell performs 2 critical functions: 1) moving filtered water from the GF to the water storage reservoirs which supply the units with cooling water, and 2) providing process water for the WRF plant. | $ 394,920 | $ 310,435 | $ 705,355 | 12/20/2011 |
| 27. | 100236 | Main Transformer C Replacement -U1 | The purpose of this project is to replace the Generator Step-up transformer "C" for Unit 2. The transformer is required to convert the electrical power from the generator to a voltage that can be transmitted to the power grid. The transformer is approaching the end of its useful life and must be replaced to ensure reliable transmission of electricity. | $ - | $ 638,242 | $ 638,242 | 12/31/2011 |
| 28. | 100126 | Boric Acid Concentrator Vent Line Reroute | The purpose of this project is to reroute the Boric Acid Concentrator vent line from its current connection to an HVAC duct directly to an exhaust duct to prevent tritium-laden steam from condensing in the HVAC duct. | $ 26,705 | $ 575,488 | $ 602,193 | 3/31/2012 |
| 29. | 110006 | Fixed In-Core Detectors Repl. U2R16 | The scope of this project is replacement of depleted in core detectors to ensure accurate measurement of in-core parameters as required by technical specifications. The detectors are located inside the reactor vessel and record various measurements to ensure how the fuel is being used. | $ - | $ 582,573 | $ 582,573 | 5/15/2011 |
| 30. | 090089 | Hydrazine Injection Mod - U1 | The purpose of this project is to modify the Hydrazine Chemical Addition system to address industry-wide issues related to pump failures. Hydrazine is a chemical which removes dissolved oxygen gas to prolong the life of the steam generators and system piping. Failure to maintain the hydrazine levels results in corrosion and corrosion product transport to steam generators. | $ 87,724 | $ 436,029 | $ 523,753 | 11/15/2011 |
| 31. | 090090 | Hydrazine Injection Mod - Unit 3 | The purpose of this project is to modify the Hydrazine Chemical Addition system to address industry-wide issues related to pump failures. Hydrazine is a chemical which removes dissolved oxygen gas to prolong the life of the steam generators and system piping. Failure to maintain the hydrazine levels results in corrosion and corrosion product transport to steam generators. | $ 87,697 | $ 435,107 | $ 522,804 | 5/15/2012 |

## Nuclear Generation Post-Test Year Plant Additions

| Line No. | WA # | Project Description | Purpose | Project Cost to Date 12/31/2010 | Cost to Complete | Projected Closed Cost | Estimated In-Service Date |
|---|---|---|---|---|---|---|---|
| 32. | 090132 | Cask Load Pit Leak Detection U3 | The purpose of this project is to install both a leak detection system and a water level indicator in the cask load pit (CLP) for each unit. These are required to bring the CLPs into compliance with 10CFR50 Appendix A, General Design Criteria 60 & 64, which mandate that the site provides the means to control the release of radioactive materials and monitor such releases. From the plant's inception it has been assumed that the CLPs would not be full often enough to present a risk of leaks and potential radiation exposure. However, due to fuel movements and inspections, reactor loading during outages, and dry storage campaigns, the CLPs are full more than originally anticipated. Therefore, to increase control and monitoring, leak detection systems and water level indicators are being installed in the CLPs. | $ 195,625 | $ 286,951 | $ 482,576 | 6/21/2011 |
| 33. | 080043 | Fatigue Rule Software (formerly Employee Time Cap) | The purpose of this project is to acquire and implement software that applies fatigue management rules and work hour controls to nuclear utility workers who direct work or work on safety-related equipment in the access-controlled area. This project is required to comply with the March 2008 issuance by the NRC of 10 CFR Part 26 Fitness for Duty Programs, Final Rule, which requires stringent monitoring of hours worked by affected personnel. | $ 412,435 | $ 52,552 | $ 464,987 | 10/15/2011 |
| 34. | 080073 | Cask Load Pit Leak Detection U2 | The purpose of this project is to install both a leak detection system and a water level indicator in the cask load pit (CLP) for each unit. These are required to bring the CLPs into compliance with 10CFR50 Appendix A, General Design Criteria 60 & 64, which mandate that the site provides the means to control the release of radioactive materials and monitor such releases. From the plant's inception it has been assumed that the CLPs would not be full often enough to present a risk of leaks and potential radiation exposure. However, due to fuel movements and inspections, reactor loading during outages, and dry storage campaigns, the CLPs are full more than originally anticipated. Therefore, to increase control and monitoring, leak detection systems and water level indicators are being installed in the CLPs. | $ 3,553 | $ 458,868 | $ 462,421 | 6/23/2012 |
| 35. | 090087 | Personnel Air Lock (PAL) Mod - Unit 2 | This WA includes the design and replacement of all 4 Personal Air Lock (PAL) doors operating mechanisms in Unit 2. The PAL doors allow personnel to enter containment while still maintaining the integrity of the containment dome to control potential radioactive release. | $ 8,160 | $ 454,036 | $ 462,196 | 5/7/2011 |
| 36. | 000030 | Rad Monitoring System Monitors | The purpose of this project is replacement of the monitors for the radiation monitoring system at unit 1, due to their age and poor condition. The Radiation Monitoring System (RMS) provides radiation level indication of radiological conditions throughout the plant to the operations staff. The microcomputers function independently to monitor radiation levels, initiate alarms, initiate trips and control sampling (process monitors). | $ 377,253 | $ 78,896 | $ 456,149 | 12/15/2011 |
| 37. | 110101 | ISFSI Berm Stabilization | The purpose of this project is to stabilize the existing ISFSI berm and install OSHA approved safety features to improve the safety for workers performing tasks on and near the berm, especially in low-light conditions. The ISFSI berm serves as a radiation shield for dry cask storage of spent nuclear fuel. | $ 308,098 | $ 107,131 | $ 415,229 | 1/28/2011 |
| 38. | 090204 | SC-942 Replacement pH/Conductivity Meters U2 | The purpose of this replacement is to ensure reliable and accurate pH and conductivity analysis of the Secondary Chemistry (SC) system. All outdated and obsolete pH and conductivity analyzers and associated sensing units will be replaced with state of the art and cost saving multiple channel, multiple function instrumentation and sensors. | $ 241,388 | $ 142,719 | $ 384,107 | 5/15/2011 |

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| Line No. | WA # | Project Description | Purpose | Project Cost to Date 12/31/2010 | Cost to Complete | Projected Closed Cost | Estimated In-Service Date |
|---|---|---|---|---|---|---|---|
| 39. | 090205 | SC-942 Replacement pH/Conductivity Meters U3 | The purpose of this replacement is to ensure reliable and accurate pH and conductivity analysis of the Secondary Chemistry (SC) system. All outdated and obsolete pH and conductivity analyzers and associated sensing units will be replaced with state of the art and cost saving multiple channel, multiple function instrumentation and sensors. | $ 27,166 | $ 353,969 | $ 381,135 | 5/15/2012 |
| 40. | 100142 | Resin Processing Equipment | The scope of this project is to purchase and install new spent resin processing equipment to replace the current equipment that is over 20 years old. It has become unreliable and replacement parts are difficult to procure. The three units use resin in the primary and secondary systems to purify water. Once the resin is expended, it is discharged into liners or high integrity containers for disposal utilizing resin processing equipment to complete this evolution | $ 214,344 | $ 162,395 | $ 376,739 | 12/31/2011 |
| 41. | 110088 | Cooling Tower NRQ Circuit Breakers | The purpose of this project is to purchase and install new circuit breakers to replace the existing twenty one cooling tower fan breakers on the cooling towers. The breakers have been utilized in the cooling tower environment for over 20 years and need replacement/refurbishment to ensure safety and equipment reliability. The breaker is designed to isolate a fault and actuate a vibration switch to trip the breaker thereby removing the energy source for the cooling tower fans. Failure of these to operate as expected can cause significant physical damage to the cooling towers. | $ - | $ 369,354 | $ 369,354 | 4/15/2011 |
| 42. | 080071 | RWT Instrumentation System Replacement, U2 | The purpose of this project is design and installation of modifications to the Refueling Water Storage System to increase the operating margin of this system by expanding the usable operational volume of the Refueling Water Tanks (RWTs). This increase is necessary because the NRC, in an equipment inspection, questioned the adequacy of the safety margins in the operating ranges of the Refueling Water Storage System, to prevent air entrainment in the piping if the water level in RWT tanks was reduced below the design minimums due to continuous pump suction. To comply with the NRC's recommendations, the RWT's instrumentation will be modified and additional vent lines will be added -- increasing the safety margins of the Refueling Water Storage System. | $ 161,434 | $ 186,326 | $ 347,760 | 4/30/2011 |
| 43. | 090145 | Building B - Classroom Addition | The purpose of this project is to construct a large classroom, capacity 65, to be used for Operator training. The site currently has several small classrooms near the simulators which are sufficient for most training required for new and requalifying operators. For those times, however, when the class size needs to be larger (i.e., interdisciplinary training, training for an entire shift), the site does not have sufficient space to accommodate the class. The Operations Department has expanded significantly recently to ensure it has the necessary operators to run the site as its aging work force begins retiring, increasing the demand for training and training rooms. | $ 274,529 | $ 47,013 | $ 321,542 | 1/21/2011 |

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| Line No. | WA # | Project Description | Purpose | Project Cost to Date 12/31/2010 | Cost to Complete | Projected Closed Cost | Estimated In-Service Date |
|---|---|---|---|---|---|---|---|
| 44. | 100036 | Fiber Optic & DS Line (Well for Firing Range) | The purpose of this project is to simultaneously rectify two current problems at PV: 1) the need for daily monitoring of the evaporation ponds, required by the Aquifer Protection Permit governing the ponds' operation, and 2) the need for potable water at the site firing range, which is next to the evaporation ponds. The scope of the project includes a 3.7 mile common trench that contains both a fiber optic line from the Water Reclamation control room in the Energy Information Center and a domestic service (DS) water line from U3. The fiber optic line terminates at the evaporation ponds and the DS water line terminates at the firing range. Because the fiber optic line permits remote monitoring of the evaporation ponds, daily trips to the ponds are eliminated, resulting in considerable man hour savings. | $ 316,570 | $ 2,441 | $ 319,011 | 1/19/2011 |
| 45. | 090254 | QA-1316-Fuel Bldg Normal Lighting Mod U3 | The purpose of this project is replacement of the general area lighting in the fuel buildings in all 3 units to bring the illumination up to the level required by American National Standards Institute / Illuminating Engineering Society of North America standard RP-07-01. In several areas of these buildings, the illumination level is less than 25% of the minimum requirements, causing unsafe work conditions due to the poor visibility. | $ 58,468 | $ 260,277 | $ 318,745 | 10/28/2011 |
| 46. | 090165 | Chemistry Class Software Repl. | The purposes of this project are to: 1) develop a replacement for the Chemistry CLASS software application that captures and monitors the chemistry analyses and instrument calibrations at PV, and 2) integrate the new CLASS application's data sources with 2 other Chemistry applications -- LabMaster (used to monitor equipment) and Shift Logs (used to track technician workflow) -- that use the same data but require duplicate data entry at present. The replacement of CLASS is required because the programming language utilized for the application (Visual Basic 6) is no longer supported by the vendor (Microsoft), creating a security risk to the PV network that could be exploited because Microsoft will no longer provide software patches. A breach would allow an unauthorized user access to the site network. The second piece of the project -- combining disparate data entry for several Chemistry programs is justified economically as it will eliminate keying errors that cause data integrity issues. | $ 18,506 | $ 294,423 | $ 312,929 | 3/15/2012 |
| 47. | 060069 | UFM System Replacement, U3R15 | Palo Verde currently uses Ultrasonic Flow Meters (UFM) and Venturi nozzles on the Feedwater system to determine Reactor Thermal Power. The UFM system in all three units have been experiencing an increasing rate of failures over the past few years, mainly caused by the electronics units. The purpose of the UFM upgrade is to remove the existing LEFM Model 8300 electronics unit (one electronic unit per PV unit) and replace it with 2 (one unit needed for each feedwater line) of the Model 2000FE electronic platforms. | $ 111,707 | $ 195,201 | $ 306,908 | 4/29/2012 |
| 48. | 100122 | Warehouse Admin Area Outside PA | The purpose of this project is to reconfigure the administrative area of the existing warehouse to support a more efficient workflow of Supply Chain functions. The admin area is currently out of compliance with National Electrical Code and National Fire Protection Association standards resulting in a habitability issue with the building. The reconfiguration of this area will bring it into compliance and provide for improved efficiency and workflow for the receipt and inspection of parts in the near term. For the long-term, this reconfigured area will be needed when areas of the Warehouse are used for shops and mock up areas as well as storage of large items and equipment. | $ 19,474 | $ 266,293 | $ 285,767 | 6/25/2011 |

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|---|---|---|---|---|---|---|---|
| 49. | 080052 | Personnel Air Lock (PAL) Mod - Unit 3 | This WA includes the design and replacement of all 4 Personal Air Lock (PAL) doors operating mechanisms in Unit 3. The PAL doors allow personnel to enter containment while still maintaining the integrity of the containment dome to control potential radioactive release. | $ 206,800 | $ 68,976 | $ 275,776 | 4/29/2012 |
| 50. | 080075 | LLRWSF Crane Control Replacement | The purpose of this project is to replace the remote controls for the low level radioactive waste storage facility crane which is used to handle low level radioactive waste materials. The current controls trip while the crane is under load which requires that the controls be reset. To date, this reset has allowed work to continue but there is concern that the controls will fail completely and result in a safety risk to the plant and personnel. | $ 132,653 | $ 135,691 | $ 268,344 | 9/15/2011 |
| 51. | 110071 | Equipment Reliability S/W - Phase 2 | The purpose of this project is to implement four equipment reliability (ER) software modules, following on from Project # 090144: Equipment Reliability Integrated System, in which four ER software modules were also implemented. All eight of these modules in both projects are supplied by Insert Key Solutions (IKS), the leading vendor of ER software programs for the nuclear power generation industry. They provide a robust, integrated set of tools to manage the complex ER function. The IKS suite of modules are based on the INPO AP-913 document, "Equipment Reliability Process Description". The four modules in #110071 will replace two existing, in-house developed and supported applications / websites. Based on forecast efficiency gains in the equipment maintenance function, the project expects to produce considerable annual "soft-dollar" savings that give the project positive economic metrics. | $ 86,964 | $ 176,810 | $ 263,774 | 12/31/2011 |
| 52. | 090088 | Personnel Air Lock (PAL) Mod - Unit 1 | This WA includes the design and replacement of all 4 Personal Air Lock (PAL) doors operating mechanisms in Unit 1. The PAL doors allow personnel to enter containment while still maintaining the integrity of the containment dome to control potential radioactive release. | $ - | $ 260,447 | $ 260,447 | 11/5/2011 |
| 53. | 090203 | SC-942 Replacement pH/Conductivity Meters U1 | The purpose of this replacement is to ensure reliable and accurate pH and conductivity analysis of the Secondary Chemistry (SC) system. All outdated and obsolete pH and conductivity analyzers and associated sensing units will be replaced with state of the art and cost saving multiple channel, multiple function instrumentation and sensors. | $ 76,731 | $ 176,800 | $ 253,531 | 12/15/2011 |
| 54. | 080113 | Control Room Entrance | The purpose of this project is to remodel the shift managers' offices as well as the corridor, airlock, calibration room, Shift Technical Advisor's office and kitchen in each unit. The area is degraded and lacks technology that will make the operators more efficient and ensure their safety. | $ 10,935 | $ 241,521 | $ 252,456 | 5/15/2012 |
| 55. | 110022 | Cathodic Protection 2011-Repl. | The scope of this project is to replace of anode beds to maintain cathodic protection of the underground piping and structures. The anode beds degrade over time as they perform their function and must be replaced periodically. The site has a Cathodic Protection program to ensure replacement of the beds so as to allow them to continue providing their protective function. | $ - | $ 252,365 | $ 252,365 | 12/15/2011 |

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| Line No. | WA # | Project Description | Purpose | Project Cost to Date 12/31/2010 | Cost to Complete | Projected Closed Cost | Estimated In-Service Date |
|---|---|---|---|---|---|---|---|
| 56. | 100221 | Glass Top Simulators | The purpose of this project is to procure 11 virtual simulation control panels (common name - Glass Top Simulators) and to install them at strategic site locations to address problems with access to the two full-scope, plant-referenced simulators. Demands on the full-scope simulators are increasing due to: 1) larger classes for operator training, 2) additional training courses for Operations and Engineering (e.g., Just In Time Training), and 3) personnel requiring simulator access to model proposed plant modifications. The Glass Top Simulators will meet this demand for additional simulator time and reduce pressure on the full-scope simulators. An economic analysis of the "soft-dollar" benefits of the Glass Top Simulators indicated substantial positive returns on this investment by increasing the efficiency of the site's training classes and improving the process of designing complex plant modifications. | $ 155,079 | $ 84,114 | $ 239,193 | 2/10/2011 |
| 57. | 110100 | Condensate Polisher Rubber Relining - U2 | The purpose of this project is the replacement of the worn out rubber relining of the polishers in the condensate system. | $ - | $ 224,601 | $ 224,601 | 12/1/2011 |
| 58. | 100002 | WRF GF Filter Media - 2011 Scope | The purpose of this project is replacement of the filter media (composed of sand and coal) in the gravity filter system at the Water Reclamation Facility (WRF). The gravity filter system is an important step in the conversion of waste water influent to water sufficiently pure to use for cooling the nuclear units during production of power. Over time (about 12-15 years) the media becomes depleted and must be replaced. | $ - | $ 218,362 | $ 218,362 | 12/1/2011 |
| 59. | 100028 | UFM System Replacement, U2R16 | Palo Verde currently uses Ultrasonic Flow Meters (UFM) and Venturi nozzles on the Feedwater system to determine Reactor Thermal Power. The UFM system in all three units have been experiencing an increasing rate of failures over the past few years, mainly caused by the electronics units. The purpose of the UFM upgrade is to remove the existing LEFM Model 8300 electronics unit (one electronic unit per PV unit) and replace it with 2 (one unit needed for each feedwater line) of the Model 2000FE electronic platforms. platforms. | $ 85,786 | $ 123,443 | $ 209,229 | 4/30/2011 |
| 60. | 090070 | SWMS 2010 Project | The purpose of this WA is to upgrade the Site Work Management System (SWMS) software. The scope includes upgrades to the general user interface (improvements to 10 high-use forms & interface programming upgrades to improve functionality) and replacement of the systems interface between the PeopleSoft Human Resources system and SWMS to improve the timeliness and speed of data transfer between them. Benefits from the proposed upgrades include increased ease of use for all users across the site and reduced time to process incoming contractors. An economic analysis identified considerable "soft-dollar", personnel-related efficiencies from this project. | $ 103,475 | $ 101,184 | $ 204,659 | 6/28/2011 |
| 61. | 110023 | UFM System Replacement, U1R16 | Palo Verde currently uses Ultrasonic Flow Meters (UFM) and Venturi nozzles on the Feedwater system to determine Reactor Thermal Power. The UFM system in all three units has been experiencing an increasing rate of failures over the past few years, mainly caused by the electronics units. The purpose of the UFM upgrade is to remove the existing LEFM Model 8300 electronics unit (one electronic unit per PV unit) and replace it with 2 (one unit needed for each feedwater line) of the Model 2000FE electronic platforms. platforms. | $ - | $ 199,920 | $ 199,920 | 3/15/2012 |

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|---|---|---|---|---|---|---|---|
| 62. | 090063 | Monitoring Wells (6) | The purpose of this project is to install six monitoring wells near the site's perimeter to enhance PV's capability for early detection of any contamination of ground water from inadvertent radiological releases. The project is required to comply with the 2007 initiative issued by the Nuclear Energy Institute (NEI), titled "Industry Ground Water Protection Initiative - Final Guidance Document", which was issued to respond to industry-wide concerns to increase protection of aquifers. | $ 110,587 | $ 88,027 | $ 198,614 | 5/31/2012 |
| 63. | 100090 | Dilute Caustic Tanks (2) | The purpose of this project is replacement of two dilute caustic tanks of 15,000 gallon capacity. Both the tanks and the associated concrete pads are showing signs of degradation and need to be replaced. Failure to replace these tanks and pads could ultimately result in a chemical spill, creating an environmental incident. | $ - | $ 182,653 | $ 182,653 | 5/1/2012 |
| 64. | 100113 | WRF Chemical Production Bldg HVAC Ductwork | The purpose of this project is to purchase and install HVAC ductwork, duct heaters, controls, and roof exhaust fans in the chemical production building located at the Water Reclamation Facility, to replace degraded components. The chemical production building contains equipment for the production and storage of chemicals used at PVNGS. The HVAC system is designed to regulate temperature, maintain a slight positive air pressure in the building, and exhaust corrosive and hazardous gases. The HVAC system has suffered severe corrosion from high humidity and chemical vapors. Completion of this project will allow the building's HVAC system to meet the original design requirements. | $ 9,454 | $ 173,095 | $ 182,549 | 6/30/2011 |
| 65. | 090130 | RMS Server Replacement | The Radiation Monitoring System (RMS) is responsible for monitoring potential areas of radiological exposure and alerting plant personnel when there is an event which could impact plant personnel or public safety. The purpose of this project is to replace all of the existing hardware with new, supported Intel hardware and ensure that the latest version of Solaris will operate on it. A rule of thumb for electronic equipment reliable useful life, especially for equipment such as servers and hard drives is five years. This equipment has been working for 10 years. | $ 110,476 | $ 63,071 | $ 173,547 | 6/15/2011 |
| 66. | 110048 | WRF Cell Frame Replace 2011 | The purpose of this project is to replace the sodium hypochlorite production skids used in the Water Reclamation Facility for biological control of water streams on the site. The site has two such skids, each of which is required to be rebuilt every three years due to degradation of the frame and cells from the chemicals used to produce sodium hypochlorite. This skid was last rebuilt in 2008. | $ - | $ 173,442 | $ 173,442 | 12/31/2011 |
| 67. | 110116 | Roof Replacements - 2011 WRF | The purpose of this project is to replace or repair degraded roofs as identified in a site roof study. Roofs were evaluated and a timeline was established to replace or repair the most degraded roofs first. This plan is being executed over a number of years. | $ 65,003 | $ 97,288 | $ 162,291 | 10/28/2011 |

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|---|---|---|---|---|---|---|---|
| 68. | 110083 | CW Tie In - Isolation Valve for Tower #1 - U2 | The purpose of this project is to install an additional isolation valve in the circulating water tie-in system for Unit 2 - Cooling Tower #1. At the time of implementation of project ID #100111 for the circulating water (CW) tie-in work in U2R15, the valve assembly, piping, and vault were not installed on the 96" line to tower #1, due to outage time constraints. This project completes the work planned in project #100111, and brings the CW configuration of U2 into alignment with the other 2 units. Replacement of the existing isolation valve is required because when it is closed, the valve leaks at the rate of 200-300 gallons per minute, creating unsafe working conditions and presenting a risk of a leak to the aquifer during pumping operation to handle the water. | $ - | $ 161,370 | $ 161,370 | 5/7/2011 |
| 69. | 090253 | QA-1316: Fuel Bldg Normal Lighting Mod U2 | The purpose of this project is replacement of the general area lighting in the fuel buildings in all 3 units to bring the illumination up to the level required by American National Standards Institute / Illuminating Engineering Society of North America standard RP-07-01. In several areas of these buildings, the illumination level is less than 25% of the minimum requirements, causing unsafe work conditions due to the poor visibility. | $ - | $ 158,617 | $ 158,617 | 3/2/2012 |
| 70. | 110109 | WRF Replacement FC Turn/Rake Drives - 2011 | The purpose of this project is replacement of the turn drives and rake drives in the Water Reclamation Facility (WRF) clarifier filtering systems. These drives being replaced are original equipment and have reached the end of their useful lives. The drives are critical components in the clarifiers that remove solids from the influent that is purified and used in the cooling systems of the three units. | $ - | $ 155,973 | $ 155,973 | 12/31/2011 |
| 71. | 110027 | FAC Mod, 2011 | The purpose of this project is to replace carbon steel piping with stainless steel piping. All three PVNGS Units have experienced severe wall thinning in the carbon steel piping lines due to erosion / corrosion which could lead to piping system rupture. If the pipe ruptured, water flow necessary for plant operations would be interrupted. | $ - | $ 149,182 | $ 149,182 | 11/11/2011 |
| 72. | 100132 | Site Schedule Adherence (On-Line KPI's) | The purpose of this project is to develop and implement a software program to collate and present key performance indicators (KPI's) for the on-line work management function. At present these metrics are obtained using an inefficient combination of: 1) Microsoft Access databases, 2) spreadsheets, and 3) manual numerical computations. This process produces conflicting results/ measurements. In addition, the current on-line work management performance monitoring system does not meet the needs of the station to align individual and work group performance to station goals. These deficiencies in current measurement keep the station from being aligned with industry best practice and do not support the station complying with pending revisions to INPO AP-928 "Work Management Process Description." This application will replace the disparate systems currently in use and remove the ambiguity of the current data by consistently obtaining the metric data from the source systems, which in turn will permit alignment to the station's Operational Focus indicators. An economic analysis of the "soft-dollar" efficiencies from this project indicates positive returns. | $ 10,735 | $ 132,947 | $ 143,682 | 12/15/2011 |

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| Line No. | WA # | Project Description | Purpose | Project Cost to Date 12/31/2010 | Cost to Complete | Projected Closed Cost | Estimated In-Service Date |
|---|---|---|---|---|---|---|---|
| 73. | 110115 | Roof Replacements - 2011 Unit 3 | The purpose of this project is to replace or repair degraded roofs as identified in a site roof study. Roofs were evaluated and a timeline was established to replace or repair the most degraded roofs first. This plan is being executed over a number of years. | $ 38,369 | $ 95,251 | $ 133,620 | 11/28/2011 |
| 74. | 110114 | Roof Replacements - 2011 Unit 2 | The purpose of this project is to replace or repair degraded roofs as identified in a site roof study. Roofs were evaluated and a timeline was established to replace or repair the most degraded roofs first. This plan is being executed over a number of years. | $ 62,143 | $ 70,220 | $ 132,363 | 8/26/2011 |
| 75. | 110038 | Roof Replacements - 2011 Unit 1 | The purpose of this project is to replace or repair degraded roofs as identified in a site roof study. Roofs were evaluated and a timeline was established to replace or repair the most degraded roofs first. This plan is being executed over a number of years. | $ 63,222 | $ 67,901 | $ 131,123 | 6/25/2011 |
| 76. | 100202 | Cooling Tower NRQ Circuit Breakers-2012 | The purpose of this project is to purchase and install new circuit breakers to replace the existing twenty one cooling tower fan breakers on the cooling towers. The breakers have been utilized in the cooling tower environment for over 20 years and need replacement/refurbishment to ensure safety and equipment reliability. The breaker is designed to isolate a fault and actuate a vibration switch to trip the breaker thereby removing the energy source for the cooling tower fans. Failure of these to operate as expected can cause significant physical damage to the cooling towers. | $ - | $ 122,229 | $ 122,229 | 6/1/2012 |
| 77. | 110099 | Stairway in WRF Tunnels | The purpose of this project is to design, build and replace all three Spent Washwater Thickener tunnel stairways in the Water Reclamation Facility, bringing the stairways into OSHA compliance (OSHA Regulation 1910 Subpart D, Walking and Working Surfaces, Regulation 1926.1051, General Requirements, and Regulation 1926.1052). This scope addresses the findings of an inspection by WRF personnel and the PVNGS Safety Department that revealed stairways not in compliance with OSHA requirements. The design of the stairs will accommodate the riser requirement, allow required head clearance, provide a landing/entry way, and correct handrail deficiencies. The scope will also include demolition of the existing access systems and foundations, and relocation of electrical components. | $ 41,523 | $ 77,576 | $ 119,099 | 5/31/2011 |
| 78. | 100083 | CW Screen Gate Replacement-U3 | The purpose of this project is to replace circulating water pump sliding screens with a set of two screens. The screens are designed to prevent debris from entering downstream components such as the condenser and causing tube leaks or negatively affecting condenser performance. Currently the system only has one screen which cannot easily be cleaned. The dual screen system will allow one screen to be lifted for cleaning while leaving the second in place. | $ - | $ 116,178 | $ 116,178 | 8/31/2011 |
| 79. | 120002 | RCP Seals Replacement U3R16 | The purpose of this project is the replacement of the reactor coolant pump seals during U3 outage, as part of the Long Range Plan (LRP) to maintain equipment reliability. | $ - | $ 114,636 | $ 114,636 | 4/29/2012 |

## Nuclear Generation Post-Test Year Plant Additions

| Line No. | WA # | Project Description | Purpose | Project Cost to Date 12/31/2010 | Cost to Complete | Projected Closed Cost | Estimated In-Service Date |
|---|---|---|---|---|---|---|---|
| 80. | 100234 | CW Screen gate replacement-U1 | The purpose of this project is to replace circulating water pump sliding screens with a set of two screens. The screens are designed to prevent debris from entering downstream components such as the condenser and causing tube leaks or negatively affecting condenser performance. Currently the system only has one screen which cannot easily be cleaned. The dual screen system will allow one screen to be lifted for cleaning while leaving the second in place. | $ - | $ 110,645 | $ 110,645 | 8/31/2011 |
| 81. | 100235 | CW Screen Gate Replacement-U2 | The purpose of this project is to replace circulating water pump sliding screens with a set of two screens. The screens are designed to prevent debris from entering downstream components such as the condenser and causing tube leaks or negatively affecting condenser performance. Currently the system only has one screen which cannot easily be cleaned. The dual screen system will allow one screen to be lifted for cleaning while leaving the second in place. | $ - | $ 110,338 | $ 110,338 | 8/31/2011 |
| 82. | 110091 | ZT-1282 Turbine Building Roll-up Door | The purpose of this project is to install a new Roll-up door at the ground level on the north side of each turbine building to facilitate the movement of people and equipment into the building during outages and feed pump crane testing. This project will eliminate the need for the removal and replacement of the turbine building wall and the use of a temporary, less than optimally safe ramp for access. | $ - | $ 96,470 | $ 96,470 | 4/30/2012 |
| 83. | 100120 | AO Briefing Room - Unit 3 | The purpose of this project is to upgrade the Auxiliary Operator (AO) Briefing Rooms in Unit 3 by installing new technology to enable AOs to more efficiently perform their routine tasks and to allow a single briefing for operators in all three units at one time to enhance shift turnovers. The deficient layout was identified evaluated exercise and subsequent benchmarking at other sites. The project returned a positive net present value based on the efficiencies gained by the availability of improved technology. | $ - | $ 89,042 | $ 89,042 | 5/15/2011 |
| 84. | 090235 | AO Briefing Rooms - Unit 1 | The purpose of this project is to upgrade the Auxiliary Operator (AO) Briefing Rooms in Unit 1 by installing new technology to enable AOs to more efficiently perform their routine tasks and to allow a single briefing for operators in all three units at one time to enhance shift turnovers. The deficient layout was identified evaluated exercise and subsequent benchmarking at other sites. The project returned a positive net present value based on the efficiencies gained by the availability of improved technology. | $ - | $ 89,008 | $ 89,008 | 4/15/2011 |
| 85. | 100119 | AO Briefing Rooms - Unit 2 | The purpose of this project is to upgrade the Auxiliary Operator (AO) Briefing Rooms in Unit 2 by installing new technology to enable AOs to more efficiently perform their routine tasks and to allow a single briefing for operators in all three units at one time to enhance shift turnovers. The deficient layout was identified evaluated exercise and subsequent benchmarking at other sites. The project returned a positive net present value based on the efficiencies gained by the availability of improved technology. | $ 52,772 | $ 35,666 | $ 88,438 | 2/28/2011 |

## Nuclear Generation Post-Test Year Plant Additions

| Line No. | WA # | Project Description | Purpose | Project Cost to Date 12/31/2010 | Cost to Complete | Projected Closed Cost | Estimated In-Service Date |
|---|---|---|---|---|---|---|---|
| 86. | 060068 | Main Control Board for PVLAN, U3R15 | The Main Control Board (MCB) Local Area Network project will install a secured fiber backbone in the control room boards and on the 120 foot of the control room that connects to the Palo Verde Local Area Network (PVLAN). Enough fiber will be installed throughout for future growth. Three switches and a media converter will also be installed. The fiber network is critical to upgrading the various communication systems to ensure reliability. | $ 56,212 | $ 32,179 | $ 88,391 | 4/29/2012 |
| 87. | 110003 | 2011 RCP Seals Replacement U1R16 | The purpose of this project is the replacement of the reactor coolant pump seals during U3 outage, as part of the Long Range Plan (LRP) to maintain equipment reliability. | $ - | $ 87,023 | $ 87,023 | 11/5/2011 |
| 88. | 090127 | Potential Transformer Replacement - U1 | The purpose of this project is to replace the 500 kV Potential Transformer. The 500 kV potential transformer (PT) is used to transform high output voltage to a reduced level that can be used for metering and protective relays. Each unit at Palo Verde Nuclear Generating Station (PVNGS) has three 500 kV PTs. The existing PT manufacturer will not refurbish the existing PT requiring the replacement. | $ - | $ 81,428 | $ 81,428 | 11/3/2011 |
| 89. | 090128 | Potential Transformer Replacement - U2 | The purpose of this project is to replace the 500 kV Potential Transformer. The 500 kV potential transformer (PT) is used to transform high output voltage to a reduced level that can be used for metering and protective relays. Each unit at Palo Verde Nuclear Generating Station (PVNGS) has three 500 kV PTs. The existing PT manufacturer will not refurbish the existing PT requiring the replacement. | $ - | $ 79,320 | $ 79,320 | 4/30/2011 |
| 90. | 110081 | PRA Model Other External Events | The purpose of this WA is to develop and implement a Probabilistic Risk Assessment (PRA) - Other External Events (e.g. externally-caused flood, airplane crash). This project is required to comply with NRC Regulatory Guide 1.200 Rev. 2 (effective 4/1/10) to enable continued use of the PRA going for risk-informed regulatory applications. If this work is not performed, NRC approval of future Notices of Enforcement Discretion, Exigent Technical Specification changes, and numerous industry burden reduction initiatives that support shortened refueling outage durations would be in jeopardy due to the possibility that the NRC may not grant requests to extend intervals between equipment testing. | $ - | $ 73,659 | $ 73,659 | 11/23/2011 |
| 91. | 110087 | Uninterruptible Power Supply - Simulator | The purpose of this project is to procure and install an uninterruptible power supply (UPS) to protect the site's simulators from power surges/outages. Building B, which houses the simulators, has had numerous power surges/outages in recent years. The simulators have many electronic components that are vulnerable to power surges, which will now be protected by the new UPS equipment. | $ - | $ 69,026 | $ 69,026 | 4/20/2011 |
| 92. | 100231 | Chemistry Ion Chromatography (ICS)-U1 | The scope of this project is to replace obsolete instruments used to control and minimize the concentrations of impurities in various secondary and primary plant systems. According to the vendor, the life expectancy of an Ion Chromatography System is about 7 to 10 years. PVNGS current instruments are over 15 years old and were declared obsolete by the vendor (Dionex Corporation). | $ 66,639 | $ 1,542 | $ 68,181 | 3/15/2011 |
| 93. | 100075 | Gamma Portal Monitors | The purpose of this project is to purchase replacement radiation monitors for obsolete units. The gamma portal monitors are used to scan personnel leaving the Radiological Controlled Area (RCA) to ensure that radiation levels are within acceptable ranges as established in nuclear industry standards. | $ 60,432 | $ 2,330 | $ 62,762 | 5/15/2011 |

## Nuclear Generation Post-Test Year Plant Additions

| Line No. | WA # | Project Description | Purpose | Project Cost to Date 12/31/2010 | Cost to Complete | Projected Closed Cost | Estimated In-Service Date |
|---|---|---|---|---|---|---|---|
| 94. | 110086 | Simulator: Develop DFWCS Emulation for PC's | The purpose of this project is to replace the plant's simulator emulation model, and install a PC based version, for the Digital Feed Water Control System (DFWCS). The current model is outdated and does not provide sufficient fidelity to the actual operation of the DFWCS. By improving the fidelity between the plant and simulators for the DFWCS, the incorporation of future planned modifications to this system will be facilitated. | $ - | $ 62,389 | $ 62,389 | 12/31/2011 |
| 95. | 090169 | RP Tool Monitors | The purpose of this project is to purchase three SAM-12 monitors to replace the remaining obsolete Merlin Gerin tool monitor. The initial tool monitors were purchased approximately 14 years ago and the electronics (computer and high voltage modules) are obsolete. The new tool monitors are needed to continue required monitoring of articles from the RCA. | $ 57,084 | $ 2,641 | $ 59,725 | 6/15/2011 |
| 96. | 100027 | Main Control Board for PVLAN, U1 | The Main Control Board (MCB) Local Area Network project will install a secured fiber backbone in the control room boards and on the 120 foot of the control room that connects to the Palo Verde Local Area Network (PVLAN). Enough fiber will be installed throughout for future growth. Three switches and a media converter will also be installed. The fiber network is critical to upgrading the various communication systems to ensure reliability. | $ 622 | $ 57,861 | $ 58,483 | 11/5/2011 |
| 97. | 100230 | Personnel Contamination Monitors-U3 | The purpose of this project is to replace the Eberline PCM-2 contamination monitors at the RCA Egress in each Unit 3 with Canberra Argos-5AB contamination monitors to conform to industry practice of 30-35 nCi Co-60 or about 75-80 nCi of Cs-137, monitoring thresholds for personnel leaving the Radiological Controlled Area (RCA). | $ 53,918 | $ 2,495 | $ 56,413 | 6/15/2011 |
| 98. | 100229 | Personnel Contamination Monitors-U2 | The purpose of this project is to replace the Eberline PCM-2 contamination monitors at the RCA Egress in each Unit 2 with Canberra Argos-5AB contamination monitors to conform to industry practice of 30-35 nCi Co-60 or about 75-80 nCi of Cs-137, monitoring thresholds for personnel leaving the Radiological Controlled Area (RCA). | $ 53,918 | $ 2,495 | $ 56,413 | 6/15/2011 |
| 99. | 100228 | Personnel Contamination Monitors-U1 | The purpose of this project is to replace the Eberline PCM-2 contamination monitors at the RCA Egress in each Unit 1 with Canberra Argos-5AB contamination monitors to conform to industry practice of 30-35 nCi Co-60 or about 75-80 nCi of Cs-137, monitoring thresholds for personnel leaving the Radiological Controlled Area (RCA). | $ 53,918 | $ 2,495 | $ 56,413 | 6/15/2011 |
| 100. | 100137 | Personnel Contamination Monitors | The scope of this project is to purchase the Eberline PCM-2 contamination monitors at the Dry Active Waste Processing Storage facility will be replaced with Canberra Argos-5AB contamination monitors to conform to industry practice of 30-35 nCi Co-60 or about 75-80 nCi of Cs-137, monitoring thresholds for personnel leaving the Radiological Controlled Area (RCA). | $ 53,918 | $ 2,495 | $ 56,413 | 6/15/2011 |
| 101. | 090138 | Potential Transformer Replacement - Common | The purpose of this project is to replace the 500 kV Potential Transformer. The 500 kV potential transformer (PT) is used to transform high output voltage to a reduced level that can be used for metering and protective relays. Each unit at Palo Verde Nuclear Generating Station (PVNGS) has three 500 kV PTs. The existing PT manufacturer will not refurbish the existing PT requiring the replacement. | $ - | $ 54,197 | $ 54,197 | 7/31/2011 |

## Nuclear Generation Post-Test Year Plant Additions

| Line No. | WA # | Project Description | Purpose | Project Cost to Date 12/31/2010 | Cost to Complete | Projected Closed Cost | Estimated In-Service Date |
|---|---|---|---|---|---|---|---|
| 102. | 110040 | Motor Replacements 2011 -U1 | The purpose of this project is replacement of motors in Unit 1 >100 horsepower during fall refueling outage work. As part of the Long Range Plan these are being replaced systematically to preclude failure during operation. | $ - | $ 52,718 | $ 52,718 | 12/15/2011 |
| 103. | 070020 | SI Check Valve Repl. 2011 | The scope of this project is replacement of safety injection check valves in the refueling outages. As part of the preventive Maintenance Program these are being replaced systematically to preclude failure during operation. | $ - | $ 51,663 | $ 51,663 | 5/6/2011 |
| 104. | 110118 | Pump Replacement 2011- U1 | The purpose of this project is to replace thee pumps during the Unit 1 Fall Refueling Outage. As part of the Long Range Plan, these are being replaced systematically to preclude failure during operation. | $ - | $ 48,040 | $ 48,040 | 12/1/2011 |
| 105. | 100233 | Chemistry Ion Chromatography (ICS)-U3 | The scope of this project is to replace obsolete instruments used to control and minimize the concentrations of impurities in various secondary and primary plant systems. The life expectancy of an Ion Chromatography System is about 7 to 10 years. PVNGS current instruments are over 15 years old and were declared obsolete by the vendor (Dionex Corporation). | $ 44,426 | $ 3,083 | $ 47,509 | 9/15/2011 |
| 106. | 100232 | Chemistry Ion Chromatography (ICS)-U2 | The scope of this project is to replace obsolete instruments used to control and minimize the concentrations of impurities in various secondary and primary plant systems. The life expectancy of an Ion Chromatography System is about 7 to 10 years. PVNGS current instruments are over 15 years old and were declared obsolete by the vendor (Dionex Corporation). | $ 44,426 | $ 3,083 | $ 47,509 | 9/15/2011 |
| 107. | 020097 | Rad Mon Sys Monitor Replacement U3 | The purpose of this project is replacement of the monitors for the radiation monitoring system at unit 3, due to their age and poor condition. The Radiation Monitoring System (RMS) provides radiation level indication of radiological conditions throughout the plant to the operations staff. The microcomputers function independently to monitor radiation levels, initiate alarms, initiate trips and control sampling (process monitors). | $ 12,815 | $ 33,940 | $ 46,755 | 12/15/2011 |
| 108. | 100155 | Fire Alarm System - Service Building | The purpose of this project is to replace the Service Building Fire Alarm panel. This panel is obsolete and replacement parts cannot not be acquired. The PVNGS Fire Marshall has identified these panels as deficient and a safety hazard which will be eliminated with the completion of this project. | $ - | $ 46,275 | $ 46,275 | 9/30/2011 |
| 109. | 120018 | FAC Mod, 2012 | The purpose of this project is to replace carbon steel piping with stainless steel piping. All three PVNGS Units have experienced severe wall thinning in the carbon steel piping lines due to erosion / corrosion which could lead to piping system rupture. If the pipe ruptured, water flow necessary for plant operations would be interrupted. | $ - | $ 45,491 | $ 45,491 | 4/29/2012 |
| 110. | 110002 | 2011 RCP Seals Replacement U2R16 | The purpose of this project is replacement of the reactor coolant pump seals during U2 outage, as part of the Long Range Plan (LRP). The scope of this project is to replace the reactor coolant pump seals after several operating cycles to preclude failure during operation. | $ - | $ 42,546 | $ 42,546 | 5/7/2011 |
| 111. | 100216 | SOCA Video Intrusion Detection System | The purpose of this project is to install a video intrusion detection system to enhance site security. This system will address vulnerabilities identified in force-on-force drills and site security self assessments. | $ - | $ 39,166 | $ 39,166 | 6/30/2012 |

## Nuclear Generation Post-Test Year Plant Additions

| Line No. | WA # | Project Description | Purpose | Project Cost to Date 12/31/2010 | Cost to Complete | Projected Closed Cost | Estimated In-Service Date |
|---|---|---|---|---|---|---|---|
| 112. | 100219 | DG Fire Rated Roll Up Door Repl - U3 | The purpose of this project is to replace degraded and broken fire doors for the two diesel generators in Unit 3 to conform to fire safety regulations. The doors are original to the plant and have exceeded their expected useful life. The doors are held open to allow access to the diesel generators. In case of fire, a heat sensitive release allows the door to drop within a designated time period to ensure the diesels are protected from the fire. | $ 8,549 | $ 29,375 | $ 37,924 | 6/30/2011 |
| 113. | 020096 | Rad Mon Sys Monitor Replacement U2 | The purpose of this project is replacement of the monitors for the radiation monitoring system at unit 2, due to their age and poor condition. The Radiation Monitoring System (RMS) provides radiation level indication of radiological conditions throughout the plant to the operations staff. The microcomputers function independently to monitor radiation levels, initiate alarms, initiate trips and control sampling (process monitors). | $ 2,375 | $ 32,974 | $ 35,349 | 12/15/2011 |
| 114. | 100078 | Pump Replacements 2011-U2 | The purpose of this project is to replace four pumps during the Spring Unit 2 Refueling Outage. As part of the Long Range Plan, these are being replaced systematically to preclude failure during operation. | $ - | $ 34,341 | $ 34,341 | 5/6/2011 |
| 115. | 100157 | Fire Alarm System - D Building | The purpose of this project is to replace the Building D Fire Alarm panel. This panel is obsolete and replacement parts cannot not be acquired. The PVNGS Fire Marshall has identified these panels as deficient and a safety hazard which will be eliminated with the completion of this project. | $ - | $ 30,850 | $ 30,850 | 9/30/2011 |
| 116. | 110034 | WRF Tolleson Flow Meter Replacement | The purpose of this project is to replace the flow-meter at the Tolleson Water Treatment plant. It is used for billing purposes to determine the water sent to the plant. The current flow-meter is obsolete and not working consistently, and repair is more expensive than replacement. | $ - | $ 30,505 | $ 30,505 | 6/30/2011 |
| 117. | 100168 | Pump Replacements 2012 | The purpose of this project is to replace pumps during the Spring Refueling Outage. As part of the Long Range Plan, these are being replaced systematically to preclude failure during operation. | $ - | $ 30,442 | $ 30,442 | 5/1/2012 |
| 118. | 100237 | Motor Replacements 2011 -U2 | The scope of this WA is replacement of motors in Unit 2 >100 horsepower during spring refueling outage work. As part of the Long Range Plan, these are being replaced systematically to preclude failure during operation. | $ - | $ 29,782 | $ 29,782 | 5/6/2011 |
| 119. | 110001 | Main Cond Expansion Joint U1R16 | The scope of this project is to replace main condenser expansion joints in regular 10 year intervals, as part of the Long Range Plan (LRP). It has been determined that the life expectancy of the expansion joints is approximately 10 years after which the seals become subject to failure. Failure of the seals allows air to enter the condenser and cause a turbine trip. | $ - | $ 26,107 | $ 26,107 | 11/11/2011 |
| 120. | 100062 | Chemistry Ion Chromatography Systems (ICS) | The scope of this project is to replace obsolete instruments used to control and minimize the concentrations of impurities in various secondary and primary plant systems. The life expectancy of an Ion Chromatography System is about 7 to 10 years. PVNGS current instruments are over 15 years old and were declared obsolete by the vendor (Dionex Corporation). | $ 22,213 | $ 3,084 | $ 25,297 | 9/15/2011 |
| 121. | 100258 | Hoisting Equipment -JIB Crane | The purpose of this project is to purchase and install two new 5 ton capacity JIB cranes that would mount to the top of the main generator hydrogen domes. The cranes would allow the site to work on both ends of the generator at one time and free up the existing crane to support turbine work. | $ - | $ 24,956 | $ 24,956 | 12/1/2011 |

## Nuclear Generation Post-Test Year Plant Additions

| Line No. | WA # | Project Description | Purpose | Project Cost to Date 12/31/2010 | Cost to Complete | Projected Closed Cost | Estimated In-Service Date |
|---|---|---|---|---|---|---|---|
| 122. | 100238 | Motor Replacement 2011 -U3 | The purpose of this project is to replace motors in U3 as part of the online schedule work. As part of the Long Range Plan, these are being replaced systematically to preclude failure during operation. | $ - | $ 20,277 | $ 20,277 | 12/1/2011 |
| 123. | 110026 | Super Mic/Dimensional Calibration | The scope of this project is to replace the dimensional calibration tool used in the testing and calibration of plant equipment. | $ - | $ 17,094 | $ 17,094 | 11/20/2011 |
| 124. | 100218 | DG Fire Rated Roll Up Door Repl - U2 | The purpose of this project is to replace degraded and broken fire doors for the two diesel generators in Unit 2 to conform to fire safety regulations. The doors are original to the plant and have exceeded their expected useful life. The doors are held open to allow access to the diesel generators. In case of fire, a heat sensitive release allows the door to drop within a designated time period to ensure the diesels are protected from the fire. | $ - | $ 7,741 | $ 7,741 | 10/31/2011 |
| 125. | 100217 | DG Fire Rated Roll Up Door Repl - U1 | The purpose of this project is to replace degraded and broken fire doors for the two diesel generators in Unit 1 to conform to fire safety regulations. The doors are original to the plant and have exceeded their expected useful life. The doors are held open to allow access to the diesel generators. In case of fire, a heat sensitive release allows the door to drop within a designated time period to ensure the diesels are protected from the fire. | $ 45 | $ 7,687 | $ 7,732 | 8/31/2011 |
| 126. | **Total Nuclear Generation Post-Test Year Plant Additions** | | | **$ 65,348,526** | **$ 54,754,862** | **$ 120,103,388** | |

# TESTIMONY OF DANIEL T. FROETSCHER

**On Behalf of Arizona Public Service Company**

**Docket No. E-01345A-11-_____**

**June 1, 2011**

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**TESTIMONY OF DANIEL T. FROETSCHER**
**ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY**
**(Docket No. E-01345A-11-____)**

I. INTRODUCTION

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

A. My name is Daniel T. Froetscher. I am Arizona Public Service Company's (APS or Company) Vice President for Energy Delivery and my address is 400 North 5th Street, Phoenix, Arizona, 85004.

**Q. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?**

A. I earned a Bachelor of Applied Sciences degree and a Bachelor of Arts degree from Northern Arizona University. I began employment with APS in 1980 and have served in numerous management and leadership capacities during my tenure with the Company, including as the Southeast Division Manager and the General Manager of Rural Arizona Delivery. I was made Vice President for Energy Delivery in October 2008.

**Q. WHAT ARE YOUR RESPONSIBILITIES AT APS?**

A. I am responsible for all facets of energy delivery throughout APS's 35,000 square-mile service territory, including operation and maintenance of the company's transmission and distribution system, service restoration, new construction and planning.

**Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

A. My testimony describes the key functions of the Energy Delivery organization and how they contribute to the provision of safe, reliable and cost-effective service to APS customers. I identify representative programs, initiatives and expenditures made during the 2010 test year, discuss APS's overall performance in key operational areas and describe how such programs and performance benefit APS customers and communities. Portions of my testimony also bridge into the Customer Service organization, a part of the Company primarily

responsible for direct interactions with customers, such as handling customer inquiries and transactions, reading meters and preparing monthly billing statements. My testimony concludes by describing Energy Delivery's planned capital expenditures for the 18-month post-Test Year period and supports the following pro-forma adjustments: Emergency/Storm, Asset Management, Customer Growth, Smart Grid, Community Power Project, Other Customer & Technology, AMI Meters and IT & Facilities.

## II. SUMMARY

**Q. PLEASE SUMMARIZE YOUR TESTIMONY.**

A. Since APS's last rate case, Energy Delivery performed to the highest standards in the key operational areas of safety, reliability, compliance, meeting customer demands for new service and technology and responding to government mandates. Energy Delivery improved already high levels of safety, reliability and customer satisfaction. And it effectively planned and executed the deployment of new technologies and investments in critical and essential distribution infrastructure. Importantly, Energy Delivery performed at this level while managing the associated costs. Indeed, while the performance measures noted above have improved, Energy Delivery has steadily reduced its capital and operations and maintenance (O&M) spending since the Company's last rate case.

The ever present need to provide safe and reliable electric service lies at the core of Energy Delivery's mission and requires significant investment in APS's distribution system. APS is mindful of the observations in the Liberty Consulting Group's February 2011 Benchmarking Study ("Study"). There, Liberty made clear that diminishing reliability performance trends across the industry are "...the direct result of yesterday's lack of investment."[1] Although sacrificing

[1] Study, p. 10.

distribution investments may result in short term lower rates, the risks to reliability and safety, as well as the prospect of overall higher rates in the long term, render such a decision unwise.

Furthermore, although Arizona's current pace of economic growth is slower than the historical norm, this will not always be the case. Electrical infrastructure is not a short term proposition. Careful planning and sufficient investment today and tomorrow will ensure that Arizona is not caught flatfooted when growth does escalate. Indeed, without such distribution investment, growth may have nowhere to take root. Any perceived lack of confidence in a community's underlying infrastructure—including its electrical infrastructure—would likely deter businesses from expanding or relocating to Arizona. Continued capital investment in the distribution infrastructure—upgrading facilities to meet the needs of customers for today and tomorrow—is critical. APS has a careful and considered plan in place that reflects appropriate levels of investment to support an expanding Arizona economy.

## III. INTRODUCTION TO APS ENERGY DELIVERY

**Q. WHAT IS ENERGY DELIVERY?**

A. Energy Delivery is a business unit within APS responsible for delivering electricity from generating stations to customers in a safe, reliable, affordable and environmentally-friendly manner. Functional areas include Asset Management and Planning, Construction, Operations and Maintenance. Energy Delivery is responsible for APS's transmission and distribution systems.

**Q. PLEASE DESCRIBE THE SERVICE TERRITORY FOR WHICH ENERGY DELIVERY IS RESPONSIBLE.**

A. APS's service territory encompasses almost 35,000 square miles of distribution service area, overlaying all or part of 11 of the state's 15 counties. In 2008, the Edison Electric Institute ranked APS as having the 4th largest service territory out of 155 ranked utilities. Within this area, APS serves more than 1.1 million retail customers using infrastructure that includes more than 28,000 miles of distribution lines, over 6,000 miles of transmission lines, 417 substations, 295,000 transformers and more than 500,000 power poles and structures. Although often thought of as urban, APS's service territory is in fact a mix of urban and rural communities. With one of the lowest customer densities in the United States—ranking 36th out of the 40 utilities benchmarked by the Liberty Consulting Group[2]—and a large service territory that includes a variety of elevations, terrain and climate, Energy Delivery encounters a multitude of operational and cost challenges.

## IV. PERFORMANCE IN KEY OPERATIONAL AREAS

**Q. YOU MENTIONED THE IMPORTANCE OF SAFETY. PLEASE ELABORATE.**

A. Safety has long been a priority at APS and is identified as a Core Value within the Company's Strategic Framework. Many of our employees work with electric lines or facilities that are either energized or could become energized in an instant. Further, we have a responsibility to our customers and the general public to provide electric service in a safe, responsible fashion. While the present business and regulatory climate pushes greater efficiency and productivity, these added demands cannot come at the expense of safety; one accident is too many. Therefore, we begin and end every day—and every customer connection and

[2] Study, p. 8.

interaction—with safety foremost and continue to emphasize a zero-accident culture.

**Q. PLEASE PROVIDE SOME EXAMPLES OF SAFETY-RELATED INITIATIVES THAT HELP DRIVE SAFETY PERFORMANCE?**

A. Investment in safety—both employee and public safety—is no small endeavor. Employee safety is rooted in a number of key areas: employee training and skill development, effective policy development and execution, root cause analysis and other essential tools designed to train, instruct and enhance organizational performance.

Journeyman lineman and journeyman electrician employees, for example, participate in regular training programs throughout the year. These may be programs designed to increase skill sets (e.g., hot stick training), improve crew safety, efficiency and planning (e.g., Tailboard and Crew Foreman training), or familiarize field personnel with new equipment and procedures (e.g., Lineman's Academy and grounding procedures). Other programs are designed to deal with environmental hazards. For example, we provide annual dog bite prevention training for meter reading and customer service personnel; and, in an organization that puts over 18.6 million miles annually on the road serving its customers, we routinely review and practice defensive driving techniques. Energy Delivery also has an aggressive Fatigue Management program, essentially mandating that its employees, after a certain threshold of hours working on the job, be relieved from further work responsibilities and secure mandatory rest—a program that has enhanced both employee and public safety considerably. The number and scope of employee safety-related programs and initiatives are impressive and founded in providing employees the right training, tools and structure to keep themselves safe.

We take our responsibilities interacting with the public seriously as well. APS has three full-time Public Safety Consultants whose principal responsibilities are to interface with contractors, builders and the general public on issues that present any prospective risk or concern. Examples include working through clearance issues between buildings and overhead power lines, instructing and guiding contractors on proper adherence to state Blue Stake laws, Occupational Safety and Health Administration (OSHA) clearance requirements, or changes and modifications to regulations involving overhead cranes and safe working distances from energized electrical equipment.

Additional public outreach and training occurs through our "Weenie Wagon", a mobile, instructional device designed to demonstrate the hazards of electricity to schools, youth groups, fire and police agencies, etc. Annually, APS makes more than 120 presentations to more than 6,000 attendees, advocating for greater understanding and respect for the dangers of electricity.

Finally, several company initiatives serve a dual purpose of increasing public safety and improving service reliability. For example, APS inspects aged wood poles at routine intervals for termite damage and wood rot, and either replaces suspect poles, or "stubs" them with an adjacent, supporting pole. APS also periodically inspects pad-mounted equipment, including switching cabinets and transformers, and replaces damaged, leaking or rusted equipment. And APS annually inspects all of its 28,000 miles of distribution infrastructure, looking for potential key public safety and reliability-related issues and making repairs.

**Q. WHAT ARE THE RESULTS OF ENERGY DELIVERY'S SAFETY EFFORTS?**

A. Clearly, no single program or initiative is solely responsible for driving safety improvement. Rather, it is the combination of programs, initiatives,

communications and heightened awareness that has helped Energy Delivery improve its overall safety performance.

In connection with our emphasis on zero accidents (a part of APS's corporate "Got Safety? Get Zero" safety program), Energy Delivery and Customer Service together experienced 44 OSHA recordable injuries in 2010, more than a 20% improvement over its previous best performance and reflecting a solid 2nd quartile performance within the industry when compared against 2009 EEI data. APS has enjoyed similar improvements in the number of Lost Work Time incidents and the number of Lost Work Time days recorded—both indications that the number and severity of injuries has decreased. Energy Delivery and Customer Service achieved this safety record by actively emphasizing safety at all levels. The strong and continued emphasis on eliminating safety risks caused by human performance, efforts towards eliminating unwanted events and strong management and employee commitment to safety have produced measurable results.

**Q. WHAT ROLE DOES RELIABILITY PLAY IN ENERGY DELIVERY'S RESPONSIBILITIES?**

A. Other than safety, strengthening reliability—which includes managing the assets associated with delivering energy to our customers and planning the infrastructure needed to do the same—is Energy Delivery's most important responsibility. Electricity is an essential public commodity, particularly in an age when so many technologies, especially information technologies, are dependent upon reliable electric service. Feedback from our customers and others is clear: reliable service helps drive customer satisfaction.

Reliable service requires investments in the existing distribution system that maintain, upgrade and expand the system across the state. Over time, equipment

reaches the end of its life, becomes obsolete or fails. Storms and unplanned third party events (such as vehicle accidents, wildfires, etc.) may also damage or destroy facilities. And new and upgraded utility infrastructure provides the additional capacity needed to meet the growth-related needs of businesses and communities. In each of these situations, Energy Delivery must repair, replace and/or upgrade equipment. Managing existing assets and effectively deploying new and upgraded assets in a cost-conscious manner to keep customer rates as low as possible is Energy Delivery's most complex challenge. It takes the innovation, imagination and engagement of our entire workforce to successfully balance these competing demands.

**Q. WHAT ARE SOME OF THE MAINTENANCE PROGRAMS APS PERFORMS TO MAINTAIN OR IMPROVE RELIABILITY?**

A. APS's strong reliability record results from its comprehensive maintenance and asset management programs. APS implements 39 programs annually to maintain and improve service reliability throughout the Company's entire distribution system. They include: (i) maintaining transformers, circuit breakers, and relays in substations; (ii) performing thermographic, acoustic and corona inspections of substation and distribution line equipment; and (iii) patrolling, repairing, refurbishing and replacing aged overhead and underground equipment and distribution line component parts. Let me provide specific examples.

Under one annual maintenance program, APS ranks all distribution feeders in its system and performs a thorough end-to-end line patrol. During the patrol, we perform maintenance as necessary, such as replacing broken or suspect cross-arms, insulators and poles. We further maximize the efficiency of these patrols by simultaneously inspecting the patrolled facilities for public safety hazards.

A related program involves replacing failed or failing underground cable. APS incurs millions of dollars every year responding to, trouble-shooting, and repairing cable faults on its system. In 2010, APS repaired 1,372 cable faults and replaced over 68 miles of underground cable. In 2011, APS anticipates spending approximately $13 million as part of its cable replacement program. Such work directly improves reliability. Over the past decade, the cable replacement program has reduced the average customer interruption frequency due to cable faults by nearly 61%.

Another activity includes adding wildlife protection guards to substation and distribution equipment. Adding these guards not only accomplishes their primary purpose of protecting wildlife, but it also helps eliminate outages.

Finally, distribution reliability depends upon an effective vegetation management and tree-trimming program. Vegetation has long been cited as one of the leading contributors to distribution system power outages. APS spends approximately $8 million annually on distribution level vegetation management, typically pruning or removing over 69,000 trees along 11,000 miles of overhead distribution.

**Q. WHAT IMPACT HAVE ENERGY DELIVERY'S PROJECTS HAD ON RELIABILITY?**

A. During the 2010 Test Year, APS maintained and improved upon its already strong history of reliable performance. Reliability is typically measured by using four standard industry metrics: (i) SAIFI (System Average Interruption Frequency Index)—a measure of the average number of interruptions a customer experiences in a year; (ii) SAIDI (System Average Interruption Duration Index)—a measure of the number of interrupted minutes a customer experiences in a year; (iii) CAIDI (Customer Average Interruption Duration Index)—a measure of the number of minutes an average service interruption lasts; and (iv)

MAIFI (Momentary Average Interruption Frequency Index)—a measure of the number of momentary interruptions a customer experiences in a year.

APS has achieved excellent performance under each of these metrics. For instance, APS has reduced its SAIFI by nearly 44% since 2001. Indeed, according to the Liberty Benchmarking Study, APS "rates far better than the industry average" on SAIFI and importantly, the "favorable gap is growing with time."[3] Similarly, Energy Delivery's pro-active maintenance programs have successfully reduced APS's SAIDI by nearly 33% since 2001. By comparison, the industry is seeing an upward trend (declining performance) in SAIDI ratings.[4] Moreover, APS's CAIDI rating is "far better than the industry average," with APS appearing in the top quartile of its industry peers.[5] Finally, although little historical data regarding MAIFI exists, APS nonetheless "remains well below the industry in the number of momentary outages."[6]

**Q. PLEASE DESCRIBE APS'S RELIABILITY PERFORMANCE IN THE CONTEXT OF ITS INDUSTRY AND SERVICE AREA.**

A. Liberty Consulting reported that "[w]e would of course expect APS to appear very favorably on a bulk, national basis because of its location."[7] Although I am not certain what that quote means, we believe that our large service territory, with a complex mix of some urban but mostly rural communities, presents a challenge larger than Liberty acknowledges. The Electric Power Research Institute (EPRI) in *Distribution Reliability Indices Tracking Within the United States, 2003*, noted that:

> Service territories generally include urban, suburban, or rural, or more likely, some combination of all of these. Distribution systems designed for rural areas are generally made up of smaller

[3] Study, p. 10.
[4] *Id.*
[5] *Id.*
[6] *Id.*
[7] *Id.* at p. 9.

> substations with long radial circuits extending for many miles with little redundancy and few circuit ties. In contrast, systems in dense urban areas often deploy grid like systems and incorporate larger substations often with redundant facilities, shorter circuit lengths, and multiple feeds.
>
> Circuit distance alone is a substantial reliability issue; longer circuits have inherently more interruptions. This is due to the fact that more circuit length equates to more exposure and more potential points of failure.[8]

As the 36th least dense utility of the 40 utilities that Liberty Consulting benchmarked, APS is keenly aware of what EPRI calls a "substantial reliability issue" caused by long circuits and the reality of "little redundancy and few circuit ties." That APS nonetheless achieved the gains it did in SAIFI and SAIDI over the past decade, and resides in the 1st Quartile in terms of overall reliability, illustrates the strength of APS's commitment to reliability.

**Q. CAN YOU IDENTIFY WHY APS'S RELIABILITY NUMBERS COMPARE SO FAVORABLY TO ITS INDUSTRY PEERS?**

A. Yes, APS agrees with Liberty Consulting that "today's national reliability trends are a direct result of yesterday's lack of investment. Distribution has consistently been the least preferred area for investment and we are now seeing the results."[9] The reliability lesson taught by the Study is that investment in reliability today pays significant dividends tomorrow. APS invests not only in infrastructure to meet demand, but has also leveraged our comprehensive maintenance program to achieve this separation from the industry average.

**Q. HAVE RELIABILITY IMPROVEMENTS CONTRIBUTED IN OTHER AREAS?**

A. Yes, customer service, among others. APS places a high priority on service to its customers as evidenced by the continuous improvement in APS's J.D. Powers Reliability and Power Quality scores. J.D. Powers considers, among other

[8] *Distribution Reliability Indices Tracking Within the United States*, EPRI, Palo Alto, CA: 2003.
[9] Study, p. 10.

factors, power quality and reliability in developing customer satisfaction data.[10] Liberty Consulting relied on J.D. Powers' customer satisfaction work in its Study, noting that "APS's position vis-à-vis other [investor owned utilities] is particularly interesting; the Company ranks 4th of 89. Also of interest is the trend of performance, which exhibits a steady improvement. APS has risen to mid-top quartile from mid-second quartile just three years ago."[11]

**Q. DOES APS FACE ANY RELIABILITY CHALLENGES?**

A. Yes, Liberty Consulting noted that although APS's "performance in minimizing the duration of an outage (CAIDI) is far better than the industry average, coming recently into the top quartile," "the Company's CAIDI is drifting upwards. This trend suggests that its restoration performance is slipping. Given its performance versus the industry, it is hard to criticize such a condition, but the Company may wish to examine this trend."[12] APS is mindful of this trend in CAIDI. I note, however, that our efforts to reduce the number of outages each customer experiences has resulted in decreasing the average annual duration of outages experienced by our customers (SAIDI) by over 33% during the last decade. In addition, the rise in APS's customer satisfaction rating, as demonstrated by J.D. Powers' ranking, suggests that APS's attention to outage frequency reflects its customers' values.

**Q. PLEASE EXPLAIN HOW CUSTOMER GROWTH AND NEW DEMAND IMPACT ENERGY DELIVERY.**

A. Although growth in Arizona has slowed over the past couple of years, most prognosticators anticipate that strong residential and commercial growth will return to the state. For an electric utility company, the return of strong growth presents several challenges, not all of which are immediately obvious. Clearly, as

[10] Study, p. 9.
[11] *Id.* at p. 9.
[12] *Id.* at p. 10.

new customers request service, APS must be in a position to serve them in a safe, efficient and timely manner. Each new customer, however, places an "upstream" demand on the system. Although this demand is only incremental, and nearly invisible when looking at only one new customer at a time, it can have a tremendous impact in the aggregate. That impact primarily occurs on the servicing utility's distribution feeders, substations, capacitors, regulators and other equipment necessary to ensure that customers receive electricity of sufficient capacity and voltage to meet their needs. In many respects, the careful planning and investments APS makes today helps determine whether APS facilitates—or impedes—the coming resumption of economic growth in Arizona.

**Q. PLEASE EXPLAIN SOME OF THE CAPITAL INVESTMENTS ENERGY DELIVERY MADE DURING THE TEST YEAR TO HELP MEET NEW DEMAND AND LAY THE FOUNDATION FOR ECONOMIC GROWTH RESUMING IN ARIZONA.**

A. During 2010, APS added over 7,600 new residential and commercial meter sets to its system. To serve those new customers, APS's system needed approximately $19 million in new distribution transformers, along with $37 million in other service and extension costs, such as poles, conductors, switchgear, etc. Although the vast majority of new customer requests are smaller in scale, projects like the development of CityScape—a commercial project intended to help revitalize downtown Phoenix and create jobs—were constructed in 2010. Similarly, Energy Delivery extended service to the West Data Center of Cox Communications, a large local employer that in the past has provided significant contributions to Arizona's economy. Other new customer construction projects, large and small, are brought on line daily in communities across the state.

These new customers demand safe, reliable electric service. But the provision of such service is not limited solely to the local facilities needed to serve the new

customer. APS must make significant, sometimes less visible, investment upstream that accounts for the new load to continue providing the capacity, voltage support and operating flexibility all customers need. Downtown Phoenix, for example, benefitted from APS's development of the Evans Churchill substation, a critical infrastructure addition necessary to serve CityScape, TGen, and the expansion of facilities by the University of Arizona and Arizona State University. The addition of the Flores substation in the town of Congress alleviated incremental, but increasingly apparent, voltage and capacity problems stemming from the previous service feed from Wickenburg. And APS constructed the new Arica substation in Eloy in large part to provide improved service to the prison facility in that community. Each of these projects is absolutely essential to providing the reliable service APS customers expect and need in order to further their businesses and strengthen their communities.

**Q. YOU MENTIONED THE IMPORTANCE OF MEETING CUSTOMER DEMANDS FOR NEW TECHNOLOGY, PLEASE ELABORATE.**

A. Innovative technologies, such as smart meters, distributed renewable generation and electric/hybrid vehicles rank as a top priority for APS, our regulators and our customers. They offer tremendous potential benefits while posing a series of challenges for APS. For example, our customers are increasingly interested in electric/hybrid vehicles and the widespread deployment of distributed renewable generation, such as rooftop solar panels. Although APS is excited about both prospects, they place different demands on distribution systems that must be simultaneously considered and may present integration issues. Moreover, innovative technologies can dramatically increase the dynamic, two-way nature of a utility's power flow, potentially changing the day-to-day operational characteristics of a distribution system. Other challenges exist as well, including cost, cyber security and technology-related training for employees.

The benefits and challenges of such technologies raise many questions. How can we safely leverage these technologies to maximize cost and efficiency? Can they assist in power restoration? What dynamics do they create on a traditional power delivery system? Do they help offset traditional utility demand (e.g., solar) or add to it (e.g., electric vehicles), and if so, during what parts of the day? These and other similar questions are being considered throughout the electric industry. Although these technologies pose challenges, at APS, we also see them as opportunities to help us better understand the dynamics of and prepare for a changing technological landscape and electric grid. We look forward to exploring these opportunities with our customers.

**Q. PLEASE GIVE AN EXAMPLE OF A NEW TECHNOLOGY THAT ENERGY DELIVERY HAS IMPLEMENTED?**

A. APS has long focused on investing in new customer tools that empower customers to better manage their energy use. For instance, APS has offered Time of Use (TOU) pricing for our customers since the 1970s. APS currently has the highest penetration of TOU in the United States with over 50% of our customers on one of our TOU rates. In recent years, and in conjunction with implementing our Automated Metering Infrastructure (AMI or "smart meters"), TOU offerings have expanded in variety and scope, and now include super peak and peak event pricing.

Similarly, smart meters help our customers better manage their energy consumption and facilitate the use of power during off-peak times. Such tools help customers control their costs by enabling them to access information about their individual energy use and profiles via aps.com on a "day behind" basis. This represents an unprecedented degree of access to timely and relevant energy use information. Our customers seem to think so as well; more than 170,000 customers have created such web-based home profiles to date.

Smart technology offers even more opportunities for the future. The primary purpose of smart technology is to improve reliability, empower customers with the tools to better manage their energy use and facilitate the integration of alternative energy. It is a long-term effort that will improve system efficiency and help us maintain excellent reliability. For example, the ACC-approved Home Energy Information pilot involves deploying "smart thermostats" that permit direct control over certain appliances and display real-time energy consumption and pricing in customers' homes. With this voluntary pilot, APS seeks to not only assess customer interest in such technologies, but also evaluate how effectively these technologies change consumer behavior and electrical system demand. Over time and properly developed, APS believes that these kinds of tools will result in a more dynamic and efficient electrical system spurred largely by customer interest and behavioral changes.

Demand response is another area within which technology and innovation have converged to meet both customer and utility needs. APS's callable demand response program is designed to shed as much as 100 MW of load on a per-event basis through 2012 by incentivizing customers to change their behaviors during a specific event. This program offers pricing incentives to participants, and more than 3,300 commercial and industrial customers have enrolled to date. A parallel residential program similarly seeks to change energy consumption behaviors during callable events and has so far attracted more than 600 participants.

**Q. YOU HAVE DESCRIBED A NUMBER OF TECHNOLOGICAL INITIATIVES THAT OFFER INCREASED INFORMATION AND CONTROL TO CUSTOMERS. WHAT IS HAPPENING FROM A TECHNOLOGY STANDPOINT ON YOUR SYSTEM?**

A. APS has deployed innovative technology on its system with increasing frequency over the past few years. One of our most visible examples is the APS-developed Transformer Oil Analysis and Notification (TOAN) system. The TOAN system

monitors transformer oil data on a near real-time basis to evaluate and identify any potential abnormalities. Possessing this information so quickly lets the Company prevent otherwise catastrophic transformer fires. In fact, in the past two years, APS identified the need to take two major switchyard or substation transformers out of service before a failure occurred, permitting APS to actively manage system alternatives and take necessary action. The Edison Electric Institute (EEI) recognized APS's TOAN program in 2008 with its prestigious Edison Award, reflecting APS's outstanding contributions to the advancement of the electrical industry both nationally and worldwide.

APS's system is also becoming increasingly automated through the use of smart meters and other emerging technologies. In Flagstaff, APS continues to install a variety of different technologies ranging from automated switches to self-isolating devices to advanced communication systems. We anticipate that these technologies will provide substantial benefits to customers, principally in the area of reducing the duration and scope of power outages. Indeed, APS estimates that its customers have already experienced 500,000 fewer outage minutes due to self-isolating equipment that APS installed on two feeders in Flagstaff. In 2011, we will continue to monitor technology results in Flagstaff and will expand these technology demonstrations to a new pilot area in north Phoenix. APS plans other demonstration projects in the areas of volt-var optimization and distribution fault anticipation. And APS continues to integrate its smart meter outage notification capabilities with its Distribution Outage Management System for effective power outage reporting and more efficient and smarter outage response.

Flagstaff is also home to the Commission-approved Community Power Project. The Project involves installing on the same feeder both (i) an estimated 1.5 MW of residential and commercial rooftop and utility scale greenfield solar; and (ii)

500 kW of lithium-ion battery storage technology. The Project is intended to demonstrate the benefits and challenges associated with coupling high penetrations of distributed generation (solar) with distribution automation, smart meters and battery storage. In conjunction with the Department of Energy (DOE) and in part through a DOE grant, the project will result in a future High Penetration Solar Deployment study.

Finally, one should not lose sight of the tremendous success that APS has achieved in its distributed energy incentive programs. To date, more than 11,000 customers have participated, enabling APS to surpass 60 MW of customer-owned solar energy on its distribution system as of early 2011. We project that number to exceed 400 MW by 2015. These numbers reveal that residential rooftop solar has displaced generation that APS would have otherwise had to produce or acquire from other sources.

**Q. ON TOP OF PURSUING EACH OF THESE GOALS, YOU MENTIONED ENERGY DELIVERY'S OBJECTIVE OF PROVIDING AFFORDABLE ELECTRIC SERVICE. PLEASE DESCRIBE THE IMPORTANCE OF COST MANAGEMENT IN ENERGY DELIVERY'S OPERATIONS.**

A. Cost management has played—and will continue to play—a significant role in APS's business. Like all electric utilities, the costs of equipment and materials essential to our business (e.g., copper, steel, aluminum and other commodities) continue to escalate. With a growth rate close to triple the national average for more than a decade, material costs have affected APS more heavily than many of our peer utilities because more growth means more customers and a need for additional infrastructure to serve those customers. And although growth has slowed for the time being, APS must still fulfill its commitment of meeting the highest reliability standards while preparing for a resumption of growth in Arizona.

To meet that obligation, Energy Delivery has planned and is constructing distribution construction projects during the post-Test Year period designed to meet its planning and reliability responsibilities. These projects, however, will cost money—and represent the essence of the cost management challenge for the Delivery organization. Energy Delivery assesses system deficiencies, needs and weaknesses and only includes in its work plan those projects that specifically contribute to service reliability and/or system capacity. Balancing strategic system investments with cost management will also require organizational improvements in work processes, project management and performance measures. Energy Delivery is in the midst of a multi-year effort to produce just such operational improvements with a program we call SOAR (Standardize, Organize, Automate, Review). SOAR emphasizes maximizing effectiveness and efficiencies in planning, construction, operations and maintenance. Process improvement such as SOAR will be crucial to successfully manage costs while ensuring that the delivery system is sufficiently constructed to meet customer needs.

**Q. DOES ENERGY DELIVERY FACE ANY PARTICULAR CHALLENGES THAT MAY IMPACT COST MANAGEMENT EFFORTS?**

A. Successfully meeting the principles identified above—safety, reliability, compliance and meeting customers' demands for new service and technology—constitutes a challenging opportunity that drives costs. Tension exists between our aim to keep customer costs down and making the investments needed to meet our customers' needs and fulfill critical policy goals. Another challenge lurks, however, that, although not unique to APS, is particularly important in today's climate: our aging workforce.

It is only through our people, our employees, that we will be successful in achieving Energy Delivery's goals. Energy Delivery is not alone in facing large

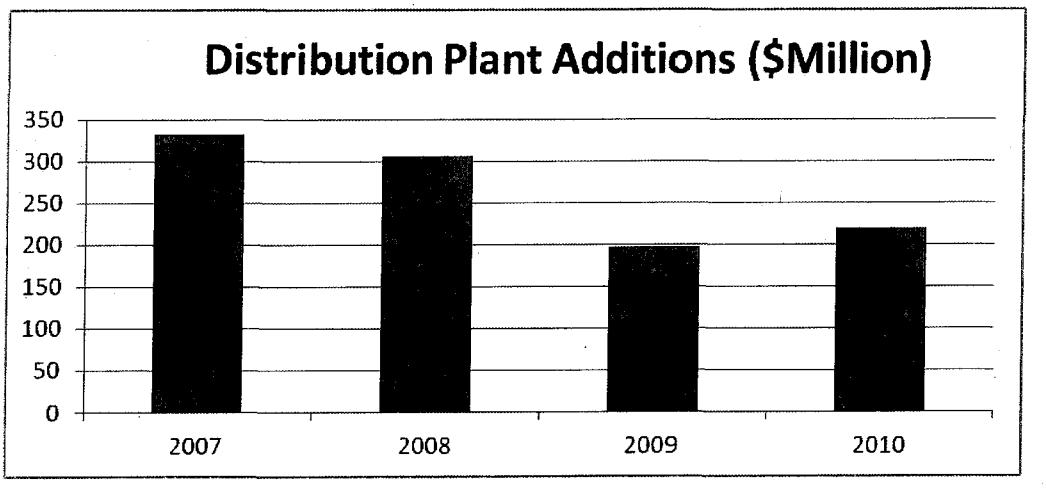
workforce turnover as the "baby boomer" generation begins to retire. Approximately 38% of Energy Delivery's regular employees qualify for retirement in the next five years, and that number will only grow. In response, we will continue recruiting and training new employees qualified to manage our existing system and its "older" technologies. At the same time, we seek creative employees with the innovative and entrepreneurial spirit we need to embrace emerging technologies. Our emphasis on workforce development flows not just from the need to capture the skills of retiring employees, but to develop new skill sets able to deal with emerging technologies, cost pressures and higher customer expectations. Although tackling this challenge may exert upward pressure on O&M costs in the short term, it is critical; without the investment and commitment of an engaged workforce, we cannot be successful.

Working together, we will continue to perform at high levels while forging the kind of vigorous, mentoring leadership and engaged workforce that can absorb and manage change. Given the spectrum of challenges facing Energy Delivery, that is a key driver of our future success.

## V. TEST YEAR EXPENDITURES

**Q. PLEASE PROVIDE MORE DETAIL ON ENERGY DELIVERY'S PLANT ADDITIONS DURING THE TEST YEAR?**

A. As Arizona's economy began to slow in 2007, Energy Delivery took a hard look at its operations as part of APS's overall commitment to cost management. With the goal of carefully calibrating capital expenditures to the predicted slowdown in new customer growth, Energy Delivery embraced a rigorous process for reviewing new construction projects. As a result, Energy Delivery reduced its plant additions by a cumulative total of 33% from 2007 to 2010 as shown in the following chart:




This downward spending trajectory represents a systematic and disciplined effort to correctly scale capital expenditures with needs. Energy Delivery's total addition to distribution plant in service during the 2010 Test Year was approximately $219 million. Critically, this Test Year figure reflects the culmination of these cost cutting measures, translating into compounded savings for APS customers.

**Q. HOW HAS ENERGY DELIVERY MANAGED ITS O&M BUDGET DURING THE TEST YEAR?**

A. The slowing economy also prompted Energy Delivery to scrutinize its O&M expenditures. Since late 2007, Energy Delivery aggressively managed work load to work force in anticipation of the slowdown in the local new customer construction market. As a result of evaluating people, process and technologies, Energy Delivery adjusted during the last three-and-a-half years by, among other items, reducing the total workforce by approximately 460 people, or 23% of Energy Delivery's total employees. In combination with this reduction, Energy Delivery also reduced the number of its vehicles by 20%.

In addition to workforce reductions, Energy Delivery strengthened overtime management by evaluating work prioritization, scheduling and work load. This

process resulted in 250,000 less overtime hours in 2010 compared to 2007, a 44% reduction that saved almost $13 million, equivalent to approximately 140 full time positions.

In addition to focusing on its own employees, Energy Delivery reduced its use of third-party contractors. In 2007, Energy Delivery's monthly average of work performed by third-party contractors peaked at approximately 30,000 hours. As the economy slowed, however, Energy Delivery brought that work in-house to reduce costs. Since the 2007 peak, Energy Delivery has reduced the monthly average to approximately 1,000 hours per month, all but eliminating our reliance on third-party contractors. In 2010, Energy Delivery sent approximately $17 million less in distribution work to third-party contractors than in 2007. This represents a reduction of over 94%, again equivalent to approximately 150 full time positions.

Streamlining its workforce, reducing overtime and bringing work in-house represent a few of the cost cutting measures Energy Delivery employed in response to the slowing economy. In the aggregate, these efforts to reduce O&M paid off. In 2007, APS's Distribution O&M was approximately $94.5 million. With just inflation alone since that time—over 5% as measured by the Consumer Price Index—Distribution O&M should have increased to $99.4 million. But it did not. By 2010, and after adding almost 44,000 meter sets, Energy Delivery reduced its O&M expenditure by $2.4 million ($7.4 million as adjusted for inflation) for a Test Year O&M expenditure of $92 million.

In sum, Energy Delivery carefully stepped down spending as new customer growth slowed beginning in 2007. Again, it was a delicate balancing act in which APS fulfilled its obligation to serve those new customers that did emerge, but

also protected customers' interests by keeping expenditures low. Critically, Energy Delivery balanced these objectives while also improving reliability and safety as discussed earlier. Because the 2010 Test Year contains these reductions in expenditures, APS customers will benefit from Energy Delivery's cost management efforts.

**Q. HOW DO ENERGY DELIVERY'S O&M EXPENDITURES COMPARE TO THOSE OF ITS PEER UTILITIES?**

A. Liberty Consulting and Concentric Energy Advisors separately evaluated Energy Delivery's O&M in light of industry norms. Liberty found that although APS experienced sharp increases in distribution O&M in 2007 and 2008, APS's per customer distribution O&M was competitive and consistently falls in the 2nd quartile.[13] Concentric echoed this finding and provided additional detail in a report attached to the testimony of APS witness Jeff Guldner. Concentric first noted that the 2007 and 2008 spikes in distribution O&M resulted from a one-time severance payment, vegetation management expenses and the Bark Beetle infestation in Arizona.[14] Concentric also considered APS's distribution O&M in light of how much of APS's distribution system resides underground, a factor which typically increases O&M expense per circuit mile. Despite having the second-highest percentage of underground distribution system in the industry, APS has been in the second or third quartile of distribution O&M, "demonstrating the Company's success at managing costs in this area."[15] Concentric concluded by noting that on a per customer basis, APS's distribution O&M is competitive against both Liberty's base and high growth panels.[16] The following chart demonstrates the trajectory of APS's Distribution O&M over the past few years.

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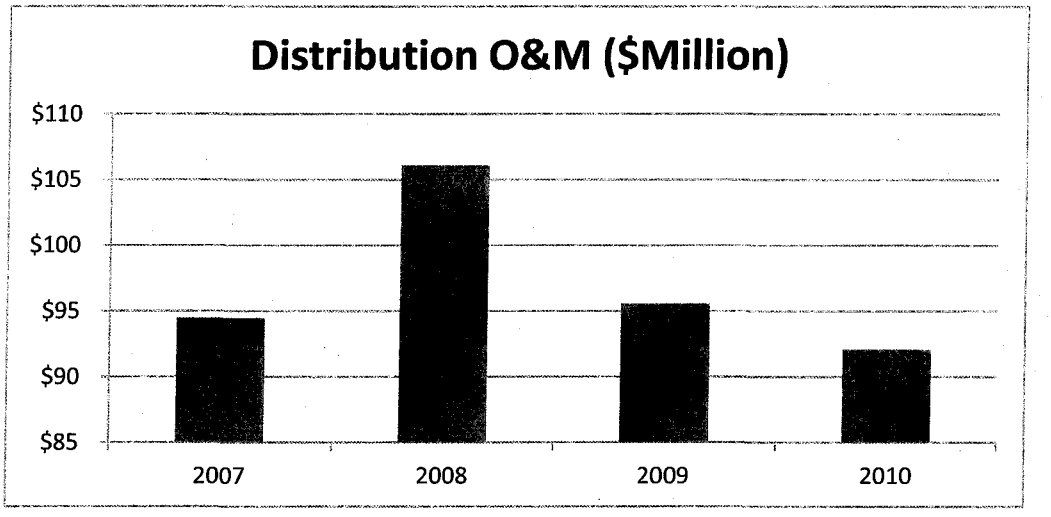
[13] Study, p. 27.
[14] *See* Concentric Energy Advisors Report, p. 18.
[15] *Id.* at 27.
[16] *Id.*




**Q. BASED UPON ENERGY DELIVERY'S EXPERIENCES AND PERFORMANCE SINCE APS'S LAST RATE CASE, WHAT LESSONS WILL ENERGY DELIVERY CARRY INTO THE POST-TEST YEAR PERIOD AND BEYOND?**

A. As I stated earlier, meeting customer demands and furthering energy policy objectives are key challenges for APS going forward. Moreover, APS is obligated to be ready for the growth that will occur as Arizona's economy revives. Managing these challenges depends in large part on system performance, in one word—*reliability*. Energy Delivery must plan, construct and maintain the APS system to lock in current levels of system performance, while ensuring that as it continually expands, the system is sufficiently reliable and has the capacity to meet future customer and community needs. It is the level of investment we make today that will determine whether APS contributes to and facilitates economic growth in Arizona, or whether business leaders can point to a lack of electric infrastructure if they seek to justify a decision to expand into another state.

In contributing to the resumption of economic growth in Arizona, however, Energy Delivery will bring its disciplined approach to cost management. Energy Delivery will deepen its focus on operational efficiency, seek improved ways of

doing business and continue its rigorous review of what projects to implement, and when. Energy Delivery's performance in the past few years demonstrates that it knows how to balance needed investments with cost management. The post-Test Year expenditures detailed below reflect that balance.

## VI. POST TEST YEAR EXPENDITURES

### A. *Total Capital Expenditures for Distribution.*

**Q. WHAT LEVEL OF PLANT ADDITIONS DOES ENERGY DELIVERY EXPECT THROUGH JUNE 30, 2012?**

A. Energy Delivery plans to add a total of $433 million in distribution and IT & facilities plant by June 30, 2012 as summarized in Attachment DTF-1. These additions contribute $159 million to the Company's Post-Test Year Plant adjustment.[17] APS Witness Jason La Benz describes additional details of the adjustment, such as accumulated depreciation, accumulated deferred income taxes, depreciation expense, property taxes and interest expense.

**Q. PLEASE PROVIDE MORE DETAIL ON WHAT MAKES UP THE DISTRIBUTION CAPITAL SPENDING FOR 2011 AND 2012.**

A. Attachment DTF-2 itemizes APS's Post-Test Year capital expenditures by specific categories. The first category concerns expenditures related to emergencies and storms and includes costs associated with both the labor and equipment required to replace facilities damaged by uncontrollable events. Examples include storm damage, cars hitting poles and equipment breaking unexpectedly, among others.

The second category involves planned outlays for asset management. This category reflects those costs that APS will incur in proactively extending the life of its distribution system by replacing end-of-life or obsolete equipment. For instance, Energy Delivery intends to spend approximately $2.8 million replacing

[17] *See* SFR B-2, page 2, column K

or stubbing aging or rotted wooden poles during the Post-Test Year period. Similarly, Energy Delivery has budgeted approximately $9 million to patrol, upgrade and replace, as appropriate, overhead facilities, particularly high SAIFI feeders. This line patrol and replacement program reflects APS's strong commitment to reliability and contributes to the reliability successes detailed earlier in my testimony. Energy Delivery's dedication to reliability also underlies its plan to incur $26 million in replacing underground cable during the Post-Test Year period. The benefits to date of replacing this underground cable—a 61% drop in the average customer interruption frequency over the past decade—make clear that leaving this cable in the ground would inevitably erode the reliability of APS's distribution system.

The final category of Post-Test Year capital expenditures arises out of installing facilities to serve anticipated local customer growth.[18] For instance, a clear area of sustained and to-be-accelerating growth is the West Valley (e.g., Goodyear, Avondale, Buckeye). As subdivisions and commercial centers develop, electrical distribution backbone infrastructure is needed—and needs to be in place in advance of customer needs. At APS's Sarival substation, two existing 20 MVA transformers will be replaced with two new 41 MVA substation transformers—adding capacity to ensure the reliably supply of energy to the anticipated West Valley growth. New feeder exits at APS's Granite Reef substation perform a similar function and will aid continued growth in North Scottsdale.

Neither the Sarival nor Granite Reef substation projects are tied to specific new customers. Instead, they represent the sometimes less visible infrastructure investments that APS must install to provide the capacity, voltage support and

[18] Attachment DTF-2 identifies customer growth-related expenditures under the headings 12 kV Lines, Distribution Subs, Relocates, Service and Extensions and Transformers.

operating flexibility that customers need. Without these investments, and the other expenditures contemplated under the new customer category, APS risks hindering anticipated growth in Arizona.

**Q. ARE THERE OTHER DISTRIBUTION CAPITAL COSTS THAT THE COMPANY WILL INCUR SUBSEQUENT TO THE TEST YEAR THROUGH JUNE 30, 2012?**

A. Yes. As I discuss earlier in my testimony, innovative technologies are a priority for both our customers and APS. We plan on investing $25.5 million as part of our Smart Grid demonstration projects, furthering our investment in substation equipment and distribution asset health monitoring; we essentially seek operating characteristic feedback before equipment may fail similar to our highly effective TOAN system. We also plan on further automating our distribution system in both Flagstaff and Phoenix, thereby improving outage responsiveness and reducing customer outage scope and duration. (*See* the schedule of costs outlined in Attachment DTF-3).

Commission-approved pilot programs in the smart home and electric vehicle areas will also be conducted, and we'll be installing an estimated 317,000 AMI meters during this time period at a cost of approximately $53.7 million (*see* the schedule of costs outlined in Attachment DTF-4).

Technology extends beyond the field distribution system as well. A projected $18.3 million in other customer and technology initiatives is planned, including a pre-pay energy services pilot, the consolidation of a number of software applications in our Call Center designed to improve our responsiveness to and handling of customer telephone inquiries, and technology to leverage our AMI system in power outage reporting, transformer loading and voltage monitoring and energy diversion detection. More detail on these project costs are included in my Attachment DTF-3.

B. *Total Capital Expenditures for Information Technology and Facilities*

**Q. MR. FROETSCHER, EARLIER YOU STATE THAT THE COMPANY WILL BE MAKING INVESTMENTS IN INFORMATION TECHNOLOGY AND FACILITIES. PLEASE ELABORATE ON THESE INVESTMENTS.**

A. Yes, APS will make substantial investments in both information technology and the Company's facilities. As detailed in Attachment DTF-5, the Company will invest over $102 million during the Post-Test Year period. One critical project encompassed by this figure involves rebuilding the Company's Deer Valley Operations Center at a cost of approximately $34 million. Deer Valley, the Company's principal Phoenix-based campus, will be upgraded to facilitate certain functions critical to APS's core operations, including APS Energy Control Center and the Metro Dispatch Headquarters and Call Center. Other related, key expenditures during the Post-Test Year period include upgrading Information Technology Disaster Recovery hardware and software, enhancing aps.com and leasing vehicles. The total adjustment to the test year APS proposes to include as an original cost rate base pro forma adjustment for (i) distribution capital expenditures; and (ii) information technology and facilities by June 30, 2012 is $433 million.

**Q. IS APS REQUESTING AN INCREASE IN TRANSMISSION RELATED-COSTS IN THIS RATE CASE?**

A. No. Distribution-related cost recovery is subject to the ACC's jurisdiction, whereas transmission-related costs are generally subject to FERC's jurisdiction. FERC reviews the prudency and pricing of APS's transmission service through the Company's Annual Informational Filing. My testimony focuses on APS's distribution system and the need for cost recovery of the distribution system related costs including Post-Test Year plant additions.

## VII. CONCLUSION

**Q. THANK YOU, MR. FROETSCHER. DO YOU HAVE ANY CONCLUDING REMARKS?**

A. APS will only be ready for the resumption of strong growth in Arizona by continuing to make the sound distribution investments today that it made leading up to and during the Test Year. It is those types of investments—which resulted from diligent study and careful analysis—that permit me to highlight the successes in safety and reliability identified above. But it is the context of these successes that is truly remarkable: Energy Delivery achieved such strong reliability and safety numbers *while reducing capital and O&M expenditures* since the last rate case.

Those reductions are not small either. Since the last rate case, Energy Delivery reduced its capital expenditures by 33%. And it reduced its O&M expenditure by $2.4 million despite adding almost 44,000 meters sets and in the face of over 5% inflation. APS customers benefit from those reductions in this rate case.

Looking forward, the distribution investments planned for the Post-Test Year period will permit Energy Delivery to build upon its strong record on safety and reliability. And these investments will continue the installation of new technologies that not only empower customers with more knowledge and control, but create operational efficiencies with cost savings that compound over time. We look forward to unlocking the opportunities afforded by these investments and building upon Energy Delivery's record.

# ARIZONA PUBLIC SERVICE COMPANY
## Distribution, Smart Grid, AMI, IT and Facilities
## Capital Post Test Year Additions - Summary
## Test Year Ending 12/31/2010

| Line | Description | | $000 |
|---|---|---|---|
| 1. | Emergency/Storm | Attachment DTF-2 | $ 16,875 |
| 2. | Asset Management | Attachment DTF-2 | 68,901 |
| 3. | Customer Growth | | |
| 4. | Transformers | Attachment DTF-2 | 29,747 |
| 5. | Service & Extensions | Attachment DTF-2 | 62,006 |
| 6. | 12 kV Lines | Attachment DTF-2 | 21,078 |
| 7. | Distribution Substation | Attachment DTF-2 | 18,624 |
| 8. | Relocates | Attachment DTF-2 | 14,427 |
| 9. | Smart Grid Demonstration Projects | Attachment DTF-3 | 25,530 |
| 10. | Community Power Project | Attachment DTF-3 | 2,233 |
| 11. | Other Customer & Technology | Attachment DTF-3 | 18,290 |
| 12. | AMI Meters | Attachment DTF-4 | 53,700 |
| 13. | IT & Facilities Plant Additions | Attachment DTF-5 | 101,573 |
| 14. | Total Post Test Year Plant Additions | | $ 432,984 |

# Distribution Capital Post Test Year Additions $000

| Line # | Category | Capital Identified in Accounting System to be Placed in Service | Additional Capital Dollars to be Placed In Service | Total Capital Dollars to be Placed In Service |
|---|---|---|---|---|
| | **Emergency Storm** | | | |
| 1. | Total Storm | $ 3,336 | $ 1,298 | $ 4,634 |
| 2. | Unplanned Emergency | 4,197 | 8,045 | 12,241 |
| 3. | **Total Emergency Storm** | **7,533** | **9,343** | **16,875** |
| | **Asset Management** | | | |
| 4. | General Reliability | 283 | 695 | 978 |
| 5. | Wood Pole Replacement - Includes line patrol replacement work | 3,082 | (232) | 2,850 |
| 6. | Service Poles - Bark Beetle | 97 | 97 | 194 |
| 7. | Network Monitoring Equipment | 238 | 931 | 1,170 |
| 8. | Substation Aged Equipment Replacement (Includes Planned Replacement) | 264 | 2,648 | 2,913 |
| 9. | Service Replacements | 584 | 7,176 | 7,760 |
| 10. | Overhead Planned Replacements -Includes High SAIFI line patrol replacement work | 1,206 | 8,137 | 9,344 |
| 11. | AT Switch Replacement | 1,034 | (698) | 336 |
| 12. | 12kV Metal Clad Sub Switch Gear Replacement | 3,586 | (37) | 3,549 |
| 13. | Capacitor Bank Radio Controls | 307 | 78 | 384 |
| 14. | UG Transformer Replacement | 78 | 4,987 | 5,065 |
| 15. | UG Cabinet Replacement | 704 | 4,150 | 4,854 |
| 16. | Underground Cable Replacement | 6,800 | 19,013 | 25,813 |
| 17. | Underground Network Cable Replacement | 0 | 2,921 | 2,921 |
| 18. | Transformer Replacement - Distribution | 441 | 183 | 624 |
| 19. | Franchise Elections | - | 146 | 146 |
| 20. | **Total Asset Management** | **18,705** | **50,197** | **68,901** |
| | **12 kV Lines** | | | |
| 21. | Sub Distribution General Projects (Base) | 12,844 | 2,103 | 14,947 |
| 22. | New Feeders | 8,032 | (2,027) | 6,005 |
| 23. | Distribution State Land ROW Renewals | - | 646 | 646 |
| 24. | Distribution Tribal Land ROW Leases - No agreements made | - | - | - |
| 25. | Efficiency Savings (2% of Total DAI) 2009 LRF was 5% of Total DAI | - | (521) | (521) |
| 26. | **Total 12 kV Lines** | **20,876** | **201** | **21,078** |
| | **Distribution Subs** | | | |
| 27. | 69kV Activity Within Substation | 379 | 2,673 | 3,052 |
| 28. | Additional Transformers | 1,472 | 1,165 | 2,637 |
| 29. | New Substations (Includes Land) | 4,623 | 3,426 | 8,048 |
| 30. | Transformer Upgrades | 3,760 | (1,768) | 1,992 |
| 31. | Forestry/Landscaping | 174 | 791 | 965 |
| 32. | Unplanned Sub Walls (Aesthetics) | 713 | 1,216 | 1,928 |
| 33. | **Total Distribution Subs** | **11,121** | **7,503** | **18,624** |
| | **Relocates** | | | |
| 34. | Highway Relocations | 9,450 | **2,697** | **12,147** |
| 35. | PV Conversion | - | 974 | 974 |
| 36. | Other Conversions | 2,355 | (1,049) | 1,306 |
| 37. | **Total Relocates** | **11,805** | **2,622** | **14,427** |
| | **Service and Extensions** | | | |
| 38. | Service & Line Extensions - Residential | 12,038 | 24,780 | 36,819 |
| 39. | Service & Line Extensions - Residential - Non -Residential | 24,407 | 135 | 24,542 |
| 40. | Streetlights & Dusk to Dawn | 2,805 | 2,340 | 5,145 |
| 41. | Forfeited Refundable Advances (CIAC) | - | (4,500) | (4,500) |
| 42. | **Total Service and Extensions** | **39,251** | **22,755** | **62,006** |
| | **Transformers** | | | |
| 43. | Transformers | - | 29,747 | 29,747 |
| 44. | **Total Transformers** | **-** | **29,747** | **29,747** |
| 45. | **Total Post Test Year** | **$ 109,290** | **$ 122,368** | **$ 231,658** |

# Smart Grid Capital Post-Test Year Additions

($ in Millions)

| Line No. | Eighteen Month Capital Forecast | | Total |
|---|---|---|---|
| 1. | **Smart Grid Demonstration Projects** | | |
| 2. | Smart Circuit Automation | | |
| 3. | Flagstaff | $ | 4.873 |
| 4. | Metro | | 9.824 |
| 5. | Asset Monitoring | | |
| 6. | Substation Health Monitoring | | 3.412 |
| 7. | Distribution Asset Monitoring | | 1.228 |
| 8. | Customer Pilots | | |
| 9. | Home Energy Information Pilot | | 1.299 |
| 10. | Electric Vehicles | | 1.722 |
| 11. | Solar Demonstration | | |
| 12. | Chase | | 1.659 |
| 13. | USAC | | 1.513 |
| 14. | **Total** | | **25.530** |
| 15. | | | |
| 16. | **Community Power Project** | | |
| 17. | Battery Storage | | 2.233 |
| 18. | | | |
| 19. | | | |
| 20. | **Other Customer & Technology Initiatives** | | |
| 21. | Marketing Systems & Products | | |
| 22. | Click Fox | | 0.248 |
| 23. | CRM/MKIS | | 1.195 |
| 24. | Proactive Alerts | | 0.419 |
| 25. | Streamlining Options | | 0.543 |
| 26. | Customer Interaction Scorecard | | 0.236 |
| 27. | Contact Center | | 4.647 |
| 28. | Leveraging AMI | | 1.936 |
| 29. | Merging of Products | | 0.945 |
| 30. | Prepay Energy Services | | 1.836 |
| 31. | Strategic IT | | 6.285 |
| 32. | Total | | 18.290 |
| 33. | | | |
| 34. | **Grand Total (14+17+32)** | **$** | **46.053** |

# ARIZONA PUBLIC SERVICE COMPANY

**AMI Post Test Year Additions**
**Test Year Ending 12/31/2010**

| Line No. | Calendar Year 2011 | AMI Meter Order/Delivery Quantities | Residential AMI Meters (90% of Monthly Purchase) | General Service AMI Meters (10% of Monthly Purchase) | Residential AMI Meter Cost (@$146/meter) | General Service AMI Meter Cost (@ $380/meter) | Total AMI Meter Cost |
|---|---|---|---|---|---|---|---|
| | | A | B | C | D=Bx$146 | E=Cx$380 | F=D+E |
| 1. | January | 18,000 | 16,200 | 1,800 | $2,365,200 | $684,000 | $3,049,200 |
| 2. | February | 18,000 | 16,200 | 1,800 | 2,365,200 | 684,000 | 3,049,200 |
| 3. | March | 18,000 | 16,200 | 1,800 | 2,365,200 | 684,000 | 3,049,200 |
| 4. | April | 18,000 | 16,200 | 1,800 | 2,365,200 | 684,000 | 3,049,200 |
| 5. | May | 18,000 | 16,200 | 1,800 | 2,365,200 | 684,000 | 3,049,200 |
| 6. | June | 18,000 | 16,200 | 1,800 | 2,365,200 | 684,000 | 3,049,200 |
| 7. | July | 18,000 | 16,200 | 1,800 | 2,365,200 | 684,000 | 3,049,200 |
| 8. | August | 18,000 | 16,200 | 1,800 | 2,365,200 | 684,000 | 3,049,200 |
| 9. | September | 18,000 | 16,200 | 1,800 | 2,365,200 | 684,000 | 3,049,200 |
| 10. | October | 18,000 | 16,200 | 1,800 | 2,365,200 | 684,000 | 3,049,200 |
| 11. | November | 18,000 | 16,200 | 1,800 | 2,365,200 | 684,000 | 3,049,200 |
| 12. | December | 18,000 | 16,200 | 1,800 | 2,365,200 | 684,000 | 3,049,200 |
| 13. | Total | 216,000 | 194,400 | 21,600 | $28,382,400 | $8,208,000 | $36,590,400 |
| 14. | | | | | | | |
| 15. | Calendar Year 2012 | | | | | | |
| 16. | January | 18,000 | 16,200 | 1,800 | $2,365,200 | $684,000 | $3,049,200 |
| 17. | February | 18,000 | 16,200 | 1,800 | 2,365,200 | 684,000 | 3,049,200 |
| 18. | March | 17,000 | 15,300 | 1,700 | 2,233,800 | 646,000 | 2,879,800 |
| 19. | April | 16,000 | 14,400 | 1,600 | 2,102,400 | 608,000 | 2,710,400 |
| 20. | May | 16,000 | 14,400 | 1,600 | 2,102,400 | 608,000 | 2,710,400 |
| 21. | June | 16,000 | 14,400 | 1,600 | 2,102,400 | 608,000 | 2,710,400 |
| 22. | Total | 101,000 | 90,900 | 10,100 | $13,271,400 | $3,838,000 | $17,109,400 |
| 23. | | | | | | | |
| 24. | | | | | | **Total AMI Meter Post Test Year Proforma =** | **$53,699,800** |

# IT and Facilities Capital Post Test Year Additions

| Line No. | WA# | Project Description | Purpose | Project Cost to Date 12/31/10 | Cost to Complete | Total Project Cost | Estimated In-Service Date |
|---|---|---|---|---|---|---|---|
| 1. | P138020 | DV Ops Cntr Phase I - DVN1 | Program/Design the demo and rebuild of the DVN1 Building. Critical Operations to be included: ECC, MDH/DOMS and the Customer Call Ceeter with supporting functions. Remove and Replace HVAC, Electrical, controls systems and all lighting. Add a Central Plant, UPS, APU systems. | $ 7,324,739 | $ 26,834,601 | $ 34,159,340 | 12/30/2011 |
| 2. | T25957 | Disaster Recovery Program Phase 1 | To enhance IS Disaster Recovery strategy and establish program to implement and progess it, to ensure sufficent disaster recovery infrastructure and support processes are in place in the event of a major site disaster impacting the DV or 502 Data Centers. | $ 6,063,877 | $ 140,289 | $ 6,204,167 | 3/1/2011 |
| 3. | Budget | Automobile Lease Purchase | Purchase of remaining asset value after lease period ends | $ - | $ 5,714,232 | $ 5,714,232 | 12/30/2011 |
| 4. | T26461 | PSFSCM Upgrade 9.1 | Define the future roadmap of PeopleSoft Portal application in accordance with HR Web Strategy. The long term vision is to integrate Sharepoint with core PeopleSoft HCM applications so that all HR employee and leader information and tools are accessed through one site. Upgrade PeopleSoft Human Capital Management (HCM) applications from version 8.9 to 9.1 (or 9.2 if available). (HR, Benefits, Payroll, Time and Labor, Employee and Manager Self Service, COBRA, Recruiting, etc.) | $ 1,036,401 | $ 3,178,683 | $ 4,215,084 | 6/1/2012 |
| 5. | Budget | CSS - APS.com Enhancements (Redesign, Mobile and Automation) | Strategic Business Requirement to support customer demands for information and functionality on company web page | $ - | $ 3,871,201 | $ 3,871,201 | 12/30/2011 |
| 6. | Budget | Contact Center | Single source solution-Cisco Unified Contact Center Enterprise (UCCE) | $ - | $ 3,473,618 | $ 3,473,618 | 12/30/2011 |
| 7. | T25434 | EMS PI Historian | Implement PI Historian for EMS including software, hardware, and displays. Provide replacement for Spectrum Historical Reporting application. | $ 2,297,427 | $ 212,606 | $ 2,510,033 | 12/30/2011 |
| 8. | Budget | Digital / Video Wall Map MDH | $40M has been spent on a new distribution operations center and we intend to remove paper maps. We need a digital display technology that will work to replace paper. | $ - | $ 2,406,422 | $ 2,406,422 | 12/30/2011 |
| 9. | T25610 | DWDM Replacement | Design/implement robust multiplexing network by using Dense Wavelength Division Multiplexing (DWDM). Replace existing DWDM nodes with Cisco nodes, increase system bandwidth, speed, reliability, segregate process and business applications by using wavelength technology, and physical separation. | $ 1,788,911 | $ 165,548 | $ 1,954,458 | 12/30/2011 |
| 10. | Budget | Prepaid Metering | Business Unit strategy to provide ACC approved new product. Modifications to AMI and CIS to allow customers to prepay with proper customer tracking and notification. | $ - | $ 1,569,406 | $ 1,569,406 | 12/30/2011 |
| 11. | Budget | Telegraph Pass(Remodel/Replace/Evaluate) | New Telegraph Pass Comm house and transition of equipment/comms from Yuma's location. Existing risk factors include degrading facilities which may no longer be able to support communications for transmission or generation. | $ - | $ 1,546,806 | $ 1,546,806 | 3/1/2012 |
| 12. | Budget | EMS Network Concentrator Upgrades | Upgrades to concentrators as Smartgrid expands. | $ - | $ 1,464,779 | $ 1,464,779 | 12/30/2011 |
| 13. | T26578 | Maximo Phase 3 | Continue the implementation of the T&D functionality into new Maximo 7 system. This phase will focus encapsulating ODL functionality in Maximo and configuring the system to set Protective Relays as Assets. | $ 601,112 | $ 421,822 | $ 1,022,934 | 12/30/2011 |
| 14. | Budget | HMI Upgrade - West Phoenix PP | Replace aging Fossil plant Operator Interface stations with next generation hardware and software. | $ - | $ 1,046,271 | $ 1,046,271 | 12/30/2011 |
| 15. | Budget | Home area network | The project is part of a comprehensive approach to reduce energy usage. It is part of a residential demand response and energy efficiency program that includes a technical assessment of in-home devices that will provide customers with transparent information regarding their energy use and associated costs. | $ - | $ 1,011,568 | $ 1,011,568 | 3/1/2012 |
| 16. | Budget | Plug in hybrid electric vehicle | Support of Electric vehicles at redesigned DVN1 | $ - | $ 1,011,568 | $ 1,011,568 | 3/1/2012 |
| 17. | Budget | TranZ 2012 capital improvements | This funding request is meant to provide funding for making changes that are of capital in nature, but are not specified as of yet. These changes will no doubt come forward and will be required changes as opposed to simple improvements in process or efficiency. Historically the dollars for this kind of change have been to address software and occasionally hardware needs that arise from regulatory, financial reporting, or urgent business opportunities. | $ - | $ 1,011,568 | $ 1,011,568 | 3/1/2012 |

# IT and Facilities Capital Post Test Year Additions

| Line No. | WA# | Project Description | Purpose | Project Cost to Date 12/31/10 | Cost to Complete | Total Project Cost | Estimated In-Service Date |
|---|---|---|---|---|---|---|---|
| 18. | T26583 | Zoning - Process Network Separation | This project will separate process control networks from business networks. | $ 1,039,614 | $ 96,207 | $ 1,135,821 | 12/30/2011 |
| 19. | T26223 | Carol Springs-Greens Peak-Signal Pe | Replace microwave equipment and antenna systems to meet performance objectives, Carol Springs Electronic Station to Greens Peak and Signal Peak | $ 849,462 | $ 78,610 | $ 928,072 | 12/30/2011 |
| 20. | T26231 | SOAR Scorecard and DWH | This project will develop a data warehouse for reporting on all T&D historical data using specialized query and reporting tools. The source of the data will be from systems including Maximo, Primavera, DOMS, OIS, TOAN, EMS, HR data, Accounting Data, KPI's and GIS. This system will allow customized data mining and complex data views. | $ 788,272 | $ 72,947 | $ 861,220 | 12/30/2011 |
| 21. | Budget | Thermostat Pilot | The project is part of a comprehensive approach to reduce energy usage. It is part of a residential demand response and energy efficiency program that includes a technical assessment of in-home devices that will provide customers with transparent information regarding their energy use and associated costs. | $ - | $ 1,011,568 | $ 1,011,568 | 3/1/2012 |
| 22. | T25594 | Transmission GIS/Vegetation Managem | Leverage the O&M collection of LIDAR vegetation and transmission data (separate, but related project) by creating a system that stores and provides the base foundation infrastructure and tools to access and maintain this data. | $ 644,044 | $ 59,600 | $ 703,644 | 12/30/2011 |
| 23. | Budget | Bill on Read date | Business need added funcationality to current systems to maintain operational efficiency | $ - | $ 873,636 | $ 873,636 | 12/30/2011 |
| 24. | Budget | Mainframe Storage Refresh | Additional disk storage media for on-going enterprise data growth. | $ - | $ 818,508 | $ 818,508 | 6/1/2012 |
| 25. | P152950 | Casa Grande - Service Center T.I. H | Upgrade and Replacement: HVAC, Energy Ventialor Recovery Units, ceiling system, lighting system and restroom fixtures | $ 823,156 | $ 76,176 | $ 899,332 | 12/30/2011 |
| 26. | Budget | CSS - Change Control Board (CIS) | Placeholder for enhancements made to the CIS applications that are geared towards reducing O&M costs for the Business, improve customer satisfaction, and improve revenue | $ - | $ 832,818 | $ 832,818 | 3/1/2012 |
| 27. | Budget | Windows 7 | Engineer, develop, build, test and implement the Windows 7 OS workstation enterprise wide. | $ - | $ 941,643 | $ 941,643 | 12/30/2011 |
| 28. | Budget | SurePay / AutoPay Upgrade | The Web Infrastructure project is an initiative aimed at keeping up with growth of the enterprise web environment in terms of servers, storage, licensing and further consolidation of web server environment. | $ - | $ 837,016 | $ 837,016 | 12/30/2011 |
| 29. | T26343 | PMAC Upgrade | This project is to replace the existing application and improve the usability of the PMAC relay setting's data being stored in the database. This will add more structure to the data so that it can be integrated with the new Maximo system and support the growing reporting needs of the Asset Management Group. This will also improve performance and other application limitations due to old technology. | $ 8,764 | $ 210,065 | $ 218,829 | 12/30/2011 |
| 30. | T26530 | ECM Records Management | This is to update the ECM infrastructure to the latest version 4.0 to 4.5 and to install the Records Manager tool. | $ 171,055 | $ 15,830 | $ 186,885 | 12/30/2011 |
| 31. | T26584 | Informatica ETL Mappings Implementa | Replace Sagent with new ETL tool (Informatica) for more functionality and better performance. | $ 138,739 | $ 12,839 | $ 151,578 | 12/30/2011 |
| 32. | Budget | Directory Services Optimization | Upgrade of current system functionality. This will collapse the many desperate AD's into a common environment. | $ - | $ 209,254 | $ 209,254 | 12/30/2011 |
| 33. | Budget | Distributed Tape Refresh | Current System Improvements and Upgrades | $ - | $ 613,881 | $ 613,881 | 6/1/2012 |
| 34. | Budget | DVO Telephony | Upgrade of telephone system in non-CHQ location for additional functionality | $ - | $ 511,568 | $ 511,568 | 6/1/2012 |
| 35. | Budget | Fossil Generation Information Management System | Fossil Generation Information Management System | $ - | $ 523,135 | $ 523,135 | 12/30/2011 |
| 36. | T26317 | 800mhz TTA | Upgrade/replace existing tower top amplifiers & receiver mulit-couplers at 6 APS microwave/radio sites state wide | $ 132,932 | $ 12,302 | $ 145,234 | 12/30/2011 |

# IT and Facilities Capital Post Test Year Additions

| Line No. | WA# | Project Description | Purpose | Project Cost to Date 12/31/10 | Cost to Complete | Total Project Cost | Estimated In-Service Date |
|---|---|---|---|---|---|---|---|
| 37. | Budget | TranZ .NET conversion 2012 | Current System Improvements and Upgrades | $ - | $ 511,568 | $ 511,568 | 6/1/2012 |
| 38. | Budget | System Health Indicator Program | Implement a solution that automates documenting & reporting System Health at a site & across plants. Integrate data from supporting systems Maximo, Smart Signal, NewCO, Vibrations, TapRoot, etc into a weighted algorithm to calc overall system health | $ - | $ 544,061 | $ 544,061 | 12/30/2011 |
| 39. | T26459 | DDO Digital Wall Map | Printing/plotting enhancements, system planning requirements, ICCP (the protocol for passing information from one control system to another) analogs, PMAC (APS's Protective Metering and Control Department) integration and Maximo devices, switching plans, equip locations, cap bank integration, continue DOMS - EMS integration for Distribution SCADA (Supervisory Control and Data Acquisition - the system that facilitates retrieval of data from field devices and remote control of same) devices, get symbology we currently have operating correctly , Vista Switch Gear & ATO's symbology for what we have, more device properties from external sources into DOMS. | $ 371,919 | $ 34,418 | $ 406,337 | 12/30/2011 |
| 41. | Budget | Budget/Planning Application | Business based need for improved budget and planning software to facilitated various reviews of budget performance and fudiciary discipline | $ - | $ 511,568 | $ 511,568 | 6/1/2012 |
| 42. | Budget | TranZ .NET conversion from VB6 and improvement of MTM process | This project is meant to upgrade the base technology from Microsoft VB6 to Microsoft .NET allowing for reduced cost for future upgrades and eliminate growing risk from Microsoft's focus turning away from older VB6 technology . | $ - | $ 523,135 | $ 523,135 | 12/30/2011 |
| 43. | T26314 | One Maximo | Consolidate the three Maximo environments and databases used in Generation (four Corners, Cholla, & Gas/Oil plants). | $ 521,169 | $ 48,230 | $ 569,399 | 12/30/2011 |
| 44. | Budget | InsideAPS enhancements and eOn sites retirements | This project is to consolidate the various old legacy eOn websites, it also includes migration of all Newsline articles from old legacy technology to InsideAPS along with various small enhancements that have been requested by corporate communications. | $ - | $ 209,254 | $ 209,254 | 12/30/2011 |
| 45. | Budget | Customer Interaction Scorecard | Business need added funcationality to current systems to maintain operational efficiency | $ - | $ 517,566 | $ 517,566 | 3/1/2012 |
| 46. | Budget | Replace non-Smartzone/P25 Capable Radios in Metro Phoenix | Excluding upgrades being done under the 2 Way Radio Enhandcement project (1509), this project will replace the remaining analog 2 Way radios that will not operate on a APCO P25 system. These radios are also at end of life and are no longer supported by the manufacturer. | $ - | $ 476,448 | $ 476,448 | 3/1/2012 |
| 47. | Budget | Flagstaff CSO | Community Joint Office - Buildout Customer Service Office with City of Flagstaff's City Building. Timing based on City of Flagstaff's approval. | $ - | $ 470,822 | $ 470,822 | 12/30/2011 |
| 48. | Budget | HR Common Retirement (Expand TIBCO HR Service) | This project is to leverage the investment of the TIBCO HR Service for all apps requiring data from PeopleSoft HCM. Currently many databases house HR Data. This project will track these and work with the business/IT teams to migrate to the new Service. | $ - | $ 423,563 | $ 423,563 | 6/1/2012 |
| 49. | Budget | TranZ .NET conversion from VB6 and improvement of Trade Capture process | This project is intended to update the technology from Microsoft VB6 to Microsoft .NET to enable not only future business needs as we evolve but to enable IT to do so much more effectively using the technological advancements in place today. | $ - | $ 418,508 | $ 418,508 | 12/30/2011 |
| 50. | Budget | Security Improvements - Generation (Saguaro and Yucca) | These are security improvement projects for Generation that moved to IT for funding / implementation. | $ - | $ 408,045 | $ 408,045 | 12/30/2011 |
| 51. | Budget | DMC Phase 2 - integrate with Resource Planning | Continuation of Water Resource Planning "Decision Modeling Center" build-out | $ - | $ 303,470 | $ 303,470 | 3/1/2012 |
| 52. | T26554 | PowerPlant Enhancements 2010 Phase | Phase 2 of PowerPlant 10.2.1 installation, to develop additional enhancement priorities identified in the IS Requirements Specification & additional interfaces, controls, and further automation of manual tasks performed by Accounting. | $ 117,001 | $ 10,827 | $ 127,829 | 12/30/2011 |
| 53. | Budget | Push e-billing integration | Purchase and implement a Matter Management and eBilling solution for the Legal Dept. | $ - | $ 354,049 | $ 354,049 | 3/1/2012 |
| 54. | T26229 | Mt Elden Cholla Microwave | Replace microwave equipment and antenna systems to meet performance objectives, Mt Eldon Electronic Station to Cholla. | $ 260,299 | $ 24,088 | $ 284,387 | 12/30/2011 |

# IT and Facilities Capital Post Test Year Additions

| Line No. | WA# | Project Description | Purpose | Project Cost to Date 12/31/10 | Cost to Complete | Total Project Cost | Estimated In-Service Date |
|---|---|---|---|---|---|---|---|
| 55. | Budget | Commitment Control and CWP | Business based need for improved budget and planning software to facilitated various reviews of budget performance and fudiciary discipline | $ - | $ 358,097 | $ 358,097 | 6/1/2012 |
| 56. | T26511 | Fossil Generation - KPI (Metrics) | Implement a system to accumulate, update, and display reports for Fossil Generation. | $ 106,972 | $ 9,899 | $ 116,871 | 12/30/2011 |
| 57. | Budget | IDM Improvements Phase 2 | IS Infrastructure uses Identity Lifecycle Manager & in-house software to de-provision users for separations/transfers. The project is to consolidate/eliminate redundant software, leverage ILM more effectively & build for future implementations | $ - | $ 353,653 | $ 353,653 | 3/1/2012 |
| 58. | Budget | EMS Real Time Upgrades | The current version of the OHM database used by APS is at end of life with the Pure Safety Organization and will no longer be supported as of December 31, 2010. Evaluation of the current OHM database has identified that the current version has many outdated analysis and reporting functions leaving our regulatory and compliance programs at risk of incorrectly interpreting the data. In addition, an evaluation through the LEAN process has identified that the current OHM system does not support the electronic forms processing and increased medical analysis and reporting necessary to ensure compliance in NRC, OSHA, and DOT regulatory programs. | $ - | $ 313,881 | $ 313,881 | 12/30/2011 |
| 59. | Budget | DV IDF Redesign | Implement an enterprise wide Purchasing & Inventory Management system that supports the new Supply Chain processes. | $ - | $ 321,250 | $ 321,250 | 6/1/2012 |
| 60. | Budget | Deer Valley to Biscuit Flat via Rose Garden and Adobe (Statewide Fiber buildout Program) | OASIS/OATI processes continue to evolve and require system changes to stay in line with new requirements. The methodology for designating and undesignating use of transmission for own load is being modified. It is far too early to know how it will impact us specifically, but it will require further automation and integration with software packages, TranZ and PCI. | $ - | $ 308,729 | $ 308,729 | 1/1/2012 |
| 61. | Budget | Websense upgrade | Foundation Infrastructure required to supprot "critical business functions" | $ - | $ 303,470 | $ 303,470 | 3/1/2012 |
| 62. | Budget | Remote location Update | Tenant improvements- recently renewed leased space in Washington DC for Government liasion. Timing- coinicides with lease renewal. | $ - | $ 293,640 | $ 293,640 | 6/1/2012 |
| 63. | Budget | OATI Based Changes to own load transmission utilization | We currently have applications like email, calendar, and contacts available on mobile devices. We are working towards a device agnostic solution that will enable us to move towards a thin client solution for all users. Taking this approach further and based on many requests from business units (eg: Fossil to access plant information) we are proposing this project to enable intranet access on mobile devices like iPhones, Droids, Blackberries thus extending the trusted platform to a broad range of applications and use cases. | $ - | $ 261,568 | $ 261,568 | 12/30/2011 |
| 64. | Budget | CHQ | Replacment of Electrical transfer switches at CHQ. Timing- based on failures and planned useful life of equipment. | $ - | $ 296,095 | $ 296,095 | 12/30/2011 |
| 65. | Budget | FileNet and Sharepoint Integration | To help with integration of FileNet & SharePoint. With SharePoint rollout/asking people to move completed documents to eDocs, we have been asked to provide tools to ease the transfer from one system to another. This project will at third party integration | $ - | $ 313,881 | $ 313,881 | 12/30/2011 |
| 66. | Budget | Enhance single-sign-on solutions for non-Microsoft integrated technologies and for SaaS solutions while maintaining compliance with tiers of information sensitivity and potential re-authentication requirements. (D13, D17) | This initiative leverages the AMI data to provide proactive customer alerts via voice, text and e-mail. Customers would have the ability to opt in for outage, usage and pricing alerts. The alerts proactively provide the customers with the information they are looking for, eliminating the need for the customer to call in for status updates or information. | $ - | $ 252,892 | $ 252,892 | 3/1/2012 |
| 67. | Budget | Union Dues - APTMS Enhancements | Current System Improvements and Upgrades | $ - | $ 278,181 | $ 278,181 | 3/1/2012 |
| 68. | Budget | Maximo Enhancements | Allow for necessary work required to maintain application integrity. Several enhancements have been identified for Phase 1,2 and 3 as the business has been using the products. OA's will be generated and this could be broken into several projects based on priority. | $ - | $ 261,568 | $ 261,568 | 12/30/2011 |
| 69. | Budget | Coolidge | Flooring. SE Divison Emergency Op's Center. Flooring is Beyond planned useful life | $ - | $ 9,104 | $ 9,104 | 3/1/2012 |
| 70. | P155480 | CHQ L-1, Remodel Gallery to Allow T | Demolition and remodeling of the open gallery, the TA receoption area, entry points and 1 meeting room. | $ 255,790 | $ 23,671 | $ 279,461 | 12/30/2011 |

# IT and Facilities Capital Post Test Year Additions

| Line No. | WA# | Project Description | Purpose | Project Cost to Date 12/31/10 | Cost to Complete | Total Project Cost | Estimated In-Service Date |
|---|---|---|---|---|---|---|---|
| 71. | Budget | EMS CIP Optimization | There are many areas where our CIP compliance is maintained by manual processes. This project is to implement automated tools/methods where possible to automate artifact generation and reduce compliance risk. | $ - | $ 240,642 | $ 240,642 | 12/30/2011 |
| 72. | T26505 | Synchronization Time Clock Replacem | Engineer and upgrade the current synchronization equipment to support the SONET network operations. The addition of the new synchronization equipment will provide redundancy, take advantage of the technology to allow the equipment to better determine a source of synchronization, and provide better alarming and reporting of the health and status of the synchronization system. | $ 6,417 | $ 594 | $ 7,010 | 12/30/2011 |
| 73. | T26542 | Matter Management eBilling | Replace internally developed Access database for Law Dept with Practice/Matter Management and e-Billing software that will bring information from various databases, speadsheets, and documents into one matter centric collaboration tool. | $ 220,123 | $ 20,370 | $ 240,493 | 12/30/2011 |
| 74. | T26441 | Decision Modeling Center | This project will develop and implement the tools required for the Water Resource Planning department: a web mapping application that will enable users access to a view-only GIS web service/mapping tool and a water modeling application, which will provide the ability to simulate and display water resource scenarios and data. | $ 81,482 | $ 174,944 | $ 256,425 | 12/30/2011 |
| 75. | Budget | Power Gem | Renewal for GIS Enterprise License Agreement, renewed every 3 years and will cover APS' entire installed software base of Environmental Systems Research Institute (ESRI) GIS software, and unlimited licenses. | $ - | $ 209,254 | $ 209,254 | 12/30/2011 |
| 76. | Budget | SOUTHERN YD | Paving & Landscaping - Improvements to newly purchased property; dust control and useability. Timing- purchased in 2010 . | $ - | $ 247,599 | $ 247,599 | 6/1/2012 |
| 77. | Budget | SQL 2000 Obsolescense | Mainstream support for SQL server (2000) version ended 4/8/2008. Once the Extended Support ends, the product will be outside of the supported security patching level, thus exposing the company network environment to additional security risks. | $ - | $ 209,254 | $ 209,254 | 12/30/2011 |
| 78. | Budget | DVF | Fire Detection and Alarm System Replacement based on failures and planned useful life. | $ - | $ 121,388 | $ 121,388 | 3/1/2012 |
| 79. | T26398 | APS Mapping Application Replacement | This project is for a solution using advancements by ESRI & Telvent to meet current needs. APS GIS is the provider of land & distribution facility data to DOMS & web map services including AMI, EIN, Wildfire, MATS & field data for the GIS field map viewer | $ 201,446 | $ 18,642 | $ 220,088 | 12/30/2011 |
| 80. | T26079 | Aruba 802.11 Security Enhancements | Implement a more secure SSID for wireless users. Also instal redundent Airwave controllers | $ 173,460 | $ 16,052 | $ 189,512 | 12/30/2011 |
| 81. | T26400 | Decoupling Project | Implement Cisco Voice Gateways to decouple Call Manager solution from the Nortel PBX, to provide access to pulic switched telephone network and eliminate PBX dependencies. Modify APS Telephone Management System to access Call Manager database to input long distance authorization codes. | $ 113,320 | $ 10,487 | $ 123,807 | 12/30/2011 |
| 82. | Budget | Firewall Replacement & Manageability Improvements | This project will assist with hardware obsolescence replacements as well as allocate resources to make tuning and process improvements that would help the performance and reliability of the system. | $ - | $ 104,627 | $ 104,627 | 12/30/2011 |
| 83. | Budget | Maximo Phase 2 | Enhance single-sign-on solutions for non-Microsoft integrated technologies and for SaaS solutions while maintaining compliance with tiers of information sensitivity and potential re-authentication requirements. (D13, D17) | $ - | $ 104,627 | $ 104,627 | 12/30/2011 |
| 84. | Budget | Implement automation of user/sites management for SharePoint | Procure and implement SharePoint administration tools that will allow automation of user management and sites management for SharePoint. | $ - | $ 104,627 | $ 104,627 | 12/30/2011 |
| 85. | Budget | SOUTHERN YD SECURITY | Security & Fencing - Improvements to newly purchased property; access control, security and useability. Timing- purchased in 2010 . | $ - | $ 104,627 | $ 104,627 | 12/30/2011 |

# IT and Facilities Capital Post Test Year Additions

| Line No. | WA# | Project Description | Purpose | Project Cost to Date 12/31/10 | Cost to Complete | Total Project Cost | Estimated In-Service Date |
|---|---|---|---|---|---|---|---|
| 86. | Budget | Implement Intranet Access for mobile devices that use GoodLink/ActiveSync/Blackberry. | We have apps available on mobile devices & working on a thin client solution for all users. Based on requests from business units this project will allow intranet access on mobile devices extending the trusted platform to a broad range of apps/use cases | $ - | $ 104,627 | $ 104,627 | 12/30/2011 |
| 87. | Budget | Purchase SharePoint migration tool, Backup/restore tool, rebuild legacy websites using sharepoint | Purchase of SharePoint Migration tool and next tier backup / storage tool (due to growth), retirement of legacy websites, creating new SharePoint sites, retirement of SharePoint 2003 and 2007 sites. | $ - | $ 101,157 | $ 101,157 | 3/1/2012 |
| 88. | Budget | Goodyear CSO | Remodel - Customer Service Office jointly with new City of Goodyear building. This project has been moved to future years based on City of Goodyear's development plan. | $ - | $ 104,627 | $ 104,627 | 12/30/2011 |
| 89. | T26596 | Zoning Process Network Separation | This project will separate process control networks from business networks. | $ 91,527 | $ 8,470 | $ 99,997 | 12/30/2011 |
| 90. | P157207 | Conference Room Upgrades L3 & L15 | Purchase and installation of the new conference room tables, seating and Audio Video equipment. | $ 73,540 | $ 6,805 | $ 80,346 | 12/30/2011 |
| 91. | T26451 | EAI Infrastructure Upgrade SS Gen | Continuation effort to restructure the EAI Corporate Domains (environments). | $ 72,809 | $ 6,738 | $ 79,547 | 12/30/2011 |
| 92. | Budget | Deer Valley Sub | Substation Control House Roofing Replacement. Replacments are scheduled on 30 year intervals based on maintained useful life. | $ - | $ 43,943 | $ 43,943 | 12/30/2011 |
| 93. | T26467 | PowerPlant Enh for IFRS | Enhance the PowerPlant application to capture the necessary data and interface to PeopleSoft for compliance with International Financial Reporting Standards. | $ 69,299 | $ 6,413 | $ 75,712 | 12/30/2011 |
| 94. | T26298 | Power Backup - Falcon Crest | Upgrade batteries and charging systems at mountain top communications sites. | $ 31,250 | $ 2,892 | $ 34,142 | 12/30/2011 |
| 95. | Budget | GIS GIS DB Changes- UFO-ID. Merge, ST Geom | To change to static unique ID data relationships in our Geodatabases. The relationships currently use an Object ID to relate to each other. This is a SW-generated ID that changes when certain functions are executed. | $ - | $ 62,776 | $ 62,776 | 12/30/2011 |
| 96. | T26299 | Power Backup - Yuma SC | Upgrade batteries and charging systems at mountain top communications sites. | $ 6,776 | $ 627 | $ 7,404 | 12/30/2011 |
| 97. | Budget | DVM | HVAC- Replace 7 units. Units beyond planned useful life | $ - | $ 58,671 | $ 58,671 | 3/1/2012 |
| 98. | T26300 | Power Backup - Childs Mtn | Upgrade batteries and charging systems at mountain top communications sites. | $ 13,282 | $ 1,229 | $ 14,512 | 12/30/2011 |
| 99. | T25576 | Black Peaks ES | Upgrade batteries and charging systems at mountain top communications sites | $ 46,880 | $ 4,338 | $ 51,218 | 12/30/2011 |
| 100. | Budget | Willow Creek Sub | Substation Control House Roofing Replacement. Replacments are scheduled on 30 year intervals based on maintained useful life. | $ - | $ 36,416 | $ 36,416 | 3/1/2012 |
| 101. | Budget | Pwr Backup - Signal Peak | Replace the obsolescence charging system and batteries | $ - | $ 10,463 | $ 10,463 | 12/30/2011 |
| 102. | Budget | PWR - Mt Elden | Replace the obsolescence charging system and batteries | $ - | $ 36,619 | $ 36,619 | 12/30/2011 |
| 103. | Budget | 32 St Sub | Substation Control House Roofing Replacement. Replacments are scheduled on 30 year intervals based on maintained useful life. | $ - | $ 32,370 | $ 32,370 | 3/1/2012 |
| 104. | Budget | Tuba City RES | Flooring & Remodel -Housing provided to area sericeman. Flooring and Furnishings are beyond their planned useful life | $ - | $ 20,231 | $ 20,231 | 3/1/2012 |
| 105. | T26157 | Power Backup Program - Mt Elden | Upgrade batteries and charging systems at mountain top communications sites. | $ 28,642 | $ 2,651 | $ 31,293 | 12/30/2011 |
| 106. | Budget | Coldwater Sub | Substation Control House Roofing. Restore has been determined as O&M per Accounting. Restorations are are scheduled every 10 years over 30 year life span. | $ - | $ 11,509 | $ 11,509 | 12/30/2011 |
| 107. | V1258 | PV U2 OSB L4 AO Briefing Room Remod | Remodel existing facility based on business unit growth and usage need changes | $ 10,923 | $ 1,011 | $ 11,934 | 12/30/2011 |
| 108. | **Total IT and Facilities Capital Post-Test Year Additions** | | | | | **$ 101,572,939** | |

**BEFORE THE**

**ARIZONA CORPORATION COMMISSION**

**DIRECT TESTIMONY OF**

**WILLIAM E. AVERA**

**On Behalf of Arizona Public Service Company**

**Docket No. E-01345A-11-____**

**June 2011**

# DIRECT TESTIMONY OF WILLIAM E. AVERA

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Sustainable Growth Rate – Non-Utility Proxy Group ..... Attachment WEA-5
Capital Asset Pricing Model –Utility Proxy Group ..... Attachment WEA-6
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Book Value Capital Structure – Utility Proxy Group ..... Attachment WEA-8
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Book Value Capital Structure – Electric Utility Operating Cos. .... Attachment WEA-10
Cost Recovery Mechanisms – Utility Proxy Group ..... Attachment WEA-11

**DIRECT TESTIMONY OF WILLIAM E. AVERA**
**ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY**
**(Docket No. E-01345A-11-_____)**

## I. INTRODUCTION AND SUMMARY OF CONCLUSIONS

**Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A. William E. Avera, 3907 Red River, Austin, Texas, 78751.

**Q. IN WHAT CAPACITY ARE YOU EMPLOYED?**

A. I am the President of FINCAP, Inc., a firm providing financial, economic, and policy consulting services to business and government.

**Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

A. The purpose of my testimony is to present to the Arizona Corporation Commission ("ACC" or the "Commission") my independent assessment of the fair rate of return on equity ("ROE") for the jurisdictional electric utility operations of Arizona Public Service Company ("APS" or "Company"). In addition, I also examined the reasonableness of APS's capital structure, considering both the specific risks faced by the Company and other industry guidelines.

### *A. Summary of Conclusions*

**Q. WHAT ARE YOUR FINDINGS REGARDING THE FAIR RATE OF RETURN ON EQUITY FOR APS?**

A. Based on the results of my analyses and the economic requirements necessary to support continuous access to capital, I recommend that APS be authorized an ROE in the range of 10.75 percent to 11.75 percent, with the midpoint being 11.25 percent. My findings were based on the following conclusions:

- In order to reflect the risks and prospects associated with APS's jurisdictional utility operations, my analyses focused on a proxy group of other utilities with comparable investment risks;

- Consistent with the fair value rate base standard, and the fact that utilities must compete for capital with firms outside their own industry, I also referenced a proxy group of comparable risk companies in the non-utility sector of the economy;

- Because investors' required return on equity is unobservable and no single method should be viewed in isolation, I applied both the discounted cash flow ("DCF") approach and capital asset pricing model ("CAPM") to estimate a fair ROE for APS. These methods are forward-looking and can be applied under the fair value rate base standard without adjustments;

- Based on the results of these analyses, and giving less weight to extremes at the high and low ends of the range, I concluded that the cost of equity for the proxy groups of utilities and non-utility companies is in the 10.6 percent to 11.60 percent range, or 10.75 percent to 11.75 percent after incorporating a minimal adjustment to account for the impact of common equity flotation costs;

- Investors view existing and proposed cost recovery and revenue adjustment mechanisms as supportive of APS's financial integrity, but there is no evidence that these provisions alone will result in a measurable change in the Company's investment risk or ROE relative to the proxy companies;

- The reasonableness of an 11.25 percent ROE for APS is also supported by the greater investment risks implied by:
    - The Company's low credit rating,
    - The pressures of funding significant capital expenditures,
    - The potential for continued regulatory lag,
    - Exposures to nuclear uncertainty, and
    - The expected upward trend in long-term capital costs.

    - As reflected in the testimony of Mr. Jeff Guldner APS is requesting a fair ROE of 11.00 percent to balance customer impact during these challenging economic times with the Company's

need to maintain is financial integrity and access to capital. This 11.00 percent ROE falls below the midpoint of my recommended range and, in my professional opinion, represents a reasonable rate of return on common equity for APS; and,

- Taken together, these factors more than offset any arguable impact attributable to the implementation of the Company's existing and proposed adjustment mechanisms.

**Q. WHAT OTHER EVIDENCE DID YOU CONSIDER IN EVALUATING YOUR ROE RECOMMENDATION IN THIS CASE?**

A. My recommendation was reinforced by the following findings:

- Sensitivity to financial market and regulatory uncertainties has increased dramatically and investors recognize that constructive regulation is a key ingredient in supporting utility credit standing and financial integrity;

- Providing APS with the opportunity to earn a return that reflects these realities is an essential ingredient to support the Company's financial position, which ultimately benefits customers by ensuring reliable service at lower long-run costs;

- Strengthening APS's financial integrity is imperative to ensure that the Company has the capability to maintain an investment grade rating while confronting the pressures associated with funding substantial infrastructure development and ensuring APS's ability to respond effectively to unforeseen events, and,

- The ROE estimates developed in my testimony, as well as the weighted cost of capital requested by APS, can and should be applied to fair value rate base, without adjustment, since the estimation methods are forward-looking and based on returns required on market values. Lowering the ROE when determining the reasonable return on fair value would amount to simply another way of reducing the Company's fair value rate base.

**Q. HOW DID YOU CONDUCT YOUR ANALYSIS OF THE COST OF EQUITY SO THAT THE RESULT CAN BE APPLIED TO THE FAIR VALUE RATE BASE WITHOUT ADJUSTMENT?**

A. I implemented the DCF and CAPM methods using forward-looking expectations applied to current market values that are consistent with a fair value rate base standard. My DCF approach used expected dividend yields and forecasted growth rates based on professional security analysts' current expectations. My application of the CAPM was based on expected dividend yields and growth forecasts underlying the expected return on the broad market. I did not employ risk premium estimates based on historical returns nor did I reference comparable earnings on original cost investment. By using forward-looking approaches that estimate the cost of equity based on current market values, the resulting reasonable ROE range is consistent with my understanding of the constitutional requirements in Arizona. Thus, the 11.00 percent return that APS selected from the lower end of my reasonable range can be applied under the fair value rate base standard without further adjustments.

**Q. IS ATTRITION A LEGITIMATE CONSIDERATION IN ESTABLISHING APS' RATES FOR ELECTRIC UTILITY SERVICE?**

A. Yes. Regulatory lag is prevalent in Arizona and attrition remains a major concern of the investment community. If the impact of attrition is ignored, the Company will be denied an opportunity to earn investors' required rate of return. My testimony demonstrates that:

- APS is undertaking a huge capital investment program in order to meet the growing requirements of customers. A continuation of regulatory lag would prevent the Company from achieving timely cost recovery, which would erode the Company's credit metrics;
- In evaluating the Company's requested ROE, the Commission should consider the economic reality that APS's actual returns have fallen systematically short of the allowed ROE;

- Setting rates at a level that considers the impact of attrition and allows the utility an opportunity to actually earn its authorized ROE is consistent with fundamental regulatory principles:
    - To be fair to investors and to benefit customers, a regulated utility must have an opportunity to actually earn a return that will maintain financial integrity, facilitate capital attraction, and compensate for risk;
    - Central to the determination of reasonable rates for utility service is the notion that owners of public utility properties are protected from confiscation;
    - Denying APS the opportunity to earn a sufficient return through the impact of attrition is the economic equivalent of taking the capital value of existing investors.
- APS's proposed cost and revenue adjustment mechanisms represents a logical approach to attenuate the impact of attrition.

**Q. WHAT IS YOUR CONCLUSION AS TO THE REASONABLENESS OF THE COMPANY'S CAPITAL STRUCTURE?**

A. Based on my evaluation, I concluded that a common equity ratio of approximately 54 percent represents a reasonable basis from which to calculate APS's overall rate of return. This conclusion was based on the following findings:

- APS's requested capitalization is consistent with the Company's need to strengthen its credit standing and financial flexibility as it seeks to raise additional capital to fund significant system investments and meet the requirements of its growing service territory;
- APS's proposed common equity ratio is consistent with the range of capitalizations maintained by the firms in my utility proxy group;
- My conclusion is reinforced by the investment community's focus on the need for a greater equity cushion to accommodate higher operating risks and the pressures of funding significant capital investments, as well as the impact of off-balance sheet commitments such as purchased power agreements;

- Regulatory support for higher equity levels is necessary to maintain APS's financial flexibility and preserve the Company's capacity to fund investments that will ensure reliable service and facilitate further development of electric utility infrastructure in Arizona.

*B. Qualifications*

**Q. WHAT ARE YOUR QUALIFICATIONS?**

A. I received a B.A. degree with a major in economics from Emory University. After serving in the U.S. Navy, I entered the doctoral program in economics at the University of North Carolina at Chapel Hill. Upon receiving my Ph.D., I joined the faculty at the University of North Carolina and taught finance in the Graduate School of Business. I subsequently accepted a position at the University of Texas at Austin where I taught courses in financial management and investment analysis. I then went to work for International Paper Company in New York City as Manager of Financial Education, a position in which I had responsibility for all corporate education programs in finance, accounting, and economics.

In 1977, I joined the staff of the Public Utility Commission of Texas ("PUCT") as Director of the Economic Research Division. During my tenure at the PUCT, I managed a division responsible for financial analysis, cost allocation and rate design, economic and financial research, and data processing systems, and I testified in cases on a variety of financial and economic issues. Since leaving the PUCT, I have been engaged as a consultant. I have participated in a wide range of assignments involving utility-related matters on behalf of utilities, industrial customers, municipalities, and regulatory commissions. I have previously testified before the Federal Energy Regulatory Commission ("FERC"), as well as the Federal Communications Commission, the Surface

Transportation Board (and its predecessor, the Interstate Commerce Commission), the Canadian Radio-Television and Telecommunications Commission, and regulatory agencies, courts, and legislative committees in over 40 states, including the ACC.

In 1995, I was appointed by the PUCT to the Synchronous Interconnection Committee to advise the Texas legislature on the costs and benefits of connecting Texas to the national electric transmission grid. In addition, I served as an outside director of Georgia System Operations Corporation, the system operator for electric cooperatives in Georgia.

I have served as Lecturer in the Finance Department at the University of Texas at Austin and taught in the evening graduate program at St. Edward's University for twenty years. In addition, I have lectured on economic and regulatory topics in programs sponsored by universities and industry groups. I have taught in hundreds of educational programs for financial analysts in programs sponsored by the Association for Investment Management and Research, the Financial Analysts Review, and local financial analysts societies. These programs have been presented in Asia, Europe, and North America, including the Financial Analysts Seminar at Northwestern University. I hold the Chartered Financial Analyst (CFA®) designation and have served as Vice President for Membership of the Financial Management Association. I have also served on the Board of Directors of the North Carolina Society of Financial Analysts. I was elected Vice Chairman of the National Association of Regulatory Commissioners ("NARUC") Subcommittee on Economics and appointed to NARUC's Technical Subcommittee on the National Energy Act. I have also served as an officer of various other professional organizations and societies. Attachment

WEA-1 contains a resume presenting the details of my experience and qualifications.

*C. Overview*

**Q. WHAT IS THE PRACTICAL TEST OF THE REASONABLENESS OF THE ROE USED IN SETTING A UTILITY'S RATES?**

A. The ROE compensates equity investors for the use of their capital to finance the plant and equipment necessary to provide utility service. Investors commit capital only if they expect to earn a return on their investment commensurate with returns available from alternative investments with comparable risks. To be consistent with sound regulatory economics and the standards set forth by the United States Supreme Court in the *Bluefield*[1] and *Hope*[2] cases, a utility's allowed ROE should be sufficient to (1) fairly compensate the utility's investors, (2) enable the utility to offer a return adequate to attract new capital on reasonable terms, and (3) maintain the utility's financial integrity.

**Q. PLEASE SUMMARIZE THE INFORMATION AND MATERIALS YOU RELIED ON TO SUPPORT THE OPINIONS AND CONCLUSIONS CONTAINED IN YOUR TESTIMONY.**

A. To prepare my testimony, I used information from a variety of sources that would normally be relied upon by a person in my capacity. I am familiar with the organization, finances, and operations of APS from my participation in prior proceedings before the ACC. In connection with the present filing, I considered and relied upon corporate disclosures, publicly available financial reports and filings, and other published information relating to APS and its parent company, Pinnacle West Capital Corporation ("Pinnacle West"). I also reviewed

[1] Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n, 262 U.S. 679 (1923).
[2] *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

information relating generally to capital market conditions and specifically to investor perceptions, requirements, and expectations for electric utilities. These sources, coupled with my experience in the fields of finance and utility regulation, have given me a working knowledge of the issues relevant to investors' required rate of return for APS, and they form the basis of my analyses and conclusions.

**Q. HOW IS YOUR TESTIMONY ORGANIZED?**

A. I first reviewed the operations and finances of APS, as well as general conditions in the electric utility industry and the capital markets. With this as a background, I described the conceptual principles underlying investors' required rate of return and then conducted various well-accepted quantitative analyses to estimate the current cost of equity, including alternative applications of the DCF approach and CAPM. From the cost of equity range indicated by my analyses, a rate of return on equity was selected taking into account the fair value rate base standard used in this jurisdiction and the economic requirements and specific risks and potential challenges for APS's electric utility operations in Arizona.

## II. FUNDAMENTAL ANALYSES

**Q. WHAT IS THE PURPOSE OF THIS SECTION?**

A. As a predicate to my analyses, this section briefly reviews the operations and finances of APS, along with the risks and prospects for the utility industry. An understanding of these fundamental factors is essential in developing an informed opinion about investor expectations and requirements that form the basis of a fair rate of return.

*A. Arizona Public Service Company*

**Q. BRIEFLY DESCRIBE APS.**

A. The principal subsidiary of Pinnacle West, APS is primarily engaged in the generation, transmission, and distribution of electric power to approximately 1.1 million customers in 11 of Arizona's 15 counties. In addition to providing retail electric utility service, the Company also sells electric power at wholesale to municipalities and other utilities. During the adjusted test year, retail energy sales amounted to 27.7 million megawatt-hours ("MWh") hours. Sales to residential customers comprised approximately 51.2 percent of retail revenues from base rates, while sales to non-residential customers comprised approximately 48.8 percent of retail revenues from base rates.[3] In addition, APS had total depreciable assets of approximately $13.7 billion,[4] with operating revenues totaling approximately $3.2 billion.[5]

The Company owns approximately 6,290 MW of generating facilities, including its 29.1% interest in the three nuclear units of the Palo Verde Nuclear Generating Station ("Palo Verde"), with a total capacity of approximately 1,146 MW. In 2010, nuclear generation accounted for approximately 27 percent of the electric energy provided by APS, with coal at 37 percent, and natural gas at 12 percent. In addition to its own generating capacity, APS relied on purchased power for the remaining 24 percent of its 2010 energy needs. APS's transmission and distribution facilities consist of approximately 17,000 pole miles of overhead lines and over 17,400 miles of underground lines.

[3] APS Rate Filing, Schedule H-2.
[4] Ibid, Schedule A-4.
[5] Ibid, Schedule E-2.

The Company's retail electric operations are subject to the jurisdiction of the Commission, with transmission operations being regulated by FERC. Additionally, APS's nuclear facilities are subject to licensing and oversight by the Nuclear Regulatory Commission ("NRC"). While the Commission originally approved rules to restructure Arizona's electric utility industry in 1999, it effectively halted this process following the Western energy crisis in 2000-2001. Although future legal and regulatory developments surrounding industry restructuring remain unresolved, at the time of this filing there are no active regulated competitors providing unbundled energy or other utility services to APS's customers. However, APS does face increasingly significant competition from distributed generation, both customer-owned and that provided by unregulated third parties.

**Q. DOES APS ANTICIPATE THE NEED TO ACCESS THE CAPITAL MARKETS GOING FORWARD?**

A. Most definitely. APS will require capital investment to provide for necessary maintenance and replacements of its utility infrastructure, as well as fund new investment in electric generation, transmission and distribution facilities. In order to keep pace with the infrastructure needs of its service territory, APS anticipates construction expenditures totaling approximately $3.3 billion over the next three years alone.[6] As Fitch noted, "Compound annual growth in capital expenditures is estimated at 14% during 2010–2012.[7] Support for APS's financial integrity and flexibility will be instrumental in attracting the capital necessary to fund these projects in an effective manner.

[6] Pinnacle West Capital Corp., *2010 Form 10-K Report* at p. 63.

[7] Fitch Ratings, Ltd., "Arizona Public Service Company," *Global Power U.S. & Canada Full Ratings Report* (Jun. 11, 2010).

**Q. HOW ARE FLUCTUATIONS IN APS'S OPERATING EXPENSES CAUSED BY VARYING FUEL AND POWER MARKET CONDITIONS ACCOMMODATED IN ITS RATES?**

A. APS recovers variations in purchased power and fuel costs through a power supply adjustor ("PSA"). Under the PSA, the base fuel rate is established based on annual projections for the following year filed with the Commission. Monthly differences between the actual costs for purchased power and fuel and the base fuel rate are deferred for future recovery or refund. At year-end, the deferred balance is either charged to or credited back to customers over the coming year. As a result, deviations in actual versus projected costs are collected on a one-year lagged basis. In the event that APS experiences unexpected volatility in power costs, it can apply to the Commission for consideration of a mid-year surcharge to address extenuating circumstances.

The PSA continues to provide for a sharing mechanism, under which APS must absorb as much as the first 10 percent of costs above the base fuel rate and may retain up to 10 percent of savings when actual costs fall below projected levels. Adjustments are limited to the sum of the prior year's total PSA plus or minus $0.004 per kilowatt-hour ("kWh"), with additional amounts being recorded in a balancing account for future recovery. However, APS is proposing to remove the PSA sharing in this case.

**Q. WHAT CREDIT RATINGS HAVE BEEN ASSIGNED TO APS?**

A. Currently, APS is assigned a corporate credit rating of "BBB-" by Standard & Poor's Corporation ("S&P"). Moody's Investors Service ("Moody's") has assigned the Company an issuer rating of "Baa2", with Fitch Ratings Ltd. ("Fitch") assigning a "BBB-" issuer default rating. The "BBB-" ratings assigned by S&P and Fitch represent the lowest rung on the ladder of the

investment grade scale, and any downgrade would place the Company in the same category as speculative, or "junk" securities.

*B. Risks for APS*

**Q. HOW HAVE INVESTORS' RISK PERCEPTIONS FOR THE UTILITY INDUSTRY EVOLVED?**

A. Implementation of structural change, along with other factors impacting the economy and the industry, has caused investors to rethink their assessment of the relative risks associated with utilities. The past decade witnessed steady erosion in credit quality throughout the utility industry, both as a result of revised perceptions of the risks in the industry and the weakened finances of the utilities themselves. In December 2009, S&P observed with respect to the industry's future that:

> Looming costs associated with environmental compliance, slack demand caused by economic weakness, the potential for permanent demand destruction caused by changes in consumer behavior and closing of manufacturing facilities, and numerous regulatory filings seeking recovery of costs are some of the significant challenges the industry has to deal with.[8]

Similarly, Moody's noted:

> [A] sustained period of sluggish economic growth, characterized by high unemployment, could stress the sector's recovery prospects, financial performance, and credit ratings. The quality of the sector's cash flows are already showing signs of decline, partly because of higher operating costs and investments.[9]

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[8] Standard & Poor's Corporation, "U.S. Regulated Electric Utilities Head Into 2010 With Familiar Concerns," *RatingsDirect* (Dec. 28, 2009).

[9] Moody's Investors Service, "U.S. Electric Utilities: Uncertain Times Ahead; Strengthening Balance Sheets Now Would Protect Credit," *Special Comment* (Oct. 28, 2010).

More recently, Moody's concluded, "we also see the sector's overall business and operating risks increasing."[10]

**Q. IS THE POTENTIAL FOR ENERGY MARKET VOLATILITY AN ONGOING CONCERN FOR INVESTORS?**

A. Yes. In recent years utilities and their customers have had to contend with dramatic fluctuations in fuel costs due to ongoing price volatility in the spot markets, and investors recognize the potential for further turmoil in energy markets. In times of extreme volatility, utilities can quickly find themselves in a significant under-recovery position with respect to power costs, which can severely stress liquidity. Coal has historically provided relative stability with respect to fuel costs, but prices experienced significant volatility over the 2007 – 2009 time period. Similarly, the Energy Information Administration ("EIA"), which is a statistical agency of the U.S. Department of Energy ("DOE"), reported that the weighted-average price paid for uranium oxide equivalent in 2008 was $45.88 per pound, representing an increase of 40 percent compared to 2007 price levels and coming on the heels of a 76 percent price increase during the previous year.[11] The power industry and its customers have also had to contend with dramatic fluctuations in gas costs due to ongoing price volatility in the spot markets.

While current expectations for significantly lower power prices reflect weaker fundamentals affecting current load and fuel prices, investors recognize the potential that such trends could quickly reverse. For example, heightened uncertainties in the Middle East have led to sharp increases in petroleum prices,

[10] Moody's Investors Service, "Regulation Provides Stability As Risks Mount," *Industry Outlook* (Jan. 19, 2011).
[11] Energy Information Administration, *2008 Uranium Marketing Annual Report* (May 26, 2009).

and the potential ramifications of the Japanese nuclear accident on the future cost and availability of nuclear generation in the U.S. have not been lost on investors. S&P observed that "short-term price volatility from numerous possibilities ... is always possible,"[12] while Moody's concluded that utilities remain exposed to fluctuations in energy prices, observing, "This view, that commodity prices remain low, could easily be proved incorrect, due to the evidence of historical volatility."[13]

**Q. DOES THE PSA COMPLETELY SHIELD APS FROM EXPOSURE TO FLUCTUATIONS IN POWER SUPPLY COSTS?**

A. No. The investment community views the Company's ability to periodically adjust retail rates to accommodate fluctuations in fuel costs as an important source of support for APS's financial integrity. Nevertheless, they also recognize that there can still be a lag between the time APS actually incurs the expenditure and when it is recovered from ratepayers. As a result, APS is not insulated from the potential need to finance deferred fuel costs.[14] Indeed, despite the significant investment of resources to manage fuel procurement, investors are aware that the best that APS can do is to recover something less than its actual costs during times of rising fuel costs. In other words, APS earns no return on deferred fuel costs and is exposed to disallowances for imprudence in its fuel procurement.

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[12] Standard & Poor's Corporation, "Top 10 Investor Questions: U.S. Regulated Electric Utilities," *RatingsDirect* (Jan. 22, 2010).

[13] Moody's Investors Service, "U.S. Electric Utilities: Uncertain Times Ahead; Strengthening Balance Sheets Now Would Protect Credit," *Special Comment* (Oct. 28, 2010).

[14] Moody's has noted that the Company's financial metrics have been negatively impacted in the past as a result of power cost deferrals. Moody's Investors Service, "Credit Opinion: Arizona Public Service Company," *Credit Opinion* (Dec. 17, 2007).

**Q. WHAT OTHER FINANCIAL PRESSURES IMPACT INVESTORS' RISK ASSESSMENT OF THE COMPANY?**

A. Investors are aware of the financial and regulatory pressures faced by utilities associated with rising costs and the need to undertake significant capital investments. S&P noted that cost increases and capital projects, along with uncertain load growth, were a significant challenge to the utility industry.[15] As Moody's observed:

> [W]e also see the sector's overall business risk and operating risks increasing, owing primarily to rising costs associated with upgrading and expanding the nation's trillion dollar electric infrastructure.[16]

As noted earlier, investors anticipate that APS will undertake significant electric utility capital expenditures. While providing the infrastructure necessary to meet the energy needs of customers is certainly desirable, it imposes additional financial responsibilities on the Company.

**Q. ARE ENVIRONMENTAL CONSIDERATIONS ALSO AFFECTING INVESTORS' EVALUATION OF ELECTRIC UTILITIES?**

A. Yes. Utilities are confronting increased environmental pressures that could impose significant uncertainties and costs. Moody's noted that "the prospect for new environmental emission legislation – particularly concerning carbon dioxide – represents the biggest emerging issue for electric utilities."[17] While the momentum for carbon emissions legislation has slowed, expectations for eventual regulations continue to pose uncertainty. Fitch recently concluded,

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[15] Standard & Poor's Corporation, "Industry Economic And Ratings Outlook," *RatingsDirect* (Feb. 2, 2010).
[16] Moody's Investors Service, "Regulation Provides Stability As Risks Mount," *Industry Outlook* (Jan. 19, 2011).
[17] Moody's Investors Service, "U.S. Investor-Owned Electric Utilities," *Industry Outlook* (Jan. 2009).

"Prospects of costly environmental regulations will create uncertainty for investors in the electricity business in 2011."[18] With respect to APS specifically, Fitch noted that, "Spending in the generation category is expected to outpace transmission and distribution, driven in large part by investment in environmental remediation equipment."[19] The imperative of meeting evolving emissions standards implies significant capital expenditures for those utilities, such as APS, that rely significantly on coal-fired generation.

**Q. WHAT OTHER CONSIDERATIONS AFFECT INVESTORS' EVALUATION OF APS?**

A. In evaluating an investment in the Company, investors would also consider the fact that Palo Verde accounts for approximately 18 percent of APS's company-owned generation capacity – its largest single generating resource. S&P observed that APS is "highly exposed to nuclear power availability and operations."[20] While customers benefit from the advantages of fuel cost savings and diversity that nuclear power confers, investors also associate nuclear facilities with risks that are not encountered with other sources of generation. These concerns have been exacerbated by the events at the Fukushima Daiichi nuclear complex in Japan, as S&P recently noted:

> Standard & Poor's Ratings Service believes that the failure of the back-up safety systems will heighten scrutiny of the systematic risks for U.S. nuclear power generators. We aren't taking any rating actions at this time. Still, the failures and their consequences raise the likelihood of greater costs and enhanced

[18] Fitch Ratings Ltd., "2011 Outlook: U.S. Utilities, Power, and Gas," *Global Power North America Special Report* (Dec. 20, 2010)
[19] Fitch Ratings Ltd., "Arizona Public Service Company," *Global Power U.S. & Canada Full Ratings Report* (Jun. 11, 2010).
[20] Standard & Poor's Corporation, "Arizona Public Service Co.," *RatingsDirect* (Apr. 27, 2010).

> regulatory oversight for existing U.S. facilities. A renewed public focus on the inherent risks of nuclear power will demand as much. This could result in delays in license-extension approvals and deteriorating economics for new plant construction. At the same time, closure of nuclear power plants, either due to increased costs or regulatory action, might significantly affect U.S. electricity supply and have substantial capital spending implications for utilities.[21]

*C. Impact of Capital Market Conditions*

**Q. WHAT ARE THE IMPLICATIONS OF RECENT CAPITAL MARKET CONDITIONS?**

A. The deep financial and real estate crisis that the country experienced in late 2008, and continuing into 2009 led to unprecedented price fluctuations in the capital markets as investors dramatically revised their risk perceptions and required returns. As a result of investors' trepidation to commit capital, stock prices declined sharply while the yields on corporate bonds experienced a dramatic increase.

With respect to utilities specifically, as of December 2010, the Dow Jones Utility Average stock index remained approximately 25 percent below the previous high reached in May 2008. This prolonged sell-off in common stocks and sharp fluctuations in utility bond yields reflect the fact that the utility industry is not immune to the impact of financial market turmoil and the ongoing economic downturn. As the Edison Electric Institute ("EEI") noted in a letter to congressional representatives in September 2008 as the financial crisis intensified, capital market uncertainties have serious implications for utilities and their customers:

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[21] Standard & Poor's Corporation, "The U.S. Nuclear Power Industry Looks At Japan And Awaits More Scrutiny," *Global Credit Research* (Mar. 16, 2011).

> In the wake of the continuing upheaval on Wall Street, capital markets are all but immobilized, and short-term borrowing costs to utilities have already increased substantially. If the financial crisis is not resolved quickly, financial pressures on utilities will intensify sharply, resulting in higher costs to our customers and, ultimately, could compromise service reliability.[22]

Similarly, an October 1, 2008 *Wall Street Journal* report confirmed that utilities had been forced to delay borrowing or pursue more costly alternatives to raise funds.[23] In December 2008, Fitch confirmed "sharp repricing of and aversion to risk in the investment community," and noted that the disruptions in financial markets and the fundamental shift in investors' risk perceptions had increased the cost of capital for utilities.[24]

While conditions have improved significantly since the depths of the crisis, investors have nonetheless had to confront ongoing fluctuations in share prices and stress in the credit markets. As the Wall Street Journal noted in February 2010:

> Stocks pulled out of a 167-point hole with a late rally Friday, capping a wild week reminiscent of the most volatile days of the credit crisis. ... It was a return to the unusual relationships, or correlations, seen at major flash points over the past two years when investors fled risky assets and jumped into safe havens. This market behavior, which has reasserted itself repeatedly since the financial crisis began, suggests that investment decisions are still

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[22] *Letter to House of Representatives*, Thomas R. Kuhn, President, Edison Electric Institute (Sep. 24, 2008).

[23] Smith, Rebecca, "Corporate News: Utilities' Plans Hit by Credit Markets," *Wall Street Journal* at B4 (Oct. 1, 2008).

[24] Fitch Ratings Ltd., "U.S. Utilities, Power and Gas 2009 Outlook," *Global Power North America Special Report* (Dec. 22. 2008).

> being driven more by government support and liquidity concerns than market fundamentals.[25]

In response to renewed capital market uncertainties initiated by unrest in the Middle East, the natural disaster in Japan, ongoing concerns over the European sovereign debt crisis, and questions over the sustainability of economic growth, investors have repeatedly fled to the safety of U.S. Treasury bonds, and stock prices have experienced renewed volatility.[26] The dramatic rise in the price of gold and other commodities also attests to investors' heightened concerns over prospective challenges and risks, including the overhanging threat of inflation and renewed economic turmoil. With respect to electric utilities, Fitch observed that, "the outlook for the sector would be adversely affected by significantly higher inflation and interest rates."[27] Moody's recently concluded:

> Over the past few months, we have been reminded that global financial markets, which are still receiving extraordinary intervention benefits by sovereign governments, are exposed to turmoil. Access to the capital markets could therefore become intermittent, even for safer, more defensive sectors like the power industry.[28]

Uncertainties surrounding economic and capital market conditions heighten the risks faced by electric utilities, which, as described earlier, face a variety of operating and financial challenges.

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[25] Gongloff, Mark, "Stock Rebound Is a Crisis Flashback – Late Surge Recalls Market's Volatility at Peak of Credit Difficulties; Unusual Correlations," *Wall Street Journal* at B1 (Feb. 6, 2010).

[26] The Wall Street Journal recently reported that the Dow Jones Industrial Average experienced its largest drop since August 2010, which marked the fourth triple-digit move in less than two weeks. Tom Lauricella and Jonathan Cheng, "Dow Below 12000 on Mideast Worries – Troubles in Europe and China Add to Jitters," *Wall Street Journal* C1 (March. 11, 2011).

[27] Fitch Ratings Ltd., "2011 Outlook: U.S. Utilities, Power, and Gas," *Global Power North America Special Report* (Dec. 20, 2010).

[28] Moody's Investors Service, "Regulation Provides Stability As Risks Mount," *Industry Outlook* (Jan. 19, 2011).

**Q. HOW DO INTEREST RATES ON LONG-TERM BONDS COMPARE WITH THOSE PROJECTED FOR THE NEXT FEW YEARS?**

A. Table WEA-1 below compares current interest rates on 30-year Treasury bonds, triple-A rated corporate bonds, and double-A rated utility bonds with near-term projections from the Value Line Investment Survey ("Value Line"), IHS Global Insight, Blue Chip Financial Forecasts ("Blue Chip"), and the EIA:

**TABLE WEA-1**
**INTEREST RATE TRENDS**

| | Current (a) | 2012 | 2013 | 2014 | 2015 |
|---|---|---|---|---|---|
| 30-Yr. Treasury | | | | | |
| Value Line (b) | 4.4% | 4.9% | 5.2% | 5.5% | 6.0% |
| IHS Global Insight (c) | 4.4% | 4.7% | 5.0% | 5.1% | 6.0% |
| Blue Chip (d) | 4.4% | 4.8% | 5.2% | 5.4% | 5.5% |
| AAA Corporate | | | | | |
| Value Line (b) | 5.0% | 5.6% | 6.0% | 6.3% | 6.5% |
| IHS Global Insight (c) | 5.0% | 5.2% | 6.0% | 6.2% | 6.8% |
| Blue Chip (d) | 5.0% | 5.4% | 5.8% | 6.1% | 6.3% |
| S&P (e) | 5.0% | 6.1% | 5.7% | 5.9% | 6.3% |
| AA Utility | | | | | |
| IHS Global Insight (c) | 5.2% | 5.4% | 6.3% | 6.4% | 7.2% |
| EIA (f) | 5.2% | 5.5% | 6.4% | 7.0% | 7.4% |

(a) Based on monthly average bond yields for the six-month period Oct. 2010 - Mar. 2011 reported at www.credittrends.moodys.com and http://www.federalreserve.gov/releases /h15/data.htm.
(b) The Value Line Investment Survey, Forecast for the U.S. Economy (Feb. 25, 2011).
(c) IHS Global Insight, *U.S. Economic Outlook* at 19 (Feb. 2011).
(d) *Blue Chip Financial Forecasts,* Vol. 29, No. 12 (Dec. 1, 2010).
(e) Standard & Poor's Corporation, "U.S. Economic Forecast: Pouring Water On Troubled Oil," *RatingsDirect* (Mar. 8, 2011).
(f) Energy Information Administration, *Annual Energy Outlook 2011 Early Release* (Dec. 16, 2010).

As evidenced above, there is a clear consensus that the cost of permanent capital will be higher in the 2012-2015 timeframe than it is currently. As a result, current cost of capital estimates are likely to understate investors' requirements at the time the outcome of this proceeding becomes effective and beyond.

**Q. WHAT DO THESE EVENTS IMPLY WITH RESPECT TO THE ROE FOR APS?**

A. No one knows the future of our complex global economy. We know that the financial crisis had been building for a long time, and few predicted that the economy would fall as rapidly as it has, or that corporate bond yields would fluctuate as dramatically as they did. While conditions in the economy and capital markets appear to have stabilized significantly since 2009, investors continue to react swiftly and negatively to any future signs of trouble in the financial system or economy. The fact remains that the electric utility industry requires significant new capital investment. Given the importance of reliable electric utility service, it would be unwise to ignore investors' increased sensitivity to risk and future capital market trends in evaluating a fair ROE in this case. Similarly, the Company's capital structure must also preserve the financial flexibility necessary to maintain access to capital even during times of unfavorable market conditions.

## III. CAPITAL MARKET ESTIMATES

**Q. WHAT IS THE PURPOSE OF THIS SECTION?**

A. In this section, I develop capital market estimates of the cost of equity. First, I address the concept of the cost of equity, along with the risk-return tradeoff principle fundamental to capital markets. Next, I describe DCF and CAPM analyses conducted to estimate the cost of equity for benchmark groups of comparable risk firms. In recognition of the fair value rate base standard in Arizona, I have applied the DCF and CAPM in a forward-looking manner and I have avoided applying historical risk premium and comparable earnings approaches. Finally, I examine the issue of flotation costs, which are properly considered in evaluating a fair ROE.

### *A. Economic Standards*

**Q. WHAT ROLE DOES THE RETURN ON COMMON EQUITY PLAY IN A UTILITY'S RATES?**

A. The return on common equity is the cost of inducing and retaining investment in the utility's physical plant and assets. This investment is necessary to finance the asset base needed to provide utility service. Competition for investor funds is intense and investors are free to invest their funds wherever they choose. Investors will commit money to a particular investment only if they expect it to produce a return commensurate with those from other investments with comparable risks.

**Q. WHAT FUNDAMENTAL ECONOMIC PRINCIPLE UNDERLIES THE COST OF EQUITY CONCEPT?**

A. The fundamental economic principle underlying the cost of equity concept is the notion that investors are risk averse. In capital markets where relatively risk-free assets are available (*e.g.*, U.S. Treasury securities), investors can be induced to hold riskier assets only if they are offered a premium, or additional return, above the rate of return on a risk-free asset. Because all assets compete with each other for investor funds, riskier assets must yield a higher expected rate of return than safer assets to induce investors to invest and hold them.

Given this risk-return tradeoff, the required rate of return ($k$) from an asset (i) can generally be expressed as:

$$k_i = R_f + RP_i$$

where: $R_f$ = risk-free rate of return, and
$RP_i$ = Risk premium required to hold riskier asset i.

Thus, the required rate of return for a particular asset at any time is a function of: (1) the yield on risk-free assets, and (2) the asset's relative risk, with

investors demanding correspondingly larger risk premiums for bearing greater risk.

**Q. IS THERE EVIDENCE THAT THE RISK-RETURN TRADEOFF PRINCIPLE ACTUALLY OPERATES IN THE CAPITAL MARKETS?**

A. Yes. The risk-return tradeoff can be readily documented in segments of the capital markets where required rates of return can be directly inferred from market data and where generally accepted measures of risk exist. Bond yields, for example, reflect investors' expected rates of return, and bond ratings measure the risk of individual bond issues. Comparing the observed yields on government securities, which are considered free of default risk, to the yields on bonds of various rating categories demonstrates that the risk-return tradeoff does, in fact, exist.

**Q. DOES THE RISK-RETURN TRADEOFF OBSERVED WITH FIXED INCOME SECURITIES EXTEND TO COMMON STOCKS AND OTHER ASSETS?**

A. It is generally accepted that the risk-return tradeoff evidenced with long-term debt extends to all assets. Documenting the risk-return tradeoff for assets other than fixed income securities, however, is complicated by two factors. First, there is no standard measure of risk applicable to all assets. Second, for most assets – including common stock – required rates of return cannot be directly observed. Yet there is every reason to believe that investors exhibit risk aversion in deciding whether or not to hold common stocks and other assets, just as when choosing among fixed-income securities.

**Q. IS THIS RISK-RETURN TRADEOFF LIMITED TO DIFFERENCES BETWEEN FIRMS?**

A. No. The risk-return tradeoff principle applies not only to investments in different firms, but also to different securities issued by the same firm. The securities issued by a utility vary considerably in risk because they have different characteristics and priorities. Long-term debt secured by a mortgage on property is senior among all capital in its claim on a utility's net revenues and is, therefore, the least risky.[29] Following bonds are other debt instruments also holding contractual claims on the utility's net revenues, such as subordinated debentures. The last investors in line are common shareholders. They receive only the net revenues, if any, remaining after all other claimants have been paid. As a result, the rate of return that investors require from a utility's common stock, the most junior and riskiest of its securities, must be considerably higher than the yield offered by the utility's senior, long-term debt.

**Q. WHAT DOES THE ABOVE DISCUSSION IMPLY WITH RESPECT TO ESTIMATING THE COST OF EQUITY FOR A UTILITY?**

A. Although the cost of equity cannot be observed directly, it is a function of the returns available from other investment alternatives and the risks to which the equity capital is exposed. Because it is unobservable, the cost of equity for a particular utility must be estimated by analyzing information about capital market conditions generally, assessing the relative risks of the company specifically, and employing various quantitative methods that focus on investors' required rates of return. These various quantitative methods typically attempt to infer investors' required rates of return from stock prices, interest rates, or other capital market data.

[29] That being said, even secured long-term debt is effectively "junior" to long-term cost commitments necessary to operate the underlying business such as power agreements, fuel contracts and certain leases. The magnitude of these non-debt obligations can affect the cost of all forms of capital, including equity.

**Q. DID YOU RELY ON A SINGLE METHOD TO ESTIMATE THE COST OF EQUITY FOR APS?**

A. No. In my opinion, no single method or model should be relied on by itself to determine a utility's cost of common equity because no single approach can be regarded as definitive. Therefore, I applied both the DCF and CAPM methods to estimate the cost of common equity. In my opinion, comparing estimates produced by one method with those produced by other approaches ensures that the estimates of the cost of common equity pass fundamental tests of reasonableness and economic logic.

*B. Comparable Risk Proxy Groups*

**Q. HOW DID YOU IMPLEMENT THESE QUANTITATIVE METHODS TO ESTIMATE THE COST OF COMMON EQUITY FOR APS?**

A. Application of the DCF model and other quantitative methods to estimate the cost of common equity requires observable capital market data, such as stock prices. Moreover, even for a firm with publicly traded stock, the cost of common equity can only be estimated. As a result, applying quantitative models using observable market data only produces an estimate that inherently includes some degree of observation error. Thus, the accepted approach to increase confidence in the results is to apply the DCF model and other quantitative methods to a proxy group of publicly traded companies that investors regard as risk-comparable.

**Q. WHAT SPECIFIC PROXY GROUP OF UTILITIES DID YOU RELY ON FOR YOUR ANALYSIS?**

A. In order to reflect the risks and prospects associated with APS's jurisdictional utility operations, my DCF analyses focused on a reference group of other utilities composed of those companies classified by The Value Line Investment

Survey ("Value Line") as electric utilities with: (1) an S&P corporate credit rating of "BBB-" to "BBB+", (2) a Value Line Safety Rank of "2" or "3", (3) a Value Line Financial Strength Rating of "B" to "B++", and (4) a market capitalization of $1.6 billion or greater. In addition, I eliminated three utilities (FirstEnergy Corp., Northeast Utilities, and Progress Energy, Inc.) that otherwise would have been in the proxy group, but are not appropriate for inclusion because they are currently involved in a major merger or acquisition. These criteria resulted in a proxy group composed of twenty-one companies, which I will refer to as the "Utility Proxy Group."

**Q. WHAT OTHER PROXY GROUP DID YOU CONSIDER IN EVALUATING A FAIR ROE FOR APS?**

A. Under the regulatory standards established by *Hope* and *Bluefield*, the salient criterion in establishing a meaningful benchmark to evaluate a fair ROE is relative risk, not the particular business activity or degree of regulation. With regulation taking the place of competitive market forces, required returns for utilities should be in line with those of non-utility firms of comparable risk operating under the constraints of free competition. Consistent with this accepted regulatory standard, I also applied the DCF model to a reference group of comparable risk companies in the non-utility sectors of the economy. I refer to this group as the "Non-Utility Proxy Group".

**Q. DO UTILITIES HAVE TO COMPETE WITH NON-REGULATED FIRMS FOR CAPITAL?**

A. Yes. The cost of capital is an opportunity cost based on the returns that investors could realize by putting their money in other alternatives. Clearly, the total capital invested in utility stocks is only the tip of the iceberg of total common stock investment, and there are a plethora of other enterprises available to

investors beyond those in the utility industry. Utilities must compete for capital, not just against firms in their own industry, but with other investment opportunities of comparable risk.

**Q. IS IT CONSISTENT WITH THE *BLUEFIELD* AND *HOPE* CASES TO CONSIDER REQUIRED RETURNS FOR NON-UTILITY COMPANIES?**

A. Yes. Returns in the competitive sector of the economy form the very underpinning for utility ROEs because regulation purports to serve as a substitute for the actions of competitive markets. The Supreme Court has recognized that it is the degree of risk, not the nature of the business, which is relevant in evaluating an allowed ROE for a utility. The *Bluefield* case refers to "business undertakings attended with comparable risks and uncertainties." [30] It does not restrict consideration to other utilities. Similarly, the *Hope* case states:

> By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks.[31]

As in the *Bluefield* decision, there is nothing to restrict "other enterprises" solely to the utility industry.

Indeed, in teaching regulatory policy I usually observe that in the early applications of the comparable earnings approach, utilities were explicitly eliminated due to a concern about circularity. In other words, soon after the *Hope* decision regulatory commissions did not want to get involved in circular logic by looking to the returns of utilities that were established by the same or

[30] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n*, 262 U.S. 679 (1923).
[31] *Federal Power Comm'n v. Hope Natural Gas Co.* (320 U.S. 391, 1944).

similar regulatory commissions in the same geographic region. To avoid circularity, regulators looked only to the returns of non-utility companies.

**Q. DOES CONSIDERATION OF THE RESULTS FOR THE NON-UTILITY PROXY GROUP MAKE THE ESTIMATION OF THE COST OF EQUITY USING THE DCF MODEL MORE RELIABLE?**

A. Yes. The estimates of growth from the DCF model depend on analysts' forecasts. It is possible for utility growth rates to be distorted by short-term trends in the industry or the industry falling into favor or disfavor by analysts. The result of such distortions would be to bias the DCF estimates for utilities. For example, Value Line recently observed that near-term growth rates understate the longer-term expectations for gas utilities:

> Natural Gas Utility stocks have fallen near the bottom of our Industry spectrum for Timeliness. Accordingly, short-term investors would probably do best to find a group with better prospects over the coming six to 12 months. Longer-term, we expect these businesses to rebound. An improved economic environment, coupled with stronger pricing, should boost results across this sector over the coming years.[32]

Because the Non-Utility Proxy Group includes low risk companies from many industries, it diversifies away any distortion that may be caused by the ebb and flow of enthusiasm for a particular sector.

**Q. WHAT CRITERIA DID YOU APPLY TO DEVELOP THE NON-UTILITY PROXY GROUP?**

A. My comparable risk proxy group of non-utility firms was composed of those U.S. companies followed by Value Line that: (1) pay common dividends; (2) have a Safety Rank of "1"; (3) have a Financial Strength Rating of "B++" or

[32] The Value Line Investment Survey at 445 (Mar. 12, 2010).

greater; (4) have a beta of 0.85 or less; and, (5) have investment grade credit ratings from S&P.

**Q. DO THESE CRITERIA PROVIDE OBJECTIVE EVIDENCE TO EVALUATE INVESTORS' RISK PERCEPTIONS?**

A. Yes. Credit ratings are assigned by independent rating agencies for the purpose of providing investors with a broad assessment of the creditworthiness of a firm. Ratings generally extend from triple-A (the highest) to D (in default). Other symbols (*e.g.*, "A+") are used to show relative standing within a category. Because the rating agencies' evaluation includes virtually all of the factors normally considered important in assessing a firm's relative credit standing, corporate credit ratings provide a broad, objective measure of overall investment risk that is readily available to investors. Although the credit rating agencies are not immune to criticism, their rankings and analyses are widely cited in the investment community and referenced by investors.[33] Investment restrictions tied to credit ratings continue to influence capital flows, and credit ratings are also frequently used as a primary risk indicator in establishing proxy groups to estimate the cost of common equity.

While credit ratings provide the most widely referenced benchmark for investment risks, other quality rankings published by investment advisory services also provide relative assessments of risks that are considered by investors in forming their expectations for common stocks. Value Line's primary risk indicator is its Safety Rank, which ranges from "1" (Safest) to "5" (Riskiest). This overall risk measure is intended to capture the total risk of a

[33] While the ratings agencies were faulted during the financial crisis for failing to adequately assess the risk associated with structured finance products, investors continue to regard corporate credit ratings as a reliable guide to investment risks.

stock, and incorporates elements of stock price stability and financial strength. Given that Value Line is perhaps the most widely available source of investment advisory information, its Safety Rank provides useful guidance regarding the risk perceptions of investors.

The Financial Strength Rating is designed as a guide to overall financial strength and creditworthiness, with the key inputs including financial leverage, business volatility measures, and company size. Value Line's Financial Strength Ratings range from "A++" (strongest) down to "C" (weakest) in nine steps. Finally, Value Line's beta measures the volatility of a security's price relative to the market as a whole. A stock that tends to respond less to market movements has a beta less than 1.00, while stocks that tend to move more than the market have betas greater than 1.00.

**Q. HOW DO THE OVERALL RISKS OF YOUR PROXY GROUPS COMPARE WITH APS?**

A. Table WEA-2 compares the Utility Proxy Group with the Non-Utility Proxy Group and APS across four key indicators of investment risk. Because the Company does not have publicly traded common stock, the Value Line risk measures shown reflect those published for the Company's parent, Pinnacle West:

**TABLE WEA-2**
**COMPARISON OF RISK INDICATORS**

| | S&P Credit Rating | Value Line Safety Rank | Value Line Financial Strength | Beta |
|---|---|---|---|---|
| Utility Group | BBB | 3 | B+ | 0.74 |
| Non-Utility Proxy Group | A | 1 | A+ | 0.70 |
| APS | BBB- | 3 | B+ | 0.70 |

**Q. DO THESE COMPARISONS INDICATE THAT INVESTORS WOULD VIEW THE FIRMS IN YOUR PROXY GROUPS AS RISK-COMPARABLE TO THE COMPANY?**

A. Yes. As discussed earlier, APS is assigned a corporate credit rating of "BBB-" by S&P, which falls below the average corporate credit rating for the Utility Proxy Group. Meanwhile, the average Value Line Safety Rank and Financial Strength Rating for the Utility Proxy Group are identical to the values assigned to the Company's parent, while the average beta value for the Utility Proxy Group suggests somewhat greater risk than investors would associate with APS. Considered together, a comparison of these objective measures, which consider of a broad spectrum of risks, including financial and business position, and exposure to firm-specific factors, indicates that investors would likely conclude that the overall investment risks for APS are comparable to, or greater than, those of the firms in the Utility Proxy Group.

With respect to the Non-Utility Proxy Group, its average credit ratings, Safety Rank, and Financial Strength Rating suggest less risk than for APS, with its 0.70 average beta indicating identical risk. While the impact of differences in regulation is reflected in objective risk measures, my analyses conservatively focus on a lower-risk group of non-utility firms.

*C. Discounted Cash Flow Analyses*

**Q. HOW IS THE DCF MODEL USED TO ESTIMATE THE COST OF EQUITY?**

A. DCF models attempt to replicate the market valuation process that sets the price investors are willing to pay for a share of a company's stock. The model rests on the assumption that investors evaluate the risks and expected rates of return from all securities in the capital markets. Given these expectations, the price of each stock is adjusted by the market until investors are adequately compensated for the risks they bear. Therefore, we can look to the market to determine what investors believe a share of common stock is worth. By estimating the cash flows investors expect to receive from the stock in the way of future dividends and capital gains, we can calculate their required rate of return. In other words, the cash flows that investors expect from a stock are estimated, and given its current market price, we can "back-into" the discount rate, or cost of equity, that investors implicitly used in bidding the stock to that price. Notationally, the general form of the DCF model is as follows:

$$P_0 = \frac{D_1}{(1+k_e)^1} + \frac{D_2}{(1+k_e)^2} + \cdots + \frac{D_t}{(1+k_e)^t} + \frac{P_t}{(1+k_e)^t}$$

where: $P_0$ = Current price per share;
$P_t$ = Expected future price per share in period t;
$D_t$ = Expected dividend per share in period t;
$k_e$ = Cost of equity.

That is, the cost of equity is the discount rate that will equate the current price of a share of stock with the present value of all expected cash flows from the stock.

**Q. WHAT FORM OF THE DCF MODEL IS CUSTOMARILY USED TO ESTIMATE THE COST OF EQUITY IN RATE CASES?**

A. Rather than developing annual estimates of cash flows into perpetuity, the DCF model can be simplified to a "constant growth" form:[34]

$$P_0 = \frac{D_1}{k_e - g}$$

where: g = Investors' long-term growth expectations.

The cost of equity ($k_e$) can be isolated by rearranging terms within the equation:

$$k_e = \frac{D_1}{P_0} + g$$

This constant growth form of the DCF model recognizes that the rate of return to stockholders consists of two parts: 1) dividend yield ($D_1/P_0$); and 2) growth ($g$). In other words, investors expect to receive a portion of their total return in the form of current dividends and the remainder through price appreciation.

**Q. WHAT FORM OF THE DCF MODEL DID YOU USE?**

A. I applied the constant growth DCF model to estimate the cost of equity for APS, which is the form of the model most commonly relied on to establish the cost of equity for traditional regulated utilities and the method most often referenced by regulators. Other forms of the general, or non-constant DCF model, such as "two-stage" or "multi-stage" analyses can be used to estimate the cost of equity.

[34] The constant growth DCF model is dependent on a number of strict assumptions, which in practice are never strictly met. These include a constant growth rate for both dividends and earnings; a stable dividend payout ratio; the discount rate exceeds the growth rate; a constant growth rate for book value and price; a constant earned rate of return on book value; no sales of stock at a price above or below book value; a constant price-earnings ratio; a constant discount rate (*i.e.*, no changes in risk or interest rate levels and a flat yield curve); and all of the above extend to infinity.

However, these approaches generally require several very specific assumptions regarding investors' expected cash flows that must occur at given points in the future. This makes the results of non-constant growth DCF applications sensitive to changes in assumptions, and therefore subject to greater controversy in a rate case setting.

While the complexity of non-constant DCF models may impart an aura of accuracy, there is no evidence that investors' current view of electric utilities anticipates a series of discrete, clearly defined stages. As a result, there is no discernable transition that would support use of the multi-stage DCF approach to evaluate a fair rate of return for APS. Moreover, to the extent that each of these time-specific suppositions about future cash flows do not reflect what real-world investors actually anticipate, the resulting cost of equity estimate will be biased. Indeed, the benchmark for growth in a DCF model is what investors expect when they purchase stock. Unless we replicate investors' thinking, we cannot uncover their required returns and thus the market cost of equity. In practice, applying a non-constant DCF model would lead to error if it ignores the views of real-world investors.

**Q. HOW IS THE CONSTANT GROWTH FORM OF THE DCF MODEL TYPICALLY USED TO ESTIMATE THE COST OF EQUITY?**

A. The first step in implementing the constant growth DCF model is to determine the expected dividend yield ($D_1/P_0$) for the firm in question. This is usually calculated based on an estimate of dividends to be paid in the coming year divided by the current price of the stock. The second, and more controversial, step is to estimate investors' long-term growth expectations ($g$) for the firm. The

final step is to sum the firm's dividend yield and estimated growth rate to arrive at an estimate of its cost of equity.

**Q. HOW WAS THE DIVIDEND YIELD FOR THE UTILITY PROXY GROUP DETERMINED?**

A. Estimates of dividends to be paid by each of these utilities over the next twelve months, obtained from Value Line, served as $D_1$. This annual dividend was then divided by the corresponding stock price for each utility to arrive at the expected dividend yield. The expected dividends, stock prices, and resulting dividend yields for the firms in the utility proxy group are presented on Attachment WEA-2. As shown there, dividend yields for the firms in the Utility Proxy Group ranged from 2.1 percent to 5.9 percent.

**Q. WHAT IS THE NEXT STEP IN APPLYING THE CONSTANT GROWTH DCF MODEL?**

A. The next step is to evaluate long-term growth expectations, or "*g*", for the firm in question. In constant growth DCF theory, earnings, dividends, book value, and market price are all assumed to grow in lockstep, and the growth horizon of the DCF model is infinite. But implementation of the DCF model is more than just a theoretical exercise; it is an attempt to replicate the mechanism investors used to arrive at observable stock prices. A wide variety of techniques can be used to derive growth rates, but the only "*g*" that matters in applying the DCF model is the value that investors expect.

**Q. ARE HISTORICAL GROWTH RATES LIKELY TO BE REPRESENTATIVE OF INVESTORS' EXPECTATIONS FOR ELECTRIC UTILITIES?**

A. No. If past trends in earnings, dividends, and book value are to be representative of investors' expectations for the future, then the historical

conditions giving rise to these growth rates should be expected to continue. That is clearly not the case for electric utilities, where structural and industry changes have led to declining growth in dividends, earnings pressure, and, in many cases, significant write-offs. While these conditions serve to depress historical growth measures, they are not representative of long-term expectations for the electric utility industry or the expectations that investors have incorporated into current market prices. As a result, historical growth measures for utilities do not currently meet the requirements of the DCF model.

**Q. WHAT ARE INVESTORS MOST LIKELY TO CONSIDER IN DEVELOPING THEIR LONG-TERM GROWTH EXPECTATIONS?**

A. While the DCF model is technically concerned with growth in dividend cash flows, implementation of this DCF model is solely concerned with replicating the forward-looking evaluation of real-world investors. In the case of electric utilities, dividend growth rates are not likely to provide a meaningful guide to investors' current growth expectations. This is because utilities have significantly altered their dividend policies in response to more accentuated business risks in the industry.[35] As a result of this trend towards a more conservative payout ratio, dividend growth in the utility industry has remained largely stagnant as utilities conserve financial resources to provide a hedge against heightened uncertainties.

As payout ratios for firms in the electric utility industry trended downward, investors' focus has increasingly shifted from dividends to earnings as a measure of long-term growth. Future trends in earnings, which provide the

[35] For example, the payout ratio for electric utilities fell from approximately 80% historically to on the order of 60%. The Value Line Investment Survey (Sep. 15, 1995 at 161, Feb. 4, 2011 at 2237).

source for future dividends and ultimately support share prices, play a pivotal role in determining investors' long-term growth expectations. The importance of earnings in evaluating investors' expectations and requirements is well accepted in the investment community. As noted in *Finding Reality in Reported Earnings* published by the Association for Investment Management and Research:

> [E]arnings, presumably, are the basis for the investment benefits that we all seek. "Healthy earnings equal healthy investment benefits" seems a logical equation, but earnings are also a scorecard by which we compare companies, a filter through which we assess management, and a crystal ball in which we try to foretell future performance.[36]

Value Line's near-term projections and its Timeliness Rank, which is the principal investment rating assigned to each individual stock, are also based primarily on various quantitative analyses of earnings. As Value Line explained:

> The future earnings rank accounts for 65% in the determination of relative price change in the future; the other two variables (current earnings rank and current price rank) explain 35%.[37]

The fact that investment advisory services focus on growth in earnings indicates that the investment community regards this as a superior indicator of future long-term growth. Indeed, "A Study of Financial Analysts: Practice and Theory," published in the *Financial Analysts Journal*, reported the results of a survey conducted to determine what analytical techniques investment analysts

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[36] Association for Investment Management and Research, "Finding Reality in Reported Earnings: An Overview", p. 1 (Dec. 4, 1996).
[37] The Value Line Investment Survey, *Subscriber's Guide*, p. 53.

actually use.[38] Respondents were asked to rank the relative importance of earnings, dividends, cash flow, and book value in analyzing securities. Of the 297 analysts that responded, only 3 ranked dividends first while 276 ranked it last. The article concluded:

> Earnings and cash flow are considered far more important than book value and dividends.[39]

More recently, the *Financial Analysts Journal* reported the results of a study of the relationship between valuations based on alternative multiples and actual market prices, which concluded, "In all cases studied, earnings dominated operating cash flows and dividends."[40]

**Q. DO THE GROWTH RATE PROJECTIONS OF SECURITY ANALYSTS CONSIDER HISTORICAL TRENDS?**

A. Yes. Professional security analysts study historical trends extensively in developing their projections of future earnings. Hence, to the extent there is any useful information in historical patterns, that information is incorporated into analysts' growth forecasts.

**Q. WHAT ARE SECURITY ANALYSTS CURRENTLY PROJECTING IN THE WAY OF GROWTH FOR THE FIRMS IN THE UTILITY PROXY GROUP?**

A. The earnings growth projections for each of the firms in the Utility Proxy Group reported by Value Line, Thomson Reuters ("IBES"), and Zacks Investment Research ("Zacks") are displayed on Attachment WEA-2.[41]

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[38] Block, Stanley B., "A Study of Financial Analysts: Practice and Theory", *Financial Analysts Journal* (July/August 1999).
[39] *Id.* at 88.
[40] Liu, Jing, Nissim, Doron, & Thomas, Jacob, "Is Cash Flow King in Valuations?," *Financial Analysts Journal*, Vol. 63, No. 2 (March/April 2007) at 56.
[41] Formerly I/B/E/S International, Inc., IBES growth rates are now compiled and published by Thomson Reuters.

**Q. SOME ARGUE THAT ANALYSTS' ASSESSMENTS OF GROWTH RATES ARE BIASED. DO YOU BELIEVE THESE PROJECTIONS ARE INAPPROPRIATE FOR ESTIMATING INVESTORS' REQUIRED RETURN USING THE DCF MODEL?**

A. No. In applying the DCF model to estimate the cost of common equity, the only relevant growth rate is the forward-looking expectations of investors that are captured in current stock prices. Investors, just like securities analysts and others in the investment community, do not know how the future will actually turn out. They can only make investment decisions based on their best estimate of what the future holds in the way of long-term growth for a particular stock, and securities prices are constantly adjusting to reflect their assessment of available information.

Any claims that analysts' estimates are not relied upon by investors are illogical given the reality of a competitive market for investment advice. If financial analysts' forecasts do not add value to investors' decision making, then it is irrational for investors to pay for these estimates. Similarly, those financial analysts who fail to provide reliable forecasts will lose out in competitive markets relative to those analysts whose forecasts investors find more credible. The reality that analyst estimates are routinely referenced in the financial media and in investment advisory publications (e.g., Value Line) implies that investors use them as a basis for their expectations.

The continued success of investment services such as Thompson Reuters and Value Line, and the fact that projected growth rates from such sources are widely referenced, provides strong evidence that investors give considerable weight to analysts' earnings projections in forming their expectations for future growth. While the projections of securities analysts may be proven optimistic or

pessimistic in hindsight, this is irrelevant in assessing the expected growth that investors have incorporated into current stock prices, and any bias in analysts' forecasts – whether pessimistic or optimistic – is similarly irrelevant if investors share the analysts' views. Earnings growth projections of security analysts provide the most frequently referenced guide to investors' views and are widely accepted in applying the DCF model. As explained in *New Regulatory Finance*:

> Because of the dominance of institutional investors and their influence on individual investors, analysts' forecasts of long-run growth rates provide a sound basis for estimating required returns. Financial analysts exert a strong influence on the expectations of many investors who do not possess the resources to make their own forecasts, that is, they are a cause of $g$ [growth]. The accuracy of these forecasts in the sense of whether they turn out to be correct is not an issue here, as long as they reflect widely held expectations.[42]

**Q. HOW ELSE ARE INVESTORS' EXPECTATIONS OF FUTURE LONG-TERM GROWTH PROSPECTS OFTEN ESTIMATED WHEN APPLYING THE CONSTANT GROWTH DCF MODEL?**

A. In constant growth theory, growth in book equity will be equal to the product of the earnings retention ratio (one minus the dividend payout ratio) and the earned rate of return on book equity. Furthermore, if the earned rate of return and the payout ratio are constant over time, growth in earnings and dividends will be equal to growth in book value. Despite the fact that these conditions are seldom, if ever, met in practice, this "sustainable growth" approach may provide a rough guide for evaluating a firm's growth prospects and is frequently proposed in regulatory proceedings.

[42] Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports, Inc.* at 298 (2006).

Accordingly, while I believe that analysts' forecasts provide a superior and more direct guide to investors' growth expectations, I have included the "sustainable growth" approach for completeness. The sustainable growth rate is calculated by the formula, $g = br+sv$, where "b" is the expected retention ratio, "r" is the expected earned return on equity, "s" is the percent of common equity expected to be issued annually as new common stock, and "v" is the equity accretion rate.

**Q. WHAT IS THE PURPOSE OF THE "SV" TERM?**

A. Under DCF theory, the "sv" factor is a component of the growth rate designed to capture the impact of issuing new common stock at a price above, or below, book value. When a company's stock price is greater than its book value per share, the per-share contribution in excess of book value associated with new stock issues will accrue to the current shareholders. This increase to the book value of existing shareholders leads to higher expected earnings and dividends, with the "sv" factor incorporating this additional growth component.

**Q. WHAT GROWTH RATE DOES THE EARNINGS RETENTION METHOD SUGGEST FOR THE UTILITY PROXY GROUP?**

A. The sustainable, "br+sv" growth rates for each firm in the proxy group are summarized on Attachment WEA-2, with the underlying details being presented on Attachment WEA-3. For each firm, the expected retention ratio (b) was calculated based on Value Line's projected dividends and earnings per share. Likewise, each firm's expected earned rate of return (r) was computed by dividing projected earnings per share by projected net book value. Because Value Line reports end-of-year book values, an adjustment was incorporated to compute an average rate of return over the year, consistent with the theory underlying this approach to estimating investors' growth expectations.

Meanwhile, the percent of common equity expected to be issued annually as new common stock (s) was equal to the product of the projected market-to-book ratio and growth in common shares outstanding, while the equity accretion rate (v) was computed as 1 minus the inverse of the projected market-to-book ratio.

**Q. WHAT COST OF EQUITY ESTIMATES WERE IMPLIED FOR THE UTILITY PROXY GROUP USING THE DCF MODEL?**

A. After combining the dividend yields and respective growth projections for each utility, the resulting cost of equity estimates are shown on Attachment WEA-2.

**Q. IN EVALUATING THE RESULTS OF THE CONSTANT GROWTH DCF MODEL, IS IT APPROPRIATE TO ELIMINATE ESTIMATES THAT ARE EXTREME LOW OR HIGH OUTLIERS?**

A. Yes. In applying quantitative methods to estimate the cost of equity, it is essential that the resulting values pass fundamental tests of reasonableness and economic logic. Accordingly, DCF estimates that are implausibly low or high should be eliminated when evaluating the results of this method.

**Q. HOW DID YOU EVALUATE DCF ESTIMATES AT THE LOW END OF THE RANGE?**

A. It is a basic economic principle that investors can be induced to hold more risky assets only if they expect to earn a return to compensate them for their risk bearing. As a result, the rate of return that investors require from a utility's common stock, the most junior and riskiest of its securities, must be considerably higher than the yield offered by senior, long-term debt. Consistent with this principle, the DCF results must be adjusted to eliminate estimates that are determined to be extreme low outliers when compared against the yields available to investors from less risky utility bonds.

**Q. WHAT DOES THIS TEST OF LOGIC IMPLY WITH RESPECT TO THE DCF RESULTS FOR THE UTILITY PROXY GROUP?**

A. As noted earlier, the average S&P corporate credit rating for the Utility proxy Group is "BBB", with APS being rated "BBB-". Companies rated "BBB-", "BBB", and "BBB+" are all considered part of the triple-B rating category, with Moody's monthly yields on triple-B bonds averaging approximately 6.0 percent in March 2011.[43] It is inconceivable that investors are not requiring a substantially higher rate of return for holding common stock. Consistent with this principle, the DCF results for the Utility Proxy Group must be adjusted to eliminate estimates that are determined to be extreme low outliers when compared against the yields available to investors from less risky utility bonds.

**Q. HAVE SIMILAR TESTS BEEN APPLIED BY REGULATORS?**

A. Yes. FERC has noted that adjustments are justified where applications of the DCF approach produce illogical results. FERC evaluates DCF results against observable yields on long-term public utility debt and has recognized that it is appropriate to eliminate estimates that do not sufficiently exceed this threshold. In a 2002 opinion establishing its current precedent for determining ROEs for electric utilities, for example, FERC noted:

> An adjustment to this data is appropriate in the case of PG&E's low-end return of 8.42 percent, which is comparable to the average Moody's "A" grade public utility bond yield of 8.06 percent, for October 1999. Because investors cannot be expected to purchase stock if debt, which has less risk than stock, yields essentially the same return, this low-end return cannot be considered reliable in this case.[44]

[43] Moody's Investors Service, www.credittrends.com.
[44] *Southern California Edison Company*, 92 FERC ¶ 61,070 at p. 22 (2000).

Similarly, in its August 2006 decision in *Kern River Gas Transmission Company*, FERC noted that:

> [T]he 7.31 and 7.32 percent costs of equity for El Paso and Williams found by the ALJ are only 110 and 122 basis points above that average yield for public utility debt.[45]

The Commission upheld the opinion of Staff and the Administrative Law Judge that cost of equity estimates for these two proxy group companies "were too low to be credible."[46]

The practice of eliminating low-end outliers has been affirmed in numerous FERC proceedings,[47] and in its April 15, 2010 decision in *SoCal Edison*, FERC affirmed that, "it is reasonable to exclude any company whose low-end ROE fails to exceed the average bond yield by about 100 basis points or more."[48]

**Q. WHAT ELSE SHOULD BE CONSIDERED IN EVALUATING DCF ESTIMATES AT THE LOW END OF THE RANGE?**

A. As indicated earlier, while corporate bond yields have declined substantially as the worst of the financial crisis has abated, it is generally expected that long-term interest rates will rise as the recession ends and the economy returns to a more normal pattern of growth. As shown in Table WEA-3 below, forecasts of IHS Global Insight and the EIA imply an average triple-B bond yield of 7.16 percent over the period 2012-2015:

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[45] *Kern River Gas Transmission Company*, Opinion No. 486, 117 FERC ¶ 61,077 at P 140 & n. 227 (2006).
[46] *Id.*
[47] *See, e.g., Virginia Electric Power Co.*, 123 FERC ¶ 61,098 at P 64 (2008).
[48] *Southern California Edison Co.*, 131 FERC ¶ 61,020 at P 55 (2010) ("*SoCal Edison*").

**TABLE WEA-3**
**IMPLIED BBB BOND YIELD**

| | 2012-15 |
|---|---|
| Projected AA Utility Yield | |
| IHS Global Insight (a) | 6.33% |
| EIA (b) | 6.58% |
| Average | 6.45% |
| Current BBB - AA Yield Spread (c) | 0.71% |
| **Implied Triple-B Utility Yield** | **7.16%** |

(a) IHS Global Insight, *U.S. Economic Outlook* at 19 (Feb. 2011).
(b) Energy Information Administration, *Annual Energy Outlook 2011 Early Release* (Dec. 16, 2010).
(c) Based on monthly average bond yields for the six-month period Oct. 2010 - Mar. 2011.

The increase in debt yields anticipated by IHS Global Insight and EIA is also supported by the widely-referenced Blue Chip Financial Forecasts, which projects that yields on corporate bonds will climb more than 100 basis points through the period 2012-2016.[49]

**Q. WHAT DOES THIS TEST OF LOGIC IMPLY WITH RESPECT TO THE DCF RESULTS FOR THE UTILITY PROXY GROUP?**

A. As shown on Attachment WEA-2, eight low-end DCF estimates ranged from 0.7 percent to 6.5 percent. Five of these values were below current utility bond yields, with cost of equity estimates below 7.0 percent being less than the yield on triple-B utility bonds expected during the period 2012-2015. In light of the risk-return tradeoff principle and the test applied in *SoCal Edison*, it is inconceivable that investors are not requiring a substantially higher rate of return for holding common stock, which is the riskiest of a utility's securities. As a result, consistent with the test of economic logic applied by FERC and the

[49] *Blue Chip Financial Forecasts*, Vol. 29, No. 12 (Dec. 1, 2010) & Vol. 30, No. 3 (Mar. 1, 2011).

upward trend expected for utility bond yields, these values provide little guidance as to the returns investors require from utility common stocks and should be excluded.

**Q. DO YOU ALSO RECOMMEND EXCLUDING ESTIMATES AT THE HIGH END OF THE RANGE OF DCF RESULTS?**

A. Yes. The upper end of the cost of common equity range produced by the DCF analysis presented in Attachment WEA-2 was set by estimates of 18.8 percent and 17.1 percent for ITC Holdings Corp. I determined that, when compared with the balance of the remaining estimates, these values should be excluded in evaluating the results of the DCF model for the Utility Proxy Group. This is also consistent with the precedent adopted by FERC, which has established that estimates found to be "extreme outliers" should be disregarded in interpreting the results of the DCF model.[50]

**Q. WHAT COST OF COMMON EQUITY ESTIMATES ARE IMPLIED BY YOUR DCF RESULTS FOR THE UTILITY PROXY GROUP?**

A. As shown on Attachment WEA-2 and summarized in Table WEA-4, below, after eliminating illogical low- and high-end values, application of the constant growth DCF model resulted in cost of common equity estimates ranging from 9.3 percent to 11.40 percent:

[50] See, *e.g.*, *ISO New England, Inc.*, 109 FERC ¶ 61,147 at P 205 (2004).

TABLE WEA-4
DCF RESULTS –UTILITY PROXY GROUP

| Growth Rate | Average Cost of Equity |
|---|---|
| Value Line | 11.2% |
| IBES | 11.0% |
| Zacks | 10.9% |
| br+sv | 9.5% |

**Q. WHAT WERE THE RESULTS OF YOUR DCF ANALYSIS FOR THE NON-UTILITY PROXY GROUP?**

A. I applied the DCF model to the Non-Utility Proxy Group in exactly the same manner described earlier for the proxy group of utilities. The results of my DCF analysis for the Non-Utility Proxy Group are presented in Attachment WEA-4, with the sustainable, "br+sv" growth rates being developed on Attachment WEA-5. As shown on Attachment WEA-4 and summarized in Table WEA-5, below, after eliminating illogical low- and high-end values, application of the constant growth DCF model resulted in cost of common equity estimates on the order of at least 12 percent:

TABLE WEA-5
DCF RESULTS – NON-UTILITY PROXY GROUP

| Growth Rate | Average Cost of Equity |
|---|---|
| Value Line | 11.9% |
| IBES | 12.4% |
| Zacks | 12.5% |
| br+sv | 12.1% |

**Q. DO THE HIGHER DCF ESTIMATES FOR THE NON-UTILITY PROXY GROUP DEMONSTRATE THAT THE RISKS OF THESE COMPANIES ARE GREATER THAN APS?**

A. No. While we are accustomed to associating higher risk with higher returns, DCF estimates of investors' required rate of return do not always produce that

result. Performing the DCF calculations for the Non-Utility Proxy Group produced ROE estimates that are higher than the DCF estimates for the Utility Proxy Group, even though the risks that investors associate with the group of non-utility firms - as measured by S&P's credit ratings and Value Line's Safety Rank, Financial Strength, and Beta – are lower than the risks investors associate with the Utility Proxy Group and APS. The actual cost of equity is unobservable, and DCF estimates may depart from these values because investors' expectations may not be captured by the inputs to the ROE model, particularly the assumed growth rate. Nevertheless, regulators have relied upon DCF calculations for years in evaluating a fair ROE. The divergence between the DCF estimates for the Utility and Non-Utility Proxy Groups suggests that both should be considered to ensure a balanced end-result.

*D. Capital Asset Pricing Model*

**Q. PLEASE DESCRIBE THE CAPM.**

A. The CAPM is generally considered to be the most widely referenced method for estimating the cost of equity both among academicians and professional practitioners, with the pioneering researchers of this method receiving the Nobel Prize in 1990. The CAPM is a theory of market equilibrium that measures risk using the beta coefficient. Assuming investors are fully diversified, the relevant risk of an individual asset (*e.g.*, common stock) is its volatility relative to the market as a whole, with beta reflecting the tendency of a stock's price to follow changes in the market. The CAPM is mathematically expressed as

$$R_j = R_f + \beta_j(R_m - R_f)$$

where: $R_j$ = required rate of return for stock j;
$R_f$ = risk-free rate;
$R_m$ = expected return on the market portfolio; and,
$\beta_j$ = beta, or systematic risk, for stock j.

Like the DCF model, the CAPM is an *ex-ante,* or forward-looking model based on expectations of the future. As a result, in order to produce a meaningful estimate of investors' required rate of return, the CAPM must be applied using estimates that reflect the expectations of actual investors in the market, not with backward-looking, historical data.

**Q. HOW DID YOU APPLY THE CAPM TO ESTIMATE THE COST OF EQUITY?**

A. Application of the CAPM to the Utility Proxy Group based on a forward-looking estimate for investors' required rate of return from common stocks is presented on Attachment WEA-6. In order to capture the expectations of today's investors in current capital markets, the expected market rate of return was estimated by conducting a DCF analysis on the dividend paying firms in the S&P 500 Composite Index.

The dividend yield for each firm was calculated based on the annual indicated dividend payment obtained from Value Line, increased by one-years' growth using the rate discussed subsequently $(1 + g)$ to convert them to year-ahead dividend yields presumed by the constant growth DCF model. The growth rate was equal to the consensus earnings growth projections for each firm published by IBES, with each firm's dividend yield and growth rate being weighted by its proportionate share of total market value. Based on the weighted average of the projections for the 354 individual firms, current estimates imply an average growth rate over the next five years of 10.5 percent. Combining this average growth rate with a year-ahead dividend yield of 2.3 percent results in a current cost of common equity estimate for the market as a whole ($R_m$) of approximately 12.8 percent. Subtracting a 4.5 percent risk-free rate based on the average yield

on 30-year Treasury bonds produced a market equity risk premium of 8.3 percent.

**Q. WHAT WAS THE SOURCE OF THE BETA VALUES YOU USED TO APPLY THE CAPM?**

A. I relied on the beta values reported by Value Line, which in my experience is the most widely referenced source for beta in regulatory proceedings. As noted in *New Regulatory Finance*:

> Value Line is the largest and most widely circulated independent investment advisory service, and influences the expectations of a large number of institutional and individual investors. ... Value Line betas are computed on a theoretically sound basis using a broadly based market index, and they are adjusted for the regression tendency of betas to converge to 1.00.[51]

**Q. WHAT ELSE SHOULD BE CONSIDERED IN APPLYING THE CAPM?**

A. A. As explained by *Morningstar*:

> One of the most remarkable discoveries of modern finance is that of a relationship between firm size and return. The relationship cuts across the entire size spectrum but is most evident among smaller companies, which have higher returns on average than larger ones.[52]

Because empirical research indicates that the CAPM does not fully account for observed differences in rates of return attributable to firm size, a modification is required to account for this size effect.

[51] Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports* at 71 (2006).
[52] *Morningstar*, "Ibbotson SBBI 2010 Valuation Yearbook," at p. 85 (footnote omitted).

According to the CAPM, the expected return on a security should consist of the riskless rate, plus a premium to compensate for the systematic risk of the particular security. The degree of systematic risk is represented by the beta coefficient. The need for the size adjustment arises because differences in investors' required rates of return that are related to firm size are not fully captured by beta. To account for this, Morningstar has developed size premiums that need to be added to the theoretical CAPM cost of equity estimates to account for the level of a firm's market capitalization in determining the CAPM cost of equity.[53] Accordingly, my CAPM analyses incorporated an adjustment to recognize the impact of size distinctions, as measured by the average market capitalization for the respective proxy groups.

**Q. WHAT COST OF EQUITY ESTIMATE WAS INDICATED FOR THE UTILITY PROXY GROUP BASED ON THIS FORWARD-LOOKING APPLICATION OF THE CAPM?**

A. The average market capitalization of the Utility Proxy Group is $6.3 billion. Based on data from *Morningstar*, this means that the theoretical CAPM cost of equity estimate must be increased by 74 basis points to account for the industry group's relative size. As shown on Attachment WEA-6, adjusting the theoretical CAPM result to incorporate this size adjustment results in an average indicated cost of common equity of 11.40 percent.

**Q. WHAT COST OF COMMON EQUITY WAS INDICATED FOR THE NON-UTILITY PROXY GROUP BASED ON THIS FORWARD-LOOKING APPLICATION OF THE CAPM?**

[53] *Id.* at Table C-1.

A. As shown on Attachment WEA-7, applying the forward-looking CAPM approach to the firms in the Non-Utility Proxy Group results in an average implied cost of common equity of 10.0 percent.

**Q. SHOULD THE CAPM APPROACH BE APPLIED USING HISTORICAL RATES OF RETURN?**

A. No. The CAPM cost of common equity estimate is calibrated from investors' required risk premium between Treasury bonds and common stocks. In response to heightened uncertainties, investors have repeatedly sought a safe haven in U.S. government bonds and this "flight to safety" has pushed Treasury yields significantly lower while yield spreads for corporate debt have widened. This distortion not only impacts the absolute level of the CAPM cost of equity estimate, but it affects estimated risk premiums. Economic logic would suggest that investors' required risk premium for common stocks over Treasury bonds has also increased.

Meanwhile, backward-looking approaches incorrectly assume that investors' assessment of the required risk premium between Treasury bonds and common stocks is constant, and equal to some historical average. At no time in recent history has the fallacy of this assumption been demonstrated more concretely than it is today. This incongruity between investors' current expectations and historical risk premiums is particularly relevant during periods of heightened uncertainty and rapidly changing capital market conditions, such as those experienced recently.[54]

*E. Flotation Costs*

[54] FERC has previously rejected CAPM methodologies based on historical data because whatever historical relationships existed between debt and equity securities may no longer hold. *See Orange & Rockland Utils., Inc., 40 F.E.R.C. P63,053, at pp. 65,208 -09 (1987), aff'd, Opinion No. 314, 44 F.E.R.C. P61,253 at 65,208.*

**Q. WHAT OTHER CONSIDERATIONS ARE RELEVANT IN DETERMINING THE ROE FOR APS?**

A. The common equity used to finance the investment in utility assets is provided from either the sale of stock in the capital markets or from retained earnings not paid out as dividends. When equity is raised through the sale of common stock, there are costs associated with "floating" the new equity securities. These flotation costs include services such as legal, accounting, and printing, as well as the fees and discounts paid to compensate brokers for selling the stock to the public. Also, some argue that the "market pressure" from the additional supply of common stock and other market factors may further reduce the amount of funds that a utility nets when it issues common equity.

**Q. IS THERE AN ESTABLISHED MECHANISM FOR A UTILITY TO RECOGNIZE EQUITY ISSUANCE COSTS?**

A. No. While debt flotation costs are recorded on the books of the utility, amortized over the life of the issue, and thus increase the effective cost of debt capital, there is no similar accounting treatment to ensure that equity flotation costs are recorded and ultimately recognized. Alternatively, no rate of return is authorized on flotation costs necessarily incurred to obtain a portion of the equity capital used to finance plant. In other words, equity flotation costs are not included in a utility's rate base because neither that portion of the gross proceeds from the sale of common stock used to pay flotation costs is available to invest in plant and equipment, nor are flotation costs capitalized as an intangible asset. Unless some provision is made to recognize these issuance costs, a utility's revenue requirements will not fully reflect all of the costs incurred for the use of investors' funds. Because there is no accounting convention to accumulate the flotation costs associated with equity issues, they must be accounted for

indirectly, with an upward adjustment to the cost of common equity being the most logical mechanism.

**Q. HAS PINNACLE WEST RECENTLY ISSUED ADDITIONAL COMMON EQUITY?**

A. Yes. Pinnacle West closed on the sale of 6.9 million shares of common stock in April 2010, with the net proceeds raising approximately $252.8 million of additional equity capital. Pinnacle West contributed all of the net proceeds from this common stock offering into APS in the form of equity infusions.[55] Thus, in addition to flotation costs associated with past equity issues, APS also incurred issuance costs associated with Pinnacle West's recent sale of new common shares.

**Q. WHAT IS THE MAGNITUDE OF THE ADJUSTMENT TO THE "BARE BONES" COST OF COMMON EQUITY TO ACCOUNT FOR ISSUANCE COSTS?**

A. While there are a number of ways in which a flotation cost adjustment can be calculated, one of the most common methods used to account for flotation costs in regulatory proceedings is to apply an average flotation-cost percentage to a utility's dividend yield. Based on a review of the finance literature, *New Regulatory Finance* concluded:

> The flotation cost allowance requires an estimated adjustment to the return on equity of approximately 5% to 10%, depending on the size and risk of the issue.[56]

Alternatively, a study of data from Morgan Stanley regarding issuance costs associated with utility common stock issuances suggests an average flotation

[55] Pinnacle West Capital Corporation, *2010 Form 10-K Report* at 51.
[56] Roger A. Morin, "New Regulatory Finance," *Public Utilities Reports, Inc.* at 323 (2006).

cost percentage of 3.6 percent,[57] with Pinnacle West incurring issuance costs equal to 3.57 percent of the gross proceeds from its April 2010 public offering.

Issuance costs are a legitimate consideration in setting the ROE for a utility, and applying these expense percentages to a representative dividend yield for a utility of 4.5 percent implies a flotation cost adjustment on the order of 15 to 45 basis points.

## IV. RETURN ON EQUITY FOR APS

**Q. WHAT IS THE PURPOSE OF THIS SECTION?**

A. In addition to presenting the conclusions of my evaluation of a fair ROE for APS, this section also discusses the relationship between ROE and preservation of a utility's financial integrity and the ability to attract capital. In addition, I evaluate the reasonableness of APS's requested capital structure.

### *A. Implications for Financial Integrity*

**Q. WHY IS IT IMPORTANT TO ALLOW APS AN ADEQUATE RETURN ON FAIR VALUE RATE BASE?**

A. Given the importance of the utility industry to the economy and society, it is essential to maintain reliable and economical service to all consumers. While APS remains committed to deliver reliable service, a utility's ability to fulfill its mandate can be compromised if it lacks the necessary financial wherewithal or is unable to earn a return sufficient to attract capital.

As documented earlier, the major rating agencies have warned of exposure to uncertainties associated with ongoing capital expenditure requirements,

[57] Application of Yankee Gas Services Company for a Rate Increase, DPUC Docket No. 04-06-01, Direct Testimony of George J. Eckenroth (Jul. 2, 2004) at Exhibit GJE-11.1. Updating the results presented by Mr. Eckenroth through April 2005 also resulted in an average flotation cost percentage of 3.6%.

uncertain economic and financial market conditions, future environmental compliance costs, and the potential for continued energy price volatility. As discussed earlier, APS faces a number of potential challenges that might require the relatively swift commitment of considerable capital resources in order to maintain the high level of service to which its customers have become accustomed. For example, mandated shutdowns of generating facilities in response to security threats or a catastrophic event elsewhere in the U.S. would impose significant reliance on wholesale power markets to meet energy shortfalls. Investors understand just how swiftly unforeseen circumstances can lead to deterioration in a utility's financial condition, and stakeholders have discovered first hand how difficult and complex it can be to remedy the situation after the fact.

While providing the infrastructure necessary to enhance the power system and meet the energy needs of customers is certainly desirable, it imposes additional financial responsibilities on APS. For a utility with an obligation to provide reliable service, investors' increased reticence to supply additional capital during times of crisis highlights the necessity of preserving the flexibility necessary to overcome periods of adverse capital market conditions. These considerations heighten the importance of allowing APS an adequate return on the fair value of its investment.

**Q. WHAT ROLE DOES REGULATION PLAY IN ENSURING ACCESS TO CAPITAL FOR APS?**

A. Considering investors' heightened awareness of the risks associated with the utility industry and the damage that results when a utility's financial flexibility is compromised, the continuation of supportive regulation remains crucial to the

Company's access to capital. Investors recognize that regulation has its own risks, and that constructive regulation is a key ingredient in supporting utility credit ratings and financial integrity, particularly during times of adverse conditions.

Fitch concluded, "[G]iven the lingering rate of unemployment and voter concerns about the economy, there could well be pockets of adverse rate decisions, and those companies with little financial cushion could suffer adverse effects."[58] S&P has also emphasized the need for regulatory support, concluding, "the quality of regulation is at the forefront of our analysis of utility creditworthiness."[59] Similarly, Moody's concluded:

> For the longer term, however, we are becoming increasingly concerned about possible changes to our fundamental assumptions about regulatory risk, particularly the prospect of a more adversarial political (and therefore regulatory) environment. A prolonged recessionary climate with high unemployment, or an intense period of inflation, could make cost recovery more uncertain.[60]

With respect to APS specifically, the investment community has noted ongoing challenges posed by regulatory uncertainty.[61] Of particular concern to investors is the impact of regulatory lag and cost-recovery on the APS's ability to earn its authorized ROE and maintain its financial metrics, with Fitch noting:

> In Fitch's opinion, the regulatory compact in Arizona will continue to be the key determinant of APS's creditworthiness. Implementation of effective regulatory policies to ameliorate regulatory lag and provide APS a reasonable opportunity to earn

[58] Fitch Ratings Ltd., "U.S. Utilities, Power and Gas 2010 Outlook," *Global Power North America Special Report* (Dec. 4, 2009).
[59] Standard & Poor's Corporation, "Assessing U.S. Utility Regulatory Environments," *RatingsDirect* (Nov. 7, 2008).
[60] Moody's Investors Service, "U.S. Regulated Electric Utilities, Six-Month Update," *Industry Outlook* (July 2009).
[61] *See e.g.*, Moody's Investors Service, "Credit Opinion: Arizona Public Service Company," *Global Credit Research* (Feb. 25, 2011).

its authorized ROE will be critical to the utility's future credit ratings.[62]

**Q. WHAT ARE THE IMPLICATIONS OF THE COMPANY'S RELATIVE CREDIT STANDING?**

A. In a recent report by S&P ranking U.S. regulated utilities from strongest to weakest, APS was ranked 150 out of the total 185 companies with investment grade credit ratings.[63] During the financial crisis Fitch observed that, "'flight to quality' is selective within the [utility] sector, favoring companies at higher rating levels."[64] Because of the weaker overall credit standing associated with APS, there is little backstop in the event of a crisis and reduced flexibility to respond to other challenges, such as increased capital outlays or renewed energy market volatility.

The negative impact of declining credit quality on a utility's capital costs and financial flexibility becomes more pronounced as debt ratings move down the scale from investment to non-investment grade. In light of APS's present ratings, an inadequate rate of return imposed in this proceeding would further pressure APS's financial flexibility and credit standing. Strengthening financial integrity is imperative to ensure the capability to maintain existing ratings while confronting potential challenges.

**Q. DO CUSTOMERS BENEFIT BY ENHANCING THE UTILITY'S FINANCIAL FLEXIBILITY?**

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[62] Fitch Ratings Ltd., "Arizona Public Service Company," *Global Power U.S. & Canada Full Ratings Report* (Jun. 11, 2010).

[63] Standard & Poor's Corporation, "Issuer Ranking: U.S. Regulated Electric Utilities, Strongest To Weakest," *RatingsDirect* (Apr. 7, 2011).

[64] Fitch Ratings Ltd., "U.S. Utilities, Power and Gas 2009 Outlook," *Global Power North America Special Report* (Dec. 22, 2008).

A. Yes. While providing a return on fair value that is sufficient to maintain APS's ability to attract capital, even under duress, is consistent with the economic requirements embodied in the U.S. Supreme Court's *Bluefield* decision, it is also in customers' best interests.[65] Ultimately, it is customers and the service area economy that enjoy the benefits that come from ensuring that the utility has the financial wherewithal to take whatever actions are required to ensure a reliable energy supply. By the same token, customers also bear a significant burden when the ability of the utility to attract capital is impaired and service quality is compromised.

*B. Capital Structure*

**Q. IS AN EVALUATION OF THE CAPITAL STRUCTURE MAINTAINED BY A UTILITY RELEVANT IN ASSESSING ITS RETURN ON EQUITY?**

A. Yes. Other things equal, a higher debt ratio, or lower common equity ratio, translates into increased financial risk for all investors. A greater amount of debt means more investors have a senior claim on available cash flow, thereby reducing the certainty that each will receive their contractual payments. This increases the risks to which lenders are exposed, and they require correspondingly higher rates of interest. From common shareholders' standpoint, a higher debt ratio means that there are proportionately more investors ahead of them, thereby increasing the uncertainty as to the amount of cash flow, if any, that will remain.

**Q. WHAT COMMON EQUITY RATIO IS IMPLICIT IN APS'S REQUESTED CAPITAL STRUCTURE?**

A. APS's capital structure is presented in the testimony of Witness Jim Hatfield. As

[65] The end result requirement of the *Hope* case was affirmed in the *Duquesne* case cited earlier and in the more recent *Verizon Comm. Et al v. FCC*, 535 U.S. 467 (2002).

summarized in his testimony, the common equity ratio used to compute APS's overall rate of return was approximately 54 percent in this filing.

**Q. WHAT WAS THE AVERAGE BOOK VALUE CAPITALIZATION MAINTAINED BY THE UTILITY PROXY GROUP?**

A. As shown on Attachment WEA-8, common equity ratios at December 31, 2010 ranged from 25.3 percent to 63.8 percent and averaged 45.5 percent for the firms in the Utility Proxy Group.

**Q. WHAT OTHER BENCHMARKS ARE RELEVANT IN ASSESSING APS'S CAPITAL STRUCTURE UNDER THE FAIR VALUE RATE BASE STANDARD?**

A. To be able to raise capital, companies must pay returns that are competitive at the current market prices of their securities, not the embedded book value of the mix of stocks and bonds. Reference to market values is also consistent with the underlying premise of the fair value rate base standard.[66] As a result, the market value capitalizations for the firms in the Utility Proxy Group also serve as a benchmark in evaluating APS's proposed capital structure.

As shown on Attachment WEA-9, at year-end 2010, the market value capitalizations for the firms in the Utility Proxy Group implied an average common equity ratio of 53.8 percent.

**Q. WHAT CAPITALIZATION IS REPRESENTATIVE FOR THE UTILITY PROXY GROUP GOING FORWARD?**

A. As shown on Attachment WEA-8, Value Line expects that the average book value common equity ratio for the Utility Proxy Group of 48.5 percent over its

[66] The U.S. Supreme Court in *Duquesne Light Co. v. Barasch*, 488 U.S. 299 (1989) noted that the purpose of fair value ratemaking is to provide a fair return on the market value of plant. Using a market value capital structure would seem to be more consistent with this objective than original cost given that Arizona is a fair value jurisdiction.

three-to-five year forecast horizon. On a market value basis, the average capitalization for this group of electric utilities implies an average common equity ratio of 54.1 percent (Attachment WEA-9).

**Q. WHAT CAPITALIZATION RATIOS ARE MAINTAINED BY OTHER ELECTRIC UTILITY OPERATING COMPANIES?**

A. Attachment WEA-10 displays capital structure data at year-end 2010 for the group of electric utility operating companies owned by the firms in the Utility Proxy Group. As shown there, common equity ratios for the electric utility operating companies corresponding to the Utility Proxy Group ranged from 26.5 percent to 62.9 percent and averaged 51.5 percent.

**Q. WHAT IMPLICATION DOES THE INCREASING RISK OF THE INDUSTRY HAVE FOR THE CAPITAL STRUCTURES MAINTAINED BY UTILITIES?**

A. As discussed earlier, utilities are facing energy market volatility, rising cost structures, the need to finance significant capital investment plans, uncertainties over accommodating economic and financial market uncertainties, and ongoing regulatory risks. Taken together, these considerations warrant a stronger balance sheet to deal with an increasingly uncertain environment. A more conservative financial profile, in the form of a higher common equity ratio, is consistent with increasing uncertainties and the need to maintain the continuous access to capital that is required to fund operations and necessary system investment, including times of adverse capital market conditions.

Moody's has repeatedly warned investors of the risks associated with debt leverage and fixed obligations and advised utilities not to squander the

opportunity to strengthen the balance sheet as a buffer against future uncertainties.[67] More recently, Moody's concluded:

> From a credit perspective, we believe a strong balance sheet coupled with abundant sources of liquidity represents one of the best defenses against business and operating risk and potential negative ratings actions.[68]

Similarly, S&P noted that, "we generally consider a debt to capital level of 50% or greater to be aggressive or highly leveraged for utilities."[69] Fitch affirmed that it expects regulated utilities "to extend their conservative balance sheet stance in 2010," and employ "a judicious mix of debt and equity to finance high levels of planned investments."[70]

**Q. WHAT OTHER FACTORS DO INVESTORS CONSIDER IN THEIR ASSESSMENT OF A COMPANY'S CAPITAL STRUCTURE?**

A. Depending on their specific attributes, contractual agreements or other obligations that require the utility to make specified payments may be treated as debt in evaluating the Company's financial risk. For example, power purchase agreements ("PPA") typically obligate the utility to make specified minimum contractual payments. As a result, when a utility enters into a PPA, the fixed charges associated with the contract increase the utility's financial risk in the same way that long-term debt and other financial obligations increase financial leverage. Because investors consider the debt impact of such fixed obligations

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[67] Moody's Investors Service, "Storm Clouds Gathering on the Horizon for the North American Electric Utility Sector," *Special Comment* (Aug. 2007); "U.S. Electric Utility Sector," *Industry Outlook* (Jan. 2008).

[68] Moody's Investors Service, "U.S. Electric Utilities Face Challenges Beyond Near-Term," *Industry Outlook* (Jan. 2010).

[69] Standard & Poor's Corporation, "Ratings Roundup: U.S. Electric Utility Sector Maintained Strong Credit Quality In A Gloomy 2009," *RatingsDirect* (Jan. 26, 2010).

[70] Fitch Ratings Ltd., "U.S. Utilities, Power, and Gas 2010 Outlook," *Global Power North America Special Report* (Dec. 4, 2009).

in assessing a utility's financial position, they imply greater risk and reduced financial flexibility. In order to offset the resulting debt equivalent, the utility must rebalance its capital structure by increasing its common equity in order to restore its effective capitalization ratios to previous levels. These commitments have been repeatedly cited by major bond rating agencies in connection with assessments of utility financial risks.[71]

As discussed earlier, a significant portion of the Company's power requirements are currently obtained through long-term purchased power contracts. These contractual payment obligations, along with the sale-leaseback agreements associated with Unit 2 of Palo Verde, are fixed commitments with debt-like characteristics and are properly considered when evaluating the financial risks implied by APS's capital structure. S&P reported that it adjusts Pinnacle West's capitalization to include $1.1 billion in imputed debt from off-balance sheet obligations associated with lease agreements, post-retirement benefit obligations, and PPAs.[72] Unless the Company takes action to offset this additional financial risk by maintaining a higher equity ratio, the resulting leverage will weaken APS's creditworthiness, implying a higher required rate of return to compensate investors for the greater risks.

**Q. WHAT DOES THIS EVIDENCE SUGGEST WITH RESPECT TO APS'S PROPOSED CAPITAL STRUCTURE?**

A. Based on my evaluation, I concluded that a capital structure consisting of approximately 54 percent common equity represents a reasonable mix of capital sources from which to calculate APS's overall rate of return. The Company's

[71] See, *e.g.*, Standard & Poor's Corporation, "Implications Of Operating Leases On Analysis Of U.S. Electric Utilities," *RatingsDirect* (Jan. 15, 2008)
[72] Standard & Poor's Corporation, "Arizona Public Service Co.," *RatingsDirect* (Apr. 27, 2010).

requested common equity ratio of approximately 54 percent is entirely consistent with the range of book value capitalizations for the proxy companies and other electric operating companies, and is essentially identical to the average market value capital structure for the Utility Proxy Group based on year-end 2010 data and Value Line's near-term projections. Because the purpose of fair value ratemaking is to provide a reasonable return on the value of the utility's rate base, reference to market values is relevant in evaluating APS's capital structure.

While industry averages provide one benchmark for comparison, each firm must select its capitalization based on the risks and prospects it faces, as well its specific needs to access the capital markets. A public utility with an obligation to serve must maintain ready access to capital so that it can meet the service requirements of its customers. The need for access becomes even more important when the company has capital requirements over a period of years, and financing must be continuously available, even during unfavorable capital market conditions.

The Company's proposed capital structure is consistent with industry benchmarks and reflects APS's ongoing efforts to maintain its credit standing and support access to capital on reasonable terms. The reasonableness of APS's requested capital structure is reinforced by the ongoing uncertainties associated with the electric power industry, the need to accommodate the additional exposures associated with the Company's resource mix, and the importance of supporting continued investment in system improvements, even during times of adverse industry or market conditions. S&P noted that the Company's credit rating could decline if APS "is unable to maintain or improve its capital

structure,"[73] while Moody's cited the need for a reduction in financial leverage to stabilize APS's credit standing.[74]

*C. Implications of Attrition*

**Q. WHAT CAUSES ATTRITION?**

A. Attrition is the deterioration of actual return below the allowed return that occurs when the relationships between revenues, costs, and rate base used to establish rates (e.g., using a historical test year) have changed by the time rates go into effect. For example, if external factors are driving costs to increase more than revenues, then the rate of return will fall short of the allowed return even if the utility is operating efficiently. Similarly, when growth in the utility's investment outstrips the rate base used in the test year, the earned rate of return will fall below the allowed return through no fault of the utility's management. These imbalances are exacerbated as the regulatory lag increases between the time when the data used to establish rates is measured and the date when the rates go into effect.

**Q. WHY IS IT NECESSARY TO ADDRESS THE IMPACT OF ATTRITION?**

A. Investors are concerned with what they can expect in the future, not what they might expect in theory if a historical test year were to repeat. To be fair to investors and to benefit customers, a regulated utility must have an opportunity to actually earn a return that will maintain financial integrity, facilitate capital attraction, and compensate for risk. In other words, it is the end result in the future that determines whether or not the *Hope* and *Bluefield* standards are met.

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[73] Standard & Poor's Corporation, "Arizona Public Service Co.," *RatingsDirect* (Apr. 27, 2010).

[74] Moody's Investors Service, "Credit Opinion: Arizona Public Service Company," *Credit Research* (Dec. 17, 2007).

**Q. HAS THE INVESTMENT COMMUNITY RECOGNIZED THE RISKS ASSOCIATED WITH ATTRITION AND LAG IN ITS EVALUATION OF APS?**

A. Yes. S&P noted that, "Regulatory lag, or the time that a company takes to pass on higher costs to customers, has typically been higher than sector averages, and is expected to persist because the company continues to require high levels of capital investment."[75] Similarly, Moody's noted, "APS's ability to earn reasonable returns has been limited due to significant regulatory lag," and concluded that the uncertain timing of rate case decisions by the ACC "causes APS to map to a factor in the Ba range for its Regulatory Framework."[76] Fitch has also cited the potential that regulatory lag could produce "significant deterioration" in credit metrics and result in rating downgrades.[77] More recently, Fitch concluded:

> Earnings attrition due to regulatory lag is a primary risk factor for APS investors. If left unaddressed, post-2011 earned returns could track significantly below authorized levels, resulting in weakening credit metrics and potential credit rating downgrades.[78]

Fitch observed that, "Implementation of effective regulatory policies to ameliorate regulatory lag and provide APS a reasonable opportunity to earn its authorized ROE will be critical to the utility's future credit ratings.[79]

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[75] Standard & Poor's Corporation, "Arizona Public Service Co.," *RatingsDirect* (Apr. 27, 2010).
[76] Moody's Investors Service, "Credit Opinion: Arizona Public Service Company," *Global Credit Research* (Feb. 25, 2011).
[77] Fitch Ratings Ltd., "Arizona Public Service Company," *Global Power U.S. & Canada Credit Analysis* (Jan. 23, 2008).
[78] Fitch Ratings Ltd., "Arizona Public Service Company," *Global Power U.S. & Canada Credit Analysis* (Jun. 11, 2010).
[79] *Id.*

Similarly, the February 28, 2011 Benchmarking Study prepared by the Liberty Consulting Group concluded that APS's earned returns have fallen significantly below benchmark levels.[80] As the study concluded:

> The graph below shows APS [return on average equity] falling consistently well below the average returns of each of the base, expanded growth and nuclear comparative panels from 2002-2009.[81]

**Q. WHAT ARE THE WAYS TO DEAL WITH ATTRITION?**

A. For many utilities, the widespread adoption of pass-through clauses for fuel, purchased power, and other costs that were rising rapidly in the late 1970's and early 1980's has helped to partially offset the impact of attrition. The use of future test years and other forward-looking mechanisms is also useful in ameliorating the impact of attrition, as is accelerated depreciation and inclusion of CWIP in rate base, particularly where financing an expensive generating plant addition is undermining a utility's financial indicators. Many jurisdictions have developed methods to attenuate regulatory lag, such as allowing interim rates, putting rates into effect subject to refund, as well as accelerating the administrative process to allow faster rate decisions. As a result of these measures, combined with the fall-off of inflation, growth, and new construction across the electric utility industry, attrition ceased to be a major regulatory issue for most utilities by the mid-1980s.

**Q. WOULD THE DECOUPLING MECHANISM PROPOSED BY APS HELP TO ATTENUATE ATTRITION?**

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[80] Liberty Consulting Group, "Benchmarking Study of Arizona Public Service Company's Operations, Cost, and Financial Performance," Docket No. E-01345A-08-0172 (Feb. 28, 2011) at 41-42 ("Benchmarking Study").
[81] *Id.*

A. Yes. Decoupled rate structures are another tool to better match a utility's revenues with the underlying costs of providing service. By improving a utility's ability to recover its fixed costs between rate cases, mechanisms, such as the Efficiency and Infrastructure Account ("EIA") mechanism proposed by APS, help to reduce attrition by addressing the impact of at least one cause; namely, declining customer sales.

**Q. IS IT REASONABLE TO CONSIDER ATTRITION IN ESTABLISHING RATES FOR APS?**

A. Yes. Setting rates at a level that considers the impact of attrition and allows the utility an opportunity to actually earn its authorized ROE is consistent with fundamental regulatory principles. That end result would maintain the utility's financial integrity, ability to attract capital and offer investors fair compensation for the risk they bear. Given the past timing of rate relief and the dynamics faced by APS, there is every reason to believe that attrition would lead to under-earning the allowed ROE if the impact of regulatory lag and rising costs and capital requirements is ignored.

Central to the determination of reasonable rates for utility service is the notion that owners of public utility properties are protected from confiscation. The Supreme Court has reaffirmed that the end result test must be applied to the actual returns that investors expect if they put their money at risk to finance utilities.[82] This end result can only be achieved for APS if the ROE is sufficient

[82] *Verizon Communications, et al v. Federal Communications Commission, et al*, 535 U.S. 467 (2002). While I cannot comment on the legal significance of this case, I found the economic wisdom of looking to the reasonable expectations of actual investors compelling. I understand that as a fair value state, Arizona law may have requirements beyond the *Hope* and *Bluefield* end-result tests. But economic logic and common sense confirm that a utility cannot attract capital on reasonable terms if investors expect future returns to fall short of those offered by comparable investments.

to offset the impact of attrition. Thus, whatever the Commission ultimately determines to be investors' required return, the only way to achieve that end result is to set the ROE at a level that is sufficient to give APS an opportunity to actually earn investors' required rate of return in the future.

Indeed, not allowing the Company an opportunity to earn a sufficient return is the economic equivalent of taking the capital value of existing investors.

**Q. HOW DOES NOT ALLOWING APS AN ACTUAL OPPORTUNITY TO EARN ITS COST OF CAPITAL RESULT IN TAKING VALUE FROM APS INVESTORS?**

A. In real world capital markets, investors have many competing places to put their money. If the money that is dedicated to utility public service does not have an opportunity to earn a return commensurate with that available from alternatives of equivalent risk in the capital markets, investors are not being adequately compensated for the use of their money and bearing risk. Since the capital dedicated to utility service cannot be withdrawn from public service, its economic value to investors is reduced by the amount necessary to make the utility investment competitive with alternative investments on the open market.[83] This reduction in economic value necessary to bring the rate of earnings on utility investment into line with market opportunities of commensurate risk constitutes a taking of investors' capital by the governmental authority setting rates.

[83] Individual owners of utility bonds and stocks can sell their claims on future cash flows to other investors, but they cannot withdraw the underlying capital from the utility. The government will not allow capital that is invested in utility rate base to be withdrawn. Therefore, the governmental authority having control over the rates must be set them as to allow that capital to earn of return that is competitive with the earnings available other opportunities of commensurate risk. Failing to allow such a return constitutes a taking of the economic value of the capital dedicated to public utility service.

We can observe how inadequate returns reduce economic value in the marketplace. Consider a bond issued by a risky entity. Generally the bond is sold to the public at close to face value ($1000) and can be traded in the market. Whoever owns the bond will receive the coupon payments over the life of the bond and receive the $1000 principal repayment at maturity. As the level of interest rates vary or the risk of the cash flow promises from the issuer of the bond change, so will the market value of the bond. If the risk increases that the promised payments will not be made in full, the value of the bond drops in the capital market. Only by lowering the price that investors must pay for the bond can the expected return be made competitive with other opportunities in the capital markets. If an investor owns the bond and does not sell it when the risk increases, the economic value of their investment is reduced as the market price declines.

Similarly, capital that is dedicated to public service in the rate base of APS has its value affected by the risks and prospects of APS relative to other opportunities in the capital market. Since the money invested in APS's fair value rate base cannot be withdrawn, the effect of not having an opportunity to earn returns commensurate with the underlying risk causes the economic value of its securities to fall. This reduction in value due to an inadequate opportunity to earn a return commensurate with risk is the economic equivalent of the government taking value from the private property of investors without compensation.

*D. Impact of Adjustment Mechanisms*

**Q. HOW ARE FLUCTUATIONS IN ENERGY COSTS FOR APS ACCOMMODATED IN RATES?**

A. Concerns over the risks associated with energy price volatility and rising costs have become increasingly pronounced in the industry. The Company's retail electric rates contain a fuel and purchased power adjustment clause ("PSA"), whereby increases and decreases in the cost of fuel for electric generation are reflected in the rates charged to retail electric customers. The ACC requires periodic filings and hearings to establish the amount of price adjustments under the PSA and also provides for deferral and subsequent recovery or refund of variances between the estimated cost of fuel and purchased power and the actual costs incurred. Under the existing PSA, APS defers 90 percent of the difference between retail fuel and purchased power costs and the Base Fuel Rate. As discussed earlier, the Company absorbs as much as 10 percent of the retail fuel and purchased power costs above the Base Fuel Rate and retains up to 10 percent of the benefit from the retail fuel and purchased power costs that are below the Base Fuel Rate. The PSA rate may not be increased or decreased more than $0.004 per kWh in a year without permission of the ACC.

As a result, while the PSA mechanism is supportive of APS's financial integrity, there can be a lag between the time the Company actually incurs power cost expenditures and when they are recovered from ratepayers. Thus, APS is not entirely shielded from the need to finance deferred power supply costs. Thus, while the PSA is a valuable means of mitigating the risks associated with energy cost volatility, they do not eliminate them.

**Q. DOES APS OPERATE UNDER OTHER COST RECOVERY MECHANISMS?**

A. Yes. The ACC has approved a recovery mechanism to track the costs that APS incurs in providing transmission services, as well as costs related to energy

efficiency programs and renewable energy standards. APS is also proposing the implementation of a revenue decoupling mechanism, the EIA, and an Environmental and Reliability Account ("ERA") mechanism for environmental and generation capacity additions, which will provide APS a more timely recovery of the revenue requirement associated with qualified investments made by APS.

**Q. WHAT WOULD BE THE EFFECT OF APS'S TWO NEW PROPOSED MECHANISMS FROM INVESTORS' PERSPECTIVE?**

A. Revenue decoupling mechanisms address the investment community's heightened concerns over the risks associated with declining consumption by helping to preserve a utility's opportunity to collect the level of revenues per customer it was authorized when rates were established. APS's distributed generation, energy conservation and efficiency programs may be desirable, but as S&P noted, "policy objectives can sometimes increase utilities' uncertainty and credit risk."[84] S&P went on to conclude that, "efficiency programs that lack decoupling may carry a higher level of credit risk."[85] Because utility revenues and cash flow typically depend on sales volume, a utility will be unable to recover its fixed costs on a timely basis, if at all, to the degree that usage is declining. Regulatory mechanisms, such as the EIA proposed by APS, are essential to mitigate regulatory lag while ensuring that conservation efforts do not undermine the utility's financial integrity and credit standing.

**Q. WOULD APPROVAL OF APS'S PROPOSED EIA AND ERA MECHANISMS IMPLY THAT ITS INVESTMENT RISKS ARE LOWER**

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[84] Standard & Poor's Corporation, "When Energy Efficiency Means Lower Electric Bills, How Do Utilities Cope?," *RatingsDirect* (Mar. 9, 2009).
[85] *Id.*

**THAN FOR THE COMPANIES IN THE PROXY GROUPS USED IN YOUR QUANTITATIVE ANALYSES?**

A. No. Adjustment clauses and cost trackers, along with rate design measures and other mechanisms designed to break the link between a utility's revenues from customer usage, have been increasingly prevalent in the utility industry in recent years. In response to the increasing risk sensitivity of investors to uncertainty over fluctuations in costs and regulatory lag, and in light of the importance of advancing other public interest goals such as energy conservation, utilities and their regulators have sought to mitigate some of the cost recovery uncertainty and align the interest of utilities and their customers in favor of reducing consumption through decoupling and other adjustment mechanisms. As Fitch observed:

> An emerging regulatory trend for integrated electric utilities is the initiation of electricity revenue decoupling in response to the recent softness of demand and state policies that include ambitious energy-efficiency targets.[86]

While not always directly analogous to the specific mechanisms approved or proposed for APS, the objective is similar; namely, to allow the utility an opportunity to earn a fair rate of return and mitigate exposure to attrition in an era of rising costs and declining consumption. Reflective of this industry trend, the companies in the Utility Proxy Group operate under a variety of cost adjustment mechanisms. As summarized on Attachment WEA-11, these mechanisms range from riders to recover bad debt expense and post-retirement

[86] Fitch Ratings Ltd., "U.S. Utilities, Power, and Gas 2010," *Global Power North America Special Report* (Dec. 4, 2009). Fitch observed that electric revenue decoupling had been initiated or was allowed in California, Ohio, Vermont, New York, and Maryland, with pilot programs in Wisconsin and Idaho, while 18 states have approved the implementation of revenue decoupling for gas utilities.

employee benefit costs to revenue decoupling and adjustment clauses designed to address the rising costs of environmental compliance measures.

For example, the utility operations of Constellation Energy, Inc. benefit from energy adjustment clauses and revenue decoupling, as well as trackers for costs associated with conservation and demand-side management programs. Similarly, Edison International Inc. and Pacific Gas and Electric Company also operate under numerous balancing account mechanisms that cover a significant portion of revenue requirements and effectively dampen the impact of fluctuations in electric sales on their ability to recover the costs of providing service. Similarly, the firms in the Non-Utility Proxy Group also have the ability to alter prices in response to rising production costs, with the added flexibility to withdraw from the market altogether.

**Q. IS THERE A DOWNSIDE TO REVENUE DECOUPLING MECHANISMS FROM AN INVESTOR PERSPECTIVE?**

A. Yes. The investment community does not view mechanisms to address revenue stabilization, such as weather mitigants or rate design mechanisms that shift away from volumetric recovery of fixed costs, as entirely positive. This is because, while such measures dampen the volatility of a utility's revenues, they also largely preclude the prospects of greater earnings due to higher consumption. This double-edged sword was noted by S&P in the context of weather adjustment clauses:

> Some LDCs are reluctant to pursue such provisions, because they don't want to forego the upside earnings potential of a significantly colder-than-normal winter.[87]

[87] Standard & Poor's Corporation, "Natural Gas Distribution," *Industry Surveys* at 18 (Nov. 29, 2001).

Similarly, Moody's warned that "it is unclear, at this time, as to whether these cost riders/trackers may prove to have hidden consequences over the long-term horizon."[88] Thus, investors would also consider the loss of upside potential in evaluating the impact of decoupling mechanisms.

**Q. WHAT DOES THIS IMPLY WITH RESPECT TO YOUR EVALUATION OF A FAIR ROE FOR APS?**

A. While the EIA and ERA mechanisms proposed for APS would be supportive of the Company's financial integrity and credit ratings, there is certainly no evidence to suggest that these provisions would justify any adjustment to the ROE range determined earlier. First, APS's investment risks are comparable to or greater than those of the proxy groups used to estimate the cost of equity. For example, the "BBB-" corporate credit rating assigned to APS indicates slightly *more* risk than the "BBB" average for the Utility Proxy Group.

As demonstrated above, utilities across the U.S. that APS competes with for new capital – including those in the Utility Proxy Group used to estimate the cost of equity – are increasingly availing themselves of similar adjustments. As a result, the impact of utilities' ability to mitigate the risk of declining revenues and cash flows is already reflected in the capital market estimates discussed earlier, and no separate adjustment to APS's ROE is necessary or warranted. While the adjustment mechanisms approved and proposed for APS address the built-in disincentives associated with increasing capital expenditures and fluctuating energy demand by attenuating exposure to declining revenues, this leveling of the playing field only serves to address factors that could otherwise impair APS's opportunity to collect its authorized revenues.

[88] Moody's Investors Service, "U.S. Investor-Owned Electric Utilities," *Industry Outlook* (January 2009).

*E. Return on Equity Recommendation*

**Q. PLEASE SUMMARIZE THE RESULTS OF YOUR ANALYSES.**

A. Reflecting the fact that investors' required return on equity is unobservable and no single method should be viewed in isolation, I used both the DCF and CAPM methods to estimate a fair ROE for APS. These methods were applied in a forward-looking manner to be consistent with the Arizona fair value rate base standard. In order to reflect the risks and prospects associated with APS's jurisdictional utility operations, my analyses focused on a proxy group of twenty-one other utilities with comparable investment risks. Consistent with the fair value rate base standard, and the fact that utilities must compete for capital with firms outside their own industry, I also referenced a proxy group of comparable risk companies in the non-utility sector of the economy.

My application of the constant growth DCF model considered four alternative growth measures based on projected earnings growth and the sustainable, "br+sv" for each firm in the respective proxy groups. In addition, I evaluated the reasonableness of the resulting DCF estimates and eliminated low- and high-end outliers that failed to meet threshold tests of economic logic. My CAPM analyses were based on forward-looking data that best reflects the underlying assumptions of this approach. The results of my alternative analyses are summarized in Table WEA-6, below:

**TABLE WEA-6**
**SUMMARY OF QUANTITATIVE RESULTS**

| DCF | Utility | Non-Utility |
|---|---|---|
| Earnings Growth | | |
| 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% |

**Q. WHAT THEN IS YOUR CONCLUSION AS TO A FAIR ROE RANGE FOR APS?**

A. Considering the relative strengths and weaknesses inherent in each method, and conservatively giving less emphasis to the upper- and lower-most boundaries of the range of results, I concluded that the cost of common equity is in the 10.6 percent to 11.60 percent range. After incorporating a minimal adjustment for flotation costs of 15 basis points to my "bare bones" cost of equity range, I concluded that my analyses indicate a fair ROE in the 10.75 percent to 11.75 percent range. In light of capital market expectations and the economic requirements necessary to maintain financial integrity and support additional capital investment even under adverse circumstances, these considerations indicate that an ROE in the range of 10.75 to 11.75 percent is reasonable.

Apart from the results of the quantitative methods summarized above, it is crucial to recognize the importance of supporting the Company's financial position so that APS remains prepared to respond to unforeseen events that may materialize in the future. Recent challenges in the economic and financial market environment highlight the imperative of maintaining the Company's financial strength in attracting the capital needed to secure reliable service at a lower cost for customers.

As discussed in the testimony of Mr. Jeff Guldner, APS is requesting an ROE of 11.00 percent in this case. Because the Company's requested ROE falls below the 11.25 percent midpoint of my recommended range it represents a reasonable compromise between balancing the impact on customers and the need to provide APS with a return that is adequate to compensate investors, maintain financial integrity, and attract capital. The reasonableness of an 11.00 percent ROE is reinforced by the economic reality that APS's actual returns have fallen systematically short of the allowed ROE, and the fact that current cost of capital estimates are likely to understate investors' requirements at the time the outcome of this proceeding becomes effective and beyond.

## V. FAIR VALUE RATE OF RETURN

**Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?**

A. This section examines the alternatives the Commission might consider for rate of return to fair value based on the economic and financial realities facing APS in this case. It is clear that "backing into" the fair value rate of return to yield the same revenue requirement as original cost ratemaking has been rejected by the Arizona Court of Appeals in *Chaparral City Water Company, v. Arizona Corporation Commission ("Chaparral")*[89] and subsequent Commission orders. It is also clear that the Commission feels it has the flexibility to apply fair value principals in a manner that fits the facts and circumstances of the utility and achieves regulatory objectives.[90] In the UNS Electric decision the Commission repeated the regulatory benchmark: "that a utility should be provided with rates that will allow it an opportunity to earn a return that is comparable to those of

[89] CA-CC-05-0002 (February 13, 2007). My discussion of this and other court cases and Commission orders cited in this section is as an economist and financial analysts, not as an attorney.
[90] UNS Electric Decision 71914 (Sept. 30, 2010), p. 42.

similarly situated enterprises."[91] Also, in the UNS Electric decision, the Commission explicitly rejected any "a one size fits all approach" to return on fair value.[92]

This section of my testimony will first demonstrate that it is in the customers' interest to grant APS rates that will allow it an ***actual*** opportunity to earn a return that is comparable to similarly situated entities. Given the history of APS being unable to earn its allowed return as documented in the Benchmarking Study discussed earlier in my testimony, the Commission should adopt ratemaking methods that offset earnings attrition. The return to fair value is a tool the Commission could use to offset the effects of attrition and support continued recovery of financial resilience. Second, this section examines methods beyond those advocated in other cases by witnesses before this Commission to find a return to fair value increment consistent with economic and financial realities of APS. These approaches would achieve the key regulatory policy objectives in this case – maintaining APS's access to capital markets and financial integrity, so as to protect APS customers, as well as the customers of other Arizona utilities and the economy of Arizona, from the adverse effects that would result if APS were to lose its investment grade credit rating.

**Q. WHY IS IT IMPORTANT FOR THE COMMISSION TO USE THE FAIR VALUE RETURN TO SUPPORT APS'S FINANCIAL INTEGRITY?**

A. Due to recent constructive decisions, APS has recovered from its precarious financial position. RUCO witness Dr. Ben Johnson correctly warned in the last

[91] Id., p. 44.
[92] Id., p. 51.

rate case (pp. 16-22) that APS customers, customers of other Arizona utilities, and the economy of the state would suffer if APS were to be driven deeper into financial distress. Dr. Johnson urged the Commission to show that it understands the severity of APS's financial weakness and demonstrate to the investment community that it supports APS's efforts to maintain an investment grade bond rating. The recent financial crisis highlights the importance of regulatory support, as lower rated companies can be denied access to capital during times of financial market turmoil.

Giving a reasonable measure of return to the fair value increment would provide a clear signal that the Commission is willing to use the regulatory tools at its disposal to support APS's efforts to maintain investment grade ratings and improve its credit standing. By approving the ERA and the EIA, the Commission will address possible drags on APS's ability to earn its allowed return, but those features do not increase return. Moreover, as documented earlier, the utilities in the Utility Proxy Group enjoy similar mechanisms, while the low-risk firms in the Non-Utility Proxy Group are able to adjust their prices without regulatory intervention. Therefore, to assure that APS has realistic opportunity to earn a return comparable to the similarly situated entities in the Utility and Non-Utility Proxy Groups, a return to fair value should be used to offset anticipated attrition.

**Q. ARE THE METHODS YOU HAVE USED TO ESTIMATE A FAIR VALUE ROE APPLICABLE ONLY TO ORIGINAL COST RATE BASE?**

A. No. Most, but not all, utility proceedings apply the cost of capital to original cost rate base.[93] However, in my consulting and teaching outside of the utility regulatory arena, the cost of capital concept is applied to investment bases other than original cost. For example, cost of capital is applied to fair market values in valuing businesses and in capital budgeting. Indeed, a widely accepted authority in the valuation literature, Dr. Shannon P. Pratt, CFA, has written:

> Cost of capital estimation is at once the most critical and the most difficult element of most business valuations and capital expenditure decisions.[94]

In his authoritative text, Pratt discusses the same DCF and CAPM approaches applied by the witnesses in this and other utility rate cases. In the entire book devoted to the cost of capital, Dr. Pratt devotes only a few paragraphs to utility rate setting while detailing many other contexts in which the cost of capital concept is applied to an investment base other than original cost.

A recent and widespread application of standard ROE methods to a rate base other than original cost in the regulatory arena is in the area of telephone regulation. The Federal Communication Commission ("FCC") established a method of setting rates for unbundled network elements ("UNEs") pursuant to the Telecommunications Act of 1996 using a method termed Total Element Long-Run Incremental Cost ("TELRIC"). In the TELRIC method, the cost of capital is applied to a rate base derived from the cost of replicating the

[93] Although in my experience, Arizona is unique in having the fair value standard established in the state constitution, other states have used variations of fair value rate base at various times pursuant to legislative statutes. For example, when the PUCT was first established in 1975, the legislation provided for fair value rate base. The Texas Legislature subsequently eliminated the fair value language for electric and telephone utilities. For gas utilities in Texas, the Texas Railroad Commission has the option of using a fair value rate base.

[94] Shannon Pratt, CFA, *Cost of Capital: Estimation and Applications* (1998), Preface, p. xvii.

incumbent telephone companies' network using current technologies. This forward-looking measure of investment value departs significantly from original cost for most telephone companies. In *Verizon Communications v. FCC, et al.*, 535 U.S. 476 (May 13, 2002) ("*Verizon*"),[95] the U.S. Supreme Court upheld this application of the cost of capital to TELRIC rate base, rather than to original cost. I have been involved in a number of UNE cases in many states, and the cost of capital estimated using DCF and/or CAPM methods has been routinely applied to the current value rate base by state commissions and the FCC.

**Q. WOULD INVESTORS RECEIVE ANY "WINDFALL" IF APS IS GRANTED THE OPPORTUNITY TO EARN A RETURN ON A RATE BASE THAT EXCEEDS ORIGINAL COST?**

A. No. Equity investors expect that they will benefit when the value of an investment rises above the price originally paid; indeed, the expectation of an increase in investment value is one of the two sources of cash flow in the DCF model. For corporations in both the non-utility and utility sectors there is often a significant difference between the original cost (less depreciation) of equity investment as reflected on the balance sheet and the value that equity garners in the market as common stock. The conventions of Generally Accepted Accounting Principles do not equate to the concept of economic value in the marketplace. It is incorrect to state that the appreciation in the value of an investment is not attributable to the funds supplied by investors or that it is "cost-free" to investors. As will be discussed later, when the cost of capital for a company is estimated in the competitive sector, the market value weights of debt

[95] *In the Matter of Petition of Worldcom, Inc. Pursuant to Section 252(E)(5) for Preemption of the Jurisdiction of the Virginia State Corp. Comm'n regarding Interconnection Disputes with Verizon Va. Inc.*, 18 F.C.C.R. 17,722 (August 29, 2003).

and equity, rather than book value weights, are used to account for investors' market value not reflected in book value. The claim of debt holders may be limited to the amount they have loaned to the business, but their claim is senior to equity investors. While equity investors have a junior claim on the value of the corporation, their claim is open-ended. As a result, any residual value after meeting the obligations to debt investors inures to the benefit of equity investors.[96] But to say that the appreciation did not come from investors' funds is economic nonsense. Without the original investment, the subsequent appreciation would not have been possible.

Outside the world of original cost utility ratemaking, there is no link between the concepts of original cost and the cost of capital. Indeed, in *Verizon* the U.S. Supreme Court observed that the linkage between original investment and rate base is not unbroken in the regulatory arena:

> "Cost" as used in calculating rate base under the traditional cost-of-service method did not stand for all past capital expenditures, but at most for those that were prudent, while prudent investment itself could be denied recovery when unexpected events rendered investment useless. *Duquesne Light Co. v. Barasch, 488 U.S. 299, 312, 102 L. Ed. 2d 646, 109 S. Ct. 609 (1989).*[97]

The *Duquesne* case cited by the U.S. Supreme Court compared the fair value standard to the outcome of competitive markets where investors received the gains (or losses) derived from their investments:

> [The] fair value standard mimics the operation of the competitive market. To the extent utilities' investment in plant are good ones

[96] There may be equity claimants who are senior to common stock investors, *e.g.*, preferred stock. These claimants are ignored in this discussion since APS only has debt and common stock investors.
[97] *Verizon* at 10.

> (because their benefits exceed their costs) they are rewarded with an opportunity to earn an "above cost" return, that is, a fair return on the current "market value" of the plant. To the extent utilities' investments turn out to be bad ones (such as plants that are canceled and so never used and useful to the public), the utilities suffer because the investments have no fair value and so justify no return.[98]

Clearly, the capital appreciation of investments that result in market value exceeding book value is not a "cost-free" asset, but is instead the fruit of the equity investors' commitment of capital and risk-bearing.

**Q. IS ANY ADDITIONAL RETURN ON AN INCREMENT OF RATE BASE ABOVE ORIGINAL COST EXCESSIVE?**

A. No. Although this incremental value was not separately financed, it has what economists understand as opportunity cost because it requires that investors forgo other opportunities to leave their funds invested in the utility. That value increment is the private property of investors and it is being used to serve the public in the utility. Any argument that it is "cost-free" ignores the opportunity cost principle and would be akin to saying that homeowners have no ownership claim to the appreciation in the value of their home because they have no explicit financing cost.[99]

**Q. IS A ZERO PERCENT RETURN ON THE FAIR VALUE INCREMENT APPROPRIATE IN THIS CASE?**

A. No. A zero percent return would be economically and financially equivalent to "backing into the fair value return" based on the return to original cost. As observed by the court in *Chaparral,* granting the same return as original cost

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[98] *Duquesne Light Co. v. Barasch, 488 U.S. 299, 312, 102 L. Ed. 2d 646, 109 S. Ct. 609 (1989),* pp. 308-09.

[99] In an original cost jurisdiction, utility investors understand that earnings will be tied to original cost with the *Hope* and *Bluefield* protections.

would render the provisions of the Arizona Constitution without any economic effect. APS investors in a fair value regulatory regime would have the same compensation as an original cost jurisdiction.

**Q. IS IT LOGICAL TO LIMIT THE RETURN TO FAIR VALUE INCREMENT TO A RISK-FREE TREASURY YIELD ADJUSTED FOR INFLATION, AS IT IS SOMETIMES ARGUED BEFORE THIS COMMISSION?**

A. No. Because the return from the fair value increment is not risk-free, risk-free Treasuries yields are not a reasonable benchmark. A utility is not granted a guaranteed return, only an opportunity to earn the allowed return (including any fair value increment). As documented in the Benchmarking Study and in the testimony in this case, APS has consistently earned significantly less than the allowed return due to attrition. One surrogate for the required risky return would be the yield on utility bonds, rather than risk-free Treasury bonds. As noted earlier, the average yield on triple-B rated utility bonds in March 2011 was approximately 6.00 percent.

**Q. IS A BOND YIELD THE MOST ECONOMICALLY RELEVANT RETURN BENCHMARK FOR THE FAIR VALUE INCREMENT?**

A. No. The inflation-adjusted cost of equity would be more consistent with the economics of the fair value increment. The fair value increment is the difference between the fair value rate base and the original cost rate base. As discussed above, debt investors have a specified claim against the company's value and cash flow. The capital structure applied to the original cost rate base considers the debt claims and they are provided for by the use of the embedded cost of debt applied to the debt percentage of the capital structure. After the debt claims are satisfied, the residual inures to the benefit of equity holders. As a result, the

equity cost estimate is the proper economic benchmark for the return to the fair value increment. Therefore, my 11.25 percent recommended ROE (or the 11.00 percent ROE requested by APS) could be the starting point with a forward-looking inflation estimate subtracted. This equity return is consistent with the economic reality that equity investors retain the residual value after debt claims have been satisfied. Therefore, the top of the range of reasonable returns to the fair value increment should be the inflation adjusted equity return.

**Q. SHOULD THE METHOD OF DERIVING THE RETURN TO FAIR VALUE RATE BASE RECOMMEDED BY RUCOIN CHAPARRAL CITY WATER DECISION NO. 70441 (JULY 28, 2008) BE APPLIED IN THIS CASE?**

A. No. The capital structure should be adjusted to recognize market values. Since the fair value rate base in this case is an average of current value and original cost, so also should the capital structure be the average of original cost and market value. Specifically, APS's adjusted original cost capital structure of approximately 54 percent common equity and 46 percent long-term debt should be averaged with the market value capital structure of 56 percent equity and 44 percent debt for Pinnacle West, as identified in Attachment WEA-9 to my Direct Testimony. The resulting capital structure would be 55 percent equity and 45 percent debt.[100]

Market value capital structures are used in the competitive sector and have been used in UNE cases in determining the cost of capital to be applied to the current value TELRIC rate base. Indeed, in 2002 Dr. Johnson and I both testified in a UNE case for Southwestern Bell Telephone before the Missouri Public Service Commission in Docket TO-2002-222. He recommended the use of an original

[100] Computed as (54%+56%)/2 and (44% + 46%)/2, respectively.

cost capital structure and I recommended a market value capital structure. In its August 6, 2002 Order, the Missouri Public Service Commission adopted Dr. Johnson's original cost capital structure recommendation and accepted my cost of debt and cost of equity recommendations based on the DCF and CAPM. On June 17, 2004, the U.S. District Court for the Western District of Missouri (Central Division) issued an order finding that the use of book value capital structure "is at odds with the TELRIC methodology" and that market value capital structure should be used in calculating the cost of capital for UNE rates.[101]

**Q. IS ANY ADJUSTMENT TO THE COST OF EQUITY NECESSARY TO AVOID DOUBLE-COUNTING INFLATION?**

A. There is a reasonable argument that the cost of equity estimates presented in my testimony incorporate market methods of the DCF and CAPM for non-utility companies, where the values of investment can change over time with inflation and other influences. On the other hand, some, but not all of the inputs to the fair value rate base incorporate inflation and may be expected to do so in the future. I believe it may be reasonable to apply a reduction to the equity return to avoid double-counting inflation. But to produce a reasonable return on fair value rate base, as the FCC and most states have done in the TELRIC cases, the market value capital structure must first be incorporated into the return to fair value rate base, as I have recommended above.

**Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?**

A. Yes, it does.

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[101] *Southwestern Bell Telephone L.P., d/b/a SBC Missouri v. Missouri Public Service Commission, et al.*, Case No. 03-04148-CV-C-NKL (June 17, 2004) at 8.

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## Employment

| | |
|---|---|
| *Principal,*<br>FINCAP, Inc.<br>(Sep. 1979 to present) | Financial, economic and policy consulting to business and government. Perform business and public policy research, cost/benefit analyses and financial modeling, valuation of businesses (almost 200 entities valued), estimation of damages, statistical and industry studies. Provide strategy advice and educational services in public and private sectors, and serve as expert witness before regulatory agencies, legislative committees, arbitration panels, and courts. |
| *Director, Economic Research Division,*<br>Public Utility Commission of Texas<br>(Dec. 1977 to Aug. 1979) | Responsible for research and testimony preparation on rate of return, rate structure, and econometric analysis dealing with energy, telecommunications, water and sewer utilities. Testified in major rate cases and appeared before legislative committees and served as Chief Economist for agency. Administered state and federal grant funds. Communicated frequently with political leaders and representatives from consumer groups, media, and investment community. |
| *Manager, Financial Education,*<br>International Paper Company<br>New York City<br>(Feb. 1977 to Nov. 1977) | Directed corporate education programs in accounting, finance, and economics. Developed course materials, recruited and trained instructors, liaison within the company and with academic institutions. Prepared operating budget and designed financial controls for corporate professional development program. |

*Lecturer in Finance,*
The University of Texas at Austin
(Sep. 1979 to May 1981)
Assistant Professor of Finance,
(Sep. 1975 to May 1977)

Taught graduate and undergraduate courses in financial management and investment theory. Conducted research in business and public policy. Named Outstanding Graduate Business Professor and received various administrative appointments.

*Assistant Professor of Business,*
University of North Carolina at Chapel Hill
(Sep. 1972 to Jul. 1975)

Taught in BBA, MBA, and Ph.D. programs. Created project course in finance, Financial Management for Women, and participated in developing Small Business Management sequence. Organized the North Carolina Institute for Investment Research, a group of financial institutions that supported academic research. Faculty advisor to the Media Board, which funds student publications and broadcast stations.

## Education

*Ph.D., Economics and Finance,*
University of North Carolina at Chapel Hill
(Jan. 1969 to Aug. 1972)

Elective courses included financial management, public finance, monetary theory, and econometrics. Awarded the Stonier Fellowship by the American Bankers' Association and University Teaching Fellowship. Taught statistics, macroeconomics, and microeconomics.

Dissertation: *The Geometric Mean Strategy as a Theory of Multiperiod Portfolio Choice*

*B.A., Economics,*
Emory University, Atlanta, Georgia
(Sep. 1961 to Jun. 1965)

Active in extracurricular activities, president of the Barkley Forum (debate team), Emory Religious Association, and Delta Tau Delta chapter. Individual awards and team championships at national collegiate debate tournaments.

## Professional Associations

Received Chartered Financial Analyst (CFA) designation in 1977; Vice President for Membership, Financial Management Association; President, Austin Chapter of Planning Executives Institute; Board of Directors, North Carolina Society of Financial Analysts; Candidate Curriculum Committee, Association for Investment Management and Research; Executive Committee of Southern Finance Association; Vice Chair, Staff Subcommittee on Economics and National Association of Regulatory Utility Commissioners (NARUC); Appointed to NARUC Technical Subcommittee on the National Energy Act.

## Teaching in Executive Education Programs

*University-Sponsored Programs:* Central Michigan University, Duke University, Louisiana State University, National Defense University, National University of Singapore, Texas A&M University, University of Kansas, University of North Carolina, University of Texas.

*Business and Government-Sponsored Programs:* Advanced Seminar on Earnings Regulation, American Public Welfare Association, Association for Investment Management and Research, Congressional Fellows Program, Cost of Capital Workshop, Electricity Consumers Resource Council, Financial Analysts Association of Indonesia, Financial Analysts Review, Financial Analysts Seminar at Northwestern University, Governor's Executive Development Program of Texas, Louisiana Association of Business and Industry, National Association of Purchasing Management, National Association of Tire Dealers, Planning Executives Institute, School of Banking of the South, State of Wisconsin Investment Board, Stock Exchange of Thailand, Texas Association of State Sponsored Computer Centers, Texas Bankers' Association, Texas Bar Association, Texas Savings and Loan League, Texas Society of CPAs, Tokyo Association of Foreign Banks, Union Bank of Switzerland, U.S. Department of State, U.S. Navy, U.S. Veterans Administration, in addition to Texas state agencies and major corporations.

Presented papers for Mills B. Lane Lecture Series at the University of Georgia and Heubner Lectures at the University of Pennsylvania. Taught graduate courses in finance and economics for evening program at St. Edward's University in Austin from January 1979 through 1998.

## Expert Witness Testimony

Testified in over 300 cases before regulatory agencies addressing cost of capital, regulatory policy, rate design, and other economic and financial issues.

*Federal Agencies:* Federal Communications Commission, Federal Energy Regulatory Commission, Surface Transportation Board, Interstate Commerce Commission, and the Canadian Radio-Television and Telecommunications Commission.

*State Regulatory Agencies:* Alaska, Arizona, Arkansas, California, Colorado, Connecticut, Delaware, Florida, Georgia, Hawaii, Idaho, Illinois, Indiana, Iowa, Kansas, Kentucky, Maryland, Michigan, Missouri, Nevada, New Mexico, Montana, Nebraska, North Carolina, Ohio, Oklahoma, Oregon, Pennsylvania, South Carolina, South Dakota, Texas, Utah, Virginia, Washington, West Virginia, Wisconsin, and Wyoming.

Testified in 42 cases before federal and state courts, arbitration panels, and alternative dispute tribunals (89 depositions given) regarding damages, valuation, antitrust liability, fiduciary duties, and other economic and financial issues.

## Board Positions and Other Professional Activities

Audit Committee and Outside Director, Georgia System Operations Corporation (electric system operator for member-owned electric cooperatives in Georgia); Chairman, Board of Print Depot, Inc. and FINCAP, Inc.; Co-chair, Synchronous Interconnection Committee, appointed by Public Utility Commission of Texas and approved by governor; Appointed by Hays County Commission to Citizens Advisory Committee of Habitat Conservation Plan, Operator of AAA Ranch, a certified organic producer of agricultural products; Appointed to Organic Livestock Advisory Committee by Texas Agricultural Commissioner Susan Combs; Appointed by Texas Railroad Commissioners to study group for *The UP/SP Merger: An Assessment of the Impacts on the State of Texas; A*ppointed by Hawaii Public Utilities Commission to team reviewing affiliate relationships of Hawaiian Electric Industries; Chairman, Energy Task Force, Greater Austin-San Antonio Corridor Council; Consultant to Public Utility Commission of Texas on cogeneration policy and other matters; Consultant to

Public Service Commission of New Mexico on cogeneration policy; Evaluator of Energy Research Grant Proposals for Texas Higher Education Coordinating Board.

## Community Activities

Board of Directors, Sustainable Food Center; Chair, Board of Deacons, Finance Committee, and Elder, Central Presbyterian Church of Austin; Founding Member, Orange-Chatham County (N.C.) Legal Aid Screening Committee.

## Military

Captain, U.S. Naval Reserve (retired after 28 years service); Commanding Officer, Naval Special Warfare Engineering (SEAL) Support Unit; Officer-in-Charge of SWIFT patrol boat in Vietnam; Enlisted service as weather analyst (advanced to second class petty officer).

## Bibliography

### Monographs

*Ethics and the Investment Professional* (video, workbook, and instructor's guide) and *Ethics Challenge Today* (video), Association for Investment Management and Research (1995)

"Definition of Industry Ethics and Development of a Code" and "Applying Ethics in the Real World," in *Good Ethics: The Essential Element of a Firm's Success*, Association for Investment Management and Research (1994)

"On the Use of Security Analysts' Growth Projections in the DCF Model," with Bruce H. Fairchild in *Earnings Regulation Under Inflation*, J. R. Foster and S. R. Holmberg, eds. Institute for Study of Regulation (1982)

*An Examination of the Concept of Using Relative Customer Class Risk to Set Target Rates of Return in Electric Cost-of-Service Studies*, with Bruce H. Fairchild, Electricity Consumers Resource Council (ELCON) (1981); portions reprinted in *Public Utilities Fortnightly* (Nov. 11, 1982)

"Usefulness of Current Values to Investors and Creditors," *Research Study on Current-Value Accounting Measurements and Utility*, George M. Scott, ed., Touche Ross Foundation (1978)

"The Geometric Mean Strategy and Common Stock Investment Management," with Henry A. Latané in *Life Insurance Investment Policies*, David Cummins, ed. (1977)

*Investment Companies: Analysis of Current Operations and Future Prospects*, with J. Finley Lee and Glenn L. Wood, American College of Life Underwriters (1975)

### Articles

"Should Analysts Own the Stocks they Cover?" *The Financial Journalist*, (March 2002)

"Liquidity, Exchange Listing, and Common Stock Performance," with John C. Groth and Kerry Cooper, *Journal of Economics and Business* (Spring 1985); reprinted by National Association of Security Dealers

"The Energy Crisis and the Homeowner: The Grief Process," *Texas Business Review* (Jan.–Feb. 1980); reprinted in *The Energy Picture: Problems and Prospects*, J. E. Pluta, ed., Bureau of Business Research (1980)

"Use of IFPS at the Public Utility Commission of Texas," *Proceedings of the IFPS Users Group Annual Meeting* (1979)

"Production Capacity Allocation: Conversion, CWIP, and One-Armed Economics," *Proceedings of the NARUC Biennial Regulatory Information Conference* (1978)

"Some Thoughts on the Rate of Return to Public Utility Companies," with Bruce H. Fairchild in *Proceedings of the NARUC Biennial Regulatory Information Conference* (1978)

"A New Capital Budgeting Measure: The Integration of Time, Liquidity, and Uncertainty," with David Cordell in *Proceedings of the Southwestern Finance Association* (1977)

"Usefulness of Current Values to Investors and Creditors," in *Inflation Accounting/Indexing and Stock Behavior* (1977)

"Consumer Expectations and the Economy," *Texas Business Review* (Nov. 1976)

"Portfolio Performance Evaluation and Long-run Capital Growth," with Henry A. Latané in *Proceedings of the Eastern Finance Association* (1973)

Book reviews in *Journal of Finance* and *Financial Review*. Abstracts for *CFA Digest*. Articles in *Carolina Financial Times*.

**Selected Papers and Presentations**

"Economic Perspective on Water Marketing in Texas," 2009 Water Law Institute, The University of Texas School of Law, Austin, TX (Dec. 2009).

"Estimating Utility Cost of Equity in Financial Turmoil," SNL EXNET 15th Annual FERC Briefing, Washington, D.C. (Mar. 2009)

"The Who, What, When, How, and Why of Ethics," San Antonio Financial Analysts Society (Jan. 16, 2002). Similar presentation given to the Austin Society of Financial Analysts (Jan. 17, 2002)

"Ethics for Financial Analysts," Sponsored by Canadian Council of Financial Analysts: delivered in Calgary, Edmonton, Regina, and Winnipeg, June 1997. Similar presentations given to Austin Society of Financial Analysts (Mar. 1994), San Antonio Society of Financial Analysts (Nov. 1985), and St. Louis Society of Financial Analysts (Feb. 1986)

"Cost of Capital for Multi-Divisional Corporations," Financial Management Association, New Orleans, Louisiana (Oct. 1996)

"Ethics and the Treasury Function," Government Treasurers Organization of Texas, Corpus Christi, Texas (Jun. 1996)

"A Cooperative Future," Iowa Association of Electric Cooperatives, Des Moines (December 1995). Similar presentations given to National G & T Conference, Irving, Texas (June 1995), Kentucky Association of Electric Cooperatives Annual Meeting, Louisville (Nov. 1994), Virginia, Maryland, and Delaware Association of Electric Cooperatives Annual Meeting, Richmond (July 1994), and Carolina Electric Cooperatives Annual Meeting, Raleigh (Mar. 1994)

"Information Superhighway Warnings: Speed Bumps on Wall Street and Detours from the Economy," Texas Society of Certified Public Accountants Natural Gas, Telecommunications and Electric Industries Conference, Austin (Apr. 1995)

"Economic/Wall Street Outlook," Carolinas Council of the Institute of Management Accountants, Myrtle Beach, South Carolina (May 1994). Similar presentation given to Bell Operating Company Accounting Witness Conference, Santa Fe, New Mexico (Apr. 1993)

"Regulatory Developments in Telecommunications," Regional Holding Company Financial and Accounting Conference, San Antonio (Sep. 1993)

"Estimating the Cost of Capital During the 1990s: Issues and Directions," The National Society of Rate of Return Analysts, Washington, D.C. (May 1992)

"Making Utility Regulation Work at the Public Utility Commission of Texas," Center for Legal and Regulatory Studies, University of Texas, Austin (June 1991)

"Can Regulation Compete for the Hearts and Minds of Industrial Customers," Emerging Issues of Competition in the Electric Utility Industry Conference, Austin (May 1988)

"The Role of Utilities in Fostering New Energy Technologies," Emerging Energy Technologies in Texas Conference, Austin (Mar. 1988)

"The Regulators' Perspective," Bellcore Economic Analysis Conference, San Antonio (Nov. 1987)

"Public Utility Commissions and the Nuclear Plant Contractor," Construction Litigation Superconference, Laguna Beach, California (Dec. 1986)

"Development of Cogeneration Policies in Texas," University of Georgia Fifth Annual Public Utilities Conference, Atlanta (Sep. 1985)

"Wheeling for Power Sales," Energy Bureau Cogeneration Conference, Houston (Nov. 1985).

"Asymmetric Discounting of Information and Relative Liquidity: Some Empirical Evidence for Common Stocks" (with John Groth and Kerry Cooper), Southern Finance Association, New Orleans (Nov. 1982)

"Used and Useful Planning Models," Planning Executive Institute, 27th Corporate Planning Conference, Los Angeles (Nov. 1979)

"Staff Input to Commission Rate of Return Decisions," The National Society of Rate of Return Analysts, New York (Oct. 1979)

""Discounted Cash Life: A New Measure of the Time Dimension in Capital Budgeting," with David Cordell, Southern Finance Association, New Orleans (Nov. 1978)

"The Relative Value of Statistics of Ex Post Common Stock Distributions to Explain Variance," with Charles G. Martin, Southern Finance Association, Atlanta (Nov. 1977)

"An ANOVA Representation of Common Stock Returns as a Framework for the Allocation of Portfolio Management Effort," with Charles G. Martin, Financial Management Association, Montreal (Oct. 1976)

"A Growth-Optimal Portfolio Selection Model with Finite Horizon," with Henry A. Latané, American Finance Association, San Francisco (Dec. 1974)

"An Optimal Approach to the Finance Decision," with Henry A. Latané, Southern Finance Association, Atlanta (Nov. 1974)

"A Pragmatic Approach to the Capital Structure Decision Based on Long-Run Growth," with Henry A. Latané, Financial Management Association, San Diego (Oct. 1974)

"Growth Rates, Expected Returns, and Variance in Portfolio Selection and Performance Evaluation," with Henry A. Latané, Econometric Society, Oslo, Norway (Aug. 1973)

**DCF MODEL**



**UTILITY PROXY GROUP**

| | | (a) | (a) | | (b) | (c) | (d) | (e) | (f) | (f) | (f) | (f) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Dividend Yield | | | Growth Rates | | | | Cost of Equity Estimates | | | |
| | Company | Price | Dividends | Yield | V Line | IBES | Zacks | br+sv | V Line | IBES | Zacks | br+sv |
| 1 | Ameren Corp. | $ 26.91 | $ 1.54 | 5.7% | -2.0% | -1.7% | 4.0% | 2.5% | 3.7% | 4.0% | 9.7% | 8.2% |
| 2 | American Elec Pwr | $ 34.92 | $ 1.86 | 5.3% | 3.5% | 4.0% | 4.0% | 4.9% | 8.8% | 9.3% | 9.3% | 10.2% |
| 3 | CenterPoint Energy | $ 15.58 | $ 0.79 | 5.1% | 2.5% | 4.9% | 5.5% | 4.5% | 7.6% | 10.0% | 10.6% | 9.5% |
| 4 | Cleco Corp. | $ 32.62 | $ 1.12 | 3.4% | 8.0% | 3.0% | 7.0% | 4.1% | 11.4% | 6.4% | 10.4% | 7.6% |
| 5 | CMS Energy | $ 18.88 | $ 0.86 | 4.6% | 7.0% | 5.9% | 6.0% | 4.7% | 11.6% | 10.5% | 10.6% | 9.3% |
| 6 | Constellation Energy | $ 30.90 | $ 0.96 | 3.1% | 6.0% | 9.9% | 9.9% | 4.7% | 9.1% | 13.0% | 13.0% | 7.8% |
| 7 | DTE Energy Co. | $ 48.18 | $ 2.30 | 4.8% | 5.5% | 5.8% | 5.0% | 3.6% | 10.3% | 10.6% | 9.8% | 8.3% |
| 8 | Edison International | $ 35.81 | $ 1.29 | 3.6% | -1.0% | 5.0% | 5.0% | 4.7% | 2.6% | 8.6% | 8.6% | 8.3% |
| 9 | Great Plains Energy | $ 19.25 | $ 0.85 | 4.4% | 6.0% | 8.9% | 9.0% | 2.1% | 10.4% | 13.3% | 13.4% | 6.5% |
| 10 | Hawaiian Elec. | $ 24.04 | $ 1.24 | 5.2% | 11.5% | 7.0% | 8.6% | 4.2% | 16.7% | 12.2% | 13.8% | 9.4% |
| 11 | IDACORP, Inc. | $ 36.77 | $ 1.20 | 3.3% | 5.5% | 4.7% | 4.7% | 5.0% | 8.8% | 8.0% | 8.0% | 8.2% |
| 12 | Integrys Energy Group | $ 49.24 | $ 2.72 | 5.5% | 9.5% | 7.9% | 10.4% | 3.1% | 15.0% | 13.4% | 15.9% | 8.6% |
| 13 | ITC Holdings Corp. | $ 67.71 | $ 1.39 | 2.1% | 14.0% | 16.7% | 15.0% | 13.7% | 16.1% | 18.8% | 17.1% | 15.7% |
| 14 | Pepco Holdings | $ 18.21 | $ 1.08 | 5.9% | 0.5% | 7.0% | 4.3% | 2.0% | 6.4% | 12.9% | 10.2% | 7.9% |
| 15 | PG&E Corp. | $ 43.00 | $ 1.92 | 4.5% | 6.0% | 6.2% | 7.7% | 6.7% | 10.5% | 10.7% | 12.2% | 11.1% |
| 16 | Pinnacle West Capital | $ 42.31 | $ 2.10 | 5.0% | 6.0% | 6.4% | 5.8% | 3.7% | 11.0% | 11.4% | 10.8% | 8.6% |
| 17 | Portland General Elec. | $ 23.23 | $ 1.07 | 4.6% | 3.0% | 4.7% | 5.2% | 3.7% | 7.6% | 9.3% | 9.8% | 8.3% |
| 18 | PPL Corp. | $ 24.58 | $ 1.40 | 5.7% | 4.0% | -5.0% | -5.0% | 7.2% | 9.7% | 0.7% | 0.7% | 12.9% |
| 19 | TECO Energy | $ 17.81 | $ 0.84 | 4.7% | 8.0% | 6.1% | 5.3% | 6.1% | 12.7% | 10.8% | 10.0% | 10.8% |
| 20 | Westar Energy | $ 25.68 | $ 1.28 | 5.0% | 8.5% | 6.5% | 5.3% | 4.6% | 13.5% | 11.5% | 10.3% | 9.6% |
| 21 | Wisconsin Energy | $ 29.37 | $ 1.06 | 3.6% | 7.5% | 8.5% | 8.0% | 5.5% | 11.1% | 12.1% | 11.6% | 9.2% |
| | **Average (g)** | | | | | | | | **11.2%** | **11.0%** | **10.9%** | **9.5%** |

(a) Recent price and estimated dividend for next 12 mos. from The Value Line Investment Survey, *Summary and Index* (Mar. 25, 2011).
(b) The Value Line Investment Survey (Feb. 4, Feb. 25, & Mar. 25, 2011).
(c) *Thomson ReutersCompany in Context Report* (Apr. 4, 2011).
(d) www.zacks.com (retrieved Mar. 22, 2011).
(e) See Attachment WEA-3.
(f) Sum of dividend yield and respective growth rate.
(g) Excludes highlighted figures.

**BR + SV GROWTH RATE**

**UTILITY PROXY GROUP**

| | | (a) | (a) | (a) | | | (b) | (c) | | (d) | (e) | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | ---------- | 2015 | ---------- | | | Adjustment | | | --------- "sv" Factor -------- | | | |
| | Company | EPS | DPS | BVPS | b | r | Factor | Adjusted r | br | s | v | sv | br + sv |
| 1 | Ameren Corp. | $2.50 | $1.54 | $36.50 | 38.4% | 6.8% | 1.0188 | 7.0% | 2.7% | 0.0104 | (0.2167) | -0.23% | **2.5%** |
| 2 | American Elec Pwr | $3.75 | $2.10 | $36.00 | 44.0% | 10.4% | 1.0287 | 10.7% | 4.7% | 0.0097 | 0.2000 | 0.19% | **4.9%** |
| 3 | CenterPoint Energy | $1.30 | $0.90 | $9.75 | 30.8% | 13.3% | 1.0253 | 13.7% | 4.2% | 0.0051 | 0.5125 | 0.26% | **4.5%** |
| 4 | Cleco Corp. | $2.75 | $1.60 | $28.50 | 41.8% | 9.6% | 1.0265 | 9.9% | 4.1% | - | 0.1231 | 0.00% | **4.1%** |
| 5 | CMS Energy | $1.75 | $1.10 | $14.75 | 37.1% | 11.9% | 1.0300 | 12.2% | 4.5% | 0.0063 | 0.3140 | 0.20% | **4.7%** |
| 6 | Constellation Energy | $3.25 | $1.00 | $47.75 | 69.2% | 6.8% | 1.0250 | 7.0% | 4.8% | 0.0083 | (0.1938) | -0.16% | **4.7%** |
| 7 | DTE Energy Co. | $4.25 | $2.70 | $46.50 | 36.5% | 9.1% | 1.0200 | 9.3% | 3.4% | 0.0086 | 0.1913 | 0.16% | **3.6%** |
| 8 | Edison International | $3.25 | $1.40 | $40.25 | 56.9% | 8.1% | 1.0285 | 8.3% | 4.7% | - | (0.0063) | 0.00% | **4.7%** |
| 9 | Great Plains Energy | $1.75 | $1.20 | $23.50 | 31.4% | 7.4% | 1.0231 | 7.6% | 2.4% | 0.0241 | (0.1190) | -0.29% | **2.1%** |
| 10 | Hawaiian Elec. | $2.00 | $1.30 | $18.00 | 35.0% | 11.1% | 1.0220 | 11.4% | 4.0% | 0.0098 | 0.2653 | 0.26% | **4.2%** |
| 11 | IDACORP, Inc. | $3.10 | $1.40 | $36.50 | 54.8% | 8.5% | 1.0303 | 8.8% | 4.8% | 0.0181 | 0.0875 | 0.16% | **5.0%** |
| 12 | Integrys Energy Group | $4.00 | $2.72 | $42.75 | 32.0% | 9.4% | 1.0141 | 9.5% | 3.0% | 0.0033 | 0.1000 | 0.03% | **3.1%** |
| 13 | ITC Holdings Corp. | $5.50 | $1.75 | $35.50 | 68.2% | 15.5% | 1.0553 | 16.4% | 11.1% | 0.0398 | 0.6359 | 2.53% | **13.7%** |
| 14 | Pepco Holdings | $1.55 | $1.12 | $21.60 | 27.7% | 7.2% | 1.0210 | 7.3% | 2.0% | 0.0126 | (0.0286) | -0.04% | **2.0%** |
| 15 | PG&E Corp. | $4.25 | $2.20 | $36.25 | 48.2% | 11.7% | 1.0384 | 12.2% | 5.9% | 0.0332 | 0.2368 | 0.79% | **6.7%** |
| 16 | Pinnacle West Capital | $3.50 | $2.30 | $38.25 | 34.3% | 9.2% | 1.0339 | 9.5% | 3.2% | 0.0418 | 0.1000 | 0.42% | **3.7%** |
| 17 | Portland General Elec. | $2.00 | $1.20 | $23.75 | 40.0% | 8.4% | 1.0327 | 8.7% | 3.5% | 0.0385 | 0.0500 | 0.19% | **3.7%** |
| 18 | PPL Corp. | $2.75 | $1.60 | $23.75 | 41.8% | 11.6% | 1.0511 | 12.2% | 5.1% | 0.0575 | 0.3667 | 2.11% | **7.2%** |
| 19 | TECO Energy | $1.75 | $1.00 | $13.25 | 42.9% | 13.2% | 1.0289 | 13.6% | 5.8% | 0.0075 | 0.3690 | 0.28% | **6.1%** |
| 20 | Westar Energy | $2.40 | $1.44 | $24.00 | 40.0% | 10.0% | 1.0207 | 10.2% | 4.1% | 0.0275 | 0.2000 | 0.55% | **4.6%** |
| 21 | Wisconsin Energy | $2.50 | $1.40 | $20.25 | 44.0% | 12.3% | 1.0215 | 12.6% | 5.5% | - | 0.4600 | 0.00% | **5.5%** |

**BR + SV GROWTH RATE**

**UTILITY PROXY GROUP**

| | | (a) | (a) | (f) | (a) | (a) | (f) | (g) | (a) | (a) | | (h) | (a) | (a) | (g) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | 2010 | | | 2015 | | | Chg | 2015 Price | | | | Common Shares | | |
| | Company | Eq Ratio | Tot Cap | Com Eq | Eq Ratio | Tot Cap | Com Eq | Equity | High | Low | Avg. | M/B | 2010 | 2015 | Growth |
| 1 | Ameren Corp. | 50.9% | $15,185 | $7,729 | 53.0% | $17,600 | $9,328 | 3.8% | $35.00 | $25.00 | $30.00 | 0.822 | 240.40 | 256.00 | 1.27% |
| 2 | American Elec Pwr | 46.5% | $29,185 | $13,571 | 50.5% | $35,800 | $18,079 | 5.9% | $55.00 | $35.00 | $45.00 | 1.250 | 481.00 | 500.00 | 0.78% |
| 3 | CenterPoint Energy | 26.2% | $12,199 | $3,196 | 29.0% | $14,200 | $4,118 | 5.2% | $25.00 | $15.00 | $20.00 | 2.051 | 424.70 | 430.00 | 0.25% |
| 4 | Cleco Corp. | 48.5% | $2,718 | $1,318 | 55.0% | $3,125 | $1,719 | 5.5% | $40.00 | $25.00 | $32.50 | 1.140 | 60.75 | 60.75 | 0.00% |
| 5 | CMS Energy | 29.5% | $9,473 | $2,795 | 34.0% | $11,100 | $3,774 | 6.2% | $25.00 | $18.00 | $21.50 | 1.458 | 249.60 | 255.00 | 0.43% |
| 6 | Constellation Energy | 62.8% | $12,468 | $7,830 | 67.5% | $14,900 | $10,058 | 5.1% | $50.00 | $30.00 | $40.00 | 0.838 | 199.00 | 209.00 | 0.99% |
| 7 | DTE Energy Co. | 48.7% | $13,811 | $6,726 | 47.5% | $17,300 | $8,218 | 4.1% | $70.00 | $45.00 | $57.50 | 1.237 | 170.00 | 176.00 | 0.70% |
| 8 | Edison International | 46.5% | $21,185 | $9,851 | 45.0% | $29,100 | $13,095 | 5.9% | $50.00 | $30.00 | $40.00 | 0.994 | 325.81 | 325.81 | 0.00% |
| 9 | Great Plains Energy | 49.2% | $5,868 | $2,887 | 48.5% | $7,500 | $3,638 | 4.7% | $25.00 | $17.00 | $21.00 | 0.894 | 135.71 | 155.00 | 2.69% |
| 10 | Hawaiian Elec. | 50.7% | $2,841 | $1,440 | 52.0% | $3,450 | $1,794 | 4.5% | $30.00 | $19.00 | $24.50 | 1.361 | 95.52 | 99.00 | 0.72% |
| 11 | IDACORP, Inc. | 49.8% | $2,807 | $1,398 | 50.5% | $3,750 | $1,894 | 6.3% | $50.00 | $30.00 | $40.00 | 1.096 | 47.90 | 52.00 | 1.66% |
| 12 | Integrys Energy Group | 56.8% | $5,119 | $2,907 | 54.0% | $6,200 | $3,348 | 2.9% | $55.00 | $40.00 | $47.50 | 1.111 | 77.35 | 78.50 | 0.30% |
| 13 | ITC Holdings Corp. | 30.9% | $3,614 | $1,117 | 33.5% | $5,800 | $1,943 | 11.7% | $115.00 | $80.00 | $97.50 | 2.746 | 50.72 | 54.50 | 1.45% |
| 14 | Pepco Holdings | 52.5% | $8,000 | $4,200 | 48.0% | $10,800 | $5,184 | 4.3% | $25.00 | $17.00 | $21.00 | 0.972 | 225.00 | 240.00 | 1.30% |
| 15 | PG&E Corp. | 47.4% | $21,793 | $10,330 | 54.0% | $28,100 | $15,174 | 8.0% | $55.00 | $40.00 | $47.50 | 1.310 | 370.60 | 420.00 | 2.53% |
| 16 | Pinnacle West Capital | 49.6% | $6,687 | $3,317 | 53.5% | $8,700 | $4,655 | 7.0% | $50.00 | $35.00 | $42.50 | 1.111 | 101.43 | 122.00 | 3.76% |
| 17 | Portland General Elec. | 49.7% | $3,100 | $1,541 | 50.0% | $4,275 | $2,138 | 6.8% | $30.00 | $20.00 | $25.00 | 1.053 | 75.21 | 90.00 | 3.66% |
| 18 | PPL Corp. | 40.0% | $20,620 | $8,248 | 51.5% | $26,700 | $13,751 | 10.8% | $45.00 | $30.00 | $37.50 | 1.579 | 485.00 | 580.00 | 3.64% |
| 19 | TECO Energy | 40.8% | $5,318 | $2,170 | 47.5% | $6,100 | $2,898 | 6.0% | $25.00 | $17.00 | $21.00 | 1.585 | 214.90 | 220.00 | 0.47% |
| 20 | Westar Energy | 46.4% | $5,181 | $2,404 | 45.5% | $6,500 | $2,958 | 4.2% | $35.00 | $25.00 | $30.00 | 1.250 | 112.13 | 125.00 | 2.20% |
| 21 | Wisconsin Energy | 49.0% | $7,765 | $3,805 | 48.0% | $9,825 | $4,716 | 4.4% | $45.00 | $30.00 | $37.50 | 1.852 | 233.80 | 233.80 | 0.00% |

(a) The Value Line Investment Survey (Dec. 24, 2010, Feb. 4, & Feb. 25, 2011).
(b) Computed using the formula 2*(1+5-Yr. Change in Equity)/(2+5 Yr. Change in Equity).
(c) Product of average year-end "r" for 2015 and Adjustment Factor.
(d) Product of change in common shares outstanding and M/B Ratio.
(e) Computed as 1 - B/M Ratio.
(f) Product of total capital and equity ratio.
(g) Five-year rate of change.
(h) Average of High and Low expected market prices divided by 2014-16 BVPS.

NON-UTILITY PROXY GROUP

| | Company | (a) Dividend Yield | (a) Growth Rates V Line | (b) Growth Rates IBES | (c) Growth Rates Zacks | (d) Growth Rates br+sv | (e) Cost of Equity Estimates V Line | (e) Cost of Equity Estimates IBES | (e) Cost of Equity Estimates Zacks | (e) Cost of Equity Estimates br+sv |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 3M Company | 2.39% | 7.0% | 11.9% | 11.3% | 12.9% | 9.4% | 14.3% | 13.7% | 15.3% |
| 2 | Abbott Labs. | 3.67% | 10.0% | 8.9% | 9.0% | 15.0% | 13.7% | 12.6% | 12.7% | 18.7% |
| 3 | Alberto-Culver | 1.02% | 15.0% | 9.4% | 12.5% | 8.4% | 16.0% | 10.4% | 13.5% | 9.4% |
| 4 | AT&T Inc. | 6.09% | 5.5% | 5.7% | 7.0% | 5.4% | 11.6% | 11.8% | 13.1% | 11.5% |
| 5 | Automatic Data Proc. | 2.93% | 8.0% | 10.6% | 10.8% | 9.5% | 10.9% | 13.5% | 13.7% | 12.4% |
| 6 | Bard (C.R.) | 0.77% | 9.5% | 10.9% | 11.8% | 18.1% | 10.3% | 11.7% | 12.6% | 18.9% |
| 7 | Baxter Int'l Inc. | 2.45% | 10.0% | 9.6% | 9.3% | 15.5% | 12.5% | 12.1% | 11.8% | 17.9% |
| 8 | Becton, Dickinson | 1.97% | 9.5% | 9.9% | 10.8% | 9.0% | 11.5% | 11.9% | 12.8% | 11.0% |
| 9 | Bristol-Myers Squibb | 5.11% | 8.5% | 1.8% | 2.0% | 5.7% | 13.6% | 6.9% | 7.1% | 10.8% |
| 10 | Brown-Forman 'B' | 1.90% | 7.5% | 10.9% | 13.0% | 10.6% | 9.4% | 12.8% | 14.9% | 12.5% |
| 11 | Chubb Corp. | 2.55% | 2.5% | 8.7% | 9.8% | 8.0% | 5.1% | 11.3% | 12.4% | 10.5% |
| 12 | Church & Dwight | 0.97% | 12.0% | 11.8% | 12.0% | 10.3% | 13.0% | 12.8% | 13.0% | 11.3% |
| 13 | Coca-Cola | 2.80% | 9.5% | 8.7% | 9.0% | 9.9% | 12.3% | 11.5% | 11.8% | 12.7% |
| 14 | Colgate-Palmolive | 2.76% | 11.0% | 9.3% | 9.2% | 18.1% | 13.8% | 12.1% | 12.0% | 20.8% |
| 15 | Commerce Bancshs. | 2.22% | 7.0% | 7.0% | 7.0% | 7.9% | 9.2% | 9.2% | 9.2% | 10.1% |
| 16 | ConAgra Foods | 3.92% | 10.5% | 7.7% | 8.0% | 8.1% | 14.4% | 11.6% | 11.9% | 12.0% |
| 17 | Costco Wholesale | 1.24% | 7.5% | 13.3% | 12.9% | 8.2% | 8.7% | 14.5% | 14.1% | 9.5% |
| 18 | Cullen/Frost Bankers | 2.96% | 4.5% | 8.5% | 8.0% | 5.7% | 7.5% | 11.5% | 11.0% | 8.6% |
| 19 | CVS Caremark Corp. | 1.42% | 9.5% | 10.1% | 12.0% | 7.8% | 10.9% | 11.5% | 13.4% | 9.2% |
| 20 | Ecolab Inc. | 1.41% | 12.0% | 13.2% | 13.2% | 19.6% | 13.4% | 14.6% | 14.6% | 21.0% |
| 21 | Exxon Mobil Corp. | 2.26% | 6.0% | 12.1% | 8.4% | 13.5% | 8.3% | 14.4% | 10.7% | 15.7% |
| 22 | Gen'l Mills | 3.02% | 9.5% | 7.7% | 8.0% | 9.3% | 12.5% | 10.7% | 11.0% | 12.3% |
| 23 | Heinz (H.J.) | 3.85% | 6.5% | 7.0% | 8.0% | 13.9% | 10.4% | 10.9% | 11.9% | 17.8% |
| 24 | Hormel Foods | 2.01% | 10.5% | 10.0% | 9.3% | 10.7% | 12.5% | 12.0% | 11.3% | 12.7% |
| 25 | Int'l Business Mach. | 1.77% | 13.0% | 11.5% | 9.3% | 20.4% | 14.8% | 13.3% | 11.1% | 22.2% |
| 26 | Johnson & Johnson | 3.44% | 4.5% | 6.0% | 5.8% | 10.8% | 7.9% | 9.4% | 9.2% | 14.2% |
| 27 | Kellogg | 3.14% | 9.5% | 8.6% | 9.0% | 9.7% | 12.6% | 11.7% | 12.1% | 12.9% |
| 28 | Kimberly-Clark | 4.09% | 6.5% | 7.5% | 8.7% | 18.6% | 10.6% | 11.6% | 12.8% | 22.7% |
| 29 | Kraft Foods | 3.71% | 8.0% | 8.4% | 8.0% | 10.7% | 11.7% | 12.1% | 11.7% | 14.4% |
| 30 | Lilly (Eli) | 5.64% | -2.5% | -6.4% | -5.3% | 8.4% | 3.1% | -0.8% | 0.3% | 14.0% |
| 31 | Lockheed Martin | 3.78% | 10.0% | 8.1% | 6.8% | 20.3% | 13.8% | 11.9% | 10.6% | 24.1% |
| 32 | McCormick & Co. | 2.24% | 8.5% | 9.6% | 9.5% | 13.3% | 10.7% | 11.8% | 11.7% | 15.6% |
| 33 | McDonald's Corp. | 3.25% | 9.5% | 9.8% | 9.3% | 10.7% | 12.8% | 13.1% | 12.6% | 13.9% |
| 34 | McKesson Corp. | 0.98% | 10.0% | 14.2% | 11.0% | 11.7% | 11.0% | 15.2% | 12.0% | 12.7% |
| 35 | Medtronic, Inc. | 2.47% | 7.5% | 8.8% | 8.4% | 11.7% | 10.0% | 11.3% | 10.9% | 14.1% |
| 36 | Microsoft Corp. | 2.26% | 12.5% | 11.3% | 11.7% | 15.3% | 14.8% | 13.6% | 14.0% | 17.5% |
| 37 | NIKE, Inc. 'B' | 1.49% | 9.5% | 10.9% | 12.5% | 12.2% | 11.0% | 12.4% | 14.0% | 13.7% |
| 38 | Northrop Grumman | 2.82% | 12.5% | 11.0% | 11.1% | 7.9% | 15.3% | 13.8% | 13.9% | 10.7% |
| 39 | PepsiCo, Inc. | 2.91% | 11.0% | 8.9% | 9.5% | 14.5% | 13.9% | 11.8% | 12.4% | 17.4% |
| 40 | Pfizer, Inc. | 4.50% | 5.0% | 2.8% | 3.5% | 7.0% | 9.5% | 7.3% | 8.0% | 11.5% |
| 41 | Procter & Gamble | 3.01% | 8.0% | | 9.2% | 7.2% | 11.0% | 11.9% | 12.2% | 10.3% |
| 42 | Raytheon Co. | 3.02% | 10.0% | | 10.0% | 8.6% | 13.0% | 11.0% | 13.0% | 11.6% |
| 43 | Stryker Corp. | 1.26% | 12.5% | | 11.4% | 13.6% | 13.8% | 12.2% | 12.7% | 14.9% |
| 44 | Sysco Corp. | 3.47% | 8.0% | 10.0% | 9.7% | 14.2% | 11.5% | 13.5% | 13.2% | 17.6% |
| 45 | TJX Companies | 1.28% | 13.5% | 14.5% | 14.4% | 11.1% | 14.8% | 15.8% | 15.7% | 12.4% |
| 46 | United Parcel Serv. | 2.59% | 9.0% | 11.7% | 11.5% | 17.9% | 11.6% | 14.3% | 14.1% | 20.5% |
| 47 | Verizon Communic. | 5.63% | 4.0% | 6.2% | 14.9% | 5.7% | 9.6% | 11.8% | 20.5% | 11.3% |
| 48 | Walgreen Co. | 1.68% | 11.5% | 13.4% | 13.0% | 8.4% | 13.2% | 15.1% | 14.7% | 10.1% |
| 49 | Wal-Mart Stores | 2.16% | 10.0% | 10.7% | 11.3% | 9.9% | 12.2% | 12.9% | 13.5% | 12.1% |
| 50 | Waste Management | 3.52% | 5.5% | 9.6% | 11.0% | 5.2% | 9.0% | 13.1% | 14.5% | 8.7% |
| | **Average (f)** | | | | | | **11.9%** | **12.4%** | **12.5%** | **12.1%** |

(a) www.valueline.com (retrieved Jan. 28, 2011).

(b) *Thomson Reuters Company in Context Report* (Jan. 28, 2011).

(c) www.zacks.com (retrieved Jan. 31, 2011).

(d) See Attachment WEA-5.

(e) Sum of dividend yield and respective growth rate.

(f) Excludes highlighted figures.

BR + SV GROWTH RATE

NON-UTILITY PROXY GROUP

| | Company | (a) EPS | (a) 2014 DPS | (a) BVPS | b | r | (b) Adjust. Factor | (c) Adj. r | br | (d) s | (e) "sv" Factor v | sv | br + sv |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 3M Company | $7.60 | $3.10 | $40.05 | 59.2% | 19.0% | 1.0818 | 20.5% | 12.2% | 0.0106 | 0.6731 | 0.71% | **12.9%** |
| 2 | Abbott Labs. | $5.70 | $2.18 | $22.05 | 61.8% | 25.9% | 1.0384 | 26.8% | 16.6% | (0.0197) | 0.7900 | -1.56% | **15.0%** |
| 3 | Alberto-Culver | $2.35 | $0.55 | $17.85 | 76.6% | 13.2% | 1.0315 | 13.6% | 10.4% | (0.0330) | 0.6033 | -1.99% | **8.4%** |
| 4 | AT&T Inc. | $3.25 | $2.00 | $24.05 | 38.5% | 13.5% | 1.0327 | 14.0% | 5.4% | (0.0001) | 0.4656 | -0.01% | **5.4%** |
| 5 | Automatic Data Proc. | $3.45 | $1.60 | $22.95 | 53.6% | 15.0% | 1.0786 | 16.2% | 8.7% | 0.0111 | 0.7039 | 0.78% | **9.5%** |
| 6 | Bard (C.R.) | $7.75 | $0.85 | $31.45 | 89.0% | 24.6% | 1.0255 | 25.3% | 22.5% | (0.0564) | 0.7754 | -4.37% | **18.1%** |
| 7 | Baxter Int'l Inc. | $5.85 | $1.50 | $22.90 | 74.4% | 25.5% | 1.0560 | 27.0% | 20.1% | (0.0633) | 0.7224 | -4.57% | **15.5%** |
| 8 | Becton, Dickinson | $7.65 | $2.20 | $34.10 | 71.2% | 22.4% | 1.0306 | 23.1% | 16.5% | (0.1030) | 0.7216 | -7.43% | **9.0%** |
| 9 | Bristol-Myers Squibb | $2.35 | $1.54 | $11.65 | 34.5% | 20.2% | 1.0263 | 20.7% | 7.1% | (0.0212) | 0.6671 | -1.42% | **5.7%** |
| 10 | Brown-Forman 'B' | $4.50 | $1.48 | $20.40 | 67.1% | 22.1% | 1.0372 | 22.9% | 15.4% | (0.0640) | 0.7368 | -4.71% | **10.6%** |
| 11 | Chubb Corp. | $7.00 | $1.60 | $64.85 | 77.1% | 10.8% | 1.0184 | 11.0% | 8.5% | (0.0319) | 0.1632 | -0.52% | **8.0%** |
| 12 | Church & Dwight | $5.80 | $1.00 | $39.25 | 82.8% | 14.8% | 1.0465 | 15.5% | 12.8% | (0.0414) | 0.6075 | -2.52% | **10.3%** |
| 13 | Coca-Cola | $4.95 | $2.48 | $18.20 | 49.9% | 27.2% | 1.0479 | 28.5% | 14.2% | (0.0526) | 0.8267 | -4.34% | **9.9%** |
| 14 | Colgate-Palmolive | $7.20 | $3.20 | $13.25 | 55.6% | 54.3% | 1.0671 | 58.0% | 32.2% | (0.1557) | 0.9086 | -14.15% | **18.1%** |
| 15 | Commerce Bancshs. | $3.35 | $1.15 | $32.10 | 65.7% | 10.4% | 1.0480 | 10.9% | 7.2% | 0.0240 | 0.2867 | 0.69% | **7.9%** |
| 16 | ConAgra Foods | $2.35 | $1.00 | $15.00 | 57.4% | 15.7% | 1.0288 | 16.1% | 9.3% | (0.0217) | 0.5385 | -1.17% | **8.1%** |
| 17 | Costco Wholesale | $4.20 | $0.95 | $33.50 | 77.4% | 12.5% | 1.0315 | 12.9% | 10.0% | (0.0301) | 0.5939 | -1.79% | **8.2%** |
| 18 | Cullen/Frost Bankers | $4.35 | $2.10 | $44.00 | 51.7% | 9.9% | 1.0382 | 10.3% | 5.3% | 0.0132 | 0.2667 | 0.35% | **5.7%** |
| 19 | CVS Caremark Corp. | $4.00 | $0.56 | $38.15 | 86.0% | 10.5% | 1.0268 | 10.8% | 9.3% | (0.0395) | 0.3642 | -1.44% | **7.8%** |
| 20 | Ecolab Inc. | $3.60 | $0.85 | $14.45 | 76.4% | 24.9% | 1.0530 | 26.2% | 20.0% | (0.0056) | 0.7592 | -0.43% | **19.6%** |
| 21 | Exxon Mobil Corp. | $9.35 | $2.05 | $45.50 | 78.1% | 20.5% | 1.0546 | 21.7% | 16.9% | (0.0578) | 0.5956 | -3.44% | **13.5%** |
| 22 | Gen'l Mills | $3.15 | $1.36 | $11.95 | 56.8% | 26.4% | 1.0318 | 27.2% | 15.5% | (0.0809) | 0.7610 | -6.16% | **9.3%** |
| 23 | Heinz (H.J.) | $4.10 | $2.32 | $14.65 | 43.4% | 28.0% | 1.0908 | 30.5% | 13.3% | 0.0085 | 0.7830 | 0.66% | **13.9%** |
| 24 | Hormel Foods | $2.10 | $0.70 | $13.55 | 66.7% | 15.5% | 1.0527 | 16.3% | 10.9% | (0.0025) | 0.6387 | -0.16% | **10.7%** |
| 25 | Int'l Business Mach. | $18.00 | $3.60 | $48.75 | 80.0% | 36.9% | 1.0856 | 40.1% | 32.1% | (0.1501) | 0.7759 | -11.65% | **20.4%** |
| 26 | Johnson & Johnson | $5.85 | $2.65 | $27.60 | 54.7% | 21.2% | 1.0378 | 22.0% | 12.0% | (0.0185) | 0.6846 | -1.26% | **10.8%** |
| 27 | Kellogg | $5.10 | $1.88 | $9.95 | 63.1% | 51.3% | 1.0352 | 53.1% | 33.5% | (0.2690) | 0.8829 | -23.75% | **9.7%** |
| 28 | Kimberly-Clark | $6.25 | $2.75 | $15.55 | 56.0% | 40.2% | 1.0140 | 40.8% | 22.8% | (0.0506) | 0.8363 | -4.24% | **18.6%** |
| 29 | Kraft Foods | $3.00 | $1.40 | $24.00 | 53.3% | 12.5% | 1.0480 | 13.1% | 7.0% | 0.0716 | 0.5200 | 3.72% | **10.7%** |
| 30 | Lilly (Eli) | $3.40 | $2.20 | $15.60 | 35.3% | 21.8% | 1.0636 | 23.2% | 8.2% | 0.0032 | 0.6716 | 0.21% | **8.4%** |
| 31 | Lockheed Martin | $13.25 | $3.50 | $31.25 | 73.6% | 42.4% | 1.0882 | 46.1% | 34.0% | (0.1663) | 0.8188 | -13.62% | **20.3%** |
| 32 | McCormick & Co. | $3.50 | $1.36 | $18.95 | 61.1% | 18.5% | 1.0649 | 19.7% | 12.0% | 0.0178 | 0.7293 | 1.30% | **13.3%** |
| 33 | McDonald's Corp. | $6.05 | $3.00 | $19.00 | 50.4% | 31.8% | 1.0303 | 32.8% | 16.5% | (0.0734) | 0.8000 | -5.87% | **10.7%** |
| 34 | McKesson Corp. | $6.80 | $0.72 | $46.65 | 89.4% | 14.6% | 1.0421 | 15.2% | 13.6% | (0.0380) | 0.4957 | -1.88% | **11.7%** |
| 35 | Medtronic, Inc. | $4.50 | $1.18 | $25.95 | 73.8% | 17.3% | 1.0597 | 18.4% | 13.6% | (0.0326) | 0.5848 | -1.91% | **11.7%** |
| 36 | Microsoft Corp. | $3.35 | $0.96 | $10.75 | 71.3% | 31.2% | 1.0763 | 33.5% | 23.9% | (0.1104) | 0.7850 | -8.66% | **15.3%** |
| 37 | NIKE, Inc. 'B' | $5.65 | $1.50 | $34.60 | 73.5% | 16.3% | 1.0643 | 17.4% | 12.8% | (0.0085) | 0.6358 | -0.54% | **12.2%** |
| 38 | Northrop Grumman | $10.25 | $2.50 | $68.00 | 75.6% | 15.1% | 1.0293 | 15.5% | 11.7% | (0.0783) | 0.4868 | -3.81% | **7.9%** |
| 39 | PepsiCo, Inc. | $6.40 | $2.34 | $24.00 | 63.4% | 26.7% | 1.0724 | 28.6% | 18.1% | (0.0449) | 0.8118 | -3.64% | **14.5%** |
| 40 | Pfizer, Inc. | $2.05 | $1.16 | $13.00 | 43.4% | 15.8% | 1.0154 | 16.0% | 7.0% | - | 0.5273 | 0.00% | **7.0%** |
| 41 | Procter & Gamble | $5.25 | $2.18 | $29.45 | 58.5% | | 1.0230 | 18.2% | 10.7% | (0.0495) | 0.6900 | -3.41% | **7.2%** |
| 42 | Raytheon Co. | $7.20 | $2.00 | $38.65 | 72.2% | | 1.0231 | 19.1% | 13.8% | (0.0870) | 0.5932 | -5.16% | **8.6%** |
| 43 | Stryker Corp. | $5.35 | $0.84 | $32.75 | 84.3% | | 1.0660 | 17.4% | 14.7% | (0.0144) | 0.7213 | -1.04% | **13.6%** |
| 44 | Sysco Corp. | $2.75 | $1.10 | $10.10 | 60.0% | 27.2% | 1.0502 | 28.6% | 17.2% | (0.0385) | 0.7756 | -2.98% | **14.2%** |
| 45 | TJX Companies | $4.80 | $0.80 | $12.75 | 83.3% | 37.6% | 1.0374 | 39.1% | 32.5% | (0.2565) | 0.8355 | -21.43% | **11.1%** |
| 46 | United Parcel Serv. | $5.50 | $2.20 | $19.30 | 60.0% | 28.5% | 1.0912 | 31.1% | 18.7% | (0.0090) | 0.8245 | -0.75% | **17.9%** |
| 47 | Verizon Communic. | $3.05 | $1.96 | $18.95 | 35.7% | 16.1% | 1.0250 | 16.5% | 5.9% | (0.0032) | 0.6555 | -0.21% | **5.7%** |
| 48 | Walgreen Co. | $3.65 | $1.00 | $21.15 | 72.6% | 17.3% | 1.0252 | 17.7% | 12.8% | (0.0684) | 0.6475 | -4.43% | **8.4%** |
| 49 | Wal-Mart Stores | $6.05 | $1.75 | $23.40 | 71.1% | 25.9% | 1.0072 | 26.0% | 18.5% | (0.1157) | 0.7400 | -8.56% | **9.9%** |
| 50 | Waste Management | $2.90 | $1.60 | $15.30 | 44.8% | 19.0% | 1.0079 | 19.1% | 8.6% | (0.0515) | 0.6600 | -3.40% | **5.2%** |

NON-UTILITY PROXY GROUP

| | | (a) | (a) | (f) | (a) | (a) | | (g) | (a) | (a) | (f) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | --- Common Equity --- | | | -------- 2014 Price -------- | | | | ---- Common Shares ---- | | |
| | Company | 2009 | 2014 | Chg. | High | Low | Avg. | M/B | 2009 | 2014 | Growth |
| 1 | 3M Company | $12,764 | $28,975 | 17.8% | $135.00 | $110.00 | $122.50 | 3.059 | 710.60 | 723.00 | 0.35% |
| 2 | Abbott Labs. | $22,856 | $33,550 | 8.0% | $115.00 | $95.00 | $105.00 | 4.762 | 1,551.90 | 1,520.00 | -0.41% |
| 3 | Alberto-Culver | $1,197 | $1,640 | 6.5% | $50.00 | $40.00 | $45.00 | 2.521 | 98.26 | 92.00 | -1.31% |
| 4 | AT&T Inc. | $102,339 | $141,895 | 6.8% | $50.00 | $40.00 | $45.00 | 1.871 | 5,901.90 | 5,900.00 | -0.01% |
| 5 | Automatic Data Proc. | $5,323 | $11,700 | 17.1% | $85.00 | $70.00 | $77.50 | 3.377 | 501.70 | 510.00 | 0.33% |
| 6 | Bard (C.R.) | $2,194 | $2,830 | 5.2% | $155.00 | $125.00 | $140.00 | 4.452 | 95.92 | 90.00 | -1.27% |
| 7 | Baxter Int'l Inc. | $7,191 | $12,600 | 11.9% | $90.00 | $75.00 | $82.50 | 3.603 | 600.97 | 550.00 | -1.76% |
| 8 | Becton, Dickinson | $5,143 | $6,985 | 6.3% | $135.00 | $110.00 | $122.50 | 3.592 | 237.08 | 205.00 | -2.87% |
| 9 | Bristol-Myers Squibb | $14,785 | $19,230 | 5.4% | $40.00 | $30.00 | $35.00 | 3.004 | 1,709.50 | 1,650.00 | -0.71% |
| 10 | Brown-Forman 'B' | $1,895 | $2,750 | 7.7% | $85.00 | $70.00 | $77.50 | 3.799 | 146.96 | 135.00 | -1.68% |
| 11 | Chubb Corp. | $15,634 | $18,800 | 3.8% | $85.00 | $70.00 | $77.50 | 1.195 | 332.01 | 290.00 | -2.67% |
| 12 | Church & Dwight | $1,602 | $2,550 | 9.7% | $110.00 | $90.00 | $100.00 | 2.548 | 70.55 | 65.00 | -1.63% |
| 13 | Coca-Cola | $24,799 | $40,035 | 10.1% | $115.00 | $95.00 | $105.00 | 5.769 | 2,303.00 | 2,200.00 | -0.91% |
| 14 | Colgate-Palmolive | $3,116 | $6,100 | 14.4% | $160.00 | $130.00 | $145.00 | 10.943 | 494.17 | 460.00 | -1.42% |
| 15 | Commerce Bancshs. | $1,886 | $3,050 | 10.1% | $50.00 | $40.00 | $45.00 | 1.402 | 87.26 | 95.00 | 1.71% |
| 16 | ConAgra Foods | $4,721 | $6,300 | 5.9% | $35.00 | $30.00 | $32.50 | 2.167 | 441.66 | 420.00 | -1.00% |
| 17 | Costco Wholesale | $10,018 | $13,725 | 6.5% | $90.00 | $75.00 | $82.50 | 2.463 | 435.97 | 410.00 | -1.22% |
| 18 | Cullen/Frost Bankers | $1,894 | $2,775 | 7.9% | $65.00 | $55.00 | $60.00 | 1.364 | 60.04 | 63.00 | 0.97% |
| 19 | CVS Caremark Corp. | $35,768 | $46,750 | 5.5% | $65.00 | $55.00 | $60.00 | 1.573 | 1,391.00 | 1,225.00 | -2.51% |
| 20 | Ecolab Inc. | $2,001 | $3,400 | 11.2% | $65.00 | $55.00 | $60.00 | 4.152 | 236.60 | 235.00 | -0.14% |
| 21 | Exxon Mobil Corp. | $110,569 | $191,000 | 11.6% | $125.00 | $100.00 | $112.50 | 2.473 | 4,727.00 | 4,200.00 | -2.34% |
| 22 | Gen'l Mills | $5,175 | $7,115 | 6.6% | $55.00 | $45.00 | $50.00 | 4.184 | 656.00 | 595.00 | -1.93% |
| 23 | Heinz (H.J.) | $1,891 | $4,700 | 20.0% | $75.00 | $60.00 | $67.50 | 4.608 | 318.06 | 321.00 | 0.18% |
| 24 | Hormel Foods | $2,124 | $3,600 | 11.1% | $40.00 | $35.00 | $37.50 | 2.768 | 267.19 | 266.00 | -0.09% |
| 25 | Int'l Business Mach. | $22,755 | $53,650 | 18.7% | $240.00 | $195.00 | $217.50 | 4.462 | 1,305.30 | 1,100.00 | -3.36% |
| 26 | Johnson & Johnson | $50,588 | $73,850 | 7.9% | $95.00 | $80.00 | $87.50 | 3.170 | 2,754.30 | 2,675.00 | -0.58% |
| 27 | Kellogg | $2,272 | $3,230 | 7.3% | $95.00 | $75.00 | $85.00 | 8.543 | 381.38 | 325.00 | -3.15% |
| 28 | Kimberly-Clark | $5,406 | $6,220 | 2.8% | $105.00 | $85.00 | $95.00 | 6.109 | 417.00 | 400.00 | -0.83% |
| 29 | Kraft Foods | $25,972 | $42,000 | 10.1% | $55.00 | $45.00 | $50.00 | 2.083 | 1,477.90 | 1,750.00 | 3.44% |
| 30 | Lilly (Eli) | $9,524 | $18,000 | 13.6% | $50.00 | $45.00 | $47.50 | 3.045 | 1,149.00 | 1,155.00 | 0.10% |
| 31 | Lockheed Martin | $4,129 | $10,000 | 19.4% | $190.00 | $155.00 | $172.50 | 5.520 | 372.90 | 320.00 | -3.01% |
| 32 | McCormick & Co. | $1,335 | $2,555 | 13.9% | $75.00 | $65.00 | $70.00 | 3.694 | 131.80 | 135.00 | 0.48% |
| 33 | McDonald's Corp. | $14,034 | $19,000 | 6.2% | $105.00 | $85.00 | $95.00 | 5.000 | 1,076.70 | 1,000.00 | -1.47% |
| 34 | McKesson Corp. | $7,532 | $11,480 | 8.8% | $100.00 | $85.00 | $92.50 | 1.983 | 271.00 | 246.00 | -1.92% |
| 35 | Medtronic, Inc. | $14,629 | $26,600 | 12.7% | $70.00 | $55.00 | $62.50 | 2.408 | 1,097.30 | 1,025.00 | -1.35% |
| 36 | Microsoft Corp. | $39,558 | $85,000 | 16.5% | $55.00 | $45.00 | $50.00 | 4.651 | 8,908.00 | 7,900.00 | -2.37% |
| 37 | NIKE, Inc. 'B' | $8,693 | $16,550 | 13.7% | $105.00 | $85.00 | $95.00 | 2.746 | 485.50 | 478.00 | -0.31% |
| 38 | Northrop Grumman | $12,687 | $17,000 | 6.0% | $145.00 | $120.00 | $132.50 | 1.949 | 306.87 | 250.00 | -4.02% |
| 39 | PepsiCo, Inc. | $17,442 | $36,015 | 15.6% | $140.00 | $115.00 | $127.50 | 5.313 | 1,565.00 | 1,500.00 | -0.84% |
| 40 | Pfizer, Inc. | $90,014 | $105,000 | 3.1% | $30.00 | $25.00 | $27.50 | 2.115 | 8,070.00 | 8,070.00 | 0.00% |
| 41 | Procter & Gamble | $63,099 | $79,455 | 4.7% | $105.00 | $85.00 | $95.00 | 3.226 | 2,917.00 | 2,700.00 | -1.53% |
| 42 | Raytheon Co. | $9,827 | $12,375 | 4.7% | $105.00 | $85.00 | $95.00 | 2.458 | 383.20 | 320.00 | -3.54% |
| 43 | Stryker Corp. | $6,595 | $12,775 | 14.1% | $130.00 | $105.00 | $117.50 | 3.588 | 397.90 | 390.00 | -0.40% |
| 44 | Sysco Corp. | $3,450 | $5,700 | 10.6% | $50.00 | $40.00 | $45.00 | 4.455 | 590.03 | 565.00 | -0.86% |
| 45 | TJX Companies | $2,889 | $4,200 | 7.8% | $85.00 | $70.00 | $77.50 | 6.078 | 409.39 | 330.00 | -4.22% |
| 46 | United Parcel Serv. | $7,630 | $19,035 | 20.1% | $120.00 | $100.00 | $110.00 | 5.699 | 992.85 | 985.00 | -0.16% |
| 47 | Verizon Communic. | $41,600 | $53,439 | 5.1% | $60.00 | $50.00 | $55.00 | 2.902 | 2,835.70 | 2,820.00 | -0.11% |
| 48 | Walgreen Co. | $14,376 | $18,500 | 5.2% | $65.00 | $55.00 | $60.00 | 2.837 | 988.56 | 875.00 | -2.41% |
| 49 | Wal-Mart Stores | $70,749 | $76,025 | 1.4% | $100.00 | $80.00 | $90.00 | 3.846 | 3,786.00 | 3,250.00 | -3.01% |
| 50 | Waste Management | $6,285 | $6,800 | 1.6% | $50.00 | $40.00 | $45.00 | 2.941 | 486.12 | 445.00 | -1.75% |

(a) www.valueline.com (retrieved Jan. 28, 2011).
(b) Computed using the formula 2*(1+5-Yr. Change in Equity)/(2+5 Yr. Change in Equity).
(c) Product of year-end "r" for 2014 and Adjustment Factor.
(d) Product of change in common shares outstanding and M/B Ratio.
(e) Computed as 1 - B/M Ratio.
(f) Five-year rate of change.
(g) Average of High and Low expected market prices divided by 2013-15 BVPS.

**CAPITAL ASSET PRICING MODEL**

**UTILITY PROXY GROUP**

| | | |
|---|---|---|
| Market Rate of Return | | |
| Dividend Yield (a) | 2.3% | |
| Growth Rate (b) | 10.5% | |
| Market Return (c) | | 12.8% |
| Less: Risk-Free Rate (d) | | |
| Long-term Treasury Bond Yield | | 4.5% |
| Market Risk Premium (e) | | 8.3% |
| Utility Proxy Group Beta (f) | | 0.74 |
| Utility Proxy Group Risk Premium (g) | | 6.1% |
| Plus: Risk-free Rate (d) | | |
| Long-term Treasury Bond Yield | | 4.5% |
| Unadjusted CAPM (h) | | 10.6% |
| Size Adjustment (i) | | 0.74% |
| **Implied Cost of Equity (j)** | | **11.4%** |

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (retrieved Jan. 28, 2011).
(b) Weighted average of IBES earnings growth rates for the dividend paying firms in the S&P 500 (retrieved Feb. 23, 2011).
(c) (a) + (b)
(d) Average yield on 30-year Treasury bonds for March 2011 from the Federal Reserve Board at http://www.federalreserve.gov/releases/h15/data/Monthly/H15_TCMNOM_Y20.txt.
(e) (c) - (d).
(f) The Value Line Investment Survey (Feb. 4, Feb. 25, & Mar. 25, 2011).
(g) (e) x (f).
(h) (d) + (g).
(i) *Morningstar*, "Ibbotson SBBI 2010 Valuation Yearbook," at Table C-1 (2010).
(j) (h) + (i).

**CAPITAL ASSET PRICING MODEL**

**NON-UTILITY PROXY GROUP**

| | | |
|---|---|---|
| Market Rate of Return | | |
| Dividend Yield (a) | 2.3% | |
| Growth Rate (b) | 10.5% | |
| Market Return (c) | | 12.8% |
| Less: Risk-Free Rate (d) | | |
| Long-term Treasury Bond Yield | | 4.5% |
| Market Risk Premium (e) | | 8.3% |
| Non-Utility Proxy Group Beta (f) | | 0.71 |
| Utility Proxy Group Risk Premium (g) | | 5.9% |
| Plus: Risk-free Rate (d) | | |
| Long-term Treasury Bond Yield | | 4.5% |
| Unadjusted CAPM (h) | | 10.4% |
| Size Adjustment (i) | | -0.37% |
| **Implied Cost of Equity (j)** | | **10.0%** |

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (retrieved Jan. 28, 2011).
(b) Weighted average of IBES earnings growth rates for the dividend paying firms in the S&P 500 (retrieved Feb. 23, 2011).
(c) (a) + (b)
(d) Average yield on 30-year Treasury bonds for February 2011 from the Federal Reserve Board at http://www.federalreserve.gov/releases/h15/data/Monthly/H15_TCMNOM_Y20.txt.
(e) (c) - (d).
(f) www.valueline.com (retrieved Jan. 28, 2011).
(g) (e) x (f).
(h) (d) + (g).
(i) *Morningstar*, "Ibbotson SBBI 2010 Valuation Yearbook," at Table C-1 (2010).
(j) (h) + (i).

BOOK VALUE CAPITAL STRUCTURE



UTILITY PROXY GROUP

| | | At Fiscal Year-End 2010 (a) | | | Value Line Projected (b) | | |
|---|---|---|---|---|---|---|---|
| | Company | Long-term Debt | Preferred | Common Equity | Long-term Debt | Other | Common Equity |
| 1 | Ameren Corp. | 47.1% | 0.0% | 52.9% | 46.0% | 1.0% | 53.0% |
| 2 | American Elec Pwr | 55.1% | 0.2% | 44.7% | 49.5% | 0.0% | 50.5% |
| 3 | CenterPoint Energy | 74.7% | 0.0% | 25.3% | 71.0% | 0.0% | 29.0% |
| 4 | Cleco Corp. | 51.7% | 0.0% | 48.2% | 44.5% | 0.5% | 55.0% |
| 5 | CMS Energy | 71.7% | 0.0% | 28.3% | 65.5% | 0.5% | 34.0% |
| 6 | Constellation Energy | 34.7% | 1.5% | 63.8% | 31.5% | 1.0% | 67.5% |
| 7 | DTE Energy Co. | 49.9% | 2.1% | 48.0% | 52.5% | 0.0% | 47.5% |
| 8 | Edison International | 51.9% | 3.8% | 44.3% | 52.0% | 3.0% | 45.0% |
| 9 | Great Plains Energy | 54.0% | 0.6% | 45.4% | 51.0% | 0.5% | 48.5% |
| 10 | Hawaiian Elec. | 47.3% | 1.2% | 51.5% | 47.0% | 1.0% | 52.0% |
| 11 | IDACORP, Inc. | 51.2% | 0.0% | 48.8% | 49.5% | 0.0% | 50.5% |
| 12 | Integrys Energy Group | 47.6% | 0.0% | 52.4% | 45.0% | 1.0% | 54.0% |
| 13 | ITC Holdings Corp. | 69.1% | 0.0% | 30.9% | 66.5% | 0.0% | 33.5% |
| 14 | Pepco Holdings | 46.6% | 0.0% | 53.4% | 52.0% | 0.0% | 48.0% |
| 15 | PG&E Corp. | 50.4% | 1.1% | 48.5% | 45.0% | 1.0% | 54.0% |
| 16 | Pinnacle West Capital | 49.3% | 0.0% | 50.7% | 46.5% | 0.0% | 53.5% |
| 17 | Portland General Elec. | 53.1% | 0.0% | 46.9% | 50.0% | 0.0% | 50.0% |
| 18 | PPL Corp. | 59.9% | 0.0% | 40.1% | 47.5% | 1.0% | 51.5% |
| 19 | TECO Energy | 59.4% | 0.0% | 40.6% | 52.5% | 0.0% | 47.5% |
| 20 | Westar Energy | 54.3% | 0.4% | 45.3% | 54.0% | 0.5% | 45.5% |
| 21 | Wisconsin Energy | 53.5% | 0.4% | 46.2% | 51.5% | 0.5% | 48.0% |
| | **Average** | **53.9%** | **0.5%** | **45.5%** | **51.0%** | **0.5%** | **48.5%** |

(a) Company Form 10-K and Annual Reports.

(b) The Value Line Investment Survey (Feb. 4, Feb. 25, & Mar. 25, 2011).

MARKET VALUE CAPITAL STRUCTURE



UTILITY PROXY GROUP

| | | At Fiscal Year-End 2010 (a) | | | Value Line Projected (b) | | |
|---|---|---|---|---|---|---|---|
| | | (a) | (b) | (c) | (a) | (b) | (c) |
| | Company | Long-term Debt | Preferred | Common Equity | Long-term Debt | Other | Common Equity |
| 1 | Ameren Corp. | 51.3% | 0.0% | 48.7% | 50.8% | 1.1% | 48.1% |
| 2 | American Elec Pwr | 48.1% | 0.2% | 51.7% | 44.1% | 0.0% | 55.9% |
| 3 | CenterPoint Energy | 57.7% | 0.0% | 42.3% | 54.0% | 0.0% | 46.0% |
| 4 | Cleco Corp. | 42.9% | 0.0% | 57.1% | 41.1% | 0.5% | 58.4% |
| 5 | CMS Energy | 59.4% | 0.0% | 40.6% | 56.8% | 0.4% | 42.8% |
| 6 | Constellation Energy | 40.7% | 1.8% | 57.5% | 35.6% | 1.1% | 63.3% |
| 7 | DTE Energy Co. | 46.3% | 1.9% | 51.8% | 47.3% | 0.0% | 52.7% |
| 8 | Edison International | 45.1% | 3.3% | 51.6% | 52.1% | 3.0% | 44.9% |
| 9 | Great Plains Energy | 54.3% | 0.6% | 45.1% | 53.7% | 0.5% | 45.7% |
| 10 | Hawaiian Elec. | 37.8% | 1.0% | 61.2% | 39.7% | 0.8% | 59.4% |
| 11 | IDACORP, Inc. | 44.8% | 0.0% | 55.2% | 47.2% | 0.0% | 52.8% |
| 12 | Integrys Energy Group | 39.4% | 0.0% | 60.6% | 42.4% | 0.9% | 56.7% |
| 13 | ITC Holdings Corp. | 44.3% | 0.0% | 55.7% | 42.1% | 0.0% | 57.9% |
| 14 | Pepco Holdings | 47.6% | 0.0% | 52.4% | 52.7% | 0.0% | 47.3% |
| 15 | PG&E Corp. | 37.9% | 0.8% | 61.2% | 38.5% | 0.9% | 60.7% |
| 16 | Pinnacle West Capital | 44.0% | 0.0% | 56.0% | 43.8% | 0.0% | 56.2% |
| 17 | Portland General Elec. | 50.2% | 0.0% | 49.8% | 48.7% | 0.0% | 51.3% |
| 18 | PPL Corp. | 49.2% | 0.0% | 50.8% | 36.5% | 0.8% | 62.7% |
| 19 | TECO Energy | 45.2% | 0.0% | 54.8% | 40.9% | 0.0% | 59.1% |
| 20 | Westar Energy | 49.7% | 0.4% | 49.9% | 48.1% | 0.4% | 51.4% |
| 21 | Wisconsin Energy | 23.1% | 0.2% | 76.7% | 36.5% | 0.4% | 63.2% |
| | **Average** | **45.7%** | **0.5%** | **53.8%** | **45.4%** | **0.5%** | **54.1%** |

(a) Debt outstanding computed by multiplying long-term debt ratio by total book capital, both as reported by The Value Line Investment Survey (Feb. 4, Feb. 25, & Mar. 25, 2011).

BOOK VALUE CAPITAL STRUCTURE



ELECTRIC UTILITY OPERATING COS.

| | | At Fiscal Year-End 2010 (a) | | |
|---|---|---|---|---|
| | Company | Long-term Debt | Preferred | Common Equity |
| 1 | AEP Texas Central Co. | 54.9% | 0.4% | 44.7% |
| 2 | AEP Texas North Co. | 54.3% | 0.3% | 45.4% |
| 3 | Ameren Illinois Co. | 41.2% | 0.0% | 58.8% |
| 4 | Appalachian Power Co. | 55.6% | 0.3% | 44.1% |
| 5 | Atlantic City Electric Co. | 48.5% | 0.4% | 51.1% |
| 6 | Baltimore Gas & Electric Co. | 43.8% | 5.7% | 50.4% |
| 7 | CenterPoint Energy Houston Electric, LLC | 73.5% | 0.0% | 26.5% |
| 8 | Cleco Power | 53.1% | 0.0% | 46.9% |
| 9 | Columbus Southern Power Co. | 49.2% | 0.0% | 50.8% |
| 10 | Consumers Energy Co. | 52.1% | 0.5% | 47.4% |
| 11 | Delmarva Power & Light Co. | 47.6% | 0.0% | 52.4% |
| 12 | Detroit Edison Co. | 52.1% | 0.0% | 47.9% |
| 13 | Hawaiian Electric Co. | 43.5% | 1.4% | 55.0% |
| 14 | Idaho Power Co. | 53.4% | 0.0% | 46.6% |
| 15 | Indiana Michigan Power Co. | 54.1% | 0.2% | 45.7% |
| 16 | International Transmission Co. | 40.0% | 0.0% | 60.0% |
| 17 | ITC Great Plains | 38.8% | 0.0% | 61.2% |
| 18 | ITC Midwest | 40.0% | 0.0% | 60.0% |
| 19 | Kansas City Power & Light | 47.0% | 0.0% | 53.0% |
| 20 | Kansas Gas & Electric | 43.0% | 0.0% | 57.0% |
| 21 | Kentucky Power Co. | 55.8% | 0.0% | 44.2% |
| 22 | Kentucky Utilities Co. | 47.0% | 0.0% | 53.0% |
| 23 | Louisville Gas & Electric Co. | 41.4% | 0.0% | 58.6% |
| 24 | Michigan Elec. Transmission Co. | 39.1% | 0.0% | 60.9% |
| 25 | Ohio Power Co. | 46.1% | 0.3% | 53.6% |
| 26 | Pacific Gas & Electric Co. | 49.2% | 1.1% | 49.7% |
| 27 | Portland General Elec. | 53.1% | 0.0% | 46.9% |
| 28 | Potomac Electric Power Co. | 51.9% | 0.0% | 48.1% |
| 29 | PPL Electric Utilities Corp. | 43.1% | 7.3% | 49.6% |
| 30 | Public Service Co. of Oklahoma | 53.4% | 0.3% | 46.3% |
| 31 | Southern California Edison Co. | 45.3% | 5.5% | 49.2% |
| 32 | Southwestern Electric Pwr Co. | 51.4% | 0.1% | 48.4% |
| 33 | Tampa Electric Co. | 49.0% | 0.0% | 51.0% |
| 34 | Union Electric Co. | 48.8% | 0.0% | 51.2% |
| 35 | Upper Penninsula Power Co. | 37.1% | 0.0% | 62.9% |
| 36 | Westar Energy | 38.1% | 0.6% | 61.4% |
| 37 | Wisconsin Electric Power Co. | 39.2% | 0.6% | 60.2% |
| 38 | Wisconsin Public Service Corp. | 42.3% | 2.5% | 55.2% |
| | **Average** | **47.8%** | **0.7%** | **51.5%** |

(a) Company Form 10-K and Annual Reports.

UTILITY PROXY GROUP

| | Company | Mechanism |
|---|---|---|
| 1 | Ameren Corp. | FCA; PGA; DSMA; TCR; BDR; Cost trackers for pensions & post-retirement benefits, vegetation management, infrastructure inspections |
| 2 | American Elect Pwr | FCA: ECA |
| 3 | CenterPoint Energy | PGA; RMD; TCR |
| 4 | Cleco Corp. | FCA |
| 5 | CMS Energy | FCA; PGA; RDM; Self-implementing rates to reduce regulatory lag |
| 6 | Constellation Energy | PGA; RDM; DSMA |
| 7 | DTE Energy Co. | FCA; PGA; RDM; BDR; Cost tracker for restoration costs |
| 8 | Edison International | FCA; RDM; ICR; ECA; Variety of balancing accounts cover a substantial portion of authorized revenue requirements |
| 9 | Great Plains Energy | FCA |
| 10 | Hawaiian Elec. | FCA; RDM; ICR; Pension cost tracker |
| 11 | IDACORP, Inc. | FCA; RDM (Fixed cost adjustment mechanism); DSMA |
| 12 | Integrys Energy Group | FCA; RDM; ICR; BDR |
| 13 | ITC Holdings Corp. | RDM (formula rates with true-up mechanism) |
| 14 | Pepco Holdings | FCA; PGA; RDM |
| 15 | PG&E Corp. | FCA; RDM; ICR; ECA; TCR; Variety of balancing accounts cover a substantial portion of authorized revenue requirements |
| 16 | Portland General Elec. | FCA; RDM; ICR |
| 17 | PPL Corp. | FCA; PGA; ECA; DSMA; TCR; ICR (smart meters); Universal service cost tracker |
| 18 | TECO Energy | FCA; PGA; ECA; DSMA |
| 19 | Westar Energy | FCA; ECA; Employee benefit cost tracker |
| 20 | Wisconsin Energy | FCA; PGA |

BDR -- Bad Debt Cost Recovery Rider
DSMA -- Demand Side Management / Conservation Adjustment Clause
ECA -- Environmental and/or Emissions Cost Adjustment Clause
FCA -- Fuel and/or Purchased Power Cost Adjustment Clause
ICR -- Infrastructure / Renewables Cost Recovery
PGA -- Gas Cost Adjustment Clause
RDM -- Revenue Decoupling Mechanism
TCR -- Transmission Cost Recovery Tracker

Source: 2010 Form-10K Reports.

# TESTIMONY OF ZACHARY J. FRYER

**On Behalf of Arizona Public Service Company**

**Docket No. E-01345A-11-_____**

June 1, 2011

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**TESTIMONY OF ZACHARY J. FRYER**
**ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY**
**(Docket No. E-01345A-11-____)**

I. INTRODUCTION.

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

A. My name is Zachary J. Fryer. I am a Manager in the Regulation and Pricing Department for Arizona Public Service Company ("APS" or "Company"). I am primarily responsible for the development and coordination of the Company's regulatory filings that seek to recover an appropriate level of revenue. These filings are typically under the jurisdiction of the Arizona Corporation Commission ("ACC" or "Commission") or the Federal Energy Regulatory Commission ("FERC"). My business address is 400 North 5th Street, Phoenix, Arizona 85004.

**Q. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?**

A. I received a Bachelor of Science degree in Business with a major in Accounting from the University of Arizona in 1993. From 1993 to 1998 I was employed primarily as a financial auditor. I joined the Company in November of 1998 as a staff accountant and have spent the past 13 years working for APS in the Accounting Operations Department as well as the Regulation and Pricing Department.

Prior to my promotion to Manager in the Regulation and Pricing Department in 2007, I was responsible for the generation accounting function at APS as a supervisor of that department. I am a Certified Public Accountant and maintain an expertise in financial analysis, embedded cost analysis and evaluation of utility revenue requirements.

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

A. My testimony addresses three general areas. The first area of my testimony discusses the Standard Filing Requirements ("SFR") schedules, including Schedule A-1. Schedule A-1 presents the overall increase in revenue requirements requested in this Application. Second, I discuss the Cost of Service Study prepared to functionalize, classify, and then allocate Test Year costs and revenues, first between wholesale and retail customers and then to the various classes of retail service. It is this cost allocation study that allows APS to determine the rate of return produced by each class and subclass of customer, as well as the unit costs APS incurs to provide different services to each customer group. Finally, I address the calculation of the fair value increment that helps to derive the appropriate rate of return to apply to the Company's Fair Value Rate Base ("FVRB"). This calculation is an integral component used in the derivation of the Company's proposed revenue requirement, and I refer to the dollar revenue requirement impact of this calculation as the "fair value increment." The approach and policy to determine the "fair value increment" is discussed in the testimonies of APS Witnesses William Avera and Jeff Guldner.

## II. SUMMARY.

**Q. PLEASE SUMMARIZE YOUR TESTIMONY.**

My testimony addresses certain Standard Filing Requirements exhibits including Schedule A-1 that calculates the $95,493,000 increase in revenue requirements that is sought by the Company. This amount includes a $239,004,000 increase in non-fuel rates (which itself includes a transfer of revenue requirement from the Renewable Energy Surcharge ("RES") to base rates in the amount of $44,911,000) and a net decrease to the fuel-related component of rates in the

amount of $143,511,000. The components of the net base rate increase are as follows:

| | |
|---|---|
| Non-fuel increase (excluding RES recovery transferred to base rates) | $194,093,000 |
| RES recovery transferred to base rates | $ 44,911,000 |
| LESS: decrease in base fuel rate | ($143,511,000) |
| Net base rate increase proposed by APS | $ 95,493,000 |

If proposed rates are effective on July 1, 2012, customers will experience a $44,911,000 increase under the normal operation of the RES and $143,511,000 of savings under the normal operation of the Power Supply Adjustor ("PSA"). After, taking into consideration the transfer of recovery from the RES to base rates and the reclassification of PSA revenues to base fuel revenues as called for in the Commission-approved PSA Plan of Administration, the effective base rate revenue increase will be $95,493,000. This additional revenue will allow APS to earn a rate of return of 6.47% on a FVRB of $8,224,405,000. The additional revenue excluding "fair value increment" results in an 8.87% rate of return on an adjusted Original Cost Rate Base ("OCRB") of $5,720,277,000.

My testimony describes the Cost of Service Study that is used to support the Company's rate designs in the Company's application as well as the jurisdictional allocation of costs.

Finally, I will explain the calculation used to determine the fair value increment derived from the Company's FVRB. The mechanics of the calculation are based on those proposed by ACC Staff and adopted by the ACC in the 2007 Test Year rate filing made by APS that resulted in Decision No. 71448 (December 30, 2009).

III. STANDARD FILING REQUIREMENT SCHEDULES.

**Q. ARE YOU SPONSORING ANY STANDARD FILING REQUIREMENTS ("SFR") SCHEDULES?**

A. Yes. I am sponsoring SFR Schedules A-1, portions of B-1, B-2, C-1, C-2 and all the G schedules. Although not specifically required by the SFR, I am also sponsoring some additional schedules that are attached to my testimony and are designated as Schedule GJ (Attachment ZJF-1), Schedule GE-1 (Attachment ZJF-2), Schedule GE-2 (Attachment ZJF-3), and Schedule GE-3 (Attachment ZJF-4). I have also attached a SFR index that lists the APS witnesses responsible for preparation of the SFRs or elements of the SFRs (Attachment ZJF-5).

**Q. PLEASE DESCRIBE THE PORTIONS OF THE SFRS THAT YOU ARE SPONSORING.**

A. I am sponsoring portions of SFR Schedules A, B, C, and all of the G Schedules. In doing so, I rely on input from numerous witnesses. Moreover, I am sponsoring the allocation of rate base and expenses between Commission jurisdictional customers and other customers (the "jurisdictional splits"). These allocations are based on the results of the Cost of Service Study that are discussed in my testimony.

Schedule A-1 presents the requested overall increase in retail revenue requirements. Schedule A-1 demonstrates that the adjusted Test Year rate of return for ACC jurisdictional operations was 5.77% on a FVRB of $8,224,405,000. The rate of return on FVRB resulting from the requested increase of $95,493,000 is 6.47%.

The calculation of the Company's FVRB was based on the average of Original Cost Rate Base ("OCRB") and Reconstruction Cost New Less Depreciation ("RCND") rate base. This calculation has been accepted by the Commission for

decades as a reasonable determination in satisfying the requirement of completing a finding of fair value in order to establish new base rates. In addition to the determination of FVRB, Attachment ZJF-6 provides a detailed calculation of the fair value increment, discussed later in my Testimony. The net increase or bill impact to customers is further discussed in the testimonies of APS Witnesses Jeff Guldner and Charles Miessner. Although it is important to reflect the change in base rates, it is critical to recognize that the actual impact to customers does not equate to the base rate change due the presence of various other rate mechanisms, in this case the RES and the PSA.

Schedule B-1 provides the calculations of rate base for Total Company and ACC jurisdictional operations. The jurisdictional operations rate base calculations were developed through the Cost of Service Study.

I also sponsor portions of the C schedules that exhibit the pro forma adjustments to the Test Year and the jurisdictional splits of the pro forma adjustments between total Company and ACC jurisdictional operations. The sponsorship of the individual pro forma adjustments is noted on Schedule C-2.

The G schedules provide detailed information regarding the Company's Cost of Service Study. These schedules address existing and expected original cost rates of return by class, show pro forma adjusted amounts of Original Cost Rate Base and operating expenses allocated to ACC jurisdictional customers, and list the allocation factors used in preparing the study.

**Q. WHY DID APS NOT USE FAIR VALUE RATE BASE IN THESE G SCHEDULES?**

A. The form of the schedules set forth in the Commission's rules (A.A.C. R14-2-103) indicates that Original Cost Rate Base amounts are to be used. Had the Company used Fair Value Rate Base, the percent returns for all classes would be

less, but the overall conclusions to be drawn from the analysis would not significantly change.

**Q. PLEASE FURTHER DESCRIBE THE SFR "G" SCHEDULES.**

A. The following is a summary of these Schedules:

- SFR Schedule G-1 shows the rate-of-return at existing rates by customer class, based on the adjusted Test Year Cost of Service Study.
- SFR Schedule G-2 is similar to Schedule G-1, except it reflects returns by class that would result under APS's proposed rates.
- SFR Schedule G-3 shows the functionalized dollar amount and percentage of adjusted rate base allocated to each retail customer class.
- SFR Schedule G-4 shows the functionalized amount of operating expenses allocated to each retail customer class.
- SFR Schedule G-5 shows the amount of functionalized adjusted rate base allocated to ACC jurisdictional customers.
- SFR Schedule G-6 shows the amount of functionalized adjusted operating expense allocated to ACC jurisdictional customers.
- SFR Schedule G-7 lists the allocation factors used in preparing the Test Year Cost of Service Study.

**Q. DO YOU SPONSOR ANY ADDITIONAL SCHEDULES RELATED TO THE COST OF SERVICE?**

A. Yes. The following Schedules also relate to the study:

- Schedule GJ is a summary of the Cost of Service Study showing the jurisdictional separation of rate base costs, revenues, and operating expenses.
- Schedule GE-1 is a summary of the Cost of Service Study showing, by retail customer class, the allocation of total ACC allocated rate base costs, revenues, and operating expenses and the rate-of-return for each major customer class.

- Schedule GE-2 is a summary of the Cost of Service Study showing, by each general service subclass, the allocation of rate base costs, revenues, and operating expenses and the rate-of-return.

- Schedule GE-3 is a summary Cost of Service Study showing, by each residential subclass, the allocation of rate base costs, revenues, and operating expenses and the rate-of-return.

## IV. COST OF SERVICE STUDY.

**Q. DID THE COMPANY CONDUCT AN EMBEDDED COST OF SERVICE STUDY IN THE DEVELOPMENT OF ITS PROPOSED RATE SCHEDULES?**

A. Yes. APS conducted an embedded Cost of Service Study using the twelve-month period ending December 31, 2010 as the test period ("Test Year"). That is, the Company analyzed its historical costs, customer class sales and load characteristics during this period and used those results to allocate the various items of plant and operating expenses to each customer class. This study was a major input for designing the Company's proposed rates. The study results provided an original cost rate of return for each customer class as well as the functionalization, classification, and allocation of costs.

**Q. WHAT DO YOU MEAN BY EMBEDDED COSTS?**

A. An embedded Cost of Service Study is based on the historical costs and operating experience of the utility during the selected Test Year with certain adjustments for normalizing and/or annualizing known and measurable changes. For example, known and measurable cost changes from the test year, such as labor costs, costs of employee benefits, taxes and fuel costs, are included as adjustments to the historical data.

**Q. WAS THE USE OF A TWELVE-MONTH TEST YEAR ENDING DECEMBER 31, 2010 SUITABLE FOR THIS COST OF SERVICE STUDY?**

A. Yes. In fact, it was specifically required by the Company's 2009 Settlement Agreement. The Company's analysis also includes a number of pro forma adjustments to the Test Year that reflect known and measurable changes to its cost of service that have occurred since the Test Year, as well as other adjustments to normalize the test period. The Company has included these pro forma adjustments in its analysis, in order to obtain a better relationship between revenues, expenses, and rate base at the time closer to when the proposed rates are expected to be in effect. For example, wages and salaries are updated through a pro forma adjustment to account for current salary levels and employee count.

**Q. WHAT DO YOU MEAN BY "NORMALIZING" THE TEST YEAR INFORMATION?**

A. Normalization refers to eliminating the effect of conditions or situations that would not ordinarily occur or be expected to occur in a normal Test Year, or that recur periodically but should be averaged out over a period of years. For example, the Company would normalize the revenue impact of an abnormally hot or cool summer to better reflect APS's revenue stream during average summer months. In this case, the weather normalization adjustment reflected milder than normal temperatures. The purpose of normalization is to produce a Test Year that will likely be more generally representative of conditions that will exist during the period in which the proposed rates will be in effect.

**Q. HOW DO YOU TREAT PRO FORMA AND NORMALIZATION ADJUSTMENTS TO THE TEST YEAR IN YOUR COST OF SERVICE STUDY?**

A. Other APS witnesses sponsor a number of pro forma adjustments that were incorporated into the Test Year used during the Cost of Service Study. APS

Witnesses Jason La Benz, Peter Ewen, and Charles Miessner list, by rate base, revenue, and expense category, the monetized amount of each proposed pro forma adjustment. These amounts were then functionalized, classified, and allocated to the retail and wholesale customer classes as part of the process in performing the Cost of Service Study. The adjusted Test Year Cost of Service Study reflects each of the Company's proposed pro forma adjustments.

**Q. PLEASE DISCUSS THE DEVELOPMENT OF THE EMBEDDED COST ALLOCATION STUDY.**

A. This study was prepared using industry accepted Cost of Service Functionalization, Classification, and Allocation principles, and is generally consistent with the historical APS practices that the Commission has approved in the past.

Functionalization refers to the process of attributing a particular rate base or expense item to a particular function – namely Production, Transmission, or Distribution – in the provision of electric service. An easy example is the assignment of the costs of building and operating the Company's power plants to the Production function.

Classification refers to the process of determining the factor or factors that drive the magnitude of the cost. For example, if a cost is driven by the amount of energy consumed, it is classified as Energy; if a cost is driven by the rate at which energy is consumed, it is classified as Demand; and if a cost is driven by the number of customers taking service on the APS system irrespective of either the demand or energy utilized, it is classified as Customer.

Allocation occurs once a cost has been functionalized and classified. This is the process in which allocation factors (such as peak demand contribution, energy or customers) are applied to spread the costs to particular jurisdictions, customer

classes, and rate schedules. A simple example is the allocation of energy-related costs by kilowatt-hour ("kWh") consumption to different customer classes.

In the Cost of Service Study, the expense and rate base items that comprise APS's costs were grouped into major categories, such as Plant in Service or Operating & Maintenance ("O&M") Expense. Each of these categories was first functionalized into Production, Transmission, or Distribution related costs, then classified as Demand, Energy, or Customer-related. Allocation factors based on kilowatts, kilowatt-hours and number of customers, or customer equivalents were then developed so that allocation of the functionalized and classified costs could be made to the state jurisdiction and to the various retail customer classes and sub-classes.

**Q. HOW DID YOU ALLOCATE FUNCTIONALIZED COSTS BETWEEN JURISDICTIONS AND AMONG CUSTOMER CLASSES?**

A. Production-related assets are generally designed and built to enable the Company to meet its system peak load. Therefore, the costs associated with these investments are allocated between jurisdictions based on the average of the system peak demands occurring in the months of June, July, August, and September ("4CP") to determine jurisdictional cost responsibility. This is consistent with the allocation method that APS is required to use in its cases before FERC and prevents the potential for "stranded" costs that cannot be recovered from either jurisdiction. It has also been accepted as the jurisdictional allocation methodology by the Commission for many years.

Within the ACC-jurisdictional customer classes, production costs were allocated based on the Average and Excess Demand ("AED") method, which effectively requires all customers to contribute to meeting the fixed costs the Company incurs when providing generation services and activities. This is consistent with

the directive of the Commission contained in Decision No. 69663 (June 28, 2007) at pages 70-71.

Transmission plant was directly assigned to the non-ACC jurisdictional portion of the Cost of Service Study. A portion of those costs which equate to the existing OATT revenues are brought back into the ACC jurisdictional cost of service.

Distribution plant, unlike production and transmission plant, is generally designed to meet a customer class's peak load, which may or may not be coincident with the system peak load. Thus, allocation of costs related to distribution substations and primary distribution lines are made based on non-coincident peak loads ("NCP"). Allocation of costs related to distribution transformers and secondary distribution lines are made based on the summation of the individual peak loads or demands of all customers within a particular customer class ("ΣNCP"). Each of these allocation methods has been used by APS and accepted by the ACC for many years.

**Q. PLEASE EXPLAIN THE "ALL OTHER" OR NON-ACC JURISDICTIONAL SEGMENT OF YOUR COST OF SERVICE STUDY.**

A. The "All Other" segment, which appears as a column in the Cost of Service Study, represents the rate base, expenses, and revenues associated with service to long-term firm FERC jurisdictional resale customers that APS serves, as well as long-term transmission services APS provides to a number of entities. Because APS plans and uses Company facilities in order to fulfill these obligations, APS has allocated and assigned a portion of APS production and distribution facilities to these non-jurisdictional customers in the same manner as it does to the Company's classes of retail jurisdictional customers in preparing the Cost of Service Study, except that for jurisdictional purposes, APS used a 4CP demand allocator for the reasons described earlier.

**Q. PLEASE EXPLAIN THE USE OF REVENUE CREDITS IN THE COST OF SERVICE STUDY.**

A. APS makes sales to parties that are not traditional APS retail customers such as sales to Rate Schedule E-36 customers. In order to be certain that all the benefits of such transactions flow through to retail customers, the revenues derived from these transactions, which more than cover the incremental costs associated with producing or acquiring the required energy, are allocated to all customers. Thus, the entire margin or profit that APS realizes from these non-retail transactions is attributed to each class through the revenue credit, which benefits all customers by lowering the amount of their overall revenue requirements.

APS also treats non-firm, short-term transactions and a number of other small items, such as Rent from Electric Property, Forfeited Discounts, Miscellaneous Service Revenues, and Other Electric Revenues, as revenue credits.

**Q. HAVE YOU CALCULATED THE COSTS, RATE BASE, AND RATE OF RETURN BASED ON THE ADJUSTED TEST YEAR?**

A. Yes. In addition to establishing the Production, Transmission, and Distribution functions and the Demand, Energy, and Customer classifications for each class of retail business, the original cost rate of return for each class under both Test Year and proposed rates appears in the SFR "G" Schedules.

**Q. BASED ON THE RESULTS OF YOUR ADJUSTED TEST YEAR COST OF SERVICE STUDY, WHAT CONCLUSIONS HAVE YOU MADE?**

A. The "G", GJ, and GE Schedules plainly show that there are disparities in the rates of return that the different customer classes are providing to the Company. The residential class contributes less towards the Company's overall rate of return than does the general service class. Specifically, under current rates and adjusted operating expenses, the revenue from the residential class provides a rate of return of 6.08% while revenue from the general service class produces an 11.86%

rate of return. Overall, the rate of return provided by total retail revenues on an adjusted original cost rate base under current rates is 8.29%.

**Q. ARE THERE ANY COST ELEMENTS THAT RECEIVE RECOVERY TREATMENT OUTSIDE OF THE BASE RATE SCHEDULES?**

A. Yes. Various adjustors, surcharges, regulatory assessments, sales/transaction privilege taxes, and franchise fees are charged outside of base rates.

## V. TRANSMISSION COSTS

**Q. WOULD YOU EXPLAIN HOW TRANSMISSION COSTS WERE TREATED IN THE COST OF SERVICE STUDY?**

A. Yes. Consistent with the methods adopted in our last rate cases, the revenue requirement for transmission services was computed based on the FERC-jurisdictional rates found in the APS Open Access Transmission Tariff ("OATT").

**Q. HOW DID YOU ALLOCATE TRANSMISSION COSTS TO THE RETAIL CUSTOMERS CLASSES?**

A. It is unnecessary to perform interclass allocation of transmission costs. These costs are directly assigned. The APS OATT provides the class rate elements for each of the FERC-regulated transmission and ancillary service costs. Under the requirements established in Decision No. 69663 (June 28, 2007) and upheld in Decision No. 71448 (December 30, 2009), the APS retail rates were re-structured so the transmission component of the rates reflects the OATT charges. In this application, the Company proposes that the FERC-regulated charges be removed from base rates and directly charged to customers through the transmission rate schedule, TCA-1, that would directly incorporate the Company's then-effective OATT charges. APS is proposing to modify the existing TCA-1 to reflect this change. Effectively, the new TCA-1 will reflect the transmission costs found in base rates today, plus the then-effective adjustment that reflects the increased or

decreased OATT charges. In other words, all transmission costs would be recovered through the TCA. No such costs would remain in base rates. When the FERC-regulated transmission rates are changed, APS will re-file the retail transmission rate schedule TCA-1 with the new charges. A copy of the proposed, revised rate schedule TCA-1 is included in the testimony of Charles Miessner.

## VI. FAIR VALUE RATE OF RETURN.

**Q. WHAT IS APS'S FAIR VALUE RATE BASE AND RATE OF RETURN FOR THE ADJUSTED TEST YEAR 2010.**

A. As can be seen on SFR Schedule A-1, APS's FVRB is $8,224,405 and the rate of return is 6.17% as reflected on SFR Schedule A-1, Line 5.

**Q. HOW WAS THE FAIR VALUE RATE BASE DETERMINED?**

A. To determine the FVRB, APS used the previously Commission-approved methodology of averaging the Original Cost Rate Base ("OCRB") and the Reconstructed Cost Net Depreciation Rate Base ("RCND").

**Q. DID APS PERFORM AN INCREMENTAL CALCULATION TO ADDRESS THE APPROPRIATE LEVEL OF RETURN ON FAIR VALUE RATE BASE?**

A. Yes. A calculation of the fair value increment was performed. See Attachment ZJF-6 and SFR Schedule A-1, Line 11.

**Q. IS THIS TREATMENT CONSISTENT WITH THE METHOD USED IN APS'S LAST RATE CASE?**

A. Generally, yes. In APS's most recent rate case, Decision No. 71448 (December 30, 2009), the Commission applied a 1.5% rate of return to calculate a weighted average cost of capital that was then used to determine the appropriate fair value increment. This method was proposed by ACC Staff consultant, Ralph Smith. The Company proposes a 1.0% rate of return in this case. This return component

is below that recommended by APS Witness Dr. William Avera for the reasons described by APS Witness Jeff Guldner.

**Q. PLEASE EXPLAIN HOW THE FAIR VALUE INCREMENT WAS CALCULATED?**

A. To determine the fair value increment, APS calculated the rate of return to be applied to the FVRB as follows (See Attachment ZJF-6 for detailed calculation):

- First, FVRB is divided into three components 1) the Fair Value Increment calculated by subtracting the OCRB from the FVRB to determine the portion of fair value rate base in excess of the OCRB; 2) Debt component of OCRB, calculated by multiplying the Company's adjusted Test Year debt percentage (46%) by the OCRB; 3) Equity component of OCRB, calculated by multiplying the Company's adjusted test year equity percentage (54%) by the OCRB.

- Next, a return component of 1.0% is applied to the Fair Value Increment.

- Using the 1.0% return for the Fair Value Increment, 6.38% return on the debt component and 11.0% on the equity component, a new weighted average cost of capital is calculated.

The fair value weighted average cost of capital is applied to the FVRB and is compared to the revenue requirement reflected on SFR Schedule A-1, Line 8. The difference between those two values results in the fair value increment of $40,883,000, reflected on SFR Schedule A-1, Line 9.

VII. CONCLUSION.

**Q. WOULD YOU STATE YOUR GENERAL CONCLUSIONS AS TO COST OF SERVICE MATTERS IN THIS PROCEEDING?**

A. The 2010 adjusted test year Cost of Service Study fully supports the Company's rate request reflected on Schedule A-1. The Cost of Service Study indicates that APS's current rate schedules produce rates of return for each customer class that vary greatly from each other and from the overall average and required rate of return. While moving to cost-based pricing is an appropriate goal, moderation in changes is appropriate. APS's approach to cost of service and rate design attempts to incorporate these goals to provide better price signals to customers.

**Q. DOES THIS CONCLUDE YOUR TESTIMONY?**

A. Yes.

ARIZONA PUBLIC SERVICE COMPANY
ELECTRIC COST OF SERVICE STUDY (ADJUSTED)
FOR THE 12 MONTHS ENDING DECEMBER 31, 2010
($)

| Line No. | AVERAGE & EXCESS Description | ELECTRIC TOTAL (1) | GJ ACC JURISDICTION (2) | GJ ALL OTHER (3) |
|---|---|---|---|---|
| | **SUMMARY OF RESULTS** | | | |
| 1 | **DEVELOPMENT OF RATE BASE** | | | |
| 2 | ELECTRIC PLANT IN SERVICE | $12,598,371,933 | $10,539,862,564 | $2,058,509,369 |
| 3 | GENERAL & INTANGIBLE PLANT | $1,057,732,085 | $982,250,587 | $75,481,498 |
| 4 | LESS: RESERVE FOR DEPRECIATION | ($5,218,999,716) | ($4,528,867,636) | ($690,132,080) |
| 5 | OTHER DEFERRED CREDITS | ($1,266,301,000) | ($1,192,469,776) | ($73,831,224) |
| 6 | WORKING CASH | ($101,350,672) | ($84,458,112) | ($16,892,560) |
| 7 | MATERIALS, SUPPLIES & PREPAYMENTS | $335,128,869 | $296,522,619 | $38,606,250 |
| 8 | ACCUM. DEFERRED TAXES | ($1,931,062,000) | ($1,567,901,808) | ($363,160,192) |
| 9 | REGULATORY ASSETS | $560,583,000 | $491,882,993 | $68,700,007 |
| 10 | DECOMMISSIONING FUND | $469,886,000 | $458,475,866 | $11,410,134 |
| 11 | GAIN FROM DISP. OF PLANT | ($22,882,000) | ($22,104,012) | ($777,988) |
| 12 | MISCELLANEOUS DEFERRED DEBITS | $143,172,000 | $135,473,716 | $7,698,284 |
| 13 | CUSTOMER ADVANCES | ($121,645,000) | ($121,645,000) | $0 |
| 14 | CUSTOMER DEPOSITS | ($68,084,000) | ($68,084,000) | $0 |
| 15 | PROFORMA ADJUSTMENTS | $409,299,507 | $401,339,475 | $7,960,032 |
| 16 | **TOTAL RATE BASE** | **$6,843,849,006** | **$5,720,277,476** | **$1,123,571,529** |
| 17 | | | | |
| 18 | **DEVELOPMENT OF RETURN** | | | |
| 19 | REVENUES FROM RATES | $2,946,462,521 | $2,862,997,305 | $83,465,216 |
| 20 | PROFORMA TO BASE REVENUES FROM RATES | $5,860,414 | $5,860,414 | $0 |
| 21 | OTHER ELECTRIC REVENUE | $136,850,042 | $121,013,337 | $15,836,705 |
| 22 | **TOTAL OPERATING REVENUES** | **$3,089,172,977** | **$2,989,871,056** | **$99,301,921** |
| 23 | | | | |
| 24 | **OPERATING EXPENSES** | | | |
| 25 | OPERATION & MAINTENANCE | $1,735,768,826 | $1,830,377,943 | ($94,609,117) |
| 26 | ADMINISTRATIVE & GENERAL | $216,234,381 | $195,988,517 | $20,245,864 |
| 27 | DEPRECIATION & AMORT EXPENSE | $408,764,001 | $360,155,041 | $48,608,960 |
| 28 | AMORTIZATION ON GAIN | ($4,817,341) | ($4,655,929) | ($161,412) |
| 29 | REGULATORY ASSETS | ($2,131,520) | ($2,131,520) | $0 |
| 30 | PROFORMA ADJUSTMENTS | ($172,397,589) | ($178,895,956) | $6,498,367 |
| 31 | TAXES OTHER THAN INCOME | $134,467,497 | $114,221,382 | $20,246,115 |
| 32 | INCOME TAX | $226,357,054 | $200,455,694 | $25,901,360 |
| 33 | **TOTAL OPERATING EXPENSES** | **$2,542,245,309** | **$2,515,515,172** | **$26,730,138** |
| 34 | | | | |
| 35 | **OPERATING INCOME** | **$546,927,668** | **$474,355,885** | **$72,571,783** |
| 36 | | | | |
| 37 | **RETURN** | **$546,927,668** | **$474,355,885** | **$72,571,783** |
| 38 | | | | |
| 39 | **RATE OF RETURN (PRESENT)** | **7.99%** | **8.29%** | **6.46%** |
| 40 | | | | |
| 41 | **INDEX RATE OF RETURN (PRESENT)** | **1.00** | **1.04** | **0.81** |

ARIZONA PUBLIC SERVICE COMPANY
ELECTRIC COST OF SERVICE STUDY (ADJUSTED)
FOR THE 12 MONTHS ENDING DECEMBER 31, 2010
($)

| Line No. | AVERAGE & EXCESS Description | GE-1 TOTAL RETAIL (4) | RESIDENTIAL (5) | GENERAL SERVICE (6) | E-221 (Water Pumping) (7) | STREET LIGHTING (8) | DUSK TO DAWN (9) |
|---|---|---|---|---|---|---|---|
| | **SUMMARY OF RESULTS** | | | | | | |
| 1 | **DEVELOPMENT OF RATE BASE** | | | | | | |
| 2 | ELECTRIC PLANT IN SERVICE | $10,539,862,564 | $6,199,293,105 | $4,083,107,010 | $93,350,948 | $116,324,604 | $47,786,897 |
| 3 | GENERAL & INTANGIBLE PLANT | $982,250,587 | $608,907,751 | $353,616,322 | $8,918,531 | $8,002,038 | $2,805,946 |
| 4 | LESS: RESERVE FOR DEPRECIATION | ($4,528,867,636) | ($2,623,262,578) | ($1,805,123,078) | ($45,106,721) | ($40,310,779) | ($15,064,480) |
| 5 | OTHER DEFERRED CREDITS | ($1,192,469,776) | ($676,486,545) | ($493,096,458) | ($11,827,922) | ($8,433,143) | ($2,625,708) |
| 6 | WORKING CASH | ($84,458,112) | ($49,984,281) | ($32,370,794) | ($760,207) | ($948,463) | ($394,368) |
| 7 | MATERIALS, SUPPLIES & PREPAYMENTS | $296,522,619 | $160,699,985 | $129,625,559 | $2,986,090 | $2,389,824 | $821,161 |
| 8 | ACCUM. DEFERRED TAXES | ($1,567,901,808) | ($946,860,525) | ($580,140,677) | ($12,074,828) | ($20,130,857) | ($8,694,921) |
| 9 | REGULATORY ASSETS | $491,882,993 | $328,777,421 | $152,382,518 | $3,896,937 | $4,896,468 | $1,929,649 |
| 10 | DECOMMISSIONING FUND | $458,475,866 | $221,063,987 | $229,543,198 | $5,178,704 | $2,273,135 | $416,842 |
| 11 | GAIN FROM DISP. OF PLANT | ($22,104,012) | ($12,019,915) | ($9,685,951) | ($281,449) | ($98,393) | ($18,306) |
| 12 | MISCELLANEOUS DEFERRED DEBITS | $135,473,716 | $79,119,030 | $53,766,108 | $1,462,532 | $868,286 | $257,760 |
| 13 | CUSTOMER ADVANCES | ($121,645,000) | ($64,471,850) | ($53,356,771) | ($3,649,350) | ($167,029) | $0 |
| 14 | CUSTOMER DEPOSITS | ($68,084,000) | ($37,446,200) | ($29,395,742) | ($592,315) | ($464,170) | ($185,573) |
| 15 | PROFORMA ADJUSTMENTS | $401,339,475 | $232,401,691 | $160,545,973 | $4,157,328 | $3,139,812 | $1,094,672 |
| 16 | **TOTAL RATE BASE** | **$5,720,277,476** | **$3,419,731,076** | **$2,159,417,218** | **$45,658,280** | **$67,341,332** | **$28,129,571** |
| 17 | | | | | | | |
| 18 | **DEVELOPMENT OF RETURN** | | | | | | |
| 19 | REVENUES FROM RATES | $2,862,997,305 | $1,466,220,472 | $1,340,151,430 | $27,003,618 | $21,161,515 | $8,460,270 |
| 20 | PROFORMA TO BASE REVENUES FROM RATES | $5,860,414 | $3,912,905 | $2,448,578 | ($334,387) | ($162,967) | ($3,715) |
| 21 | OTHER ELECTRIC REVENUE | $121,013,337 | $61,674,921 | $56,525,049 | $1,216,323 | $1,167,525 | $429,518 |
| 22 | **TOTAL OPERATING REVENUES** | **$2,989,871,056** | **$1,531,808,298** | **$1,399,125,057** | **$27,885,554** | **$22,166,073** | **$8,886,073** |
| 23 | | | | | | | |
| 24 | **OPERATING EXPENSES** | | | | | | |
| 25 | OPERATION & MAINTENANCE | $1,830,377,943 | $944,559,847 | $852,325,729 | $21,406,382 | $9,538,037 | $2,547,949 |
| 26 | ADMINISTRATIVE & GENERAL | $195,988,517 | $121,052,052 | $70,878,574 | $1,797,873 | $1,706,538 | $553,479 |
| 27 | DEPRECIATION & AMORT EXPENSE | $360,155,041 | $210,089,575 | $141,959,120 | $3,413,869 | $3,393,848 | $1,298,629 |
| 28 | AMORTIZATION ON GAIN | ($4,655,929) | ($2,517,130) | ($2,055,137) | ($58,940) | ($20,846) | ($3,875) |
| 29 | REGULATORY ASSETS | ($2,131,520) | ($1,159,097) | ($934,029) | ($27,140) | ($9,488) | ($1,765) |
| 30 | PROFORMA ADJUSTMENTS | ($178,895,956) | ($96,595,944) | ($88,349,682) | ($3,249,593) | ($581,500) | ($119,236) |
| 31 | TAXES OTHER THAN INCOME | $114,221,382 | $68,268,854 | $43,005,346 | $916,769 | $1,421,827 | $608,587 |
| 32 | INCOME TAX | $200,455,694 | $70,245,750 | $126,157,797 | $920,107 | $1,875,155 | $1,256,884 |
| 33 | **TOTAL OPERATING EXPENSES** | **$2,515,515,172** | **$1,323,943,907** | **$1,142,987,717** | **$25,119,326** | **$17,323,570** | **$6,140,652** |
| 34 | | | | | | | |
| 35 | **OPERATING INCOME** | **$474,355,885** | **$207,864,392** | **$256,137,340** | **$2,766,228** | **$4,842,504** | **$2,745,421** |
| 36 | | | | | | | |
| 37 | **RETURN** | **$474,355,885** | **$207,864,392** | **$256,137,340** | **$2,766,228** | **$4,842,504** | **$2,745,421** |
| 38 | | | | | | | |
| 39 | **RATE OF RETURN (PRESENT)** | **8.29%** | **6.08%** | **11.86%** | **6.06%** | **7.19%** | **9.76%** |
| 40 | | | | | | | |
| 41 | **INDEX RATE OF RETURN (PRESENT)** | **1.04** | **0.76** | **1.48** | **0.76** | **0.90** | **1.22** |

ARIZONA PUBLIC SERVICE COMPANY
ELECTRIC COST OF SERVICE STUDY (ADJUSTED)
FOR THE 12 MONTHS ENDING DECEMBER 31, 2010
($)

Attachment ZJF-3
Schedule GE-2
Page 1 of 1

| Line No. | AVERAGE & EXCESS Description | TOTAL GENERAL SVC (10) | E-20 (Church Rate) (11) | E-32 TOU (0-100kW) (12) | E-32 TOU (101-400kW) (13) | E-32 TOU (401+ kW) (14) | E-30, E-32 (0 - 100 kW) (15) | E-32 (101 - 400 kW) (16) | E-32 (401+ kW) (17) | E-34 (18) | E-35 (19) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | <-------- GE-2 --------> | | | | | | | | | |
| | **SUMMARY OF RESULTS** | | | | | | | | | | |
| 1 | **DEVELOPMENT OF RATE BASE** | | | | | | | | | | |
| 2 | ELECTRIC PLANT IN SERVICE | $4,083,107,010 | $20,062,424 | $10,407,593 | $15,191,206 | $60,548,429 | $1,587,308,975 | $992,009,068 | $898,524,648 | $225,506,548 | $273,548,119 |
| 3 | GENERAL & INTANGIBLE PLANT | $353,616,322 | $1,497,816 | $989,085 | $1,338,535 | $5,440,676 | $141,288,394 | $80,364,945 | $75,004,636 | $20,366,321 | $27,335,914 |
| 4 | LESS: RESERVE FOR DEPRECIATION | ($1,805,123,078) | ($8,511,220) | ($4,673,942) | ($6,760,906) | ($27,424,383) | ($687,175,075) | ($437,625,366) | ($399,548,232) | ($102,898,131) | ($130,505,822) |
| 5 | OTHER DEFERRED CREDITS | ($493,096,458) | ($1,732,190) | ($1,473,030) | ($2,132,097) | ($8,841,165) | ($170,918,756) | ($114,210,397) | ($114,008,386) | ($32,719,494) | ($47,060,943) |
| 6 | WORKING CASH | ($32,370,794) | ($170,159) | ($78,791) | ($114,589) | ($453,422) | ($12,922,994) | ($7,958,244) | ($7,016,568) | ($1,699,210) | ($1,956,819) |
| 7 | MATERIALS, SUPPLIES & PREPAYMENTS | $129,625,559 | $479,238 | $376,727 | $565,304 | $2,336,282 | $43,434,348 | $30,952,751 | $30,716,217 | $8,625,123 | $12,139,569 |
| 8 | ACCUM. DEFERRED TAXES | ($680,140,677) | ($2,918,189) | ($1,476,193) | ($2,145,719) | ($8,403,471) | ($232,291,396) | ($139,667,664) | ($126,903,501) | ($31,045,426) | ($36,289,118) |
| 9 | REGULATORY ASSETS | $152,382,518 | $789,824 | $389,306 | $479,462 | $1,885,471 | $70,858,050 | $33,912,124 | $28,849,802 | $7,085,602 | $8,152,878 |
| 10 | DECOMMISSIONING FUND | $229,543,198 | $576,593 | $747,841 | $1,151,294 | $4,869,745 | $64,589,508 | $53,959,601 | $56,383,668 | $17,833,774 | $27,431,172 |
| 11 | GAIN FROM DISP. OF PLANT | ($9,685,951) | ($43,476) | ($25,170) | ($36,611) | ($153,309) | ($3,478,064) | ($2,386,593) | ($2,196,872) | ($583,491) | ($782,564) |
| 12 | MISCELLANEOUS DEFERRED DEBITS | $53,766,108 | $234,607 | $144,908 | $203,488 | $840,115 | $20,344,305 | $12,751,800 | $11,817,023 | $3,172,263 | $4,257,600 |
| 13 | CUSTOMER ADVANCES | ($53,356,771) | ($149,673) | ($200,488) | ($258,254) | ($926,224) | ($19,462,226) | ($12,725,339) | ($11,949,551) | ($3,215,417) | ($4,469,598) |
| 14 | CUSTOMER DEPOSITS | ($29,395,742) | ($82,459) | ($110,455) | ($142,279) | ($510,283) | ($10,722,286) | ($7,010,746) | ($6,583,343) | ($1,771,464) | ($2,462,427) |
| 15 | PROFORMA ADJUSTMENTS | $160,545,973 | $763,414 | $421,673 | $595,469 | $2,414,305 | $61,927,828 | $38,655,518 | $35,107,778 | $9,078,374 | $11,581,613 |
| 16 | **TOTAL RATE BASE** | **$2,159,417,218** | **$10,796,550** | **$5,439,067** | **$7,934,303** | **$31,602,764** | **$852,780,613** | **$521,011,457** | **$471,197,520** | **$117,735,373** | **$140,919,571** |
| 17 | | | | | | | | | | | |
| 18 | **DEVELOPMENT OF RETURN** | | | | | | | | | | |
| 19 | REVENUES FROM RATES | $1,340,151,430 | $3,759,314 | $5,035,623 | $6,486,512 | $23,263,793 | $488,828,889 | $319,619,809 | $300,134,494 | $80,761,001 | $112,262,015 |
| 20 | PROFORMA TO BASE REVENUES FROM RATES | $2,448,578 | $126,584 | $51,489 | ($101,380) | ($347,276) | $1,776,331 | ($2,304,531) | $3,663,807 | ($163,908) | ($252,548) |
| 21 | OTHER ELECTRIC REVENUE | $56,525,049 | $165,168 | $179,003 | $267,333 | $1,120,199 | $17,230,008 | $13,386,728 | $13,992,412 | $4,122,181 | $6,062,018 |
| 22 | **TOTAL OPERATING REVENUES** | **$1,399,125,057** | **$4,051,076** | **$5,266,115** | **$6,652,465** | **$24,036,716** | **$507,835,208** | **$330,702,006** | **$317,790,713** | **$84,719,274** | **$118,071,485** |
| 23 | | | | | | | | | | | |
| 24 | **OPERATING EXPENSES** | | | | | | | | | | |
| 25 | OPERATION & MAINTENANCE | $852,325,729 | $2,810,968 | $2,827,643 | $3,868,894 | $15,643,984 | $284,254,320 | $200,880,399 | $200,465,395 | $57,324,204 | $84,249,922 |
| 26 | ADMINISTRATIVE & GENERAL | $70,878,574 | $307,649 | $197,148 | $266,072 | $1,078,631 | $28,445,647 | $16,180,991 | $14,994,866 | $4,042,661 | $5,364,910 |
| 27 | DEPRECIATION & AMORT EXPENSE | $141,959,120 | $650,497 | $375,516 | $543,023 | $2,197,379 | $53,884,307 | $34,095,499 | $31,493,927 | $8,201,921 | $10,517,050 |
| 28 | AMORTIZATION ON GAIN | ($2,055,137) | ($8,988) | ($5,419) | ($7,916) | ($33,173) | ($728,677) | ($505,027) | ($469,378) | ($125,890) | ($170,670) |
| 29 | REGULATORY ASSETS | ($934,029) | ($4,192) | ($2,427) | ($3,530) | ($14,784) | ($335,394) | ($230,142) | ($211,828) | ($56,287) | ($75,464) |
| 30 | PROFORMA ADJUSTMENTS | ($88,349,682) | ($418,064) | ($400,181) | ($352,543) | ($1,008,092) | ($45,337,012) | ($21,549,278) | ($13,783,407) | ($3,044,830) | ($2,456,475) |
| 31 | TAXES OTHER THAN INCOME | $43,005,348 | $215,866 | $109,085 | $159,365 | $627,010 | $17,036,578 | $10,411,409 | $9,391,517 | $2,321,387 | $2,733,128 |
| 32 | INCOME TAX | $126,157,797 | $71,096 | $793,469 | $770,105 | $1,828,739 | $57,602,205 | $30,115,695 | $24,552,793 | $4,982,065 | $5,443,641 |
| 33 | **TOTAL OPERATING EXPENSES** | **$1,142,987,717** | **$3,624,832** | **$3,894,824** | **$5,243,470** | **$20,317,695** | **$394,821,973** | **$269,399,544** | **$268,433,886** | **$73,645,452** | **$105,606,042** |
| 34 | | | | | | | | | | | |
| 35 | **OPERATING INCOME** | **$256,137,340** | **$426,244** | **$1,371,291** | **$1,408,995** | **$3,719,021** | **$113,013,235** | **$61,302,461** | **$51,356,827** | **$11,073,822** | **$12,465,443** |
| 36 | | | | | | | | | | | |
| 37 | **RETURN** | **$256,137,340** | **$426,244** | **$1,371,291** | **$1,408,995** | **$3,719,021** | **$113,013,235** | **$61,302,461** | **$51,356,827** | **$11,073,822** | **$12,465,443** |
| 38 | | | | | | | | | | | |
| 39 | **RATE OF RETURN (PRESENT)** | **11.86%** | **3.95%** | **25.21%** | **17.76%** | **11.77%** | **13.25%** | **11.77%** | **10.90%** | **9.41%** | **8.85%** |
| 40 | | | | | | | | | | | |
| 41 | **INDEX RATE OF RETURN (PRESENT)** | **1.46** | **0.49** | **3.16** | **2.22** | **1.47** | **1.66** | **1.47** | **1.36** | **1.18** | **1.11** |

ARIZONA PUBLIC SERVICE COMPANY
ELECTRIC COST OF SERVICE STUDY (ADJUSTED)
FOR THE 12 MONTHS ENDING DECEMBER 31, 2010
($)

| Line No. | AVERAGE & EXCESS Description | GE-3 TOTAL RESIDENTIAL (20) | GE-3 RESIDENTIAL E-12 (21) | GE-3 RESIDENTIAL ET-1 & ET-2 (22) | GE-3 RESIDENTIAL ECT-1 & ECT-2 (23) |
|---|---|---|---|---|---|
| | **SUMMARY OF RESULTS** | | | | |
| 1 | **DEVELOPMENT OF RATE BASE** | | | | |
| 2 | ELECTRIC PLANT IN SERVICE | $6,199,293,105 | $1,860,099,673 | $3,337,603,738 | $1,001,589,694 |
| 3 | GENERAL & INTANGIBLE PLANT | $608,907,751 | $211,072,005 | $310,091,653 | $87,744,092 |
| 4 | LESS: RESERVE FOR DEPRECIATION | ($2,623,262,578) | ($790,297,750) | ($1,408,443,320) | ($424,521,509) |
| 5 | OTHER DEFERRED CREDITS | ($676,486,545) | ($223,641,038) | ($348,137,654) | ($104,707,852) |
| 6 | WORKING CASH | ($49,984,281) | ($14,671,363) | ($27,167,198) | ($8,145,720) |
| 7 | MATERIALS, SUPPLIES & PREPAYMENTS | $160,699,985 | $48,704,200 | $85,271,988 | $26,723,797 |
| 8 | ACCUM. DEFERRED TAXES | ($946,860,525) | ($291,243,794) | ($506,045,448) | ($149,571,283) |
| 9 | REGULATORY ASSETS | $328,777,421 | $117,353,027 | $166,533,568 | $44,890,826 |
| 10 | DECOMMISSIONING FUND | $221,063,987 | $67,423,813 | $115,002,344 | $38,637,829 |
| 11 | GAIN FROM DISP. OF PLANT | ($12,019,915) | ($3,411,706) | ($6,560,269) | ($2,047,939) |
| 12 | MISCELLANEOUS DEFERRED DEBITS | $79,119,030 | $25,252,431 | $41,554,828 | $12,311,771 |
| 13 | CUSTOMER ADVANCES | ($64,471,850) | ($21,737,904) | ($32,808,081) | ($9,925,866) |
| 14 | CUSTOMER DEPOSITS | ($37,446,200) | ($12,625,695) | ($19,055,417) | ($5,765,089) |
| 15 | PROFORMA ADJUSTMENTS | $232,401,691 | $70,060,314 | $124,937,719 | $37,403,658 |
| 16 | **TOTAL RATE BASE** | **$3,419,731,076** | **$1,042,336,213** | **$1,832,778,453** | **$544,616,410** |
| 17 | | | | | |
| 18 | **DEVELOPMENT OF RETURN** | | | | |
| 19 | REVENUES FROM RATES | $1,466,220,472 | $494,363,962 | $746,122,218 | $225,734,292 |
| 20 | PROFORMA TO BASE REVENUES FROM RATES | $3,912,905 | ($998,200) | $1,198,055 | $3,713,050 |
| 21 | OTHER ELECTRIC REVENUE | $61,674,921 | $18,866,889 | $32,324,144 | $10,483,889 |
| 22 | **TOTAL OPERATING REVENUES** | **$1,531,808,298** | **$512,232,651** | **$779,644,417** | **$239,931,231** |
| 23 | | | | | |
| 24 | **OPERATING EXPENSES** | | | | |
| 25 | OPERATION & MAINTENANCE | $944,559,847 | $301,232,623 | $487,258,008 | $156,069,215 |
| 26 | ADMINISTRATIVE & GENERAL | $121,052,052 | $41,430,325 | $62,025,101 | $17,596,626 |
| 27 | DEPRECIATION & AMORT EXPENSE | $210,089,575 | $64,653,462 | $111,898,804 | $33,537,308 |
| 28 | AMORTIZATION ON GAIN | ($2,517,130) | ($716,893) | ($1,370,865) | ($429,373) |
| 29 | REGULATORY ASSETS | ($1,159,097) | ($328,995) | ($632,616) | ($197,486) |
| 30 | PROFORMA ADJUSTMENTS | ($86,595,944) | ($32,246,136) | ($43,166,999) | ($11,182,809) |
| 31 | TAXES OTHER THAN INCOME | $68,268,854 | $20,699,908 | $36,656,406 | $10,912,541 |
| 32 | INCOME TAX | $70,245,750 | $34,372,431 | $28,910,241 | $6,963,077 |
| 33 | **TOTAL OPERATING EXPENSES** | **$1,323,943,907** | **$429,096,726** | **$681,578,081** | **$213,269,100** |
| 34 | | | | | |
| 35 | **OPERATING INCOME** | **$207,864,392** | **$83,135,924** | **$98,066,336** | **$26,662,131** |
| 36 | | | | | |
| 37 | **RETURN** | **$207,864,392** | **$83,135,924** | **$98,066,336** | **$26,662,131** |
| 38 | | | | | |
| 39 | **RATE OF RETURN (PRESENT)** | **6.08%** | **7.98%** | **5.35%** | **4.90%** |
| 40 | | | | | |
| 41 | **INDEX RATE OF RETURN (PRESENT)** | **0.76** | **1.00** | **0.67** | **0.61** |

# Standard Filing Requirements Index for Sponsorship

| | | | |
|---|---|---|---|
| pA-1 | Fryer | | |
| A-2<br>A-3<br>A-4<br>A-5 | La Benz<br>Hatfield | Historical<br>Projected | |
| B-1* | La Benz | | |
| B-2*<br>B-3* | La Benz<br>La Benz/Guldner<br>La Benz/Schiavoni<br>La Benz/Edington<br>La Benz/Froetscher<br>La Benz | Columns 2<br>Column 3<br>Column 4<br>Column 5<br>Column 6<br>Column 7 | |
| B-4<br>B-5 | La Benz | Column | |
| C-1* | La Benz | | |
| C-2* | La Benz<br>La Benz/Guldner<br>La Benz/Schiavoni<br>La Benz/Edington<br>La Benz/Froetscher<br>La Benz<br>Ewen<br>Miessner | Columns 1-5<br>Column 6<br>Column 7<br>Column 8<br>Column 9<br>Columns 10-27<br>Columns 28-30<br>Column 31-33 | |
| C-3 | La Benz | | |
| D-1<br>D-2<br>D-3 | La Benz<br>Hatfield | Historical<br>Projected | |
| D-4 | La Benz | | |

*Zachary Fryer sponsors the ACC jurisdictional amounts that are computed, via the Cost of Service Study.

| | | |
|---|---|---|
| E-1<br>E-2<br>E-3<br>E-4<br>E-5<br>E-6<br>E-7<br>E-8<br>E-9 | La Benz | |
| F-1<br>F-2<br>F-3 | La Benz<br>Hatfield | Historical<br>Projected |
| F-4 | Hatfield | |
| G-1<br>G-2<br>G-3<br>G-4<br>G-5<br>G-6<br>G-7 | Fryer | |
| H-1<br>H-2<br>H-3<br>H-4<br>H-5 | Miessner | |

# Calculation of Fair Value Increment

| | *Adjusted Test Year Capital Structure* | Amount | % | Cost Rate | Weighted Avg |
|---|---|---|---|---|---|
| 1. | Long-Term Debt | $ 3,382,856 | 46.06% | 6.38% | 2.94% |
| 2. | Preferred Stock | - | 0.00% | 0.00% | 0.00% |
| 3. | Common Equity | 3,961,248 | 53.94% | 11.00% | 5.93% |
| 4. | Short-Term Debt | - | 0.00% | 0.00% | 0.00% |
| 5. | Total | $ 7,344,104 | 100.00% | | 8.87% |

| | *Capital Structure with 1.0% FV Increment* | Amount | % | Cost Rate | Weighted Avg |
|---|---|---|---|---|---|
| 6. | Long-Term Debt | $ 2,634,760 | 32.04% | 6.38% | 2.04% |
| 7. | Preferred Stock | - | 0.00% | 0.00% | 0.00% |
| 8. | Common Equity | 3,085,517 | 37.52% | 11.00% | 4.13% |
| 9. | Short-Term Debt | - | 0.00% | 0.00% | 0.00% |
| 10. | FVRB Increment | 2,504,128 | 30.45% | 1.00% | 0.30% |
| 11. | Total | $ 8,224,405 | 100.00% | | 6.47% |

| | *Fair Value Increment Calculation* | Fair Value | Original Cost |
|---|---|---|---|
| 12. | Rate Base | $ 8,224,405 | $ 5,720,277 |
| 13. | Rate of Return | 6.47% | 8.87% |
| 14. | Required Operating Income | $ 532,119 | $ 507,389 |
| 15. | Adjusted Operating Income | $ 474,356 | $ 474,356 |
| 16. | Adjusted Operating Income Deficiency (line 14 - line 15) | $ 57,763 | $ 33,033 |
| 17. | Revenue Conversion Factor | 1.6532 | 1.6532 |
| 18. | Increase in Base Revenue Requirements (line 16 * line 17) | $ 95,494 | $ 54,610 |
| 19. | Fair Value Increment | $ 40,883 | |

# TESTIMONY OF JASON C. LA BENZ

**On Behalf of Arizona Public Service Company**

**Docket No. E-01345A-11-_____**

June 1, 2011

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**TESTIMONY OF JASON C. LA BENZ**
**ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY**
**(Docket No. E-01345A-11-____)**

I. INTRODUCTION

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

A. My name is Jason C. La Benz. I am the Director of Financial Reporting for Arizona Public Service Company ("APS" or the "Company"), a subsidiary of Pinnacle West Capital Corporation ("Pinnacle West"). I am responsible for the financial accounting, revenue and regulatory accounting, payroll, asset accounting, accounts payable, accounts receivable and cash control functions at Pinnacle West and APS. My business address is 400 North Fifth Street, Phoenix, Arizona 85004.

**Q. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?**

A. I received a Bachelor of Science degree in Business with a major in Accounting from Arizona State University in 1982. I joined APS in May of 1982 as a staff accountant and have spent the last 29 years working for APS and Pinnacle West in Financial Accounting, Asset Accounting, Financial Planning, and the Tax Department.

Prior to my current position in Financial Reporting, I was responsible for the asset accounting function at APS as the leader of that department. I am a Certified Public Accountant and a member of the Edison Electric Institute's Corporate Accounting Committee.

II. SUMMARY

**Q. PLEASE SUMMARIZE YOUR TESTIMONY.**

A. My testimony addresses the historical accounting information and pro forma adjustments required by the Standard Filing Requirements ("SFR") of the Arizona Corporation Commission ("ACC" or "Commission") in support of the

Company's rate case filing. I sponsor historical information for the twelve month period ending December 31, 2010, which was used as the test year in this proceeding (the "Test Year") and any prior years presented on the following SFR Schedules (APS Witness James Hatfield sponsors any projected information contained in these schedules):

- A-2 through A-5 – Summary Schedules
- B-1, B-3 through B-5 – Rate Base Schedules
- C-1 – Test Year Income Statements
- C-3 – Computation of Gross Revenue Conversion Factor
- D-1 through D-4 – Cost of Capital
- E-1 through E-9 – Financial Statements and Statistical Schedules
- F-1 through F-3 – Projections and Forecasts

I will also provide direct testimony on certain pro forma adjustments made to the Test Year on SFR Schedules B-2 and C-2. Specifically, I will be sponsoring the "Total Company" column for the following pro formas on SFR Schedule B-2:

- West Phoenix Unit 4 Regulatory Disallowance
- Adjust Rate Base for Post-Test Year Plant Additions
- Adjust Cash Working Capital for Cost of Service Pro Formas

Additionally, I will be sponsoring the "Total Company" columns for the following pro formas on SFR Schedule C-2:

- Remove Bark Beetle Remediation Amortization
- Remove Test Year Surcharges
- Include West Phoenix Unit 4 Regulatory Disallowance
- Include Interest Expense on Customer Deposits
- Adjust Depreciation Expense – 2010 Study
- Adjust for Post-Test Year Plant Additions
- Adjust Decommissioning and Spent Fuel Costs – 2010 Study
- Annualize Payroll Expense
- Normalize Employee Benefits
- Normalize Income Tax Expense / Interest Synchronization
- Annualize Property Tax Expense
- Annualize Severance Costs
- Amortize Childs-Irving Excess Decommissioning Costs
- Remove Schedule 3 Revenues
- Normalize Fossil Maintenance
- Normalize Nuclear Maintenance
- Annualize Four Corners Coal Reclamation Costs
- Adjust Cash Working Capital for Cost of Service Pro Formas

- Remove PWEC Loan Amortization
- Amortize Pension and OPEB Deferral
- Normalize Pole Attachment Revenues
- Remove Supplemental Executive Retirement Plan Benefits
- Remove Stock Compensation
- Remove Out of Period and Miscellaneous Items

These adjustments are consistent with prior filings and represent "normalizations" and "annualizations" as discussed later in my testimony. These operating income pro formas also include an income tax calculation at the current combined federal and state statutory income tax rates. The SFR Schedule C-2 pro formas that have a related Rate Base pro forma also include synchronization of interest expense. This interest expense is used in determining federal and state income tax expense.

I will discuss and explain the "Gross Revenue Conversion Factor" that is used to gross-up operating income to account for income taxes, as presented on SFR Schedule C-3. I will also present testimony concerning the capital structure of the Company and provide APS's actual overall cost of capital, as presented on SFR Schedules D-1 through D-4. (Mr. Hatfield will discuss the projected information on SFR Schedules D-1 through D-3). This discussion will include information on the cost of equity provided by Dr. William Avera, APS's return on equity ("ROE") witness, as well as the Company's cost of debt. In addition, I will sponsor the various schedules relating to the Company's financial statements on SFR Schedules E-1 through E-9. SFR Schedule E-6 refers only to "combination" utilities (e.g., electric and gas) and thus is not applicable to APS.

Finally, I will sponsor the Test Year data on SFR Schedules F-1 through F-3. These schedules also include projected income statements and projected changes in financial position. Once again, Mr. Hatfield will address and sponsor the projected information on those schedules.

## III. HISTORICAL AND TEST YEAR ACCOUNTING DATA

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

A. My testimony covers historical accounting data, including the actual data for the Test Year. The majority of this information is disclosed directly or indirectly in both the consolidated APS and consolidated Pinnacle West audited financial statements, which are included in filings made with the Securities and Exchange Commission ("SEC") for the relevant years.

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

On January 1, 2010, APS adopted amended accounting guidance relating to Variable Interest Entities ("VIE"). This amended guidance significantly changed the consolidation model for VIE's and resulted in the consolidation of the Palo Verde ("PV") lessor trusts from which we lease a portion of PV Unit 2. Consistent with Decision Nos. 55120 (July 24, 1986) and 55320 (December 5,

1986), the PV leases have been accounted for as operating leases on APS's unconsolidated financial statements. The levelized lease expense (net of the gain amortization) is currently being recovered through rates. The Test Year financial information will continue to portray the operating lease treatment reflected on APS's unconsolidated financial statements.

In large part, my testimony supports the testimony of other APS witnesses. The direct testimony of Mr. Hatfield addresses financial projections to actual Test Year data. APS witness Zachary Fryer focuses on the jurisdictional allocation of APS revenues, costs, and Rate Base items for the actual Test Year and all pro forma adjustments. Dr. Avera's testimony addresses the Company's ROE.

A. *Summary Schedules*

**Q. PLEASE DESCRIBE THE HISTORICAL INFORMATION ON SFR SCHEDULES A-2 THROUGH A-5.**

A. These summary schedules provide the "Summary Results of Operations", the "Summary of Capital Structure", the "Construction Expenditures, Net Plant Placed in Service and Gross Utility Plant in Service" and "Summary Changes in Financial Position" for the Test Year and the prior two calendar years. These schedules also include projected information. I am sponsoring the historical data for the Test Year and prior calendar years. Mr. Hatfield is sponsoring the projected information on these schedules.

B. *Rate Base Schedules*

**Q. PLEASE DESCRIBE THE INFORMATION ON SFR SCHEDULES B-1 THROUGH B-5.**

A. These schedules provide summary and detailed information of our Original Cost and Reconstructed Cost New less Depreciation ("RCND") Rate Base, including the related pro formas needed to present an adjusted Rate Base as of the end of the Test Year. I am sponsoring the "Total Company" portion of these schedules and certain pro forma adjustments. Mr. Fryer is sponsoring the "ACC" portion,

and his testimony will present the allocation of "Total Company" figures to the ACC jurisdiction.

**Q. PLEASE SUMMARIZE THE ADJUSTED TEST YEAR ORIGINAL COST RATE BASE PROPOSED BY APS.**

A. As of December 31, 2010, APS is proposing a Total Company Adjusted Original Cost Rate Base ("OCRB") of $6,843,849,000. This represents an increase of $409,300,000 over the unadjusted amount. The amount of the adjusted OCRB allocated to the ACC jurisdiction is $5,720,277,000. The requested adjustments to the Test Year amounts are summarized in SFR Schedule B-2.

**Q. WHAT IS MEANT BY THE TERMS "RCND" AND "RCN" AS USED IN YOUR TESTIMONY?**

A. The Commission regulations define Reconstructed Cost New Less Depreciation or "RCND" as:

> An amount consisting of the depreciated reconstruction cost new of the property (exclusive of contributions and/or advances in aid of construction) at the end of the test year, used and useful, plus a proper allowance for working capital and including all applicable pro forma adjustments. Contribution and advances in aid of construction, if recorded in the accounts of the public service corporation, shall be increased to a reconstruction new basis (A.A.C. R14-2-103(A)(3)(n)).

Thus, Reconstructed Cost New ("RCN") refers to the estimated cost of utility property that would be incurred if APS were to reproduce or reconstruct the property as new, using current cost levels. RCND is the net amount that results after deducting accumulated depreciation and amortization (both of which are also restated in current dollars) from the RCN amount.

**Q. WHAT DOES SFR SCHEDULE B-4 PRESENT?**

A. SFR Schedule B-4 presents the RCN and RCND amounts of APS's utility properties. These amounts were determined using a Handy-Whitman RCN Study performed by the Company.

**Q. BASED ON YOUR STUDY, WHAT IS THE RCN OF APS'S UTILITY PROPERTY DEVOTED TO SERVICE TO THE PUBLIC AS OF THE END OF THE TEST YEAR?**

A. Total RCN for APS's utility property is approximately $26.4 billion. This total amount is shown in column (A) of SFR Schedule B-4, page 2 of 2.

**Q. WOULD YOU PLEASE EXPLAIN HOW RCND WAS CALCULATED AS SHOWN ON SFR SCHEDULE B-4?**

A. To arrive at RCND, RCN column (A) is multiplied by a "condition percent," also known as a net book value percent, which is shown in column (B). RCND is shown in column (C). The condition percent used to convert RCN to RCND is calculated by first taking the original cost less accumulated depreciation (net book value) for all depreciable plant for each FERC account. This amount is then divided by the original cost for each FERC account to arrive at the condition percent. In other words, the condition percent is the percentage that results when comparing original cost less accumulated depreciation to the original cost of plant in service.

For example, assume that distribution lines have an original cost of $400,000, and accumulated depreciation of $250,000. The original cost less accumulated depreciation would be $150,000, which is $400,000 minus $250,000. Also, assume the distribution lines were purchased in 1985 and have a RCN value of $632,000. Using these assumptions, the condition percent is calculated by dividing original cost less accumulated depreciation by original cost, or $150,000/$400,000, resulting in 37.5%. Multiplying RCN by the condition percent yields RCND. In this hypothetical, the RCND for these distribution lines would be $237,000 ($632,000 x 37.5%=$237,000).

**Q. ARE THERE ANY OTHER RELATED ADJUSTMENTS NECESSARY TO DETERMINE FAIR VALUE RATE BASE?**

A. Yes. Plant-related accumulated deferred income taxes ("ADIT") were also adjusted. Plant-related ADIT arises primarily as a result of differences between

book depreciation recorded for GAAP purposes and tax depreciation used for income tax purposes. Since RCND trending results in a change in accumulated book depreciation, a corresponding change was made to original cost ADIT. To make this adjustment, the Company trended plant-related ADIT using the relationship between the Original Cost less Depreciation and RCND.

**Q. WOULD YOU PLEASE EXPLAIN SFR SCHEDULE B-4A?**

A. SFR Schedule B-4A shows the computation of adjusted jurisdictional RCND Rate Base as of December 31, 2010. Column (A) presents data for Total RCND Rate Base. Mr. Fryer provided the jurisdictional allocations of the RCND Rate Base split between "ACC" and "Other," which is presented in columns (B) and (C) respectively.

**Q. HOW DID YOU ARRIVE AT THE AMOUNTS SHOWN ON LINES 11 THROUGH 24 OF SFR SCHEDULE B-4A?**

A. The amounts shown on lines 11 through 29 of SFR Schedule B-4A for other Rate Base elements were obtained from SFR Schedule B-1, page 1 of 2, column (A). Consistent with past Commission practice, the RCND of these specific Rate Base elements are stated at their original cost levels, as these elements do not change in value with the passage of time.

**Q. WOULD YOU PLEASE EXPLAIN LINES 29 AND 30 OF SFR SCHEDULE B-4A?**

A. The amounts shown on line 29 represent the RCND Rate Base as of December 31, 2010. However, the end of Test Year data needs to be adjusted to more closely reflect the value of certain items of property when the proposed rates become effective. Therefore, it is necessary to also reflect the pro forma Rate Base adjustments in the RCND Rate Base. The RCND pro forma adjustments are shown in detail on SFR Schedules B-3. The total is shown on line 30 of SFR Schedule B-4A.

**Q. WHAT IS THE TOTAL ADJUSTED RCND RATE BASE?**

A. The total Company RCND Rate Base, as adjusted, is approximately $12.8 billion. This is shown on SFR Schedule B-4A, column (A), line 31.

**Q. PLEASE EXPLAIN COMPUTATION OF WORKING CAPITAL ON SFR SCHEDULE B-5.**

A. SFR Schedule B-5 outlines the computation of the allowance for working capital of $233,778,000 included in the Company's Rate Base. Working capital is a measure of investor funding of daily operating expenditures and a variety of non-plant investments that are necessary to sustain ongoing operations. Working capital includes materials and supplies, fuel inventories, prepayments and cash working capital. Working capital is an investment just like other capital requirements, such as power plants and transmission and distribution infrastructure; thus, it is part of APS's Rate Base. My testimony presents the calculation of the allowance for working capital, which includes a cash working capital component that is determined using a "lead/lag study." The lead/lag study is required by Decision No. 55931 (April 1, 1988).

**Q. HOW WAS THE CASH WORKING CAPITAL CALCULATED?**

A. APS calculated the cash working capital by performing a lead/lag study. A lead/lag study establishes the amount of investor funds used to maintain utility operations from the time expenditures are made to the time revenues are collected as a reimbursement for that utility service. The Company used the number of lead/lag study days derived from a calendar year 2010 study and applied this information to the Test Year income statement expenses.

In addition, the Company considered the pro forma adjustments to the Test Year income statement expenses and computed a Rate Base pro forma to reflect the related change in cash working capital (*see* the pro forma discussion in Section IV of my testimony).

C. *Test Year Income Statements*

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

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

**Q. ARE YOU SPONSORING ANY OTHER RELATED SFR SCHEDULES?**

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

**Q. PLEASE DESCRIBE SFR SCHEDULE C-3.**

A. SFR Schedule C-3 calculates the factor applied to "gross-up" income to account for income taxes. The Company applies this factor to operating income to ensure income tax expense is reflected in the requested revenue requirement. The Gross Revenue Conversion factor of 1.6532 (shown on line 5) is an algebraic transformation of APS's composite federal and state income tax rate of 39.51 percent. This factor is used on SFR Schedule A-1 (line 7) to arrive at the increase or decrease in Revenue Requirements necessary to account for income taxes.

D. *Cost of Capital*

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

A. SFR Schedule D-1 is the summary of the Company's historical and projected cost of capital. I am sponsoring the Test Year in this schedule. SFR Schedule D-2

presents supporting detail for the long-term debt summarized on SFR Schedule D-1. SFR Schedule D-3 addresses preferred stock and is included in the Company's schedules for the sake of completeness. SFR Schedule D-3 is not directly applicable because APS did not have any outstanding preferred stock as of December 31, 2010. SFR Schedule D-4 addresses the Company's cost of common equity.

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

A. The company is requesting a weighted average cost of capital of 8.87% as set forth on SFR Schedule D-1.

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

A. At the end of the Test Year, approximately 81% of APS's outstanding long-term debt consisted of unsecured notes with a weighted average interest rate of approximately 6.6%. Most of the remaining long-term debt consisted of tax-advantaged pollution control bonds. This debt has a weighted average interest rate of approximately 5.3%. APS also has a small amount of interest expense related to capitalized lease obligations.

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

A. APS's total long-term debt and common equity was approximately $7.21 billion. This amount includes approximately $3.38 billion in long-term debt (including current maturities) and approximately $3.82 billion in common equity. APS's adjusted capital structure at the end of the Test Year was approximately 46.06% debt and 53.94% equity.

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

A. I have applied two pro forma adjustments to the December 31, 2010 actual cost of capital. These adjustments remove impacts to equity of non-cash accounting

adjustments for pension and derivatives. Since these adjustments were small in comparison to total equity, there is no significant impact on the Company's capital structure.

**Q. WHAT IS THE RETURN ON EQUITY THE COMPANY IS REQUESTING?**

A. Dr. Avera concludes in his testimony that the fair rate of return on equity for APS ranges from 10.75% to 11.75%. For the purpose of this filing, the Company is proposing a return on common equity of 11.0%.

E. *Financial Statements and Statistical Schedules*

**Q. PLEASE SUMMARIZE THE INFORMATION PRESENTED ON SFR SCHEDULES E-1 THROUGH E-9.**

A. These schedules relate to historical financial and accounting information, as well as the notes to the financial statements. As noted earlier in my testimony, SFR Schedule E-6 is only required for combined electric and gas utilities and therefore does not apply to APS.

**Q. PLEASE DISCUSS SFR SCHEDULES E-1 THROUGH E-4.**

A. These schedules present APS's balance sheets, income statements, statements of cash flows and changes in stockholders' equity for the Test Year and the two prior calendar years. As discussed earlier, these financial statements continue to reflect APS's unconsolidated results, consistent with previous rate filings. The SEC Form 10-K filings reflect APS's consolidated financial statements, which include the consolidation of the PV lessor trusts from which APS leases a portion of PV Unit 2.

**Q. PLEASE DISCUSS SFR SCHEDULE E-5.**

A. SFR Schedule E-5 is a detailed statement of utility plant included in the Company's Rate Base, broken down by FERC account under the Uniform System of Accounts. The first page of SFR Schedule E-5 is a summary of gross plant in service, accumulated depreciation and amortization, nuclear fuel,

construction work in progress, and plant held for future use. The remainder of the schedule presents supporting detail for each FERC plant account.

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

A. SFR Schedule E-7 provides detailed information concerning APS's sales (in kWh), average number of customers, average kWh usage per customer, and average annual revenue per residential customer over the last three years, including the Test Year. This information is contained in or derived from APS's FERC Form 1 filings for the applicable periods. The information in SFR Schedule E-7 is separated by customer classes to show residential, commercial, industrial, irrigation, public street and highway lighting, other sales to public authorities, and sales for resale.

**Q. PLEASE DISCUSS SFR SCHEDULE E-8.**

A. SFR Schedule E-8 provides a breakdown of APS's tax expense incurred during the Test Year and the two prior calendar years for federal and state taxes.

**Q. PLEASE DISCUSS SFR SCHEDULE E-9.**

A. SFR Schedule E-9 presents the Company's SEC financial statements, including the footnotes, as filed with the Company's Form 10-K for 2010. The footnotes include, but are not limited to, the Company's accounting policies for depreciation, capitalized interest and income taxes. The footnotes also provide additional detailed information related to the income statements, the balance sheets and statements of cash flows.

F. *Projections and Forecasts*

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

A. SFR Schedule F-1 presents income statements for projected calendar years, compared with actual Test Year results, at present and proposed rates. SFR Schedule F-2 shows projected changes in the financial position of the Company for future calendar years compared with the Test Year, at present and proposed

rates. I am sponsoring the historical Test Year data in the first column of each of these SFR Schedules. Mr. Hatfield will address the projected data on these same schedules.

**Q. PLEASE DISCUSS SFR SCHEDULE F-3.**

A. SFR Schedule F-3 presents projected annual construction expenditure requirements, by property classification, for three years subsequent to the Test Year. I am sponsoring the actual Test Year information. Again, Mr. Hatfield will address the projected data on this schedule.

## IV. PRO FORMA ADJUSTMENTS TO TEST YEAR

### A. *Types of Pro Forma Adjustments*

**Q. WHAT ARE PRO FORMA ADJUSTMENTS?**

A. Pro forma adjustments are adjustments made to a historical test year to reflect conditions during the period in which rates are to be in effect. Because the Company has used a historical test year, it is necessary to adjust recorded revenues and expenses for known and measurable changes. Pro forma adjustments commonly include normalizations, annualizations and out-of-period adjustments. All of the pro forma adjustments discussed in my testimony reflect Total Company amounts prior to any jurisdictional allocation and are reflected on either SFR Schedule B-2 or SFR Schedule C-2.

**Q. WHAT ARE "NORMALIZATIONS"?**

A. Normalization adjustments compensate or adjust for unusual levels of operations experienced during the Test Year period. These adjustments generally relate to items that are abnormal in amount or nonrecurring in nature and are made to better reflect what is believed to be an ongoing level of operations.

**Q. WHAT ARE "ANNUALIZATIONS"?**

A. Annualization adjustments recognize that some events occurring during the test period are ongoing and must be adjusted to reflect their impact over an entire

twelve-month period. One example of an annualization is for the payroll increases that happen during the Test Year. Since payroll costs will be higher on an ongoing basis than what was recorded during the Test Year, an adjustment must be made to reflect the prospective level of costs.

**Q. WHAT IS AN "OUT-OF-PERIOD" ADJUSTMENT?**

A. Out-of-period adjustments remove expenses or revenues properly recorded during the Test Year, but which are associated with operations from another year.

B. *Pro Forma Adjustment Descriptions*

1. Remove Bark Beetle Remediation Amortization.

**Q. PLEASE DESCRIBE THIS ADJUSTMENT.**

A. Decision No. 69663 (June 28, 2007) ordered amortization of these previously deferred costs over a three-year period beginning July 1, 2007. The total deferral balance at June 30, 2007 was $11,508,000, resulting in an annual amortization of $3,836,000. APS completed the recovery of these previously deferred costs on June 30, 2010. Because the Test Year contains amortization from January 1, 2010 through June 30, 2010 (6 months), a pro forma is necessary to remove the 6 months of amortization. This results in an increase to pre-tax operating income of $1,918,000 (*see* Attachment JCL-1 and SFR Schedule C-2, page 1, column 1).

2. Remove Test Year Surcharges.

**Q. PLEASE EXPLAIN THE ADJUSTMENT FOR SURCHARGES AND ADJUSTORS.**

A. The adjustment is made to exclude from revenue and expense the amounts collected during the Test Year under surcharges and adjustors outside of base rates; specifically, the Renewable Energy Surcharge ("RES"), Competition Rules Compliance Charge ("CRCC"), Demand Side Management Adjustment Charge ("DSMAC"), Transmission Cost Adjustment ("TCA") and Regulatory Assessment charges. These items are not collected as part of base rates, so they must be excluded from Test Year revenue in order to calculate new base rates.

The pro forma also removes from expense the associated costs incurred. This results in a reduction to pre-tax operating income of $7,307,000 (*see* Attachment JCL-2 and SFR Schedule C-2, page 1, column 2).

APS witness Pete Ewen sponsors the Power Supply Adjustor ("PSA") pro forma in his testimony.

3. West Phoenix Unit 4 Regulatory Disallowance.

**Q. PLEASE EXPLAIN THE RATE BASE PRO FORMA ADJUSTMENT FOR THE WEST PHOENIX UNIT 4 REGULATORY DISALLOWANCE.**

A. This disallowance was recorded for regulatory purposes, but did not qualify as a disallowance for GAAP purposes. Consequently, a pro forma adjustment is needed to reduce Rate Base by the disallowed amount. Accordingly, the Rate Base reduction for the West Phoenix Unit 4 regulatory disallowance at December 31, 2010 is $8,729,000 (*see* Attachment JCL-3 and SFR Schedule B-2, page 1, column 2).

**Q. IS THERE A CORRESPONDING OPERATING INCOME ADJUSTMENT FOR THE DEPRECIATION EXPENSE RELATED TO THE WEST PHOENIX UNIT 4 REGULATORY DISALLOWANCE?**

A. Yes. The operating income pro forma reflects an annual reduction in depreciation expense. This results in an increase to pre-tax operating income of $329,000 (*see* Attachment JCL-4 and SFR Schedule C-2, page 1, column 3).

4. Include Interest Expense on Customer Deposits.

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

A. This pro forma adjustment reflects the annualized interest cost associated with customer deposits as an operating expense. This treatment conforms to the approach utilized by the Commission in the Company's previous rate cases. This adjustment was calculated by applying the 0.29 percent annual 2011 interest rate to the December 31, 2010 outstanding deposit balance. The annual interest rate is the rate required by APS Schedule 1 for customer deposits – the established one-

year Treasury Constant Maturities rate, effective on the first business day of each year (in this instance, January of 2011), as published on the Federal Reserve website. The result of this pro forma is a reduction to pre-tax operating income of $197,000 (*see* Attachment JCL-5 and SFR Schedule C-2, page 2, column 4).

5. Adjust Depreciation Expense – 2010 Study.

**Q. WHAT ADJUSTMENTS HAS THE COMPANY MADE TO DEPRECIATION AND AMORTIZATION EXPENSE?**

A. For this filing, APS witness Dr. Ronald White performed a 2010 Depreciation Study using data as of December 31, 2010. Using Dr. White's study, APS has updated depreciation rates from the rates authorized in Decision No. 71448 (December 30, 2009). APS is asking Commission approval of these depreciation rates in this proceeding. Please refer to Dr. White's testimony for further discussion. This pro forma adjustment reduces depreciation expense and thus results in an increase to pre-tax operating income of $28,646,000 (*see* Attachments JCL-6 and SFR Schedule C-2, page 2, column 5).

**Q. IS THE COMPANY PROPOSING ANY CHANGES TO ITS EXISTING AMORTIZATION RATES?**

A. No. APS is not requesting any change to the amortization rates authorized in Decision No. 71448.

6. Adjust for Post-Test Year Plant Additions.

**Q. WHAT ADJUSTMENTS HAS THE COMPANY MADE TO ACCOUNT FOR POST-TEST YEAR PLANT ADDITIONS?**

A. APS witnesses Jeff Guldner (Vice President of Rates and Regulation), Daniel Froetscher (Vice President of Energy Delivery), Mark Schiavoni (Senior Vice President of Fossil Generation), and Randy Edington (Executive Vice President and Chief Nuclear Officer) address the details of the Company's capital investments in their respective testimonies. The Company is proposing to include plant additions that go into service after the Test Year, but before new base rates

are expected to be in effect. My testimony covers the mechanics of the pro formas, as discussed below:

**Step 1**: Construction Work in Progress ("CWIP") is extracted from the general ledger as of December 31, 2010 for non-transmission plant that is expected to go into service prior to July 1, 2012 (the proposed effective date for new rates);

**Step 2**: The forecast plant in service cost of each project that is expected to go into service prior to July 1, 2012 was compiled (both projects in CWIP at December 31, 2010 and projects that begin after December 31, 2010);

**Step 3**: The plant was classified by functional area: solar generation, fossil generation, nuclear generation; and distribution, general and intangible plant;

**Step 4**: Annual accumulated depreciation and amortization, net accumulated deferred income taxes and tax credits (where applicable) on pre-existing plant in service were offset against the post-Test Year plant additions adjustment;

**Step 5**: The sum of the forecast plant in service costs, less accumulated depreciation and net deferred income taxes is, presented by functional unit and included in the Rate Base pro forma adjustments that increases Rate Base at December 31, 2010 by $432,249,000 (See Attachment JCL-7 and SFR Schedule B-2, pages 1 and 2, columns 3-6);

**Step 6**: Operations and Maintenance costs ("O&M"), property and income taxes, and depreciation expenses were calculated and reflected as a

reduction to pre-tax operating income of $41,560,000 (See Attachment JCL-8 and SFR Schedule C-2, pages 2 and 3, columns 6-9).

APS will true-up this adjustment with actual plant placed in service, net of retirements, as necessary throughout the case.

7. Decommissioning and Spent Fuel Costs.

**Q. PLEASE EXPLAIN THE NUCLEAR DECOMMISSIONING FUNDS AND WHAT IS MEANT BY A "QUALIFYING" DECOMMISSIONING FUND.**

A. Like all nuclear power plants, Palo Verde eventually will need to be decommissioned, an expensive and time consuming process. Regulatory agencies throughout the country, including the Commission, have required that the cost of this eventual decommissioning be recovered from electricity customers over the life of the facility.

Most of the amounts collected from ratepayers that relate to decommissioning of a nuclear power plant can be deposited into a "qualified" decommissioning trust. A trust is "qualified" to the extent it meets certain requirements set forth in the Internal Revenue Code and related regulations. A qualified decommissioning trust is afforded significant income tax benefits versus other funding alternatives. This favorable tax treatment is twofold. First, contributions to a qualified decommissioning trust are deductible for federal income tax purposes in the year made to the extent these do not exceed the "ruling amount" approved by the U.S. Secretary of the Treasury in a private letter ruling. The plant owner must request from the Secretary a new schedule of ruling amounts upon each renewal of the operating license of the nuclear power plant. Furthermore, the investment earnings of the assets within the trust are taxed at a federal income tax rate of 20% versus 35% if the investment earnings occurred outside of the qualified trust.

The Nuclear Regulatory Commission ("NRC") and most state regulators prefer the external funding option both because of increased security of the funding for its intended purpose and because of the income tax benefits afforded qualified decommissioning trusts.

**Q. PLEASE EXPLAIN THE NEED FOR A PRO FORMA ADJUSTMENT FOR NUCLEAR DECOMMISSIONING FUNDING AND THE CORRESPONDING EXPENSE.**

A. In Decision No. 71448, APS was ordered, upon the later date of receiving NRC approval for the Palo Verde license extension or January 1, 2012, to file a request to adjust the System Benefit Charge ("SBC") to reflect the reduction in decommissioning funding obligations. The assumed funding periods for Units 1 and 3 have been increased to 2045 and 2047 respectively to reflect the twenty-year license extension approved by the NRC in April 2011. Under the terms of the sale-leaseback, the Palo Verde Unit 2 decommissioning fund is required to be fully funded by the end of the lease, which is 2015.

In addition to the NRC's approval of the license extension, two basic components associated with determining the annual amounts to deposit into the decommissioning fund have changed: earnings assumptions and new decommissioning study cost estimates.

The earnings assumption is used to determine how much the investments will grow between now and the time of decommissioning. APS is proposing to use an after-tax earnings assumption of 4.73% for Palo Verde Units 1 and 3. APS is also proposing to use an after-tax earnings assumption of 3.72% for Palo Verde Unit 2. The assumption for Units 1 and 3 was determined using pre-tax investment return assumptions for fixed income of 5.00% and pre-tax equity returns of 7.25%. Using a 60% stocks and 40% bonds asset allocation and the applicable tax rates for qualifying and non-qualifying funds, a 4.73% after-tax

earnings assumption was calculated. The Unit 2 assumption was also determined using a pre-tax investment return assumption for fixed income of 5.00%. The Company did not assume an equity return for Unit 2 due to the restrictions included in the terms of the sale leaseback agreement, which prohibit Unit 2 from holding equities after January 31, 2010. Therefore, the after-tax earnings assumption for Unit 2 is 3.72%.

Finally, the new decommissioning funding and expense estimates reflect a new study performed by TLG Services, Inc. The decommissioning costs in this study are presented in current year's dollars. An escalation rate of 4% is used to account for the inflation that will occur between now and the time of decommissioning. The escalation rate reflects expected increases in payroll and material costs.

**Q. WHAT IS THE PRO FORMA ADJUSTMENT REQUIRED TO REFLECT NEW LEVELS OF DECOMMISSIONING TRUST FUNDING?**

A. Based on the change in assumptions described above, the new annual level of funding required is $17,249,000. This results in an increase to pre-tax operating income of $7,183,000 (*see* Attachments JCL-9 and SFR Schedule C-2, page 4, column 10).

**Q. IS SPECIFIC COMMISSION ACTION REQUIRED?**

A. Yes. As previously stated, the owner of a nuclear power plant must request a new schedule of ruling amounts upon each renewal of the operating license of the plant from the U.S. Secretary of the Treasury. Treasury Regulation Section 1.468A-3 states that in the private letter ruling process, the applicant has the burden of proving that the proposed schedule of ruling amounts is consistent with the principles of the decommissioning fund provisions, and that it is based on reasonable assumptions. The Regulation goes on to state: "If a public utility commission established or approved the currently applicable rates for the

furnishing or sale by the taxpayer of electricity from the plant, the taxpayer can generally satisfy this burden of proof by demonstrating that the schedule of ruling amounts is calculated using the assumptions used by the public utility commission in its most recent order."

8. Annualize Payroll Expense.

**Q. DID APS ANNUALIZE TEST YEAR PAYROLL?**

A. Yes. This pro forma adjustment decreases Test Year expense mainly as a result of a decrease in employee levels. This pro forma adjustment annualizes the Test Year payroll and payroll tax expense to March 2011 employee and wage levels. It also reflects an estimated 1% increase in union wages that is currently under negotiation. This estimate will be updated to actual once the union negotiations are finalized. This results in an increase to pre-tax operating income of $519,000 (*see* Attachment JCL-10 and SFR Schedule C-2, page 4, column 11).

**Q. DOES THIS TOTAL PAYROLL ADJUSTMENT ONLY AFFECT O&M?**

A. Yes. This adjustment excludes capitalized payroll costs. This O&M adjustment was estimated by calculating the percentage of APS's O&M payroll to total payroll during the Test Year. The pro forma O&M payroll and payroll taxes were allocated to operations and maintenance based on the Test Year payroll amounts recorded for each of these activities.

9. Normalize Employee Benefits.

**Q. PLEASE EXPLAIN THE NEED FOR THE EMPLOYEE BENEFIT PRO FORMA ADJUSTMENT.**

A. This adjustment is necessary to appropriately recognize the costs associated with pension and Other Post-retirement Employee Benefits ("OPEB") plans, which are primarily medical benefits for eligible retirees. This adjustment is consistent with the adjustment recommended by Staff in Decision No. 69663 and used by the Company in Decision No. 71448.

**Q. HOW WAS THE EMPLOYEE BENEFITS PRO FORMA ADJUSTMENT DETERMINED?**

A. The total change in pension and OPEB expense is the difference between the Test Year expense and the 2011 level of that expense, as determined by our actuaries, Towers Watson. As noted below, this calculation resulted in an increase to employee benefits expense.

**Q. HOW DID YOU DETERMINE THE AMOUNT OF INCREASED BENEFITS COSTS PROPERLY ALLOCABLE TO APS'S O&M?**

A. An allocation factor was calculated and applied to the total change in benefit expenses. This allocation factor was determined by comparing APS's 2010 actual O&M employee benefits to the total employee benefit costs for Pinnacle West. This results in a decrease to pre-tax operating income of $8,148,000 (*see* Attachment JCL-11 and SFR Schedule C-2, page 4, column 12).

10. Normalize Income Tax Expense / Interest Synchronization.

**Q. WHAT METHODOLOGY DID YOU USE TO DETERMINE THE FEDERAL AND STATE INCOME TAX PRO FORMA ADJUSTMENT?**

A. The Company used a "top down" approach in computing cost-of-service income tax expense. This calculation, which was also adopted in Decision No. 69663, uses the statutory rate and estimated 2010 levels of various tax credits and other permanent tax items, reflecting the Company's best estimate of on-going income tax expense. It also considers the deduction of interest expense synchronization to the end of the Test Year's Rate Base. The total federal and state income tax pro forma increases income tax expense by $23,762,000 (*see* Attachment JCL-12 and SFR Schedule C-2, page 5, column 13).

11. Annualize Property Tax Expense.

**Q. HAS APS PROPOSED AN ADJUSTMENT TO THE TEST YEAR AD VALOREM (PROPERTY) TAX?**

A. Yes. An adjustment is appropriate to reflect December 31, 2010 plant values, the current state assessment ratios and the most current estimated composite tax rate.

**Q. HOW WERE PROPERTY TAXES CALCULATED?**

A. Property taxes were calculated using December 31, 2010 property values as filed with the Arizona Department of Revenue in April 2011. These property values were then multiplied by the most current approved assessment ratios. Finally, that assessed value is multiplied by the current estimated composite tax rate. APS will update the expected composite tax rate with the actual rate when it becomes available near the end of the third quarter of 2011. This adjustment results in a reduction to pre-tax operating income of $17,971,000 (*see* Attachment JCL-13 and SFR Schedule C-2, page 5, column 14).

12. Annualize Severance Costs.

**Q. DID APS UNDERTAKE ANY PLANS TO REDUCE ITS WORKFORCE IN THE TEST YEAR?**

A. Yes. From January 2010 through March of 2011, APS reduced its employee levels by approximately 260 positions through a non-voluntary severance program.

**Q. HAS APS REFLECTED THE COSTS AND SAVINGS ASSOCIATED WITH THESE REDUCTIONS IN WORKFORCE?**

A. Yes. The first year savings associated with the elimination of these positions will be approximately $23,446,000, of which approximately $11,475,000 will be savings to APS O&M. The remainder will be a reduction to capitalized construction costs and amounts billed to participants in jointly owned facilities.

The cost associated with severing positions through a non-voluntary severance program was approximately $10,099,000. Under GAAP, these expenses were charged to O&M in 2010. For ratemaking purposes however, the Company proposes that these expenses be amortized over a 3-year period for a yearly expense of approximately $3,366,000. This matches the cost of the employee reductions with the on-going savings. Similar amortization was requested in the Company's 2003 rate filing, but was not litigated as the case resulted in a

settlement which was approved under Decision No. 67744 (April 7, 2005). This workforce reduction results in a net increase to pre-tax operating income of $6,732,000 (*see* Attachment JCL-14 and SFR Schedule C-2, page 5, column 15).

**Q. WHERE ARE THE SAVINGS RELATED TO THESE EMPLOYEE REDUCTIONS REFLECTED AS AN ADJUSTMENT TO TEST YEAR EXPENSE?**

A. The Company has adjusted the Test Year as part of the "Annualize Payroll" adjustment to reflect these savings.

**Q. DIDN'T APS ALSO ANNOUNCE REDUCTION IN CONTRACT EMPLOYEES AND THE ELIMINATION OF VACANT POSITIONS?**

A. Yes. Contract employees were used to augment the Company's construction workforce, therefore elimination of these positions impacts post-Test Year capital construction costs but not O&M. The elimination of open positions would likewise not impact Test Year O&M because APS used only on-board employees to determine its adjustment to annualize payroll expense.

13. Amortize Childs-Irving Excess Decommissioning Costs.

**Q. CAN YOU PLEASE DESCRIBE THIS PRO FORMA?**

A. Yes. The decommissioning of the Childs-Irving hydroelectric power plant was completed in December 2010. The estimated cost of decommissioning this plant was collected through prior retail rates. The actual cost of decommissioning this plant was $2,678,000 less than the estimate. This pro forma reflects the Company's proposal to flow this benefit back to retail customers over a three-year period. This results in an increase to pre-tax operating income of $893,000. (*See* Attachment JCL-15 and SFR Schedule C-2, page 6, column 16).

14. Remove Schedule 3 Revenues.

**Q. CAN YOU PLEASE DESCRIBE THE PRO FORMA TO REMOVE SCHEDULE 3 REVENUES?**

A. Yes. Decision No. 71448 authorized APS to record the proceeds from the Company's line extension policy ("Schedule 3") as revenue during the period

from January 1, 2010 through either the earlier of December 31, 2012, or the conclusion of APS's next rate case. Thereafter, the Schedule 3 receipts will be recorded as CIAC unless the Commission orders otherwise. Because Schedule 3 proceeds were revenue in the Test Year but will not be revenue when new rates go into effect, a pro forma is needed to remove the Schedule 3 revenue recorded in the Test Year. This pro forma reduces pre-tax operating income by $18,660,000. (*See* Attachment JCL-16 and SFR Schedule C-2, page 6, column 17).

15. Normalize Fossil and Nuclear Maintenance.

**Q. CAN YOU PLEASE DESCRIBE THE PRO FORMAS TO NORMALIZE NUCLEAR AND FOSSIL MAINTENANCE?**

A. Yes. These pro formas adjust both planned maintenance time and unplanned outage time so that the level of maintenance expense included in the Test Year is consistent with an average year. These adjustments are necessary because outage time at each of the power plants in the Test Year for planned routine maintenance and unplanned forced outages is not indicative of the normal levels of availability. I have adjusted Test Year O&M expenses to normalize maintenance levels for the Company's production plant in service at December 31, 2010. This was done separately for the Company's nuclear facilities and its fossil facilities. The fossil generation maintenance adjustment increases pre-tax operating income by $4,397,000 and the nuclear generation maintenance adjustment decreases pre-tax operating income by $5,383,000. The O&M expense adjustments include the impacts of the outage time normalization for all of the units. (*See* Attachments JCL-17 and JCL-18 and SFR Schedule C-2, pages 6 and 7, columns 18 and 19).

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

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

cycle for the plant type. For example, the Company's coal plants are on a six-year overhaul cycle, which means that each of the coal units should experience a major overhaul once in every six-year period. The nuclear units are on an 18-month refueling cycle. Any single year, such as the Test Year, does not represent the average maintenance time and associated expense levels that can reasonably be expected when rates established in this case will be in effect.

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

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

16. Annualize Four Corners Coal Reclamation Costs.

**Q. CAN YOU PLEASE DESCRIBE THE PRO FORMA TO ANNUALIZE FOUR CORNERS COAL RECLAMATION COSTS?**

A. Yes. This pro forma adjustment for Four Corners coal reclamation annualizes the estimate for final reclamation costs, the costs to account for growth, and the amortization period for Units 4 and 5. The estimate for final reclamation costs was revised based on a study performed by Marston as of August 2010. The estimate was increased due to the higher cost of materials and supplies, the use of dirt instead of ash filler, increased bond premiums, and higher demolition costs. The costs within this recent Marston study were presented on a 2010 dollar basis. Due to the long term nature of these costs, APS escalated the cost estimates for Units 1-3 through September 2012 and for Units 4 and 5 through June 2038. The Company also extended the amortization period for Units 4 and 5 from 2016 to

2038 in anticipation of an extended coal supply agreement with BHP Billiton. This results in a reduction to pre-tax operating income of $6,216,000 (*see* Attachment JCL-19 and SFR Schedule C-2, page 7, column 20).

**Q. HOW WAS THE ESCALATION CALCULATED?**

A. Total estimated costs from the Marston study were used to derive APS's share of Four Corners coal reclamation (in 2010 dollars). The reclamation costs for Units 1-3 are expected to be paid to BHP Billiton (the owner of the coal mine, who is responsible for the physical reclamation of the mine) in the third quarter of 2012 and therefore were inflated using an annual cost inflation rate of 2.5% over 1.75 years to adjust the 2010 dollar basis to the third quarter 2012. The final reclamation costs for Units 1-3 continue to be amortized through June 2016. The reclamation costs for Units 4 and 5 are inflated using an annual rate of 2.5% over 27.5 years to adjust the 2010 dollar basis to second quarter 2038, which is when the Company expects to pay this obligation. The final reclamation costs for Units 4 and 5 are amortized through June 2038.

**Q. WHY IS THE ESCALATION AND AMORTIZATION PERIOD DIFFERENT FOR UNITS 1-3?**

A. Due to the pending purchase of Southern California Edison's share of Units 4 and 5, APS is planning to shut down Units 1-3 if the transaction is consummated. The estimated shut down could occur as early as October 2012 The BHP Billiton coal supply agreement requires the Company to fully fund the final reclamation costs associated with these units prior to shut down. An amortization period this short would cause a significant increase to the amount recovered during this period. Therefore, the Company recommends amortizing the remaining costs over the original amortization period through June, 2016.

17. Adjust Cash Working Capital for Cost of Service Pro Formas.

**Q. CAN YOU PLEASE DESCRIBE THE PRO FORMA TO ADJUST CASH WORKING CAPITAL FOR COST OF SERVICE PRO FORMAS?**

A. Yes. This is a Rate Base pro forma to adjust cash working capital to include the effects of the cost of service pro formas. As discussed earlier in my testimony, the cash working capital on SFR Schedule B-5 includes a cash working capital component determined using a lead/lag study. The expense levels in that study reflect the actual expense in the Test Year. This pro forma adjusts the study to take into consideration the cost of service pro formas which adjust actual Test Year levels of expense. This pro forma decreases Rate Base at December 31, 2010 by $14,220,000 (*see* Attachment JCL-20 and SFR Schedule B-2, page 3, column 7).

**Q. ARE THERE ANY ADDITIONAL IMPACTS OF THIS RATE BASE PRO FORMA?**

A. Yes. Since the Rate Base pro forma affects total Rate Base, there is a corresponding operating income pro forma necessary to reflect the income tax impacts of interest. This pro forma was calculated using the Rate Base adjustment above and the weighted cost of debt. This adjustment increases income tax expense by $165,000 (*see* Attachment JCL-21 and SFR Schedule C-2, page 7, column 21).

18. Remove PWEC Loan Amortization.

**Q. CAN YOU PLEASE DESCRIBE THE PRO FORMA TO REMOVE PWEC LOAN AMORTIZATION?**

A. Yes. Decision No. 65796 (April 4, 2003) authorized APS to issue non-secured debt in an amount up to $500 million and loan the proceeds to PWEC. That decision also required APS to charge PWEC a 2.64 percent interest premium, and defer that premium as long as the loan was outstanding. The loan was outstanding through April 2005 when the loan was repaid. In Decision No. 67744, the Commission ordered the Company to amortize the portion of the

premium deferred through December 31, 2004 over a five year period beginning April 1, 2005. The portion of the premium deferred after December 31, 2004 was ordered to be amortized over a five-year period beginning July 1, 2007. This pro forma removes both amortization amounts from the Test Year, since both will be fully amortized when new rates are expected to go into effect. This results in a reduction to pre-tax operating income of $2,107,000 (*see* Attachment JCL-22 and SFR Schedule C-2, page 8, column 22).

19. Amortize Pension and OPEB Deferral.

**Q. CAN YOU PLEASE DESCRIBE THE PRO FORMA ADJUSTMENT TO AMORTIZE PENSION AND OPEB DEFERRAL?**

A. Yes. Commission Decision No. 71448 allowed the Company to defer for future recovery a portion of its Pension and OPEB costs above or below the Test Year level ($23,949,000 in the prior case) in years 2011 and 2012, subject to the following limitations:

a. In 2011; the deferral cannot exceed the lower of $13,500,000 or 50% of the cost above the Test Year level (any amounts over $27,000,000 cannot be deferred); and

b. In 2012; the deferral cannot exceed $29,000,000 of the cost above Test Year level.

Using the 2011 level of expense as determined by our actuaries, Towers Watson, for both 2011 and 2012 deferral calculations, APS estimates a deferral balance of $26,219,000 at the time new retail rates are expected to go into effect (July 1, 2012). The Company proposes to recover this deferral balance over a three-year period. This adjustment results in a decrease to pre-tax operating income of $8,740,000 (*see* Attachment JCL-23 and SFR Schedule C-2, page 8, column 23).

20. Normalize Pole Attachment Revenues.

**Q. CAN YOU PLEASE DESCRIBE THE PRO FORMA ADJUSTMENT TO NORMALIZE POLE ATTACHMENT REVENUES?**

A. Yes. In April 2011, the U.S. Federal Communications Commission ("FCC") voted to revamp nationwide rules governing how broadband providers can attach their lines to utility poles, with the goal of making it faster and easier to deploy new service in underserved areas.

The FCC voted unanimously for the new pole-attachment rules, which require electric utilities to allow most broadband services to attach lines to poles within 148 days of a request, with a deadline of 178 days for putting wireless broadband antennas on top of utility poles. Pole owners, which also include some telecom providers, would have an extra 60 days for requests involving large numbers of poles.

The new rules also require pole owners to give all broadband providers the same pole attachment rate as other telecom carriers. This has the impact of lowering APS's other revenues, which are an offset to the Company's cost of service. This pro forma adjustment takes into consideration the new rates and lowers pre-tax operating income by $305,000 (*see* Attachment JCL-24 and SFR Schedule C-2, page 8, column 24).

21. Remove Supplemental Executive Retirement Plan Benefits.

**Q. CAN YOU PLEASE DESCRIBE THE PRO FORMA TO REMOVE SUPPLEMENTAL EXECUTIVE RETIREMENT PLAN BENEFITS?**

A. Yes. As discussed by APS witness Jeff Guldner, the Company proposes to remove the Test Year level of expense associated with the Supplemental Executive Retirement Plan Benefits ("SERP"). This results in an increase to pre-tax operating income of $8,492,000 (*see* Attachment JCL-25 and SFR Schedule C-2, page 9, column 25).

22. Remove Stock Compensation.

**Q. CAN YOU PLEASE DESCRIBE THE PRO FORMA TO REMOVE STOCK COMPENSATION?**

A. Yes. Also discussed by APS witness Jeff Guldner, the Company proposes to remove the Test Year level of expense associated with stock compensation. This results in an increase to pre-tax operating income of $12,421,000 (*see* Attachment JCL-26 and SFR Schedule C-2, page 9, column 26).

23. Remove Out of Period and Miscellaneous Items.

**Q. CAN YOU PLEASE DESCRIBE THE PRO FORMA TO REMOVE MISCELLANEOUS AND OUT OF PERIOD ITEMS?**

A. Yes. In any Test Year, there are bound to be some items recorded that relate to periods other than the Test Year, or conversely, items recorded in other time periods that correctly belong in the Test Year. This adjustment, for the sake of simplicity, combines several smaller entries that fit this description. They are shown in aggregate in the pro forma. This adjustment results in a decrease to pre-tax operating income of $7,471,000 (*see* Attachment JCL-27 and SFR Schedule C-2, page 9, column 27).

## V. CONCLUSION

**Q. DO YOU HAVE ANY CONCLUDING REMARKS?**

A. No.

**Q. DOES THIS CONCLUDE YOUR TESTIMONY?**

A. Yes.

**ARIZONA PUBLIC SERVICE COMPANY**
**Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2, page 1, column 1**
**Total Company**
**(Thousands of Dollars)**

**Pro Forma Adjustment:** **Remove Bark Beetle Remediation Amortization**
**Adjustments to Test Year operations to remove 6-months of deferred bark beetle costs as authorized in Decision No. 69663.**

| Line No. | Description | Total Company Amount |
|---|---|---|
| | **Electric Operating Revenues** | |
| 1. | Revenues in base rates | $ - |
| 2. | Surcharge revenue | - |
| 3. | Other electric revenue | - |
| 4. | Total electric operating revenues | - |
| | **Operating Expenses** | |
| 5. | Electric fuel and purchased power | - |
| 6. | Operations and maintenance excluding fuel expenses | (1,918) |
| 7. | Depreciation and amortization | - |
| 8. | Other taxes | - |
| 9. | Total Operating Expenses | (1,918) |
| 10. | **Operating Income (before income tax)** | **1,918** |
| 11. | Current Income Tax Rate - 39.51% | 758 |
| 12. | **Operating Income After Tax** | **$ 1,160** |

**ARIZONA PUBLIC SERVICE COMPANY**
**Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2, page 1, column 2**
**Total Company**
**(Thousands of Dollars)**

**Pro Forma Adjustment:** **Remove Test Year Surcharges and Adjustors**
**Adjustment to Test Year operations to remove the Renewable Energy Standard, Competition Rules Compliance Charge, Demand Side Management Adjustment Clause, Transmission Cost Adjustor and Regulatory Assessment surcharges from both operating revenues and expenses.**

| Line No. | Description | Total Company Amount |
|---|---|---|
| | **Electric Operating Revenues** | |
| 1. | Revenues in base rates | $ - |
| 2. | Surcharge revenue | (192,761) |
| 3. | Other electric revenue | - |
| 4. | Total electric operating revenues | (192,761) |
| | **Operating Expenses** | |
| 5. | Electric fuel and purchased power | (8,201) |
| 6. | Operations and maintenance excluding fuel expenses | (177,253) |
| 7. | Depreciation and amortization | - |
| 8. | Other taxes | - |
| 9. | Total Operating Expenses | (185,454) |
| 10. | **Operating Income (before income tax)** | **(7,307)** |
| 11. | Current Income Tax Rate - 39.51% | (2,887) |
| 12. | **Operating Income After Tax** | **$ (4,420)** |

**ARIZONA PUBLIC SERVICE COMPANY**
**Detail of Pro Forma Adjustments to Original Cost Rate Base as Shown on Schedule B-2, page 1, column 2**
**Total Company**
**(Thousands of Dollars)**

**Proforma Adjustment:** **West Phoenix Unit 4 Regulatory Disallowance**
**Adjustment to reduce Test Year rate base for regulatory disallowance for West Phoenix Unit 4 as required in Decision Nos. 67744 and 69663.**

| Line No. | Description | Total Company Amount |
|---|---|---|
| 1. | Gross Utility Plant in Service | $ (13,833) |
| 2. | Less: Accumulated Depreciation and Amortization | (3,635) |
| 3. | Net Utility Plant in Service | (10,198) |
| 4. | Less:Total Deductions | (1,469) |
| 5. | Total Additions | - |
| 6. | **Total Rate Base** | **$ (8,729)** |

**ARIZONA PUBLIC SERVICE COMPANY**
**Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2, page 1, column 3**
**Total Company**
**(Thousands of Dollars)**

**Pro Forma Adjustment:** **West Phoenix Unit 4 Regulatory Disallowance**
**Adjustments to Test Year operations to reflect depreciation of regulatory disallowance of West Phoenix Unit 4.**

| Line No. | Description | Total Company Amount |
|---|---|---|
| | **Electric Operating Revenues** | |
| 1. | Revenues in base rates | $ - |
| 2. | Surcharge revenue | - |
| 3. | Other electric revenue | - |
| 4. | Total electric operating revenues | - |
| | **Operating Expenses** | |
| 5. | Electric fuel and purchased power | - |
| 6. | Operations and maintenance excluding fuel expenses | - |
| 7. | Depreciation and amortization | (329) |
| 8. | Other taxes | - |
| 9. | Total Operating Expenses | (329) |
| 10. | **Operating Income (before income tax)** | **329** |
| 11. | Interest Expense | (257) |
| 12. | Taxable Income | 586 |
| 13. | Current Income Tax Rate - 39.51% | 232 |
| 14. | **Operating Income After Tax** | **$ 97** |

**ARIZONA PUBLIC SERVICE COMPANY**
**Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2, page 2, column 4**
**Total Company**
**(Thousands of Dollars)**

**Pro Forma Adjustment:** **Interest Expense on Customer Deposits**
**Adjustment to Test Year operations to reflect the operating income impact of interest on customer deposits using January 2011 interest rates.**

| Line No. | Description | Total Company Amount |
|---|---|---|
| | **Electric Operating Revenues** | |
| 1. | Revenues in base rates | $ - |
| 2. | Surcharge revenue | - |
| 3. | Other electric revenue | - |
| 4. | Total electric operating revenues | - |
| | **Operating Expenses** | |
| 5. | Electric fuel and purchased power | - |
| 6. | Operations and maintenance excluding fuel expenses | 197 |
| 7. | Depreciation and amortization | - |
| 8. | Other taxes | - |
| 9. | Total Operating Expenses | 197 |
| 10. | **Operating Income (before income tax)** | **(197)** |
| 11. | Current Income Tax Rate - 39.51% | (78) |
| 12. | **Operating Income After Tax** | **$ (119)** |

**ARIZONA PUBLIC SERVICE COMPANY**
**Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2, page 2, column 5**
**Total Company**
**(Thousands of Dollars)**

**Pro Forma Adjustment:** **Depreciation Expense - 2010 Study**
**Adjustment to Test Year operations to reflect depreciation expense based on the 2010 depreciation study.**

| Line No. | Description | Total Company Amount |
|---|---|---|
| | **Electric Operating Revenues** | |
| 1. | Revenues in base rates | $ - |
| 2. | Surcharge revenue | - |
| 3. | Other electric revenue | - |
| 4. | Total electric operating revenues | - |
| | **Operating Expenses** | |
| 5. | Electric fuel and purchased power | - |
| 6. | Operations and maintenance excluding fuel expenses | - |
| 7. | Depreciation and amortization | 28,646 |
| 8. | Other taxes | - |
| 9. | Total Operating Expenses | 28,646 |
| 10. | **Operating Income (before income tax)** | **(28,646)** |
| 11. | Current Income Tax Rate - 39.51% | (11,318) |
| 12. | **Operating Income After Tax** | **$ (17,328)** |

**ARIZONA PUBLIC SERVICE COMPANY**
**Detail of Pro Forma Adjustments to Original Cost Rate Base as Shown on Schedule B-2, pages 1 and 2, columns 3-6**
**Total Company**
**(Thousands of Dollars)**

**Pro forma Adjustment:** **Post-Test Year Plant Additions**
**Adjustment to Test Year rate base to include Post Test Year Plant Additions with an estimated in service date prior to 6/30/2012.**

| Line No. | Description | Solar Generation | Fossil Generation | Nuclear Generation | Distribution and General and Intangible | Total Company Amount |
|---|---|---|---|---|---|---|
| 1. | Gross Utility Plant in Service | $ 277,411 | $ 156,269 | $ 120,103 | $ 432,984 | $ 986,767 |
| 2. | Less: Accumulated Depreciation and Amortization | 5,799 | 133,240 | 95,937 | 269,239 | 504,215 |
| 3. | Net Utility Plant in Service | 271,612 | 23,029 | 24,166 | 163,745 | 482,552 |
| 4. | Less: Total Deductions | 3,979 | 12,583 | 29,329 | 4,412 | 50,303 |
| 5. | Total Additions | - | | | | - |
| 6. | **Total Rate Base** | **$ 267,633** | **$ 10,446** | **$ (5,163)** | **$ 159,333** | **$ 432,249** |

**ARIZONA PUBLIC SERVICE COMPANY**
**Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2, pages 2 and 3, columns 6-9**
**Total Company**
**(Thousands of Dollars)**

**Pro Forma Adjustment:** **Post-Test Year Plant Additions**
**Adjustment to Test Year operations to include depreciation, interest expense and property taxes associated with Post-Test Year Plant Additions.**

| Line No. | Description | Solar Generation | Fossil Generation | Nuclear Generation | Distribution and General and Intangible | Total Company Amount |
|---|---|---|---|---|---|---|
| | **Electric Operating Revenues** | | | | | |
| 1. | Revenues in base rates | $ - | $ - | $ - | $ - | $ - |
| 2. | Surcharge revenue | - | - | - | - | - |
| 3. | Other electric revenue | - | - | - | - | - |
| 4. | Total electric operating revenues | - | - | - | - | - |
| | **Operating Expenses** | | | | | |
| 5. | Electric fuel and purchased power | - | - | - | - | - |
| 6. | Operations and maintenance excluding fuel expenses | 1,785 | - | - | - | 1,785 |
| 7. | Depreciation and amortization | 9,405 | 4,245 | 1,729 | 13,847 | 29,226 |
| 8. | Administrative and General | 217 | - | - | - | 217 |
| 9. | Other taxes | 978 | 950 | 735 | 7,669 | 10,332 |
| 10. | Total Operating Expenses | 12,385 | 5,195 | 2,464 | 21,516 | 41,560 |
| 11. | **Operating Income (before income tax)** | **(12,385)** | **(5,195)** | **(2,464)** | **(21,516)** | **(41,560)** |
| 12. | Interest Expense | 7,868 | 307 | (152) | 4,684 | 12,707 |
| 13. | Taxable Income | (20,253) | (5,502) | (2,312) | (26,200) | (54,267) |
| 14. | Current Income Tax Rate - 39.51% | (8,002) | (2,174) | (913) | (10,352) | (21,441) |
| 15. | **Operating Income After Tax** | **$ (4,383)** | **$ (3,021)** | **$ (1,551)** | **$ (11,164)** | **$ (20,119)** |

**ARIZONA PUBLIC SERVICE COMPANY**
**Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2, page 4, column 10**
**Total Company**
**(Thousands of Dollars)**

**Pro Forma Adjustment:** **Decommissioning and Spent Fuel Costs**
**Adjustment to Test Year operations to reflect udated decommissioning and spent fuel funding levels for Palo Verde due to license extension and updated study costs.**

| Line No. | Description | Total Company Amount |
|---|---|---|
| | **Electric Operating Revenues** | |
| 1. | Revenues in base rates | $ - |
| 2. | Surcharge revenue | - |
| 3. | Other electric revenue | - |
| 4. | Total electric operating revenues | - |
| | **Operating Expenses** | |
| 5. | Electric fuel and purchased power | (4,236) |
| 6. | Operations and maintenance excluding fuel expenses | - |
| 7. | Depreciation and amortization | (2,947) |
| 8. | Other taxes | - |
| 9. | Total Operating Expenses | (7,183) |
| 10. | **Operating Income (before income tax)** | **7,183** |
| 11. | Current Income Tax Rate - 39.51% | 2,838 |
| 12. | **Operating Income After Tax** | **$ 4,345** |

**ARIZONA PUBLIC SERVICE COMPANY**
**Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2, page 4, column 11**
**Total Company**
**(Thousands of Dollars)**

**Pro Forma Adjustment:** **Annualize Payroll Expense**
**Adjustment to Test Year operations to reflect the annualization of payroll, payroll tax and non-retirement benefit expenses to March 2011 employee levels for performance review and Union employees.**

| Line No. | Description | Total Company Amount |
|---|---|---|
| | **Electric Operating Revenues** | |
| 1. | Revenues in base rates | $ - |
| 2. | Surcharge revenue | - |
| 3. | Other electric revenue | - |
| 4. | Total electric operating revenues | - |
| 5. | | |
| | **Operating Expenses** | |
| 5. | Electric fuel and purchased power | - |
| 6. | Operations and maintenance excluding fuel expenses | (519) |
| 7. | Depreciation and amortization | - |
| 8. | Other taxes | - |
| 9. | Total Operating Expenses | (519) |
| 10. | **Operating Income (before income tax)** | **519** |
| 11. | Current Income Tax Rate - 39.51% | 205 |
| 12. | **Operating Income After Tax** | **$ 314** |

**ARIZONA PUBLIC SERVICE COMPANY**
**Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2, page 4, column 12**
**Total Company**
**(Thousands of Dollars)**

**Pro Forma Adjustment:** **Normalize Employee Benefits**
**Adjustment to Test Year operations to reflect the current December 2010 actuarial valuation of retirement program expenses.**

| Line No. | Description | Total Company Amount |
|---|---|---|
| | **Electric Operating Revenues** | |
| 1. | Revenues in base rates | $ - |
| 2. | Surcharge revenue | - |
| 3. | Other electric revenue | - |
| 4. | Total electric operating revenues | - |
| | **Operating Expenses** | |
| 5. | Electric fuel and purchased power | - |
| 6. | Operations and maintenance excluding fuel expenses | 8,148 |
| 7. | Depreciation and amortization | - |
| 8. | Other taxes | - |
| 9. | Total Operating Expenses | 8,148 |
| 10. | **Operating Income (before income tax)** | **(8,148)** |
| 11. | Current Income Tax Rate - 39.51% | (3,219) |
| 12. | **Operating Income After Tax** | **$ (4,929)** |

**ARIZONA PUBLIC SERVICE COMPANY**
**Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2, page 5, column 13**
**Total Company**
**(Thousands of Dollars)**

**Pro Forma Adjustment:** **Normalize Income Tax Expense/Interest Synchronization**
**Adjustment to Test Year operations for top down income tax true-ups consistent with Decision Nos. 69663 and 71448 using the 12/31/2010 rate base and cost of long-term debt. Tax true-ups are reflected as interest in this adjustment.**

| Line No. | Description | Total Company Amount |
|---|---|---|
| 1. | Operating Income | $ - |
| 2. | Interest and Other Net Deductions | (60,142) |
| 3. | **Taxable Income** | **60,142** |
| 4. | **Income Tax @ 39.51%** | **23,762** |
| 5. | Deferred Tax | - |
| 6. | **Net Income** | **$ (23,762)** |

**ARIZONA PUBLIC SERVICE COMPANY**
**Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2, page 5, column 14**
**Total Company**
**(Thousands of Dollars)**

**Pro Forma Adjustment:** **Annualize Property Tax Expense**
**Adjustment to Test Year operations to annualize property taxes calculated using the 2011 anticipated tax assessment ratio and tax rate.**

| Line No. | Description | Total Company Amount |
|---|---|---|
| | **Electric Operating Revenues** | |
| 1. | Revenues in base rates | $ - |
| 2. | Surcharge revenue | - |
| 3. | Other electric revenue | - |
| 4. | Total electric operating revenues | - |
| | **Operating Expenses** | |
| 5. | Electric fuel and purchased power | - |
| 6. | Operations and maintenance excluding fuel expenses | - |
| 7. | Depreciation and amortization | - |
| 8. | Other taxes | 17,971 |
| 9. | Total Operating Expenses | 17,971 |
| 10. | **Operating Income (before income tax)** | **(17,971)** |
| 11. | Current Income Tax Rate - 39.51% | (7,100) |
| 12. | **Operating Income After Tax** | **$ (10,871)** |

**ARIZONA PUBLIC SERVICE COMPANY**
**Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2, page 5, column 15**
**Total Company**
**(Thousands of Dollars)**

**Pro Forma Adjustment:** **Annualize Severance Costs**
**Adjustment to Test Year operations to amortize the expense associated with employees severed in 2010 over a three year period.**

| Line No. | Description | Total Company Amount |
|---|---|---|
| | **Electric Operating Revenues** | |
| 1. | Revenues in base rates | $ - |
| 2. | Surcharge revenue | - |
| 3. | Other electric revenue | - |
| 4. | Total electric operating revenues | - |
| | **Operating Expenses** | |
| 5. | Electric fuel and purchased power | - |
| 6. | Operations and maintenance excluding fuel expenses | (6,732) |
| 7. | Depreciation and amortization | - |
| 8. | Other taxes | - |
| 9. | Total Operating Expenses | (6,732) |
| 10. | **Operating Income (before income tax)** | **6,732** |
| 11. | Current Income Tax Rate - 39.51% | 2,660 |
| 12. | **Operating Income After Tax** | **$ 4,072** |

**ARIZONA PUBLIC SERVICE COMPANY**
**Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2, page 6, column 16**
**Total Company**
**(Thousands of Dollars)**

**Pro Forma Adjustment: Amortize Childs-Irving Excess Decommissioning Costs**
**Adjustment to amortize the excess decommissioning costs for the Childs Irving Power Plant over a three year period.**

| Line No. | Description | Total Company Amount |
|---|---|---|
| | **Electric Operating Revenues** | |
| 1. | Revenues in base rates | $ - |
| 2. | Surcharge revenue | - |
| 3. | Other electric revenue | - |
| 4. | Total electric operating revenues | - |
| | **Operating Expenses** | |
| 5. | Electric fuel and purchased power | - |
| 6. | Operations and maintenance excluding fuel expenses | - |
| 7. | Depreciation and amortization | (893) |
| 8. | Other taxes | - |
| 9. | Total Operating Expenses | (893) |
| 10. | **Operating Income (before income tax)** | **893** |
| 11. | Current Income Tax Rate - 39.51% | 353 |
| 12. | **Operating Income After Tax** | **$ 540** |

**ARIZONA PUBLIC SERVICE COMPANY**
**Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2, page 6, column 17**
**Total Company**
**(Thousands of Dollars)**

**Pro Forma Adjustment:** **Remove Schedule 3 Revenues**
**Adjustment to remove revenues associated with Schedule 3 (line extensation policy) in the Test Year.**

| Line No. | Description | Total Company Amount |
|---|---|---|
| | **Electric Operating Revenues** | |
| 1. | Revenues in base rates | $ - |
| 2. | Surcharge revenue | - |
| 3. | Other electric revenue | (18,660) |
| 4. | Total electric operating revenues | (18,660) |
| | **Operating Expenses** | |
| 5. | Electric fuel and purchased power | - |
| 6. | Operations and maintenance excluding fuel expenses | - |
| 7. | Depreciation and amortization | - |
| 8. | Other taxes | - |
| 9. | Total Operating Expenses | - |
| 10. | **Operating Income (before income tax)** | **(18,660)** |
| 11. | Current Income Tax Rate - 39.51% | (7,373) |
| 12. | **Operating Income After Tax** | **$ (11,287)** |

**ARIZONA PUBLIC SERVICE COMPANY**
**Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2, page 6, column 18**
**Total Company**
**(Thousands of Dollars)**

**Pro Forma Adjustment:** **Normalize Fossil Maintenance**
**Adjustment to Test Year operations to reflect normalization of fossil production maintenance expense.**

| Line No. | Description | Total Company Amount |
|---|---|---|
| | **Electric Operating Revenues** | |
| 1. | Revenues in base rates | $ - |
| 2. | Surcharge revenue | - |
| 3. | Other electric revenue | - |
| 4. | Total electric operating revenues | - |
| | **Operating Expenses** | |
| 5. | Electric fuel and purchased power | - |
| 6. | Operations and maintenance excluding fuel expenses | (4,397) |
| 7. | Depreciation and amortization | - |
| 8. | Other taxes | - |
| 9. | Total Operating Expenses | (4,397) |
| 10. | **Operating Income (before income tax)** | **4,397** |
| 11. | Current Income Tax Rate - 39.51% | 1,737 |
| 12. | **Operating Income After Tax** | **$ 2,660** |

**ARIZONA PUBLIC SERVICE COMPANY**
**Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2, page 7, column 19**
**Total Company**
**(Thousands of Dollars)**

**Pro Forma Adjustment:** **Normalize Nuclear Maintenance**
**Adjustment to Test Year operations to reflect normalization of nuclear production maintenance expense.**

| Line No. | Description | Total Company Amount |
|---|---|---|
| | **Electric Operating Revenues** | |
| 1. | Revenues in base rates | $ - |
| 2. | Surcharge revenue | - |
| 3. | Other electric revenue | - |
| 4. | Total electric operating revenues | - |
| | **Operating Expenses** | |
| 5. | Electric fuel and purchased power | - |
| 6. | Operations and maintenance excluding fuel expenses | 5,383 |
| 7. | Depreciation and amortization | - |
| 8. | Other taxes | - |
| 9. | Total Operating Expenses | 5,383 |
| 10. | **Operating Income (before income tax)** | **(5,383)** |
| 11. | Current Income Tax Rate - 39.51% | (2,127) |
| 12. | **Operating Income After Tax** | **$ (3,256)** |

**ARIZONA PUBLIC SERVICE COMPANY**
**Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2, page 7, column 20**
**Total Company**
**(Thousands of Dollars)**

**Pro Forma Adjustment:** **Annualize Four Corners Coal Reclamation Costs**
**Adjustment to Test Year operations to reflect most recent Four Corners coal reclamation study.**

| Line No. | Description | Total Company Amount |
|---|---|---|
| | **Electric Operating Revenues** | |
| 1. | Revenues in base rates | $ - |
| 2. | Surcharge revenue | - |
| 3. | Other electric revenue | - |
| 4. | Total electric operating revenues | - |
| | **Operating Expenses** | |
| 5. | Electric fuel and purchased power | 6,216 |
| 6. | Operations and maintenance excluding fuel expenses | - |
| 7. | Depreciation and amortization | - |
| 8. | Other taxes | - |
| 9. | Total Operating Expenses | 6,216 |
| 10. | **Operating Income (before income tax)** | **(6,216)** |
| 11. | Current Income Tax Rate - 39.51% | (2,456) |
| 12. | **Operating Income After Tax** | **$ (3,760)** |

**ARIZONA PUBLIC SERVICE COMPANY**
**Detail of Pro Forma Adjustments to Original Cost Rate Base as Shown on Schedule B-2, page 3, column 7**
**Total Company**
**(Thousands of Dollars)**

**Pro forma Adjustment:** **Adjust Cash Working Capital for Cost of Service Pro Formas**
**Adjustment to Cash Working Capital to reflect impacts of cost of service pro formas on the lead/lag study.**

| Line No. | Description | Total Company Amount |
|---|---|---|
| 1. | Gross Utility Plant in Service | $ - |
| 2. | Less: Accumulated Depreciation and Amortization | - |
| 3. | Net Utility Plant in Service | - |
| 4. | Less:Total Deductions | - |
| 5. | Total Additions | (14,220) |
| 6. | **Total Rate Base** | **$ (14,220)** |

**ARIZONA PUBLIC SERVICE COMPANY**
**Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2, page 7, column 21**
**Total Company**
**(Thousands of Dollars)**

**Pro Forma Adjustment:** **Adjust Cash Working Capital for Cost of Service Pro Formas**
**Adjustments to Test Year interest expense for cash working capital rate base pro forma adjustment.**

| Line No. | Description | Total Company Amount |
|---|---|---|
| | **Electric Operating Revenues** | |
| 1. | Revenues in base rates | $ - |
| 2. | Surcharge revenue | - |
| 3. | Other electric revenue | - |
| 4. | Total electric operating revenues | - |
| | **Operating Expenses** | |
| 5. | Electric fuel and purchased power | - |
| 6. | Operations and maintenance excluding fuel expenses | - |
| 7. | Depreciation and amortization | |
| 8. | Other taxes | - |
| 9. | Total Operating Expenses | - |
| 10. | **Operating Income (before income tax)** | - |
| 11. | Interest Expense | (418) |
| 12. | Taxable Income | 418 |
| 13. | Current Income Tax Rate - 39.51% | 165 |
| 14. | **Operating Income After Tax** | **$ (165)** |

**ARIZONA PUBLIC SERVICE COMPANY**
**Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2, page 8, column 22**
**Total Company**
**(Thousands of Dollars)**

**Pro Forma Adjustment:** **Remove PWEC Loan Amortization and Interest**
**Adjustment to Test Year operations to remove PWEC loan amortization and interest authorized in Decision Nos. 65796 and 67744.**

| Line No. | Description | Total Company Amount |
|---|---|---|
| | **Electric Operating Revenues** | |
| 1. | Revenues in base rates | $ - |
| 2. | Surcharge revenue | - |
| 3. | Other electric revenue | - |
| 4. | Total electric operating revenues | - |
| | **Operating Expenses** | |
| 5. | Electric fuel and purchased power | - |
| 6. | Operations and maintenance excluding fuel expenses | 2,107 |
| 7. | Depreciation and amortization | - |
| 10. | Other taxes | - |
| 11. | Total Operating Expenses | 2,107 |
| 12. | **Operating Income (before income tax)** | **(2,107)** |
| 13. | Current Income Tax Rate - 39.51% | (832) |
| 14. | **Operating Income After Tax** | **$ (1,275)** |

**ARIZONA PUBLIC SERVICE COMPANY**
**Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2, page 8, column 23**
**Total Company**
**(Thousands of Dollars)**

**Pro Forma Adjustment:** **Amortize Pension/OPEB Deferral**
**Adjustment to Test Year operations to reflect the recovery of the Pension/OPEB deferral authorized in Decision No. 71448 to be amortized over a three year period.**

| Line No. | Description | Total Company Amount |
|---|---|---|
| | **Electric Operating Revenues** | |
| 1. | Revenues in base rates | $ - |
| 2. | Surcharge revenue | - |
| 3. | Other electric revenue | - |
| 4. | Total electric operating revenues | - |
| | **Operating Expenses** | |
| 5. | Electric fuel and purchased power | - |
| 6. | Operations and maintenance excluding fuel expenses | 8,740 |
| 7. | Depreciation and amortization | |
| 8, | Other taxes | - |
| 9, | Total Operating Expenses | 8,740 |
| 10, | **Operating Income (before income tax)** | **(8,740)** |
| 11, | Current Income Tax Rate - 39.51% | (3,453) |
| 12, | **Operating Income After Tax** | **$ (5,287)** |

**ARIZONA PUBLIC SERVICE COMPANY**
**Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2, page 8, column 24**
**Total Company**
**(Thousands of Dollars)**

**Pro Forma Adjustment:** **Normalize Pole Attachment Revenues**
**Adjustment to Test Year Other Electric Revenues to reflect change in FCC rules impacting pole attachment fees.**

| Line No. | Description | Total Company Amount |
|---|---|---|
| | **Revenues** | |
| 1. | Revenues in Base Rates | $ - |
| 2. | Surcharge Revenue | - |
| 3. | Other Electric Revenue | (305) |
| 4. | Total Electric Operating Revenues | (305) |
| | **Other Operating Expenses** | |
| 5. | Electric fuel and purchased power | - |
| 6. | Operations and maintenance excluding fuel expenses | |
| 7. | Depreciation and amortization | |
| 8. | Income taxes | - |
| 9. | Other taxes | |
| 10. | Total Operating Expenses | - |
| 11. | **Operating Income (before income tax)** | **(305)** |
| 12. | Current Income Tax Rate - 39.51% | (121) |
| 13. | **Operating Income After Tax** | **$ (184)** |

**ARIZONA PUBLIC SERVICE COMPANY**
**Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2, page 9, column 25**
**Total Company**
**(Thousands of Dollars)**

**Pro Forma Adjustment:** **Remove Supplemental Executive Retirement Plan Benefits**
**Adjustment to Test Year operations to remove supplemental executive retirement benefits ("SERP").**

| Line No. | Description | Total Company Amount |
|---|---|---|
| | **Electric Operating Revenues** | |
| 1. | Revenues in base rates | $ - |
| 2. | Surcharge revenue | - |
| 3. | Other electric revenue | - |
| 4. | Total electric operating revenues | - |
| | **Operating Expenses** | |
| 5. | Electric fuel and purchased power | - |
| 6. | Operations and maintenance excluding fuel expenses | (8,492) |
| 7. | Depreciation and amortization | |
| 8. | Other taxes | |
| 9. | Total Operating Expenses | (8,492) |
| 10. | **Operating Income (before income tax)** | **8,492** |
| 11. | Current Income Tax Rate - 39.51% | 3,355 |
| 12. | **Operating Income After Tax** | **$ 5,137** |

**ARIZONA PUBLIC SERVICE COMPANY**
**Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2, page 9, column 26**
**Total Company**
**(Thousands of Dollars)**

**Pro Forma Adjustment: Remove Stock Compensation**
**Adjustment to Test Year operations to remove stock compensation.**

| Line No. | Description | Total Company Amount |
|---|---|---|
| | **Electric Operating Revenues** | |
| 1. | Revenues in base rates | $ - |
| 2. | Surcharge revenue | - |
| 3. | Other electric revenue | - |
| 4. | Total electric operating revenues | - |
| | **Operating Expenses** | |
| 5. | Electric fuel and purchased power | - |
| 6. | Operations and maintenance excluding fuel expenses | (12,421) |
| 7. | Depreciation and amortization | |
| 8. | Other taxes | |
| 9. | Total Operating Expenses | (12,421) |
| 10. | **Operating Income (before income tax)** | **12,421** |
| 11. | Current Income Tax Rate - 39.51% | 4,908 |
| 12. | **Operating Income After Tax** | **$ 7,513** |

**ARIZONA PUBLIC SERVICE COMPANY**
**Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2, page 9, column 27**
**Total Company**
**(Thousands of Dollars)**

**Pro Forma Adjustment:** **Remove Miscellaneous and Out of Period Items**
**Adjustment to Test Year operations to remove legal accrual reserve, bad debt reversal accrual, grant reserve, benchmark study costs, branding costs and non-recurring payroll expense.**

| Line No. | Description | Total Company Amount |
|---|---|---|
| | **Electric Operating Revenues** | |
| 1. | Revenues in base rates | $ (7,000) |
| 2. | Surcharge revenue | - |
| 3. | Other electric revenue | - |
| 4. | Total electric operating revenues | (7,000) |
| | **Operating Expenses** | |
| 5. | Electric fuel and purchased power | - |
| 6. | Operations and maintenance excluding fuel expenses | 3,000 |
| 7. | Depreciation and amortization | - |
| 8. | Administrative and General | (2,529) |
| 9. | Other taxes | - |
| 10. | Total Operating Expenses | 471 |
| 11. | **Operating Income (before income tax)** | **(7,471)** |
| 12. | Current Income Tax Rate - 39.51% | (2,952) |
| 13. | **Operating Income After Tax** | **$ (4,519)** |

# DIRECT TESTIMONY
# OF
# DR. RONALD E. WHITE

## ARIZONA PUBLIC SERVICE COMPANY
## DOCKET NO. E-01345A-11-XXXX

June 2011

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**DIRECT TESTIMONY**
**OF**
**DR. RONALD E. WHITE**
**ARIZONA PUBLIC SERVICE COMPANY**
**DOCKET NO. E-01345A-11-XXXX**

**Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A. My name is Ronald E. White. My business address is 17595 S. Tamiami Trail, Suite 212, Fort Myers, Florida 33908.

**Q. WHAT IS YOUR OCCUPATION?**

A. I am Chairman and a Senior Consultant of Foster Associates, Inc.

## I. QUALIFICATIONS

**Q. WOULD YOU BRIEFLY DESCRIBE YOUR EDUCATIONAL TRAINING AND PROFESSIONAL BACKGROUND?**

A. I received a B.S. degree in Engineering Operations and an M.S. degree and Ph.D. (1977) in Engineering Valuation from Iowa State University. I have taught graduate and undergraduate courses in industrial engineering, engineering economics, and engineering valuation at Iowa State University and previously served on the faculty for Depreciation Programs for public utility commissions, companies, and consultants, sponsored by Depreciation Programs, Inc., in cooperation with Western Michigan University. I also conduct courses in depreciation and public utility economics for clients of the firm.

I have prepared and presented a number of papers to professional organizations, committees, and conferences and have published several articles on matters relating to depreciation, valuation and economics. I am a past member of the Board of Directors of the Iowa State Regulatory Conference and an affiliate member of the joint American Gas Association (A.G.A.) – Edison Electric Institute (EEI) Depreciation Accounting Committee, where I previously served as chairman of a standing committee on capital recovery and its effect on corporate economics. I am also a member

of the American Economic Association, the Financial Management Association, the Midwest Finance Association, the Electric Cooperatives Accounting Association (ECAA), and a founding member of the Society of Depreciation Professionals.

**Q. WHAT IS YOUR PROFESSIONAL EXPERIENCE?**

A. I joined the firm of Foster Associates in 1979 as a specialist in depreciation, the economics of capital investment decisions, and cost of capital studies for ratemaking applications. Before joining Foster Associates, I was employed by Northern States Power Company (1968–1979) in various assignments related to finance and treasury activities. As Manager of the Corporate Economics Department, I was responsible for book depreciation studies, studies involving staff assistance from the Corporate Economics Department in evaluating the economics of capital investment decisions, and the development and execution of innovative forms of project financing. As Assistant Treasurer at Northern States, I was responsible for bank relations, cash requirements planning, and short–term borrowings and investments.

**Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE A REGULATORY BODY?**

A. Yes. I have testified in numerous proceedings before administrative and judicial bodies in over thirty jurisdictions, including several appearances in Arizona. I have also testified before the Federal Energy Regulatory Commission, the Federal Power Commission, the Alberta Energy Board, the Ontario Energy Board, and the Securities and Exchange Commission. I have sponsored position statements before the Federal Communications Commission and numerous local franchising authorities in matters relating to the regulation of telephone and cable television. A more detailed description of my professional qualifications is contained in Attachment REW–1.

## II. PURPOSE OF TESTIMONY

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

A. Foster Associates was engaged by Arizona Public Service Company (APS or Company) to conduct a 2011 depreciation rate study for plant subject to the jurisdiction of the Arizona Corporation Commission (ACC). The purpose of my testimony is to sponsor and describe the study conducted by Foster Associates. Depreciation rates currently used by APS were approved by the ACC pursuant to a settlement agreement in Docket No. E–01345A–08–0172. (Decision No. 71448, dated December 30, 2009).

## III. DEVELOPMENT OF DEPRECIATION RATES

**Q. WOULD YOU PLEASE EXPLAIN WHY DEPRECIATION STUDIES ARE NEEDED FOR ACCOUNTING AND RATEMAKING PURPOSES?**

A. The goal of depreciation accounting is to charge to operations a reasonable estimate of the cost of the service potential of an asset (or group of assets) consumed during an accounting interval. A number of depreciation systems have been developed to achieve this objective, most of which employ time as the apportionment base.

Implementation of a time–based (or age–life) system of depreciation accounting requires the estimation of several parameters or statistics related to a plant account. The average service life of a vintage, for example, is a statistic that will not be known with certainty until all units from the original placement have been retired from service. A vintage average service life, therefore, must be estimated initially and periodically revised as indications of the eventual average service life becomes more certain. Future net salvage rates and projection curves, which describe the expected distribution of retirements over time, are also estimated parameters of a depreciation system that are subject to future revisions. Depreciation studies should be conducted periodically to assess the continuing reasonableness of parameters and accrual rates derived from prior estimates.

The need for periodic depreciation studies is also a derivative of the ratemaking process which establishes prices for utility services based on costs. Absent regula-

tion, deficient or excessive depreciation rates will produce no adverse consequence other than a systematic over or understatement of the accounting measurement of earnings. While a continuance of such practices may not comport with the goals of depreciation accounting, the achievement of capital recovery is not dependent upon either the amount or the timing of depreciation expense for an unregulated firm. In the case of a regulated utility, however, recovery of investor–supplied capital is dependent upon allowed revenues, which are in turn dependent upon approved levels of depreciation expense. Periodic reviews of depreciation rates are, therefore, essential to the achievement of timely capital recovery for a regulated utility.

It is also important to recognize that revenue associated with depreciation is a significant source of internally generated funds used to finance plant replacements and new capacity additions. It can be shown that, given the same financing requirements and the same dividend payout ratio, an increase in internal cash generation will accelerate per–share growth in earnings, dividends, and book value over the business life of a firm. Financial theory provides that the marginal cost of external financing will be reduced by these enhanced measurements of financial performance. This is not to suggest that internal cash generation should be substituted for the goals of depreciation accounting. However, the potential for realizing a reduction in the marginal cost of external financing provides an added incentive for conducting periodic depreciation studies and adopting proper depreciation rates.

**Q. WHAT ARE THE PRINCIPAL ACTIVITIES INVOLVED IN CONDUCTING A DEPRECIATION STUDY?**

A. The first step in conducting a depreciation study is the collection of plant accounting data needed to conduct a statistical analysis of past retirement experience. Data are also collected to permit an analysis of the relationship between retirements and realized gross salvage and removal expense. The data collection phase should include a verification of the accuracy of the plant accounting records and a reconciliation of the assembled data to the official plant records of the company.

The next step in a depreciation study is the estimation of service life statistics from an analysis of past retirement experience. The term *life analysis* is used to describe the activities undertaken in this step to obtain a mathematical description of the forces of retirement acting upon a plant category. The mathematical expressions used to describe these forces are known as survival functions or survivor curves.

Life indications obtained from an analysis of past retirement experience are blended with expectations about the future to obtain an appropriate projection life curve. This step, called *life estimation*, is concerned with predicting the expected remaining life of property units still exposed to the forces of retirement. The amount of weight given to the analysis of historical data will depend upon the extent to which past retirement experience is considered descriptive of the future.

An estimate of the net salvage rate applicable to future retirements is usually obtained from an analysis of the gross salvage and removal expense realized in the past. An analysis of past experience (including an examination of trends over time) provides a baseline for estimating future salvage and cost of removal. Consideration, however, should be given to events that may cause deviations from the net salvage realized in the past. Among the factors which should be considered are the age of plant retirements, the portion of retirements that will be reused, changes in the method of removing plant, the type of plant to be retired in the future, inflation expectations, the shape of the projection life curve, and economic conditions that may warrant greater or lesser weight to be given to the net salvage observed in the past.

A comprehensive depreciation study will also include an analysis of the adequacy of the recorded depreciation reserve. The purpose of such an analysis is to compare the current balance in the recorded reserve with the balance required to achieve the goals and objectives of depreciation accounting if the amount and timing of future retirements and net salvage are realized exactly as predicted. The difference between the required (or theoretical) reserve and the recorded reserve provides a measurement of the expected excess or shortfall that will remain in the depreciation reserve if corrective action is not taken to extinguish the reserve imbalance.

Although reserve records are typically maintained by various account classifications, the total reserve for a company is the most important measure of the status of the company's depreciation practices and procedures. Differences between the theoretical reserve and the recorded reserve will arise as a normal occurrence when service lives, dispersion patterns and salvage estimates are adjusted in the course of depreciation reviews. Differences will also arise due to plant accounting activity such as transfers and adjustments, which require an identification of reserves at a different level from that maintained in the accounting system. It is appropriate, therefore, and consistent with group depreciation theory, to periodically redistribute recorded reserves among primary accounts based on the most recent estimates of retirement dispersion and salvage. A redistribution of the recorded reserve will provide an initial reserve balance for each primary account consistent with the estimates of retirement dispersion selected to describe mortality characteristics of the accounts and establish a baseline against which future comparisons can be made.

Finally, parameters estimated from service life and net salvage studies are integrated into an appropriate formulation of an accrual rate based upon a selected depreciation system. Three elements are needed to describe a depreciation system. The sub–elements most widely used in constructing a depreciation system are shown in Table 1.

| Methods | Procedures | Techniques |
|---|---|---|
| Retirement | Total Company | Whole-Life |
| Compound-Interest | Broad Group | Remaining-Life |
| Sinking-Fund | Vintage Group | Probable-Life |
| Straight-Line | Equal-Life Group | |
| Declining Balance | Unit Summation | |
| Sum-of-Years'-Digits | Item | |
| Expensing | | |
| Unit-of-Production | | |
| Net Revenue | | |

**Table 1. Elements of a Depreciation System**

These elements (*i.e.*, method, procedure and technique) can be visualized as three dimensions of a cube in which each face describes a variety of sub–elements

that can be combined to form a system. A depreciation system is therefore formed by selecting a sub–element from each face such that the system contains one method, one procedure and one technique.

## IV. 2011 Depreciation Rate Study

**Q. DID APS PROVIDE FOSTER ASSOCIATES PLANT ACCOUNTING DATA FOR CONDUCTING THE 2011 DEPRECIATION STUDY?**

A. Yes. Service life statistics estimated in this study were derived from plant accounting transactions recorded over the period 1971 through 2010. Detailed accounting transactions were extracted from the Continuing Property Record (CPR) system and assigned transaction codes which describe the nature of the accounting activity. Transaction codes for plant additions, for example, were used to distinguish normal additions from acquisitions, purchases, reimbursements and adjustments. Similar transaction codes were used to distinguish normal retirements from sales, reimbursements, abnormal retirements and adjustments. Transaction codes were also assigned to transfers, capital leases, gross salvage, cost of removal and other accounting activity that should be considered in a depreciation study.

The database used in conducting the 2008 study in Docket No. E–01345A–08–0172.was updated for the current study by appending additional plant and net salvage transactions for activity years 2008–2010 and age distributions of surviving plant at December 31, 2010. The accuracy and completeness of the assembled database was verified for activity years 2008 through 2010 by comparing the beginning plant balance, additions, retirements, transfers and adjustments, and the ending plant balance derived for each activity year to the official plant records of the Company. Activity years prior to 2008 were verified in the 2008 study. Age distributions of surviving plant at December 31, 2010 were reconciled to the CPR.

Reserve transactions recorded over the period 1980–2010 were used in the 2011 study to derive appropriate net salvage rates. Realized net salvage was blended with future net salvage estimates to derive average net salvage rates used in the computation of theoretical reserves.

**Q. DID FOSTER ASSOCIATES CONDUCT STATISTICAL LIFE STUDIES FOR APS PLANT AND EQUIPMENT?**

A. Yes. As discussed in Attachment REW–2, all plant accounts were analyzed using a technique in which first, second and third degree polynomials were fitted to a set of observed retirement ratios. The resulting function can be expressed as a survivorship function, which is numerically integrated to obtain an estimate of the average service life. The smoothed survivorship function is then fitted by a weighted least–squares procedure to the Iowa–curve family to obtain a mathematical description or classification of the dispersion characteristics of the data. Service life indications derived from the statistical analyses were blended with informed judgment and expectations about the future to obtain an appropriate projection life curve for each plant category. Plant accounts classified in Steam, Nuclear and Other Production were identified by unit and treated as life–span categories in the 2011 study.

**Q. DID FOSTER ASSOCIATES CONDUCT A NET SALVAGE ANALYSIS FOR APS PLANT AND EQUIPMENT?**

A. Yes. A five–year moving average analysis of the ratio of realized salvage and removal expense to the associated retirements was used in the 2011 study for transmission, distribution and general plant categories to: a) estimate a realized net salvage rate; b) detect the emergence of historical trends; and c) establish a basis for estimating a future net salvage rate. Cost of removal and salvage opinions obtained from Company personnel were blended with judgment and historical net salvage indications in developing estimates of the future.

Average net salvage rates for all depreciable plant accounts were estimated using direct dollar weighting of historical retirements with the historical net salvage rate, and future retirements (*i.e.*, surviving plant) with the estimated future net salvage rate.

Future net salvage rates for steam production facilities were adjusted and approved in Docket No. E–01345A–05–0816 et al. for estimated terminal dismantlement costs based on costs per kW derived in dismantling studies conducted in 2002

for the Navajo and Four Corners generating stations. This treatment was retained in the 2008 study and approved in Decision No. 71448. APS subsequently retained an independent contractor to develop a cost estimate for the demolition and abatement of the Four Corners Generating Station. The estimated cost at December 31, 2009 for dismantling Four Corners and a cost $40 per kW estimated for all other steam generating stations were used in the current depreciation study to formulate average and future net salvage rates.[1]

**Q. DID FOSTER ASSOCIATES CONDUCT AN ANALYSIS OF RECORDED DEPRECIATION RESERVES?**

A. Yes. Statement C of Attachment REW–2 provides a comparison of APS recorded, computed and redistributed reserves at December 31, 2010. The recorded reserve was $4,209,736,678 or 38.2 percent of the depreciable plant investment. The corresponding computed reserve is $3,367,619,454 or 30.6 percent of the depreciable plant investment. A proportionate amount of the measured reserve imbalance of $842,117,224 will be amortized over the composite weighted–average remaining life of each rate category using the remaining life depreciation rates proposed in this study. Statement D of Attachment REW–2 provides an estimate of the investment and net salvage components of the rebalanced reserves.

**Q. IS FOSTER ASSOCIATES RECOMMENDING A REBALANCING OF DEPRECIATION RESERVES FOR APS?**

A. Yes. It is the opinion of Foster Associates that a redistribution of recorded reserves is again appropriate for APS. Offsetting reserve imbalances attributable to both the passage of time and parameter adjustments recommended in the current study should be realigned among primary accounts to reduce offsetting imbalances and increase depreciation rate stability.

[1] A cost of $39 per kW for Navajo and $40 per kW for all other steam generating stations was approved in Decision No. 71448. An estimated cost of $40 per kW was used for Navajo in the current study to establish consistency with other plant units.

A redistribution of the recorded reserve for depreciable plant was achieved by multiplying the calculated reserve for each primary account within a function (or plant location) by the ratio of the function (or location) total recorded reserves (net of amortizable accounts) to the function (or location) total calculated reserve. The sum of the redistributed reserves within a function (or location) is, therefore, equal to the function (or location) total recorded depreciation reserve before the redistribution. Depreciation reserves for amortizable categories were redistributed by setting the recorded reserves for the proposed amortization accounts equal to the theoretical reserves derived from the proposed amortization periods and distributing the residual imbalances to the remaining depreciable accounts within the appropriate function.

**Q. DID FOSTER ASSOCIATES CONSIDER THE ANTICIPATED PURCHASE OF FOUR CORNERS UNITS 4 & 5 AND THE SUBSEQUENT SHUTDOWN OF UNITS 1–3 IN REBALANCING RESERVES FOR STEAM PRODUCTION PLANTS?**

A. Yes. Rebalanced reserves for Units 1–3 were set equal to computed reserves derived from a 2012 estimated year of shutdown. Estimated dismantlement costs for Units 1–3 were added to the estimated dismantlement costs for Units 4 & 5 and reserves were rebalanced over all steam production units. This treatment marginally increases the unrecovered investment of plant units other than Four Corners and allocates the unrecovered investment of Units 1–3 over the longer estimated average remaining lives of other steam units.

**Q. PLEASE DESCRIBE THE DEPRECIATION SYSTEM CURRENTLY APPROVED BY THE COMMISSION FOR APS.**

A. Current depreciation rates were developed for each primary account using a depreciation system composed of the straight–line method, vintage group procedure, remaining–life technique.

The formulation of an account accrual rate using the currently approved system is given by:

$$\text{Accrual Rate} = \frac{1.0 - \text{Reserve Ratio} - \text{Future Net Salvage Rate}}{\text{Remaining Life}}.$$

A remaining–life rate is equivalent to the sum of a whole–life rate and an amortization of any reserve imbalance over the estimated remaining life of a rate category. Stated as an equation, a remaining–life accrual rate is equivalent to

$$\text{Accrual Rate} = \frac{1.0 - \text{Average Net Salvage}}{\text{Average Life}} + \frac{\text{Computed Reserve} - \text{Recorded Reserve}}{\text{Remaining Life}}$$

where both the computed reserve and the recorded reserve are expressed as ratios to the plant in service.

**Q. IS FOSTER ASSOCIATES RECOMMENDING A CHANGE IN THE DEPRECIATION SYSTEM FOR APS?**

A. No. Depreciation rates recommended in the 2008 study for all depreciable plant categories were derived from a system composed of the straight–line method, vintage group procedure, remaining–life technique. This change in procedure from broad group to vintage group was recommended by Foster Associates (and approved by the ACC) to more nearly achieve the goals and objectives of depreciation accounting.

Depreciation rates recommended in the 2011 study were developed using the currently approved system. It is the opinion of Foster Associates that this system will remain appropriate for APS, provided depreciation studies are conducted periodically and parameters are routinely adjusted to reflect changing operating conditions. Although the emergence of economic factors such as restructuring and performance based regulation may ultimately encourage abandonment of the straight–line method, no attempt was made in the current study to address this concern. It is also the opinion of Foster Associates that amortization accounting currently approved for selected general support asset accounts is consistent with the goals and objectives of depreciation accounting and remains appropriate for these plant categories.

**Q. PLEASE SUMMARIZE THE DEPRECIATION RATES AND ACCRUALS FOSTER ASSOCIATES IS RECOMMENDING FOR APS IN THE 2011 STUDY.**

A. Table 2 provides a summary of the changes in annual rates and accruals resulting from adoption of the parameters and depreciation system recommended in the 2011 depreciation study.

| | Accrual Rate | | | 2011 Annualized Accrual | | |
|---|---|---|---|---|---|---|
| Function | Current | Proposed | Difference | Current | Proposed | Difference |
| A | B | C | D=C-B | E | F | G=F-E |
| Production | | | | | | |
| Steam | 3.35% | 2.84% | -0.51% | $59,943,328 | $50,825,171 | ($9,118,157) |
| Nuclear | 2.77% | 1.44% | -1.33% | 72,235,832 | 37,539,055 | (34,696,777) |
| Other | 3.00% | 2.62% | -0.38% | 43,949,098 | 38,279,711 | (5,669,387) |
| Transmission | 2.27% | 2.40% | 0.13% | 2,337,578 | 2,477,081 | 139,503 |
| Distribution | 2.26% | 2.37% | 0.11% | 104,066,081 | 109,307,181 | 5,241,100 |
| General Plant | 5.25% | 5.90% | 0.65% | 22,836,498 | 25,639,197 | 2,802,699 |
| Total | 2.77% | 2.40% | -0.37% | $305,368,415 | $264,067,396 | ($41,301,019) |

**Table 2. Current and Proposed Rates and Accruals**

Foster Associates is recommending primary account depreciation rates equivalent to a composite rate of 2.40 percent. Depreciation expense is currently accrued at rates that composite to 2.77 percent. The recommended change in the composite depreciation rate is, therefore, a reduction of 0.37 percentage points.

A continued application of current rates would provide annualized depreciation expense of $305,368,415 compared with an annualized expense of $264,067,396 using the rates developed in this study. The proposed 2011 expense reduction is $41,301,019. The computed change in annualized accruals includes a reduction of $62,327,472 attributable to an amortization of a $842,117,224 reserve imbalance. The remaining portion of the change is attributable to adjustments in service life and net salvage statistics recommended in the 2011 study.

**Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

A. Yes, it does.

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# Ronald E. White, Ph.D.

**Education**

1961 - 1964 Valparaiso University
Major: Electrical Engineering

1965 Iowa State University
B.S., Engineering Operations

1968 Iowa State University
M.S., Engineering Valuation
Thesis: The Multivariate Normal Distribution and the Simulated Plant Record Method of Life Analysis

1977 Iowa State University
Ph.D., Engineering Valuation
Minor: Economics
Dissertation: A Comparative Analysis of Various Estimates of the Hazard Rate Associated With the Service Life of Industrial Property

**Employment**

2007 - Present Foster Associates, Inc.
Chairman

1996 - 2007 Foster Associates, Inc.
Executive Vice President

1988 - 1996 Foster Associates, Inc.
Senior Vice President

1979 - 1988 Foster Associates, Inc.
Vice President

1978 - 1979 Northern States Power Company
Assistant Treasurer

1974 - 1978 Northern States Power Company
Manager, Corporate Economics

1972 - 1974 Northern States Power Company
Corporate Economist

1970 - 1972 Iowa State University
Graduate Student and Instructor

1968 - 1970 Northern States Power Company
Valuation Engineer

1965 - 1968 Iowa State University
Graduate Student and Teaching Assistant

**Publications**

*A New Set of Generalized Survivor Tables*, Journal of the Society of Depreciation Professionals, October, 1992.

*The Theory and Practice of Depreciation Accounting Under Public Utility Regulation,* Journal of the Society of Depreciation Professionals, December, 1989.

*Standards for Depreciation Accounting Under Regulated Competition,* paper presented at The Institute for Study of Regulation, Rate Symposium, February, 1985.

*The Economics of Price-Level Depreciation,* paper presented at the Iowa State University Regulatory Conference, May, 1981.

*Depreciation and the Discount Rate for Capital Investment Decisions,* paper presented at the National Communications Forum - National Electronics Conference, October 1979.

*A Computerized Method for Generating a Life Table From the 'h-System' of Survival Functions,* paper presented at the American Gas Association - Edison Electric Institute Depreciation Accounting Committee Meeting, December, 1975.

*The Problem With AFDC is ...,* paper presented at the Iowa State University Conference on Public Utility Valuation and the Rate Making Process, May, 1973.

*The Simulated Plant-Record Method of Life Analysis,* paper presented at the Missouri Public Service Commission Regulatory Information Systems Conference, May, 1971.

*Simulated Plant-Record Survivor Analysis Program (User's Manual),* special report published by Engineering Research Institute, Iowa State University, February, 1971.

*A Test Procedure for the Simulated Plant-Record Method of Life Analysis,* Journal of the American Statistical Association, September, 1970.

*Modeling the Behavior of Property Records,* paper presented at the Iowa State University Conference on Public Utility Valuation and the Rate Making Process, May, 1970.

*A Technique for Simulating the Retirement Experience of Limited-Life Industrial Property,* paper presented at the National Conference of Electric and Gas Utility Accountants, May, 1969.

*How Dependable are Simulated Plant-Record Estimates?,* paper presented at the Iowa State University Conference on Public Utility Valuation and the Rate Making Process, April, 1968.

**Testifying Witness**

Alabama Public Service Commission, Docket No. 18488, General Telephone Company of the Southeast; testimony concerning engineering economy study techniques.

Alabama Public Service Commission, Docket No. 20208, General Telephone Company of the South; testimony concerning the equal-life group procedure and remaining-life technique.

Alberta Energy and Utilities Board, Application No. 1250392, Aquila Networks Canada; rebuttal testimony supporting proposed depreciation rates.

Alberta Energy and Utilities Board, Case No. RE95081, Edmonton Power Inc.; rebuttal evidence concerning appropriate depreciation rates.

Alberta Energy and Utilities Board, 1999/2000 General Tariff Application, Edmonton Power Inc.; direct and rebuttal evidence concerning appropriate depreciation rates.

Arizona Corporation Commission, Docket No. T-01051B-97-0689, U S West Communications, Inc.; testimony concerning appropriate depreciation rates.

Arizona Corporation Commission, Docket No. G-1032A-02-0598, Citizens Communications Company; testimony supporting proposed depreciation rates.

Arizona Corporation Commission, Docket No. E–01345A–08–0172, Arizona Public Service Company; testimony supporting proposed depreciation rates.

Arizona Corporation Commission, Docket No. E–0135A–03–0437, Arizona Public

Service Company; rebuttal testimony supporting net salvage rates.

Arizona Corporation Commission, Docket No. E–01345A–05–0816, Arizona Public Service Company; testimony supporting proposed depreciation rates.

Arizona Corporation Commission, Docket No. G–04204A–06–0463, UNS Gas, Inc.; testimony supporting proposed depreciation rates.

Arizona Corporation Commission, Docket No. E–04204A–06–0783, UNS Electric, Inc.; testimony supporting proposed depreciation rates.

Arizona Corporation Commission, Docket No. E–04204A–09–0206, UNS Electric, Inc, testimony supporting proposed depreciation rates.

Arizona State Board of Equalization, Docket No. 6302-07-2, Arizona Public Service Company; testimony concerning valuation and assessment of contributions in aid of construction.

California Public Utilities Commission, Case Nos. A.92-06-040, 92-06-042, GTE California Incorporated; rebuttal testimony supporting depreciation study techniques.

California Public Utilities Commission. Docket No. GRC A.05–12–002, Pacific Gas and Electric Company; testimony regarding estimation of net salvage rates.

California Public Utilities Commission. Docket No. GRC A.06–12–009/A.06–12–010, San Diego Gas & Electric Company and Southern California Gas Company; testimony regarding estimation of net salvage rates.

Public Utilities Commission of the State of Colorado, Application No. 36883-Reopened. U S WEST Communications; testimony concerning equal-life group procedure.

State of Connecticut Department of Public Utility Control, Docket No. 10–12–02, Yankee Gas Services Company; testimony supporting recommended depreciation rates.

State of Connecticut Department of Public Utility Control, Docket No. 09–12–05, The Connecticut Light and Power Company; testimony supporting recommended depreciation rates.

State of Connecticut Department of Public Utility Control, Docket No. 06–12PH01, Yankee Gas Services Company; testimony supporting recommended depreciation rates.

State of Connecticut Department of Public Utility Control, Docket No. 05–03–17, The Southern Connecticut Gas Company; testimony supporting recommended depreciation rates.

Delaware Public Service Commission, Docket No. 81-8, Diamond State Telephone Company; testimony concerning the amortization of inside wiring.

Delaware Public Service Commission, Docket No. 82-32, Diamond State Telephone Company; testimony concerning the equal-life group procedure and remaining-life technique.

Public Service Commission of the District of Columbia, Formal Case No. 842, District of Columbia Natural Gas; testimony concerning depreciation rates.

Public Service Commission of the District of Columbia, Formal Case No. 1016, Washington Gas Light Company - District of Columbia; testimony supporting proposed depreciation rates.

Public Service Commission of the District of Columbia, Formal Case No. 1054, Washington Gas Light Company - District of Columbia; testimony supporting proposed depreciation rates.

Federal Communications Commission, Prescription of Revised Depreciation Rates for AT&T Communications; statement concerning depreciation, regulation and competition.

Federal Communications Commission, Petition for Modification of FCC Depreciation Prescription Practices for AT&T; statement concerning alignment of depreciation expense used for financial reporting and regulatory purposes.

Federal Communications Commission, Docket No. *99*-117, Bell Atlantic; affidavit concerning revenue requirement and capital recovery implications of omitted plant retirements.

Federal Energy Regulatory Commission, Docket No. ER10-2110-000, ITC Midwest; testimony supporting proposed depreciation rates.

Federal Energy Regulatory Commission, Docket No. ER10-185-000, Michigan Electric Transmission Company; testimony supporting proposed depreciation rates.

Federal Energy Regulatory Commission, Docket No. ER09-1530-000, ITC*Transmission*; testimony supporting proposed depreciation rates.

Federal Energy Regulatory Commission, Docket No. ER95-267-000, New England Power Company; testimony supporting proposed depreciation rates.

Federal Energy Regulatory Commission, Docket No. RP89-248, Mississippi River Transmission Corporation; rebuttal testimony concerning appropriateness of net salvage component in depreciation rates.

Federal Energy Regulatory Commission, Docket No. ER91-565, New England Power Company; testimony supporting proposed depreciation rates.

Federal Energy Regulatory Commission, Docket No. ER78-291, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Federal Energy Regulatory Commission, Docket Nos. RP80-97 and RP81-54, Tennessee Gas Pipeline Company; testimony concerning offshore plant depreciation rates.

Federal Power Commission, Docket No. E-8252, Northern States Power Company; testimony concerning general financial requirements and measurements of financial performance.

Federal Power Commission, Docket No. E-9148, Northern States Power Company; testimony concerning general financial requirements and measurements of financial performance.

Federal Power Commission, Docket No. ER76-818, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Federal Power Commission, Docket No. RP74-80, *Northern* Natural Gas Company; testimony concerning depreciation expense.

Public Utilities Commission of the State of Hawaii, Docket No. 00-0309, The Gas Company; testimony supporting proposed depreciation rates.

Public Utilities Commission of the State of Hawaii, Docket No. 94-0298, GTE Hawaiian Telephone Company Incorporated; testimony concerning the need for shortened service lives and disclosure of asset impairment losses.

Idaho Public Utilities Commission, Case No. U-1002-59, General Telephone Company of the Northwest, Inc.; testimony concerning the remaining-life technique and the equal-life group procedure.

Illinois Commerce Commission, Case No. 04–0476, Illinois Power Company;

testimony supporting proposed depreciation rates.

Illinois Commerce Commission, Docket No. 94-0481, Citizens Utilities Company of Illinois; rebuttal testimony concerning applications of the Simulated Plant-Record method of life analysis.

Iowa State Commerce Commission, Docket No. RPU 82-47, North Central Public Service Company; testimony on depreciation rates.

Iowa State Commerce Commission, Docket No. RPU 84-34, General Telephone Company of the Midwest; testimony concerning the remaining-life technique and the equal-life group procedure.

Iowa State Utilities Board, Docket No. DPU-86-2, Northwestern Bell Telephone Company; testimony concerning capital recovery in competition.

Iowa State Utilities Board, Docket No. RPU-84-7, Northwestern Bell Telephone Company; testimony concerning the deduction of a reserve deficiency from the rate base.

Iowa State Utilities Board, Docket No. DPU-88-6, U S WEST Communications; testimony concerning depreciation subject to refund.

Iowa State Utilities Board, Docket No. RPU-90-9, Central Telephone Company of Iowa; testimony concerning depreciation rates.

Iowa State Utilities Board, Docket No. RPU-93-9, U S WEST Communications; testimony concerning principles of depreciation accounting and abandonment of FASB 71.

Iowa State Utilities Board, Docket No. DPU-96-1, U S WEST Communications; testimony concerning principles of depreciation accounting and abandonment of FASB 71.

Iowa State Utilities Board, Docket No. RPU-05-2, Aquila Networks; testimony supporting recommended depreciation rates.

Kansas Corporation Commission, Docket No. 10–KCPE–415–RTS; Kansas City Power and Light; cross–answering testimony addressing how third–party reimbursements should be recorded and treated in estimating net salvage rates.

Kansas Corporation Commission, Docket No. 04–AQLE–1065–RTS, Aquila Networks – WPE (Kansas); testimony supporting proposed depreciation rates.

Kansas Corporation Commission, Docket No. 03–KGSG–602–RTS, Kansas Gas Service, a Division of ONEOK, Inc.; rebuttal testimony supporting net salvage rates.

Kansas Corporation Commission, Docket No. 06–KGSG–1209–RTS, Kansas Gas Service, a Division of ONEOK, Inc.; testimony supporting proposed depreciation rates.

Kentucky Public Service Commission, Case No. 97-224, Jackson Purchase Electric Cooperative Corporation; rebuttal testimony supporting proposed depreciation rates.

Maryland Public Service Commission, Case No. 8485, Baltimore Gas and Electric Company; testimony supporting proposed depreciation rates.

Maryland Public Service Commission, Case No. 9096, Baltimore Gas and Electric Company; testimony supporting proposed depreciation rates.

Maryland Public Service Commission, Case No. 7689, Washington Gas Light Company; testimony concerning life analysis and net salvage.

Maryland Public Service Commission, Case No. 8960, Washington Gas Light

Company; testimony supporting proposed depreciation rates.

Maryland Public Service Commission, Case No. 9103, Washington Gas Light Company; rebuttal testimony supporting proposed depreciation rates.

Commonwealth of Massachusetts Department of Public Utilities, D.P.U. 10–70, Western Massachusetts Electric Company; testimony supporting proposed depreciation rates.

Commonwealth of Massachusetts Department of Telecommunications and Energy, D.T.E. 06–55, Western Massachusetts Electric Company; testimony supporting proposed depreciation rates.

Massachusetts Department of Public Utilities, Case No. DPU 91-52, Massachusetts Electric Company; testimony supporting proposed depreciation rates which include a net salvage component.

Michigan Public Service Commission, Case No. U–16117, The Detroit Edison Company; testimony supporting proposed depreciation rates.

Michigan Public Service Commission, Case No. U–15699, Michigan Consolidated Gas Company; testimony supporting proposed depreciation rates.

Michigan Public Service Commission, Case No. U–13899, Michigan Consolidated Gas Company; testimony concerning service life estimates.

Michigan Public Service Commission, Case No. U-13393, Aquila Networks – MGU; testimony supporting proposed depreciation rates.

Michigan Public Service Commission, Case No. U-12395, Michigan Gas Utilities; testimony supporting proposed depreciation rates including amortization accounting and redistribution of recorded reserves.

Michigan Public Service Commission, Case No. U-6587, General Telephone Company of Michigan; testimony concerning use of a theoretical depreciation reserve with the remaining-life technique.

Michigan Public Service Commission, Case No. U-7134, General Telephone Company of Michigan; testimony concerning the equal-life group depreciation procedure.

Minnesota Public Service Commission, Docket No. E-611, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Minnesota Public Service Commission, Docket No. E-1086, Northern States Power Company; testimony concerning depreciation rates.

Minnesota Public Service Commission, Docket No. G-1015, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Public Service Commission of the State of Missouri, Case No. ER-2009-0090, KCP&L Greater Missouri Operations, rebuttal testimony concerning depreciation rates.

Public Service Commission of the State of Missouri, Case No. ER-2001-672, Missouri Public Service, a division of Utilicorp United Inc.; surrebuttal testimony regarding computation of income tax expense.

Public Service Commission of the State of Missouri, Case No. TO-82-3, Southwestern Bell Telephone Company; rebuttal testimony concerning the remaining-life technique and the equal-life group procedure.

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conducting depreciation studies.

Public Service Commission of the State of Missouri, Case No. GR-99-315, Laclede Gas Company; rebuttal testimony concerning treatment of net salvage in development of depreciation rates.

Public Service Commission of the State of Missouri, Case No. HR–2004–0024, Aquila Inc. d/b/a/ Aquila Networks–L & P; testimony supporting depreciation rates.

Public Service Commission of the State of Missouri, Case No. ER–2004–0034, Aquila Inc. d/b/a/ Aquila Networks–L & P and Aquila Networks–MPS; testimony supporting depreciation rates.

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Montana Public Service Commission, Docket No. D95.9.128, The Montana Power Company; testimony supporting proposed depreciation rates.

Nebraska Public Service Commission, Docket No. NG–0041, Aquila Networks (PNG Nebraska); testimony supporting proposed depreciation rates.

Public Service Commission of Nevada, Docket No. 92-7002, Central Telephone Company-Nevada; testimony supporting proposed depreciation rates.

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New Hampshire Public Utilities Commission, Docket No. DR95-169, Granite State Electric Company; testimony supporting proposed net salvage rates.

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New York Public Service Commission, Case No. 10–E–0050. Niagara Mohawk Power Corporation d/b/a National Grid; testimony supporting recommended depreciation rates.

North Carolina Utilities Commission, Docket No. E-7, SUB 487, Duke Power Company; rebuttal testimony concerning proposed depreciation rates.

North Carolina Utilities Commission, Docket No. P-19, SUB 207, General Telephone Company of the South; rebuttal testimony concerning the equal-life group depreciation procedure.

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Company; testimony concerning rate of return and general financial requirements.

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Ontario Energy Board, E.B.R.O. 385, Tecumseh Gas Storage Limited; testimony concerning depreciation rates.

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Public Utilities Commission of Ohio, Case No. 82-886-TP-AIR, General Telephone Company of Ohio; testimony concerning the remaining-life technique and the equal-life group procedure.

Public Utilities Commission of Ohio, Case No. 84-1026-TP-AIR, General Telephone Company of Ohio; testimony in support of the equal-life group procedure and the remaining-life technique.

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Public Utilities Commission of Ohio, Case No. 83-300-TP-AIR, The Ohio Bell Telephone Company; testimony concerning straight-line age-life depreciation.

Public Utilities Commission of Ohio, Case No. 84-1435-TP-AIR, The Ohio Bell Telephone Company; testimony in support of test period depreciation expense.

Public Utilities Commission of Oregon, Docket No. UM 204, GTE of the Northwest; testimony concerning the theory and practice of depreciation accounting under public utility regulation.

Public Utilities Commission of Oregon, Docket No. UM 840, GTE Northwest Incorporated; rebuttal testimony concerning principles of capital recovery.

Pennsylvania Public Utility Commission, Docket No. R-80061235, The Bell Telephone Company of Pennsylvania; testimony concerning the proper depreciation reserve to be used with an original cost rate base.

Pennsylvania Public Utility Commission, Docket No. R-811512, General Telephone Company of Pennsylvania; testimony concerning the proper depreciation reserve to be used with an original cost rate base.

Pennsylvania Public Utility Commission, Docket No. R-811819, The Bell Telephone Company of Pennsylvania; testimony concerning the proper depreciation reserve to be used with an original cost rate base.

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Telephone Company of Pennsylvania; testimony concerning capital recovery under competition.

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Public Utilities Commission of the State of South Dakota, Case No. F-3062, Northern States Power Company; testimony concerning general financial requirements and measurements of financial performance.

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State of Vermont Public Service Board, Docket No. 6596, Citizens Communications Company – Vermont Electric Division; testimony supporting recommended depreciation rates.

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Commonwealth of Virginia State Corporation Commission, Case No. PUE-2002-00364, Washington Gas Light Company; testimony supporting proposed depreciation rates.

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**Other Consulting Activities**

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John Reigle, et al. v. Baltimore Gas & Electric Co., et al., Case No. C-2001-73230-CN, Circuit Court for Anne Arundel County, Maryland.

SR International Business Insurance Co. vs. WTC Properties et. al., 01,CV–9291 (JSM) and other related cases.

BellSouth Telecommunications, Inc. v. Citizens Utilities Company d/b/a/ Louisiana Gas Service Company, CA No. 95-2207, United States District Court, Eastern District of Louisiana.

Affidavit on behalf of Continental Cablevision, Inc. and its operating cable television systems regarding basic broadcast tier and equipment and installation cost-of-service rate justification.

Office of Chief Counsel, Internal Revenue Service. In Re: Kansas City Southern Railway Co., et. al. Docket Nos. 971-72, 974-72, and 4788-73.

Office of Chief Counsel, Internal Revenue Service. In Re: Northern Pacific Railway

Co., Docket No. 4489-69.

United States Department of Justice. In Re: Burlington Northern Inc. v. United States, Ct. Cl. No. 30-72.

Minnesota District Court. In Re: Northern States Power Company v. Ronald G. Blank, et. al. File No. 394126; testimony concerning depreciation and engineering economics.

**Faculty**

Depreciation Programs for public utility commissions, companies, and consultants, sponsored by Depreciation Programs, Inc., in cooperation with Western Michigan University. (1980 - 1999)

United States Telephone Association (USTA), Depreciation Training Seminar, November 1999.

Depreciation Advocacy Workshop, a three-day team-training workshop on preparation, presentation, and defense of contested depreciation issues, sponsored by Gilbert Associates, Inc., October, 1979.

Corporate Economics Course, Employee Education Program, Northern States Power Company. (1968 - 1979)

Perspectives of Top Financial Executives, Course No. 5-300, University of Minnesota, September, 1978.

Depreciation Programs for public utility commissions, companies, and consultants, jointly sponsored by Western Michigan University and Michigan Technological University, 1973.

**Professional Associations**

Advisory Committee to the Institute for Study of Regulation, sponsored by the American University and The University of Missouri-Columbia.

American Economic Association.

American Gas Association - Edison Electric Institute Depreciation Accounting Committee.

Board of Directors, Iowa State Regulatory Conference.

Edison Electric Institute, Energy Analysis Division, Economic Advisory Committee, 1976-1980.

Financial Management Association.

The Institute of Electrical and Electronics Engineers, Inc., Power Engineering Society, Engineering and Planning Economics Working Group.

Midwest Finance Association.

Society of Depreciation Professionals (Founding Member and Chairman, Policy Committee.

**Moderator**

Depreciation Open Forum, Iowa State University Regulatory Conference, May 1991.

The Quantification of Risk and Uncertainty in Engineering Economic Studies, Iowa State University Regulatory Conference, May 1989.

Plant Replacement Decisions with Added Revenue from New Service Offerings, Iowa State University Regulatory Conference, May 1988.

Economic Depreciation, Iowa State University Regulatory Conference, May 1987.

Opposing Views on the Use of Customer Discount Rates in Revenue Requirement Comparisons, Iowa State University Regulatory Conference, May 1986.

Cost of Capital Consequences of Depreciation Policy, Iowa State University Regulatory Conference, May 1985.

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Ratemaking Treatment of Large Capacity Additions, Iowa State University Regulatory Conference, May 1983.

The Economics of Excess Capacity, Iowa State University Regulatory Conference, May 1982.

New Developments in Engineering Economics, Iowa State University Regulatory Conference, May 1980.

Training in Engineering Economy, Iowa State University Regulatory Conference, May 1979.

The Real Time Problem of Capital Recovery, Missouri Public Service Commission, Regulatory Information Systems Conference, September 1974.

**Speaker**

Group Depreciation Practices of Regulated Utilities (IAS 16 Property, Plant and Equipment), Hydro One Networks, Inc., November 2008.

Economics, Finance and Engineering Valuation. Florida Gulf Coast University, April 2007.

Depreciation Studies for Regulated Utilities, Hydro One Networks, Inc., April 2006.

Depreciation Studies for Cooperatives and Small Utilities. TELERGEE CFO and Controllers Conference, November, 2004.

Finding the "D" in RCNLD (Valuation Applications of Depreciation), Society of Depreciation Professionals Annual Meeting, September 2001.

Capital Asset and Depreciation Accounting, City of Edmonton Value Engineering Workshop, April 2001.

A Valuation View of Economic Depreciation, Society of Depreciation Professionals Annual Meeting, October 1999.

Capital Recovery in a Changing Regulatory Environment, Pennsylvania Electric Association Financial-Accounting Conference, May 1999.

Depreciation Theory and Practice, Southern Natural Gas Company Accounting and Regulatory Seminar, March 1999.

Depreciation Theory Applied to Special Franchise Property, New York Office of Real Property Services, March 1999.

Capital Recovery in a Changing Regulatory Environment, PowerPlan Consultants Annual Client Forum, November 1998.

Economic Depreciation, AGA Accounting Services Committee and EEI Property Accounting and Valuation Committee, May 1998.

Discontinuation of Application of FASB Statement No. 71, Southern Natural Gas Company Accounting Seminar, April 1998.

Forecasting in Depreciation, Society of Depreciation Professionals Annual Meeting, September 1997.

Economic Depreciation In Response to Competitive Market Pricing, 1997 TELUS Depreciation Conference, June 1997.

Valuation of Special Franchise Property, City of New York, Department of Finance Valuation Seminar, March 1997.

Depreciation Implications of FAS Exposure Draft 158-B, 1996 TLG Decommissioning Conference, October 1996.

Why Economic Depreciation?, American Gas Association Depreciation Accounting Committee Meeting, August 1995.

The Theory of Economic Depreciation, Society of Depreciation Professionals Annual Meeting, November 1994.

Vintage Depreciation Issues, G & T Accounting and Finance Association Conference, June 1994.

Pricing and Depreciation Strategies for Segmented Markets (Regulated and Competitive), Iowa State Regulatory Conference, May 1990.

Principles and Practices of Depreciation Accounting, Canadian Electrical Association and Nova Scotia Power Electric Utility Regulatory Seminar, December 1989.

Principles and Practices of Depreciation Accounting, Duke Power Accounting Seminar, September 1989.

The Theory and Practice of Depreciation Accounting Under Public Utility Regulation, GTE Capital Recovery Managers Conference, February 1989.

Valuation Methods for Regulated Utilities, GTE Capital Recovery Managers Conference, January 1988.

Depreciation Principles and Practices for REA Borrowers, NRECA 1985 National Accounting and Finance Conference, September 1985.

Depreciation Principles and Practices for REA Borrowers, Kentucky Association of Electric Cooperatives, Inc., Summer Accountants Association Meeting, June 1985.

Considerations in Conducting a Depreciation Study, NRECA 1984 National Accounting and Finance Conference, October 1984.

Software for Conducting Depreciation Studies on a Personal Computer, United States Independent Telephone Association, September 1984.

Depreciation—An Assessment of Current Practices, NRECA 1983 National Accounting and Finance Conference, September 1983

Depreciation—An Assessment of Current Practices, REA National Field Conference, September 1983.

An Overview of Depreciation Systems, Iowa State Commerce Commission, October 1982.

Depreciation Practices for Gas Utilities, Regulatory Committee of the Canadian Gas Association, September 1981.

Practice, Theory, and Needed Research on Capital Investment Decisions in the Energy Supply Industry, workshop, sponsored by Michigan State University and the Electric Power Research Institute, November 1977.

Depreciation Concepts Under Regulation, Public Utilities Conference, sponsored by The University of Texas at Dallas, July 1976.

Electric Utility Economics, Mid-Continent Area Power Pool, May 1974.

**Honors and Awards**

The Society of Sigma Xi.

Professional Achievement Citation in Engineering, Iowa State University, 1993.

Attachment REW–2

# 2011 Depreciation Rate Study

**Arizona Public Service Company**

Prepared by
Foster Associates, Inc.

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# EXECUTIVE SUMMARY

## INTRODUCTION

This report presents a review and update of depreciation rates and parameters for utility plant owned and operated by Arizona Public Service Company (APS). The report contains recommended 2011 depreciation rates and parameters for: a) steam and other production assets; b) nuclear assets; and c) electric transmission, distribution and general plant categories. Work on the study commenced in January 2011 and progressed through April, at which time the project was completed.

Foster Associates is a public utility economic consulting firm headquartered in Bethesda, Maryland offering economic research and consulting services on issues and problems arising from governmental regulation of business. Areas of specialization supported by the firm's Fort Myers, Florida office include property life forecasting, technological forecasting, depreciation estimation, and valuation of industrial property.

Foster Associates has undertaken numerous depreciation engagements for both public and privately owned business entities including detailed statistical life studies, analyses of required net salvage rates, and the selection of depreciation systems that will most nearly achieve the goals of depreciation accounting under the constraints of either government regulation or competitive market pricing. Foster Associates is widely recognized for industry leadership in the development of depreciation systems, life analysis techniques and computer software for conducting depreciation and valuation studies.

Depreciation rates currently used by APS were approved by the Arizona Corporation Commission (ACC) pursuant to a settlement agreement in Docket No. E–01345A–08–0172. (Decision No. 71448, dated December 30, 2009). With the exception of Account 370.01 (Meters – Electronic), parameters (*i.e.*, projection curves, projection lives and future net salvage rates used to derive the approved rates were developed in the Company's 2008 depreciation study.[1] The Decision further provided that "... upon the later date of receiving Nuclear Regulatory Commission approval for the Palo Verde license extension or January 1, 2012, APS is authorized to adjust depreciation rates used for recording depreciation expense on the Palo Verde generating unit to reflect such license extension, and APS shall file a request to adjust the System Benefit Charge ('SBC') to reflect the corresponding reduction in the decommissioning trust funding obligations. APS is also required to provide a depreciation rate study in its next rate case"[2]

The principal findings and recommendations developed in the current study

[1] The settlement agreement provided that the prior approved rate of 3.68 percent would be retained for Account 370.01 rather than adopting the Company's proposed five–year amortization.
[2] Docket No. E–01345A–08–0172, Decision No. 71448, §XI, p. 10.

are summarized in Section IV of this report. Statement A provides a comparative summary of current and proposed annual depreciation rates for each rate category. Statement B provides a comparison of current and proposed annual depreciation accruals. Statement C provides a comparison of computed, recorded and redistributed depreciation reserves for each rate category. Statement D provides a summary of the investment and net salvage components of rebalanced reserves. Statement E provides a summary of the components used to obtain weighted–average net salvage rates. Statement F provides a computation of the estimated future net salvage rate for steam production facilities. Statement G contains the computation of terminal dismantlement costs for steam production facilities. Statement H provides a comparative summary of current and proposed parameters including projection life, projection curve and future net salvage rates. The statement also contains current and proposed statistics including average service life, average remaining life, and average net salvage rates.

## SCOPE OF STUDY

The principal activities undertaken in the course of the current study included:

- Collection of plant and net salvage data;
- Reconciliation of data to the official records of the Company;
- Field visits and discussions with APS operations and plant accounting personnel;
- Estimation of projection lives and retirement dispersion patterns;
- Analysis of gross salvage and cost of removal;
- Analysis and redistribution of recorded depreciation reserves; and
- Development of recommended accrual rates for each rate category.

## DEPRECIATION SYSTEM

A depreciation rate is formed by combining the elements of a depreciation system. A depreciation system is composed of a method, a procedure and a technique. A depreciation method (*e.g.*, straight–line) describes the component of the system that determines the acceleration or deceleration of depreciation accruals in relation to either time or use. A depreciation procedure (*e.g.*, vintage group) identifies the level of grouping or sub–grouping of assets within a plant category. The level of grouping specifies the weighting used to obtain composite life statistics for an account. A depreciation technique (*e.g.*, remaining–life) describes the life statistic used in the system.

With the exception of selected general support asset categories for which amortization accounting has been approved, APS is currently using a depreciation system composed of the straight–line method, vintage group procedure, remain-

ing–life technique. Amortization accounting is used for general plant categories in which the unit cost of plant items is small in relation to the number of units classified in the account. Plant is retired (*i.e.*, credited to plant and charged to the reserve) as each vintage achieves an age equal to the amortization period. Any realized net salvage for amortizable accounts is netted against current–year vintage additions.

The matching and expense recognition principles of accounting provide that the cost of an asset (or group of assets) should be allocated to operations over an estimate of the economic life of the asset in proportion to the consumption of service potential. It is the opinion of Foster Associates that the objectives of depreciation accounting are being achieved using the currently approved vintage–group procedure, which distinguishes service lives among vintages, and the remaining–life technique, which provides cost apportionment over the estimated weighted–average remaining life of a rate category. It is also the opinion of Foster Associates that amortization accounting remains appropriate for the approved amortization categories.

## PROPOSED DEPRECIATION RATES

Table 1 below provides a summary of the changes in annual rates and accruals resulting from an application of the service life and net salvage parameters recommended in the current study.

| | Accrual Rate | | | 2011 Annualized Accrual | | |
|---|---|---|---|---|---|---|
| Function | Current | Proposed | Diff. | Current | Proposed | Difference |
| A | B | C | D=C-B | E | F | G=F-E |
| Production | | | | | | |
| Steam | 3.35% | 2.84% | -0.51% | $59,943,328 | $50,825,171 | ($9,118,157) |
| Nuclear | 2.77% | 1.44% | -1.33% | 72,235,832 | 37,539,055 | (34,696,777) |
| Other | 3.00% | 2.62% | -0.38% | 43,949,098 | 38,279,711 | (5,669,387) |
| Transmission | 2.27% | 2.40% | 0.13% | 2,337,578 | 2,477,081 | 139,503 |
| Distribution | 2.26% | 2.37% | 0.11% | 104,066,081 | 109,307,181 | 5,241,100 |
| General Plant | 5.25% | 5.90% | 0.65% | 22,836,498 | 25,639,197 | 2,802,699 |
| Total | 2.77% | 2.40% | -0.37% | $305,368,415 | $264,067,396 | ($41,301,019) |

**Table 1. Current and Proposed Rates and Accruals**

Foster Associates is recommending primary account depreciation rates equivalent to a composite rate of 2.40 percent. Depreciation expense is currently accrued at rates that composite to 2.77 percent. The recommended change in the composite depreciation rate is, therefore, a reduction of 0.37 percentage points.

A continued application of current rates would provide annualized depreciation expense of $305,368,415 compared with an annualized expense of

$264,067,396 using the rates developed in this study. The proposed 2011 expense reduction is $41,301,019. The computed change in annualized accruals includes a reduction of $62,327,472 attributable to an amortization of a $842,117,224 reserve imbalance. The remaining portion of the change is attributable to adjustments in service life and net salvage statistics recommended in the 2011 study.

Of the 170 plant accounts included in the 2011 study, Foster Associates is recommending rate reductions for 97 accounts and rate increases for 73 accounts.

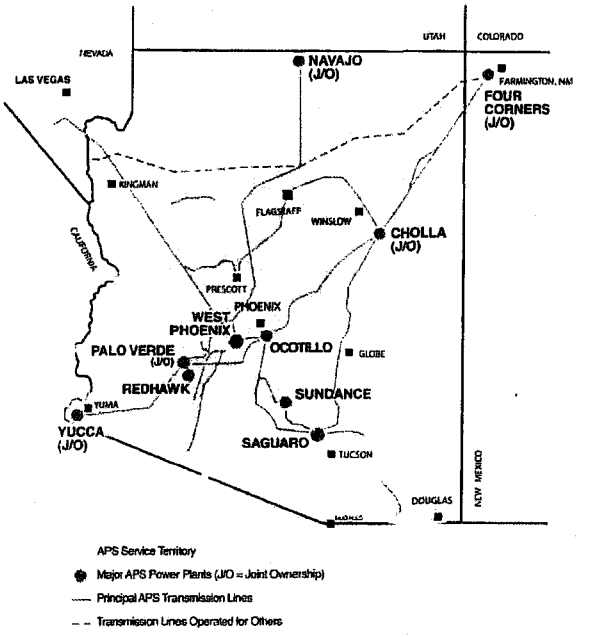
# COMPANY PROFILE

## GENERAL

Arizona Public Service Company is the largest subsidiary of Pinnacle West Capital Corporation. APS provides electric service to more than 1.1 million customers in 11 of Arizona's 15 counties.

Incorporated in 1920 under the laws of the state of Arizona, APS employs more than 6,600 employees, including employees at jointly–owned generating facilities for which APS serves as the generating facility manager.

In addition to the Palo Verde Nuclear Generating Station, APS owns and operates six natural–gas plants, one oil plant, two coal–fired plants, and an increasing array of renewable energy power generation.




APS has built an infrastructure consisting of more than 30,000 miles of transmission and distribution lines and 400 substations.

## GENERATING RESOURCES

The Palo Verde Nuclear Generating Station is owned by a consortium of seven utilities in the Southwest and is operated by APS. Its three units are capable of generating nearly 4,000 megawatts of electricity. APS owns or leases 29.1 percent of the plant.

The five–unit, 2060 megawatt Four Corners Power Plant, located on the Navajo Indian Reservation, is owned by APS and five other utilities in the Southwest. The plant is operated by APS and fueled by low–sulfur coal from the nearby Navajo mine.

The 1027 megawatt Cholla Power Plant is located in northeastern Arizona. APS operates the plant and owns Units 1, 2 and 3, which are capable of producing 647 megawatts of electricity. PacifiCorp owns the 380 megawatt Unit 4. Cholla is fueled by coal from the McKinley Mine in New Mexico.

The Navajo Power Plant is located in northern Arizona on the Navajo Indian Reservation near Page. The plant's three 750 megawatt coal–fueled, steam–electric generating units are owned by a partnership of five utility companies and

the U.S. Bureau of Reclamation. APS owns 14 percent of the plant, which is operated by Salt River Project.

The Redhawk Power Station, which began operating in mid–2002, is comprised of two identical 492 megawatt natural gas–fueled combined–cycle units. The plant is owned and operated by APS.

The natural gas–fueled West Phoenix Power Plant has seven generating units: two combustion turbine units and five units that employ combined–cycle technology. Owned and operated by APS, West Phoenix generates about 950 megawatts of electricity.

Ocotillo is a natural gas–fueled Power Plant owned and operated by APS. Located in Tempe, Arizona, the plant has two steam and two combustion turbine units that are capable of generating about 330 megawatts.

The natural gas–fueled Saguaro Power Plant, located north of Tucson, has two steam units and three combustion turbine units. APS owns and operates all five of the generating units that have a combined capacity of about 395 megawatts available to the APS system.

Sundance Generating Station in Coolidge, Arizona is the newest member of the APS fleet. APS purchased the 420 megawatt station in the spring of 2005. The simple–cycle, natural gas–fueled station consists of 10 quick–start combustion turbines.

APS operates the natural gas–fueled Yucca Power Plant located near Yuma in southwestern Arizona. The Company owns six combustion turbine units that produce nearly 243 megawatts for APS customers.

APS has one oil–only power plant, Douglas, located in the town of Douglas, Arizona with a 16 megawatt capacity.

Since 1996, APS has completed a number of solar projects around the state. The current capacity of their solar plants is about five megawatts.

## TRANSMISSION AND DISTRIBUTION FACILITIES

Transmission facilities consist of approximately 5,992 pole miles of overhead lines and approximately 49 miles of underground lines, 5,769 miles of which are located in Arizona. APS shares ownership of some of its transmission facilities with other companies.

Distribution facilities consist of approximately 11,098 miles of overhead lines and approximately 17,417 miles of underground primary cable, all of which are located in Arizona.

# STUDY PROCEDURE

## INTRODUCTION

The purpose of a depreciation study is to analyze the mortality characteristics, net salvage rates and adequacy of depreciation accruals and recorded depreciation reserves for each rate category. This study provides the foundation and documentation for recommended changes in the depreciation rates used by APS for its steam, nuclear, other production, transmission, distribution and general plant categories. The proposed rates are subject to approval by the Arizona Corporation Commission.

## SCOPE

The steps involved in conducting a depreciation study can be grouped into five major tasks:

- Data Collection;
- Life Analysis and Estimation;
- Net Salvage Analysis;
- Depreciation Reserve Analysis; and
- Development of Accrual Rates.

The scope of the 2011 study included a consideration of each of these tasks as described below.

## DATA COLLECTION

The minimum database required to conduct a statistical life study consists of a history of vintage year additions and unaged activity–year retirements, transfers and adjustments. These data must be appropriately adjusted for transfers, sales and other plant activity that would otherwise bias the measured service life of normal retirements. The age distribution of surviving plant for unaged data can be estimated by distributing plant in service at the beginning of the study year to prior vintages in proportion to the theoretical amount surviving from a projection or survivor curve identified in the life study. The statistical methods of life analysis used to examine unaged plant data are known as *semi–actuarial techniques.*

A far more extensive database is required to apply statistical methods of life analysis known as *actuarial techniques.* Plant data used in an actuarial life study most often include age distributions of surviving plant at the beginning of a study year and the vintage year, activity year, and dollar amounts associated with normal retirements, reimbursed retirements, sales, abnormal retirements, transfers, corrections, and extraordinary adjustments over a series of prior activity years. An actuarial database may include age distributions of surviving plant at the beginning of the earliest activity year, rather than at the beginning of the study year. Plant additions, however, must be included in a database containing an opening age distribu-

tion to derive aged survivors at the beginning of the study year. All activity year transactions with vintage year identification are coded and stored in a database. These data are processed by a computer program and transaction summary reports are created in a format reconcilable to official plant records. The availability of such detailed information is dependent upon an accounting system that supports aged property records. The Continuing Property Record (CPR) system used by APS provides aged transactions for all plant accounts.

Service life statistics estimated in this study were derived from plant accounting transactions recorded over the period 1971 through 2010. Detailed accounting transactions were extracted from the CPR system and assigned transaction codes which describe the nature of the accounting activity. Transaction codes for plant additions, for example, were used to distinguish normal additions from acquisitions, purchases, reimbursements and adjustments. Similar transaction codes were used to distinguish normal retirements from sales, reimbursements, abnormal retirements and adjustments. Transaction codes were also assigned to transfers, capital leases, gross salvage, cost of removal and other accounting activity that should be considered in a depreciation study.

The database used in conducting the 2008 study was updated for the current study by appending additional plant and net salvage transactions for activity years 2008–2010 and age distributions of surviving plant at December 31, 2010. The accuracy and completeness of the assembled database was verified for activity years 2008 through 2010 by comparing the beginning plant balance, additions, retirements, transfers and adjustments, and the ending plant balance derived for each activity year to the official plant records of the Company. Activity years prior to 2008 were verified in the 2008 study. Age distributions of surviving plant at December 31, 2010 were reconciled to the CPR.

Reserve transactions recorded over the period 1980–2010 were used in the 2011 study to derive appropriate net salvage rates. Realized net salvage was blended with future net salvage estimates to derive average net salvage rates used in the computation of theoretical reserves.

## LIFE ANALYSIS AND ESTIMATION

Life analysis and life estimation are terms used to describe a two–step procedure for estimating the mortality characteristics of a plant category. The first step (*i.e.*, life analysis) is largely mechanical and primarily concerned with history. Statistical techniques are used in this step to obtain a mathematical description of the forces of retirement acting upon a plant category and an estimate of the *projection life* of the account. The mathematical expressions used to describe these life characteristics are known as *survival functions* or *survivor curves*.

The second step (*i.e.*, life estimation) is concerned with predicting the ex-

pected remaining life of property units still exposed to forces of retirement. It is a process of blending the results of a life analysis with informed judgment (including expectations about the future) to obtain an appropriate projection life and curve descriptive of the parent population from which a plant account is viewed as a random sample. The amount of weight given to a life analysis will depend upon the extent to which past retirement experience is considered descriptive of the future.

The analytical methods used in a life analysis are broadly classified as actuarial and semi–actuarial techniques. Actuarial techniques can be applied to plant accounting records that reveal the age of a plant asset at the time of its retirement from service. Stated differently, each property unit must be identifiable by date of installation and age at retirement. Semi–actuarial techniques can be used to derive service life and dispersion estimates when age identification of retirements is not maintained or readily available. Age identification of retirements was available for all plant accounts included in the 2011 APS depreciation study.

An actuarial life analysis program designed and developed by Foster Associates was used in this study. The first step in an actuarial analysis involves a systematic treatment of the available data for the purpose of constructing an observed life table. A complete life table contains the life history of a group of property units installed during the same accounting period and various probability relationships derived from the data. A life table is arranged by age–intervals (usually defined as one year) and shows the number of units (or dollars) entering and leaving each age–interval and probability relationships associated with this activity. A life table minimally shows the age of each survivor and the age of each retirement from a group of units installed in a given accounting year.

A life table can be constructed in any one of at least five methods. The annual–rate or retirement–rate method was used in this study. The mechanics of the annual–rate method require the calculation of a series of ratios obtained by dividing the number of units (or dollars) surviving at the beginning of an age interval into the number of units (or dollars) retired during the same interval. This so–called "retirement ratio" (or set of ratios) is an estimator of the hazard rate or conditional probability of retirement during an age interval. The cumulative proportion surviving is obtained by multiplying the retirement ratio for each age interval by the proportion of the original group surviving at the beginning of that age interval and subtracting this product from the proportion surviving at the beginning of the same interval. The annual–rate method is applied to multiple groups or vintages by combining the retirements and/or survivors of like ages for each vintage included in the analysis.

The second step in an actuarial analysis involves graduating or smoothing the observed life table and fitting the smoothed series to a family of survival func-

tions. The functions used in this study are the Iowa–type curves which are mathematically described in terms of the Pearson frequency curve family. The observed life table was smoothed by a weighted least–squares procedure in which first, second and third degree orthogonal polynomials were fitted to the observed retirement ratios. The resulting function can be expressed as a survivorship function which is numerically integrated to obtain an estimate of the projection life. The smoothed survivorship function is then fitted by a weighted least–squares procedure to the Iowa–curve family to obtain a mathematical description or classification of the dispersion characteristics of the data.

The set of computer programs used in this analysis provides multiple rolling–band, shrinking–band and progressive–band analyses of an account. Observation bands are defined in terms of a "retirement era" that restricts the analysis to the retirement activity of all vintages represented by survivors at the beginning of a selected era. In a rolling–band analysis, a year of retirement experience is added to each successive retirement band and the earliest year from the preceding band is dropped. A shrinking–band analysis begins with the total retirement experience available and the earliest year from the preceding band is dropped for each successive band. A progressive–band analysis adds a year of retirement activity to a previous band without dropping earlier years from the analysis. Rolling, shrinking and progressive band analyses are used to detect the emergence of trends in the behavior of the dispersion and projection life.

Options available in the Foster Associates actuarial life analysis program include: the width and location of both placement and observation bands; the interval of years included in a selected band analysis; the estimator of the hazard rate (actuarial, conditional proportion retired, or maximum likelihood); the elements to include on the diagonal of a weight matrix (exposures, inverse of age, inverse of variance, or unweighted); and the age at which an observed life table is truncated. The program also provides tabular and graphics output as an aid in the analysis.

While actuarial and semi–actuarial statistical methods are well suited to an analysis of plant categories containing a large number of homogeneous units (*e.g.*, meters and services), the concept of retirement dispersion is interpreted differently for plant categories composed of major items of plant that will most likely be retired as a single unit. Plant retirements from an integrated system prior to the retirement of the entire facility are more properly viewed as interim retirements that will be replaced in order to maintain the integrity of the system. Additionally, plant facilities may be added to the existing system (*i.e.*, interim additions) in order to expand or enhance its productive capacity without extending the service life of the existing system. A proper depreciation rate can be developed for an integrated system using a life–span method. All plant accounts classified in Steam, Nuclear and Other Production were identified by unit and treated as life–span

categories in the 2011 study.

## NET SALVAGE ANALYSIS

Depreciation rates designed to achieve the goals and objectives of depreciation accounting will include a parameter for future net salvage and a variable for average net salvage reflecting both realized and future net salvage rates.

Estimates of net salvage rates applicable to future retirements are most often derived from an analysis of gross salvage and cost of removal realized in the past. An analysis of past experience (including an examination of trends over time) provides a reasonable basis for estimating future salvage and cost of removal. However, consideration should also be given to events that may cause deviations from net salvage realized in the past. Among the factors that should be considered are: the age of plant retirements; the portion of retirements likely to be reused; changes in the method of removing plant; the type of plant to be retired in the future; inflation expectations; the shape of the projection life curve; and economic conditions that may warrant greater or lesser weight to be given to net salvage rates observed in the past.

Average net salvage rates for an account or plant function are derived from a direct dollar weighting of a) historical retirements with historical (or realized) net salvage rates and b) future retirements *(i.e.*, surviving plant) with the estimated future net salvage rate. Average net salvage rates will change, therefore, as additional years of retirement and net salvage activity become available and as subsequent plant additions alter the weighting of future net salvage estimates.

Future net salvage rates for steam production facilities were adjusted and approved in Docket No. E–01345A–05–0816 et al. for estimated terminal dismantlement costs based on costs per kW derived in dismantling studies conducted in 2002 for the Navajo and Four Corners generating stations. This treatment was retained and approved in the 2008 study. APS subsequently retained an independent contractor to develop a cost estimate for the demolition and abatement of the Four Corners Generating Station. The estimated cost at December 31, 2009 for dismantling Four Corners and the prior approved cost of $40 per kW estimated for all other steam generating stations were used in the current depreciation study to formulate average and future net salvage rates.[2] Statement G provides a computation of terminal dismantlement costs used in Statement F to derive future net salvage rates for steam production facilities. The distinction between average and future net salvage rates is shown in Statement E.

[2] A cost of $39 per kW for Navajo and $40 per kW for all other steam generating stations was approved in Decision No. 71448. An estimated cost of $40 per kW was used for Navajo in the current study to establish consistency with other plant units.

Special consideration should also be given to the treatment of insurance proceeds and other forms of third–party reimbursements credited to the depreciation reserve. A properly conducted net salvage study will exclude such activity from the estimate of future parameters and include the activity in the computation of realized and average net salvage rates.

A five–year moving average analysis of the ratio of realized salvage and removal expense to the associated retirements was used in the 2011 study for transmission, distribution and general plant categories to: a) estimate a realized net salvage rate; b) detect the emergence of historical trends; and c) establish a basis for estimating a future net salvage rate. Cost of removal and salvage opinions obtained from Company personnel were blended with judgment and historical net salvage indications in developing estimates of the future.

Average net salvage rates for all depreciable plant accounts were estimated using direct dollar weighting of historical retirements with the historical net salvage rate, and future retirements (*i.e.*, surviving plant) with the estimated future net salvage rate. The computation of estimated average net salvage rates is shown in Statement E.

## DEPRECIATION RESERVE ANALYSIS

The purpose of a depreciation reserve analysis is to compare the current level of recorded reserves with the level required to achieve the goals or objectives of depreciation accounting if the amount and timing of future retirements and net salvage are realized as predicted. The difference between a required (or theoretical) depreciation reserve and a recorded reserve provides a measurement of the expected excess or shortfall that will remain in the depreciation reserve if corrective action is not taken to eliminate the reserve imbalance.

Unlike a recorded reserve which represents the net amount of depreciation expense charged to previous periods of operations, a theoretical reserve is a measure of the implied reserve requirement at the beginning of a study year if the timing of future retirements and net salvage is in exact conformance with a survivor curve chosen to predict the probable life of property still exposed to the forces of retirement. Stated differently, a theoretical depreciation reserve is the difference between the recorded cost of plant presently in service and the sum of depreciation expense and net salvage that will be charged in the future if retirements are distributed over time according to a specified retirement frequency distribution.

The survivor curve used in the calculation of a theoretical depreciation reserve is intended to describe forces of retirement that will be operative in the future. However, retirements caused by forces such as accidents, physical deterioration and changing technology seldom, if ever, remain stable over time. It is unlikely, therefore, that a probability or retirement frequency distribution can be

identified that will accurately describe the age of plant retirements over the complete life cycle of a vintage. It is for this reason that depreciation rates should be reviewed periodically and adjusted for observed or expected changes in the parameters chosen to describe the underlying forces of mortality.

Although reserve records are commonly maintained by various account classifications, the sum of all reserves is the most important measure of the status of a company's depreciation practices. If statistical life studies have not been conducted or retirement dispersion has been ignored in setting depreciation rates, it is likely that some accounts will be over–depreciated and other accounts will be under–depreciated relative to a calculated theoretical reserve. Differences between a theoretical reserve and a recorded reserve also will arise as a normal occurrence when service lives, dispersion patterns and net salvage estimates are adjusted in the course of depreciation reviews. It is appropriate, therefore, and consistent with group depreciation theory to periodically redistribute or rebalance recorded reserves among the various primary accounts based upon the most recent estimates of retirement dispersion and net salvage rates.

It is the opinion of Foster Associates that a redistribution of recorded reserves is again appropriate for APS. Offsetting reserve imbalances (attributable to both the passage of time and parameter adjustments recommended in the current study) should be realigned among primary accounts to reduce offsetting imbalances and increase depreciation rate stability.

A redistribution of the recorded reserve for depreciable plant was achieved by multiplying the calculated reserve for each primary account within a function (or plant location) by the ratio of the function (or location) total recorded reserves (net of amortizable accounts) to the function (or location) total calculated reserve. The sum of the redistributed reserves within a function (or location) is, therefore, equal to the function (or location) total recorded depreciation reserve before the redistribution. Depreciation reserves for amortizable categories were redistributed by setting the recorded reserves for the proposed amortization accounts equal to the theoretical reserves derived from the proposed amortization periods and distributing the residual imbalances to the remaining depreciable accounts within the appropriate function.

Statement C provides a comparison of recorded, computed and redistributed reserves at December 31, 2010. The recorded reserve was $4,209,736,678 or 38.2 percent of the depreciable plant investment. The corresponding computed reserve is $3,367,619,454 or 30.6 percent of the depreciable plant investment. A proportionate amount of the measured reserve imbalance of $842,117,224 will be amortized over the composite weighted–average remaining life of each rate category using the remaining life depreciation rates proposed in this study.

Statement D provides an estimate of the investment and net salvage components of the rebalanced reserves.

## DEVELOPMENT OF ACCRUAL RATES

The goal or objective of depreciation accounting is cost allocation over the economic life of an asset in proportion to the consumption of service potential. Ideally, the cost of an asset—which represents the cost of obtaining a bundle of service units—should be allocated to future periods of operation in proportion to the amount of service potential expended during an accounting interval. The service potential of an asset is the present value of future net revenue (*i.e.*, revenue less expenses exclusive of depreciation and other non–cash expenses) or cash inflows attributable to the use of that asset alone.

Cost allocation in proportion to the consumption of service potential is often approximated by the use of depreciation methods employing time rather than net revenue as the apportionment base. Examples of time–based methods include sinking–fund, straight–line, declining balance, and sum–of–the–years' digits. The advantage of using a time–based method is that it does not require an estimate of the remaining amount of service capacity an asset will provide or the amount of capacity actually consumed during an accounting interval. Using a time–based allocation method, however, does not alter the goal of depreciation accounting. If it is predictable that the net revenue pattern of an asset will either decrease or increase over time, then an accelerated or decelerated time–based method should be used to approximate the rate at which service potential is actually consumed.

The time period over which the cost of an asset will be allocated to operations is determined by the combination of a procedure and a technique. A depreciation procedure describes the level of grouping or sub–grouping of assets within a plant category. The broad group, vintage group, equal–life group, and item (or unit) are a few of the more widely used procedures. A depreciation technique describes the life statistic used in a depreciation system. Whole life and remaining life (or expectancy) are the most common techniques.

Depreciation rates recommended in the 2011 study were developed using the currently approved system composed of the straight–line method, vintage group procedure, remaining–life technique. This formulation of the accrual rate is equivalent to a straight–line method, vintage group procedure, whole–life technique with amortization of reserve imbalances over the estimated remaining life of each rate category. It is the opinion of Foster Associates that this system will remain appropriate for APS, provided depreciation studies are conducted periodically and parameters are routinely adjusted to reflect changing operating conditions. Although the emergence of economic factors such as restructuring and performance based regulation may ultimately encourage abandonment of the

straight–line method, no attempt was made in the current study to address this concern.

It is also the opinion of Foster Associates that amortization accounting currently approved for selected general support asset accounts is consistent with the goals and objectives of depreciation accounting and remains appropriate these plant categories.

# STATEMENTS

## INTRODUCTION

This section provides a comparative summary of depreciation rates, annual depreciation accruals, recorded and computed depreciation reserves, and current and proposed service life and net salvage parameters recommended for a) steam and other production assets; b) nuclear assets; and c) electric transmission, distribution and general plant categories. The content of these statements is briefly described below.

- Statement A provides a comparative summary of current and proposed annual depreciation rates using the vintage group procedure, remaining–life technique.
- Statement B provides a comparison of current and proposed annualized 2011 depreciation accruals based upon the depreciation rates contained in Statement A.
- Statement C provides a comparison of recorded, computed and redistributed reserves for each rate category at December 31, 2010.
- Statement D provides a summary of the investment and net salvage components of rebalanced reserves.
- Statement E provides a summary of the components used to obtain weighted average net salvage rates.
- Statement F provides a computation of the estimated future net salvage rate for steam production facilities.
- Statement G contains the computation of terminal dismantlement costs for steam production facilities.
- Statement H provides a comparative summary of current and proposed parameters and statistics including projection life, projection curve, average service life, average remaining life, and average and future net salvage rates.

Current depreciation accruals shown on Statement B are the product of the plant investment (Column B) and current depreciation rates shown on Statement A. These are the effective rates used by the Company for the mix of investments recorded on December 31, 2010. Similarly, proposed depreciation accruals shown on Statements B are the product of the plant investment and proposed depreciation rates shown on Statement A. Proposed remaining life accrual rates (Statement A) are given by:

$$\text{Accrual Rate} = \frac{1.0 - \text{Reserve Ratio} - \text{Future Net Salvage Rate}}{\text{Remaining Life}}.$$

This formulation of a remaining–life accrual rate is equivalent to

$$\text{Accrual Rate} = \frac{1.0 - \text{Average Net Salvage}}{\text{Average Life}} + \frac{\text{Computed Reserve} - \text{Recorded Reserve}}{\text{Remaining Life}}$$

where Average Net Salvage, Computed Reserve and Recorded Reserve are expressed in percent.

**ARIZONA PUBLIC SERVICE COMPANY** Statement A

Component Accrual Rates
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

| Account Description | Current (at 12/31/2010) Investment | Net Salvage | Total | Proposed (at 12/31/2010) Investment | Net Salvage | Total |
|---|---|---|---|---|---|---|
| A | B | C | D=B+C | E | F | G=E+F |
| **STEAM PRODUCTION** | | | | | | |
| 311.00 Structures and Improvements | 3.15% | 0.39% | 3.54% | 2.33% | 0.27% | 2.60% |
| 312.00 Boiler Plant Equipment | 2.95% | 0.39% | 3.34% | 2.48% | 0.35% | 2.83% |
| 314.00 Turbogenerator Units | 2.93% | 0.38% | 3.31% | 2.69% | 0.35% | 3.04% |
| 315.00 Accessory Electric Equipment | 2.47% | 0.32% | 2.79% | 2.29% | 0.27% | 2.56% |
| 316.00 Miscellaneous Power Plant Equipment | 3.81% | 0.58% | 4.39% | 3.01% | 0.41% | 3.42% |
| **Total Steam Production Plant** | 2.96% | 0.39% | 3.35% | 2.50% | 0.34% | 2.84% |
| **NUCLEAR PRODUCTION** | | | | | | |
| 321.00 Structures and Improvements | 2.63% | 0.01% | 2.64% | 1.33% | 0.01% | 1.34% |
| 322.00 Reactor Plant Equipment | 2.84% | 0.05% | 2.89% | 1.50% | 0.05% | 1.55% |
| 323.00 Turbogenerator Units | 2.75% | 0.01% | 2.76% | 1.44% | 0.02% | 1.46% |
| 324.00 Accessory Electric Equipment | 2.54% | 0.01% | 2.55% | 1.19% | 0.01% | 1.20% |
| 325.00 Miscellaneous Power Plant Equipment | 2.88% | 0.04% | 2.92% | 1.47% | 0.04% | 1.51% |
| **Total Nuclear Production Plant** | 2.74% | 0.03% | 2.77% | 1.41% | 0.03% | 1.44% |
| **OTHER PRODUCTION** | | | | | | |
| 341.00 Structures and Improvements | 2.67% | 0.23% | 2.90% | 2.89% | -0.13% | 2.76% |
| 342.00 Fuel Holders, Products and Accessories | 3.04% | 0.15% | 3.19% | 3.09% | -0.14% | 2.95% |
| 343.00 Prime Movers | 2.61% | 0.09% | 2.70% | 2.57% | -0.10% | 2.47% |
| 344.00 Generators and Devices | 3.21% | 0.14% | 3.35% | 3.32% | -0.60% | 2.72% |
| 345.00 Accessory Electric Equipment | 2.79% | 0.13% | 2.92% | 2.74% | -0.12% | 2.62% |
| 346.00 Miscellaneous Power Plant Equipment | 2.92% | 0.15% | 3.07% | 3.35% | -0.15% | 3.20% |
| **Total Other Production Plant** | 2.88% | 0.12% | 3.00% | 2.92% | -0.30% | 2.62% |
| **TRANSMISSION PLANT** | | | | | | |
| 352.02 Structures and Improvements | 2.45% | | 2.45% | 2.67% | | 2.67% |
| 353.00 Station Equipment | 2.29% | | 2.29% | 2.31% | 0.11% | 2.42% |
| 354.00 Towers and Fixtures | 1.78% | | 1.78% | 1.84% | | 1.84% |
| 355.00 Poles and Fixtures | 2.03% | 0.40% | 2.43% | 1.86% | 0.37% | 2.23% |
| 356.00 Overhead Conductors and Devices | 1.72% | -0.33% | 1.39% | 1.75% | 0.33% | 2.08% |
| **Total Transmission Plant** | 2.27% | | 2.27% | 2.29% | 0.11% | 2.40% |
| **DISTRIBUTION PLANT** | | | | | | |
| 361.00 Structures and Improvements | 1.51% | 0.06% | 1.57% | 1.57% | 0.07% | 1.64% |
| 362.00 Station Equipment | 2.16% | -0.21% | 1.95% | 2.19% | -0.20% | 1.99% |
| 364.01 Poles, Towers and Fixtures - Wood | 2.26% | -0.04% | 2.22% | 2.29% | -0.02% | 2.27% |
| 364.02 Poles, Towers and Fixtures - Steel | 2.75% | 0.16% | 2.91% | 2.55% | 0.26% | 2.81% |
| 365.00 Overhead Conductors and Devices | 1.89% | -0.19% | 1.70% | 1.98% | -0.08% | 1.90% |
| 366.00 Underground Conduit | 1.46% | 0.07% | 1.53% | 1.57% | 0.08% | 1.65% |
| 367.00 Underground Conductors and Devices | 2.76% | 0.10% | 2.86% | 2.63% | 0.09% | 2.72% |
| 368.00 Line Transformers | 1.66% | 0.07% | 1.73% | 1.68% | 0.07% | 1.75% |
| 369.00 Services | 2.20% | | 2.20% | 2.20% | 0.10% | 2.30% |
| 370.01 Meters - Electronic | 3.68% | | 3.68% | 6.24% | -0.03% | 6.21% |
| 370.03 Meters - AMI | 3.82% | | 3.82% | 6.53% | | 6.53% |
| 371.00 Installations on Customers' Premises | 1.75% | 0.19% | 1.94% | 2.34% | 0.34% | 2.68% |
| 373.00 Street Lighting and Signal Systems | 1.47% | 0.13% | 1.60% | 1.72% | 0.13% | 1.85% |
| **Total Distribution Plant** | 2.23% | 0.03% | 2.26% | 2.32% | 0.05% | 2.37% |

**ARIZONA PUBLIC SERVICE COMPANY** Statement A

Component Accrual Rates
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

| Account Description | Current (at 12/31/2010) Investment | Net Salvage | Total | Proposed (at 12/31/2010) Investment | Net Salvage | Total |
|---|---|---|---|---|---|---|
| A | B | C | D=B+C | E | F | G=E+F |
| **GENERAL PLANT** | | | | | | |
| **Depreciable** | | | | | | |
| 390.00 Structures and Improvements | 2.05% | 0.11% | 2.16% | 2.19% | 0.13% | 2.32% |
| 391.CM Office Furn. and Equip. - Computer | 10.19% | 0.01% | 10.20% | 12.08% | 0.02% | 12.10% |
| 397.00 Communication Equipment | 4.72% | | 4.72% | 5.35% | | 5.35% |
| **Total Depreciable** | 5.29% | 0.04% | 5.33% | 6.09% | 0.05% | 6.14% |
| **Amortizable** | | | | | | |
| 391.FE Office Furn. and Equip. - Furniture | ← 20 Year Amortization → | | | ← 20 Year Amortization → | | |
| 393.00 Stores Equipment | ← 20 Year Amortization → | | | ← 20 Year Amortization → | | |
| 394.00 Tools, Shop and Garage Equipment | ← 20 Year Amortization → | | | ← 20 Year Amortization → | | |
| 395.00 Laboratory Equipment | ← 20 Year Amortization → | | | ← 20 Year Amortization → | | |
| 398.00 Miscellaneous Equipment | ← 24 Year Amortization → | | | ← 24 Year Amortization → | | |
| **Total Amortizable** | 4.94% | | 4.94% | 4.93% | -0.02% | 4.91% |
| **Total General Plant** | 5.22% | 0.03% | 5.25% | 5.86% | 0.04% | 5.90% |
| **TOTAL UTILITY** | 2.67% | 0.10% | 2.77% | 2.35% | 0.05% | 2.40% |
| **STEAM PRODUCTION (by Unit)** | | | | | | |
| **Cholla** | | | | | | |
| 311.00 Structures and Improvements | 1.63% | 0.18% | 1.81% | 2.87% | 0.14% | 3.01% |
| 312.00 Boiler Plant Equipment | 1.97% | 0.23% | 2.20% | 3.23% | 0.23% | 3.46% |
| 314.00 Turbogenerator Units | 2.21% | 0.21% | 2.42% | 3.38% | 0.17% | 3.55% |
| 315.00 Accessory Electric Equipment | 1.67% | 0.18% | 1.85% | 2.44% | 0.13% | 2.57% |
| 316.00 Miscellaneous Power Plant Equipment | 2.29% | 0.27% | 2.56% | 3.11% | 0.20% | 3.31% |
| **Total Cholla** | 1.95% | 0.22% | 2.17% | 3.13% | 0.20% | 3.33% |
| **Cholla Unit 1** | | | | | | |
| 311.00 Structures and Improvements | 2.29% | 0.20% | 2.49% | 3.60% | 0.17% | 3.77% |
| 312.00 Boiler Plant Equipment | 3.61% | 0.37% | 3.98% | 4.22% | 0.26% | 4.48% |
| 314.00 Turbogenerator Units | 1.44% | 0.13% | 1.57% | 4.59% | 0.24% | 4.83% |
| 315.00 Accessory Electric Equipment | 2.50% | 0.24% | 2.74% | 3.65% | 0.19% | 3.84% |
| 316.00 Miscellaneous Power Plant Equipment | 2.15% | 0.21% | 2.36% | 3.45% | 0.19% | 3.64% |
| **Total Cholla Unit 1** | 2.95% | 0.30% | 3.25% | 4.22% | 0.24% | 4.46% |
| **Cholla Unit 2** | | | | | | |
| 311.00 Structures and Improvements | 2.02% | 0.19% | 2.21% | 2.81% | 0.15% | 2.96% |
| 312.00 Boiler Plant Equipment | 1.62% | 0.17% | 1.79% | 2.51% | 0.17% | 2.68% |
| 314.00 Turbogenerator Units | 2.21% | 0.19% | 2.40% | 3.11% | 0.17% | 3.28% |
| 315.00 Accessory Electric Equipment | 1.50% | 0.14% | 1.64% | 2.30% | 0.13% | 2.43% |
| 316.00 Miscellaneous Power Plant Equipment | 2.06% | 0.21% | 2.27% | 3.25% | 0.20% | 3.45% |
| **Total Cholla Unit 2** | 1.72% | 0.17% | 1.89% | 2.60% | 0.17% | 2.77% |
| **Cholla Unit 3** | | | | | | |
| 311.00 Structures and Improvements | 1.54% | 0.19% | 1.73% | 2.19% | 0.10% | 2.29% |
| 312.00 Boiler Plant Equipment | 1.67% | 0.22% | 1.89% | 3.40% | 0.25% | 3.65% |
| 314.00 Turbogenerator Units | 2.57% | 0.27% | 2.84% | 3.04% | 0.15% | 3.19% |
| 315.00 Accessory Electric Equipment | 1.55% | 0.20% | 1.75% | 2.16% | 0.12% | 2.28% |
| 316.00 Miscellaneous Power Plant Equipment | 2.00% | 0.27% | 2.27% | 2.48% | 0.15% | 2.63% |
| **Total Cholla Unit 3** | 1.81% | 0.23% | 2.04% | 3.17% | 0.22% | 3.39% |

**ARIZONA PUBLIC SERVICE COMPANY** Statement A

Component Accrual Rates
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

| Account Description | Current (at 12/31/2010) Investment | Net Salvage | Total | Proposed (at 12/31/2010) Investment | Net Salvage | Total |
|---|---|---|---|---|---|---|
| A | B | C | D=B+C | E | F | G=E+F |
| **Cholla Common** | | | | | | |
| 311.00 Structures and Improvements | 1.55% | 0.17% | 1.72% | 2.94% | 0.15% | 3.09% |
| 312.00 Boiler Plant Equipment | 2.07% | 0.29% | 2.36% | 3.32% | 0.25% | 3.57% |
| 314.00 Turbogenerator Units | 2.20% | 0.13% | 2.33% | 2.67% | 0.13% | 2.80% |
| 315.00 Accessory Electric Equipment | 2.22% | 0.26% | 2.48% | 2.96% | 0.18% | 3.14% |
| 316.00 Miscellaneous Power Plant Equipment | 2.60% | 0.33% | 2.93% | 3.16% | 0.22% | 3.38% |
| **Total Cholla Common** | 1.92% | 0.24% | 2.16% | 3.13% | 0.20% | 3.33% |
| **Four Corners** | | | | | | |
| 311.00 Structures and Improvements | 5.32% | 0.63% | 5.95% | 0.68% | 0.36% | 1.04% |
| 312.00 Boiler Plant Equipment | 4.42% | 0.58% | 5.00% | 0.81% | 0.51% | 1.32% |
| 314.00 Turbogenerator Units | 4.73% | 0.55% | 5.28% | 0.82% | 0.49% | 1.31% |
| 315.00 Accessory Electric Equipment | 4.18% | 0.52% | 4.70% | 0.92% | 0.49% | 1.41% |
| 316.00 Miscellaneous Power Plant Equipment | 5.49% | 0.74% | 6.23% | 1.37% | 0.47% | 1.84% |
| **Total Four Corners** | 4.58% | 0.58% | 5.16% | 0.83% | 0.49% | 1.32% |
| **Four Corners Units 1-3** | | | | | | |
| 311.00 Structures and Improvements | 6.56% | 0.73% | 7.29% | | | |
| 312.00 Boiler Plant Equipment | 5.81% | 0.71% | 6.52% | | | |
| 314.00 Turbogenerator Units | 5.90% | 0.64% | 6.54% | | | |
| 315.00 Accessory Electric Equipment | 5.43% | 0.61% | 6.04% | | | |
| 316.00 Miscellaneous Power Plant Equipment | 8.65% | 1.02% | 9.67% | | | |
| **Total Four Corners Units 1-3** | 5.97% | 0.71% | 6.68% | | | |
| **Four Corners Units 4-5** | | | | | | |
| 311.00 Structures and Improvements | 2.12% | 0.35% | 2.47% | 2.36% | 1.56% | 3.92% |
| 312.00 Boiler Plant Equipment | 1.80% | 0.32% | 2.12% | 2.32% | 1.54% | 3.86% |
| 314.00 Turbogenerator Units | 2.21% | 0.36% | 2.57% | 2.68% | 1.68% | 4.36% |
| 315.00 Accessory Electric Equipment | 1.96% | 0.33% | 2.29% | 2.34% | 1.52% | 3.86% |
| 316.00 Miscellaneous Power Plant Equipment | 2.21% | 0.38% | 2.59% | 2.51% | 1.65% | 4.16% |
| **Total Four Corners Units 4-5** | 1.89% | 0.33% | 2.22% | 2.37% | 1.56% | 3.93% |
| **Four Corners Common** | | | | | | |
| 311.00 Structures and Improvements | 2.79% | 0.46% | 3.25% | 2.23% | 0.48% | 2.71% |
| 312.00 Boiler Plant Equipment | 2.71% | 0.48% | 3.19% | 2.09% | 0.49% | 2.58% |
| 314.00 Turbogenerator Units | 2.20% | 0.32% | 2.52% | 1.65% | 0.28% | 1.93% |
| 315.00 Accessory Electric Equipment | 2.95% | 0.49% | 3.44% | 2.39% | 0.53% | 2.92% |
| 316.00 Miscellaneous Power Plant Equipment | 3.09% | 0.54% | 3.63% | 2.50% | 0.58% | 3.08% |
| **Total Four Corners Common** | 2.83% | 0.49% | 3.32% | 2.24% | 0.50% | 2.74% |
| **Navajo Units 1-3** | | | | | | |
| 311.00 Structures and Improvements | 2.63% | 0.27% | 2.90% | 3.34% | 0.24% | 3.58% |
| 312.00 Boiler Plant Equipment | 2.80% | 0.32% | 3.12% | 3.42% | 0.28% | 3.70% |
| 314.00 Turbogenerator Units | 2.06% | 0.22% | 2.28% | 2.71% | 0.20% | 2.91% |
| 315.00 Accessory Electric Equipment | 2.19% | 0.24% | 2.43% | 2.93% | 0.21% | 3.14% |
| 316.00 Miscellaneous Power Plant Equipment | 3.22% | 0.36% | 3.58% | 3.75% | 0.29% | 4.04% |
| **Total Navajo Units 1-3** | 2.69% | 0.30% | 2.99% | 3.32% | 0.27% | 3.59% |
| **Ocotillo Units 1-2** | | | | | | |
| 311.00 Structures and Improvements | 3.59% | 1.02% | 4.61% | 4.91% | 0.88% | 5.79% |
| 312.00 Boiler Plant Equipment | 2.83% | 0.85% | 3.68% | 3.41% | 0.65% | 4.06% |
| 314.00 Turbogenerator Units | 2.64% | 0.79% | 3.43% | 4.74% | 0.88% | 5.62% |
| 315.00 Accessory Electric Equipment | 3.12% | 0.91% | 4.03% | 4.55% | 0.84% | 5.39% |
| 316.00 Miscellaneous Power Plant Equipment | 5.26% | 1.52% | 6.78% | 5.80% | 1.10% | 6.90% |
| **Total Ocotillo Units 1-2** | 3.09% | 0.91% | 4.00% | 4.29% | 0.80% | 5.09% |

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Component Accrual Rates
Current: VG Procedure / RL Technique
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| Account Description | Current (at 12/31/2010) Investment | Net Salvage | Total | Proposed (at 12/31/2010) Investment | Net Salvage | Total |
|---|---|---|---|---|---|---|
| A | B | C | D=B+C | E | F | G=E+F |
| **Saguaro Units 1-2** | | | | | | |
| 311.00 Structures and Improvements | 2.81% | 0.80% | 3.61% | 5.51% | 1.01% | 6.52% |
| 312.00 Boiler Plant Equipment | 2.47% | 0.71% | 3.18% | 4.40% | 0.84% | 5.24% |
| 314.00 Turbogenerator Units | 2.04% | 0.59% | 2.63% | 3.30% | 0.61% | 3.91% |
| 315.00 Accessory Electric Equipment | 4.27% | 1.23% | 5.50% | 5.65% | 1.05% | 6.70% |
| 316.00 Miscellaneous Power Plant Equipment | 3.95% | 1.16% | 5.11% | 5.11% | 0.96% | 6.07% |
| **Total Saguaro Units 1-2** | 2.67% | 0.77% | 3.44% | 4.35% | 0.82% | 5.17% |
| **NUCLEAR PRODUCTION (by Unit)** | | | | | | |
| **Palo Verde** | | | | | | |
| 321.00 Structures and Improvements | 2.63% | 0.01% | 2.64% | 1.33% | 0.01% | 1.34% |
| 322.00 Reactor Plant Equipment | 2.84% | 0.05% | 2.89% | 1.50% | 0.05% | 1.55% |
| 323.00 Turbogenerator Units | 2.75% | 0.01% | 2.76% | 1.44% | 0.02% | 1.46% |
| 324.00 Accessory Electric Equipment | 2.54% | 0.01% | 2.55% | 1.19% | 0.01% | 1.20% |
| 325.00 Miscellaneous Power Plant Equipment | 2.88% | 0.04% | 2.92% | 1.47% | 0.04% | 1.51% |
| **Total Palo Verde** | 2.74% | 0.03% | 2.77% | 1.41% | 0.03% | 1.44% |
| **Palo Verde Unit 1** | | | | | | |
| 321.00 Structures and Improvements | 2.66% | 0.01% | 2.67% | 1.13% | | 1.13% |
| 322.00 Reactor Plant Equipment | 3.16% | 0.04% | 3.20% | 1.45% | 0.04% | 1.49% |
| 323.00 Turbogenerator Units | 3.01% | 0.01% | 3.02% | 1.41% | 0.02% | 1.43% |
| 324.00 Accessory Electric Equipment | 2.64% | 0.01% | 2.65% | 1.11% | 0.01% | 1.12% |
| 325.00 Miscellaneous Power Plant Equipment | 2.86% | 0.03% | 2.89% | 1.29% | 0.02% | 1.31% |
| **Total Palo Verde Unit 1** | 2.97% | 0.03% | 3.00% | 1.34% | 0.02% | 1.36% |
| **Palo Verde Unit 2** | | | | | | |
| 321.00 Structures and Improvements | 2.66% | 0.01% | 2.67% | 1.20% | 0.01% | 1.21% |
| 322.00 Reactor Plant Equipment | 3.09% | 0.08% | 3.17% | 1.52% | 0.08% | 1.60% |
| 323.00 Turbogenerator Units | 2.93% | 0.02% | 2.95% | 1.41% | 0.01% | 1.42% |
| 324.00 Accessory Electric Equipment | 2.69% | 0.01% | 2.70% | 1.25% | 0.01% | 1.26% |
| 325.00 Miscellaneous Power Plant Equipment | 3.05% | 0.02% | 3.07% | 1.45% | 0.02% | 1.47% |
| **Total Palo Verde Unit 2** | 2.94% | 0.05% | 2.99% | 1.41% | 0.04% | 1.45% |
| **Palo Verde Unit 3** | | | | | | |
| 321.00 Structures and Improvements | 2.34% | | 2.34% | 1.22% | | 1.22% |
| 322.00 Reactor Plant Equipment | 2.38% | 0.05% | 2.43% | 1.56% | 0.05% | 1.61% |
| 323.00 Turbogenerator Units | 2.42% | 0.01% | 2.43% | 1.48% | 0.02% | 1.50% |
| 324.00 Accessory Electric Equipment | 2.34% | 0.01% | 2.35% | 1.24% | 0.01% | 1.25% |
| 325.00 Miscellaneous Power Plant Equipment | 2.51% | 0.02% | 2.53% | 1.36% | 0.02% | 1.38% |
| **Total Palo Verde Unit 3** | 2.38% | 0.03% | 2.41% | 1.44% | 0.03% | 1.47% |
| **Palo Verde Water Reclamation** | | | | | | |
| 321.00 Structures and Improvements | 2.84% | 0.02% | 2.86% | 1.69% | 0.02% | 1.71% |
| 322.00 Reactor Plant Equipment | 3.93% | 0.03% | 3.96% | 2.01% | 0.03% | 2.04% |
| 323.00 Turbogenerator Units | 2.85% | 0.02% | 2.87% | 1.45% | 0.01% | 1.46% |
| 324.00 Accessory Electric Equipment | | | | | | |
| 325.00 Miscellaneous Power Plant Equipment | 2.83% | 0.05% | 2.88% | 1.43% | 0.05% | 1.48% |
| **Total Palo Verde Water Reclamation** | 2.84% | 0.02% | 2.86% | 1.69% | 0.02% | 1.71% |

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Component Accrual Rates
Current: VG Procedure / RL Technique
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| Account Description | Current (at 12/31/2010) Investment | Net Salvage | Total | Proposed (at 12/31/2010) Investment | Net Salvage | Total |
|---|---|---|---|---|---|---|
| A | B | C | D=B+C | E | F | G=E+F |
| **Palo Verde Common** | | | | | | |
| 321.00 Structures and Improvements | 2.64% | 0.02% | 2.66% | 1.30% | 0.02% | 1.32% |
| 322.00 Reactor Plant Equipment | 2.48% | 0.08% | 2.56% | 1.22% | 0.06% | 1.28% |
| 323.00 Turbogenerator Units | 4.38% | 0.06% | 4.44% | 2.15% | 0.04% | 2.19% |
| 324.00 Accessory Electric Equipment | 2.51% | 0.01% | 2.52% | 1.21% | 0.01% | 1.22% |
| 325.00 Miscellaneous Power Plant Equipment | 2.99% | 0.06% | 3.05% | 1.64% | 0.06% | 1.70% |
| **Total Palo Verde Common** | 2.72% | 0.04% | 2.76% | 1.38% | 0.03% | 1.41% |
| **OTHER PRODUCTION (by Unit)** | | | | | | |
| **Douglas CT** | | | | | | |
| 341.00 Structures and Improvements | 5.94% | 0.29% | 6.23% | 5.13% | -0.26% | 4.87% |
| 342.00 Fuel Holders, Products and Accessories | 1.82% | 0.06% | 1.88% | 0.90% | -0.01% | 0.89% |
| 343.00 Prime Movers | 0.73% | 0.04% | 0.77% | -0.25% | 0.02% | -0.23% |
| 344.00 Generators and Devices | 0.70% | 0.03% | 0.73% | -0.28% | 0.01% | -0.27% |
| 345.00 Accessory Electric Equipment | 0.98% | 0.07% | 1.05% | 0.02% | 0.02% | 0.04% |
| 346.00 Miscellaneous Power Plant Equipment | 1.65% | 0.08% | 1.73% | 0.70% | -0.03% | 0.67% |
| **Total Douglas CT** | 0.96% | 0.05% | 1.01% | -0.01% | 0.01% | |
| **Ocotillo CT Units 1-2** | | | | | | |
| 341.00 Structures and Improvements | 2.02% | 0.10% | 2.12% | 4.19% | -0.20% | 3.99% |
| 342.00 Fuel Holders, Products and Accessories | 1.93% | 0.09% | 2.02% | 2.07% | -0.10% | 1.97% |
| 343.00 Prime Movers | 1.26% | 0.06% | 1.32% | 0.73% | -0.03% | 0.70% |
| 344.00 Generators and Devices | 3.26% | 0.13% | 3.39% | 3.44% | -0.61% | 2.83% |
| 345.00 Accessory Electric Equipment | 1.68% | 0.10% | 1.78% | 1.60% | -0.06% | 1.54% |
| 346.00 Miscellaneous Power Plant Equipment | 1.77% | 0.08% | 1.85% | 2.14% | -0.09% | 2.05% |
| **Total Octillo CT Units 1-2** | 2.22% | 0.10% | 2.32% | 2.21% | -0.29% | 1.92% |
| **Redhawk CC Units 1-2** | | | | | | |
| 341.00 Structures and Improvements | 3.01% | 0.42% | 3.43% | 3.13% | -0.12% | 3.01% |
| 342.00 Fuel Holders, Products and Accessories | 3.46% | 0.17% | 3.63% | 3.63% | -0.18% | 3.45% |
| 343.00 Prime Movers | 2.98% | 0.07% | 3.05% | 3.11% | -0.08% | 3.03% |
| 344.00 Generators and Devices | 3.02% | 0.12% | 3.14% | 3.33% | -0.83% | 2.50% |
| 345.00 Accessory Electric Equipment | 2.99% | 0.12% | 3.11% | 3.11% | -0.10% | 3.01% |
| 346.00 Miscellaneous Power Plant Equipment | 3.27% | 0.17% | 3.44% | 3.60% | -0.18% | 3.42% |
| **Total Redhawk CC Units 1-2** | 3.01% | 0.12% | 3.13% | 3.24% | -0.50% | 2.74% |
| **Saguaro** | | | | | | |
| 341.00 Structures and Improvements | 3.82% | 0.19% | 4.01% | 4.60% | -0.22% | 4.38% |
| 342.00 Fuel Holders, Products and Accessories | 1.62% | 0.07% | 1.69% | 1.27% | -0.03% | 1.24% |
| 343.00 Prime Movers | 1.38% | 0.07% | 1.45% | 0.63% | -0.03% | 0.60% |
| 344.00 Generators and Devices | 3.10% | 0.15% | 3.25% | 2.92% | -0.19% | 2.73% |
| 345.00 Accessory Electric Equipment | 1.35% | 0.08% | 1.43% | 0.63% | -0.02% | 0.61% |
| 346.00 Miscellaneous Power Plant Equipment | 3.20% | 0.16% | 3.36% | 2.57% | -0.12% | 2.45% |
| **Total Saguaro** | 2.71% | 0.13% | 2.84% | 2.43% | -0.15% | 2.28% |
| **Saguaro CT Units 1-2** | | | | | | |
| 341.00 Structures and Improvements | 3.82% | 0.19% | 4.01% | 4.60% | -0.22% | 4.38% |
| 342.00 Fuel Holders, Products and Accessories | 1.62% | 0.07% | 1.69% | 1.27% | -0.03% | 1.24% |
| 343.00 Prime Movers | 1.25% | 0.06% | 1.31% | 0.45% | -0.02% | 0.43% |
| 344.00 Generators and Devices | 4.08% | 0.18% | 4.26% | 3.36% | -0.52% | 2.84% |
| 345.00 Accessory Electric Equipment | 1.23% | 0.07% | 1.30% | 0.46% | -0.01% | 0.45% |
| 346.00 Miscellaneous Power Plant Equipment | 3.20% | 0.16% | 3.36% | 2.57% | -0.12% | 2.45% |
| **Total Saguaro CT Units 1-2** | 2.33% | 0.11% | 2.44% | 1.76% | -0.17% | 1.59% |

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|---|---|---|---|---|---|---|
| A | B | C | D=B+C | E | F | G=E+F |
| **Saguaro CT Unit 3** | | | | | | |
| 341.00 Structures and Improvements | | | | | | |
| 342.00 Fuel Holders, Products and Accessories | | | | | | |
| 343.00 Prime Movers | 2.94% | 0.15% | 3.09% | 2.85% | -0.14% | 2.71% |
| 344.00 Generators and Devices | 2.94% | 0.15% | 3.09% | 2.85% | -0.14% | 2.71% |
| 345.00 Accessory Electric Equipment | 2.94% | 0.15% | 3.09% | 2.85% | -0.14% | 2.71% |
| 346.00 Miscellaneous Power Plant Equipment | | | | | | |
| **Total Saguaro CT Unit 3** | 2.94% | 0.15% | 3.09% | 2.85% | -0.14% | 2.71% |
| **Solar Units** | | | | | | |
| 341.00 Structures and Improvements | 0.52% | 0.02% | 0.54% | -3.55% | 0.20% | -3.35% |
| 342.00 Fuel Holders, Products and Accessories | | | | | | |
| 343.00 Prime Movers | | | | | | |
| 344.00 Generators and Devices | 5.59% | 0.31% | 5.90% | 3.93% | -0.86% | 3.07% |
| 345.00 Accessory Electric Equipment | 5.36% | 0.27% | 5.63% | 7.41% | -0.37% | 7.04% |
| 346.00 Miscellaneous Power Plant Equipment | | | | | | |
| **Total Solar Units** | 5.46% | 0.30% | 5.76% | 3.90% | -0.82% | 3.08% |
| **Sundance** | | | | | | |
| 341.00 Structures and Improvements | 2.21% | 0.11% | 2.32% | 2.06% | -0.10% | 1.96% |
| 342.00 Fuel Holders, Products and Accessories | 2.19% | 0.11% | 2.30% | 2.05% | -0.10% | 1.95% |
| 343.00 Prime Movers | 2.20% | 0.11% | 2.31% | 2.04% | -0.11% | 1.93% |
| 344.00 Generators and Devices | 3.02% | 0.15% | 3.17% | 2.51% | -0.13% | 2.38% |
| 345.00 Accessory Electric Equipment | 2.19% | 0.11% | 2.30% | 2.05% | -0.10% | 1.95% |
| 346.00 Miscellaneous Power Plant Equipment | 2.19% | 0.11% | 2.30% | 2.49% | -0.12% | 2.37% |
| **Total Sun Dance** | 2.20% | 0.11% | 2.31% | 2.05% | -0.11% | 1.94% |
| **West Phoenix** | | | | | | |
| 341.00 Structures and Improvements | 2.54% | 0.15% | 2.69% | 3.04% | -0.14% | 2.90% |
| 342.00 Fuel Holders, Products and Accessories | 3.53% | 0.18% | 3.71% | 3.69% | -0.17% | 3.52% |
| 343.00 Prime Movers | 2.97% | 0.12% | 3.09% | 2.89% | -0.10% | 2.79% |
| 344.00 Generators and Devices | 3.32% | 0.15% | 3.47% | 3.38% | -0.37% | 3.01% |
| 345.00 Accessory Electric Equipment | 3.31% | 0.16% | 3.47% | 3.36% | -0.15% | 3.21% |
| 346.00 Miscellaneous Power Plant Equipment | 3.08% | 0.16% | 3.24% | 3.95% | -0.17% | 3.78% |
| **Total West Phoenix** | 3.17% | 0.14% | 3.31% | 3.23% | -0.25% | 2.98% |
| **West Phoenix CC Units 1-3** | | | | | | |
| 341.00 Structures and Improvements | 4.01% | 0.19% | 4.20% | 5.00% | -0.24% | 4.76% |
| 342.00 Fuel Holders, Products and Accessories | 3.75% | 0.19% | 3.94% | 4.02% | -0.18% | 3.84% |
| 343.00 Prime Movers | | | | | | |
| 344.00 Generators and Devices | 3.83% | 0.16% | 3.99% | 4.08% | -0.65% | 3.43% |
| 345.00 Accessory Electric Equipment | 3.77% | 0.18% | 3.95% | 4.01% | -0.15% | 3.86% |
| 346.00 Miscellaneous Power Plant Equipment | 2.98% | 0.16% | 3.14% | 4.17% | -0.18% | 3.99% |
| **Total West Phoenix CC Units 1-3** | 3.78% | 0.17% | 3.95% | 4.08% | -0.50% | 3.58% |
| **West Phoenix CC Unit 4** | | | | | | |
| 341.00 Structures and Improvements | 3.04% | 0.15% | 3.19% | 3.05% | -0.15% | 2.90% |
| 342.00 Fuel Holders, Products and Accessories | 2.98% | 0.15% | 3.13% | 2.98% | -0.15% | 2.83% |
| 343.00 Prime Movers | 2.98% | 0.15% | 3.13% | 2.98% | -0.15% | 2.83% |
| 344.00 Generators and Devices | 3.02% | 0.16% | 3.18% | 3.07% | -0.30% | 2.77% |
| 345.00 Accessory Electric Equipment | 3.25% | 0.16% | 3.41% | 3.57% | -0.18% | 3.39% |
| 346.00 Miscellaneous Power Plant Equipment | 3.19% | 0.16% | 3.35% | 3.72% | -0.17% | 3.55% |
| **Total West Phoenix CC Unit 4** | 3.00% | 0.15% | 3.15% | 3.02% | -0.18% | 2.84% |

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|---|---|---|---|---|---|---|
| A | B | C | D=B+C | E | F | G=E+F |
| **West Phoenix CC Unit 5** | | | | | | |
| 341.00 Structures and Improvements | 3.02% | 0.16% | 3.18% | 2.92% | -0.15% | 2.77% |
| 342.00 Fuel Holders, Products and Accessories | | | | | | |
| 343.00 Prime Movers | 3.06% | 0.10% | 3.16% | 3.01% | -0.08% | 2.93% |
| 344.00 Generators and Devices | 3.03% | 0.15% | 3.18% | 2.97% | -0.19% | 2.78% |
| 345.00 Accessory Electric Equipment | 3.02% | 0.15% | 3.17% | 2.91% | -0.15% | 2.76% |
| 346.00 Miscellaneous Power Plant Equipment | 3.18% | 0.16% | 3.34% | 3.40% | -0.17% | 3.23% |
| **Total West Phoenix CC Unit 5** | 3.04% | 0.13% | 3.17% | 2.98% | -0.14% | 2.84% |
| **West Phoenix CT Units 1-2** | | | | | | |
| 341.00 Structures and Improvements | 1.36% | 0.07% | 1.43% | 3.80% | -0.19% | 3.61% |
| 342.00 Fuel Holders, Products and Accessories | 1.57% | 0.08% | 1.65% | 0.61% | -0.03% | 0.58% |
| 343.00 Prime Movers | 1.95% | 0.08% | 2.03% | 1.00% | -0.03% | 0.97% |
| 344.00 Generators and Devices | 2.48% | 0.13% | 2.61% | 2.25% | -0.21% | 2.04% |
| 345.00 Accessory Electric Equipment | 1.83% | 0.10% | 1.93% | 0.95% | -0.04% | 0.91% |
| 346.00 Miscellaneous Power Plant Equipment | 3.46% | 0.17% | 3.63% | 3.25% | -0.16% | 3.09% |
| **Total West Phoenix CT Units 1-2** | 2.11% | 0.10% | 2.21% | 1.55% | -0.09% | 1.46% |
| **West Phoenix Common** | | | | | | |
| 341.00 Structures and Improvements | 1.59% | 0.13% | 1.72% | 2.76% | -0.12% | 2.64% |
| 342.00 Fuel Holders, Products and Accessories | | | | | | |
| 343.00 Prime Movers | | | | | | |
| 344.00 Generators and Devices | | | | | | |
| 345.00 Accessory Electric Equipment | | | | | | |
| 346.00 Miscellaneous Power Plant Equipment | | | | | | |
| **Total West Phoenix Common** | 1.59% | 0.13% | 1.72% | 2.76% | -0.12% | 2.64% |
| **Yucca** | | | | | | |
| 341.00 Structures and Improvements | 3.31% | 0.12% | 3.43% | 2.50% | -0.10% | 2.40% |
| 342.00 Fuel Holders, Products and Accessories | 1.41% | 0.03% | 1.44% | 1.00% | -0.05% | 0.95% |
| 343.00 Prime Movers | 2.50% | | 2.50% | 2.65% | -0.13% | 2.52% |
| 344.00 Generators and Devices | 2.61% | 0.12% | 2.73% | 1.28% | -0.24% | 1.04% |
| 345.00 Accessory Electric Equipment | 2.41% | 0.11% | 2.52% | 1.03% | -0.04% | 0.99% |
| 346.00 Miscellaneous Power Plant Equipment | 2.37% | 0.11% | 2.48% | 1.11% | -0.06% | 1.05% |
| **Total Yucca** | 2.46% | 0.02% | 2.48% | 2.38% | -0.13% | 2.25% |
| **Yucca CT Units 1-4** | | | | | | |
| 341.00 Structures and Improvements | 3.58% | 0.17% | 3.75% | 2.29% | -0.08% | 2.21% |
| 342.00 Fuel Holders, Products and Accessories | 0.81% | 0.04% | 0.85% | 0.11% | | 0.11% |
| 343.00 Prime Movers | 0.58% | 0.03% | 0.61% | -0.09% | | -0.09% |
| 344.00 Generators and Devices | 2.61% | 0.12% | 2.73% | 1.27% | -0.24% | 1.03% |
| 345.00 Accessory Electric Equipment | 2.36% | 0.13% | 2.49% | 0.75% | -0.03% | 0.72% |
| 346.00 Miscellaneous Power Plant Equipment | 2.37% | 0.11% | 2.48% | 1.11% | -0.06% | 1.05% |
| **Total Yucca CT Units 1-4** | 1.69% | 0.08% | 1.77% | 0.64% | -0.09% | 0.55% |
| **Yucca CT Units 5-6** | | | | | | |
| 341.00 Structures and Improvements | 2.72% | | 2.72% | 2.97% | -0.15% | 2.82% |
| 342.00 Fuel Holders, Products and Accessories | 2.72% | | 2.72% | 2.97% | -0.15% | 2.82% |
| 343.00 Prime Movers | 2.72% | | 2.72% | 2.97% | -0.15% | 2.82% |
| 344.00 Generators and Devices | 2.72% | | 2.72% | 2.97% | -0.15% | 2.82% |
| 345.00 Accessory Electric Equipment | 2.72% | | 2.72% | 2.97% | -0.15% | 2.82% |
| 346.00 Miscellaneous Power Plant Equipment | 2.72% | | 2.72% | | | |
| **Total Yucca CT Units 5-6** | 2.72% | | 2.72% | 2.97% | -0.15% | 2.82% |

**ARIZONA PUBLIC SERVICE COMPANY**

Component Accruals

Current: VG Procedure / RL Technique

Proposed: VG Procedure / RL Technique

Statement B

| Account Description | 12/31/10 Investment | Current 2011 Annualized Accrual | | | Proposed 2011 Annualized Accrual | | | Difference |
|---|---|---|---|---|---|---|---|---|
| | | Investment | Net Salvage | Total | Investment | Net Salvage | Total | |
| A | B | C | D | E=C+D | F | G | H=F+G | I=H-E |
| **STEAM PRODUCTION** | | | | | | | | |
| 311.00 Structures and Improvements | $168,068,708 | $5,299,006 | $650,659 | $5,949,665 | $3,907,814 | $468,971 | $4,376,785 | ($1,572,880) |
| 312.00 Boiler Plant Equipment | 1,114,508,323 | 32,896,330 | 4,318,033 | 37,214,363 | 27,592,917 | 3,922,683 | 31,515,600 | (5,698,763) |
| 314.00 Turbogenerator Units | 260,287,212 | 7,625,434 | 981,350 | 8,606,784 | 7,012,405 | 909,063 | 7,921,468 | (685,316) |
| 315.00 Accessory Electric Equipment | 164,350,445 | 4,059,821 | 528,092 | 4,587,913 | 3,758,257 | 454,941 | 4,213,198 | (374,715) |
| 316.00 Miscellaneous Power Plant Equipment | 81,726,740 | 3,110,985 | 473,618 | 3,584,603 | 2,460,131 | 337,989 | 2,798,120 | (786,483) |
| **Total Steam Production Plant** | $1,788,941,428 | $52,991,576 | $6,951,752 | $59,943,328 | $44,731,524 | $6,093,647 | $50,825,171 | ($9,118,157) |
| **NUCLEAR PRODUCTION** | | | | | | | | |
| 321.00 Structures and Improvements | $698,846,801 | $18,352,868 | $82,295 | $18,435,163 | $9,265,673 | $66,624 | $9,332,297 | ($9,102,866) |
| 322.00 Reactor Plant Equipment | 1,130,933,859 | 32,152,405 | 598,662 | 32,751,067 | 16,955,122 | 593,091 | 17,548,213 | (15,202,854) |
| 323.00 Turbogenerator Units | 354,174,138 | 9,754,391 | 44,384 | 9,798,775 | 5,113,500 | 63,385 | 5,176,885 | (4,621,890) |
| 324.00 Accessory Electric Equipment | 275,016,677 | 6,987,700 | 27,502 | 7,015,202 | 3,260,068 | 27,502 | 3,287,570 | (3,727,632) |
| 325.00 Miscellaneous Power Plant Equipment | 145,211,312 | 4,180,067 | 55,558 | 4,235,625 | 2,141,613 | 52,477 | 2,194,090 | (2,041,535) |
| **Total Nuclear Production Plant** | $2,604,182,787 | $71,427,431 | $808,401 | $72,235,832 | $36,735,976 | $803,079 | $37,539,055 | ($34,696,777) |
| **OTHER PRODUCTION** | | | | | | | | |
| 341.00 Structures and Improvements | $67,262,184 | $1,796,973 | $154,270 | $1,951,243 | $1,943,435 | ($86,365) | $1,857,070 | ($94,173) |
| 342.00 Fuel Holders, Products and Accessories | 42,179,346 | 1,284,039 | 62,466 | 1,346,505 | 1,305,027 | (59,713) | 1,245,314 | (101,191) |
| 343.00 Prime Movers | 664,641,919 | 17,360,793 | 579,944 | 17,940,737 | 17,097,476 | (667,083) | 16,430,393 | (1,510,344) |
| 344.00 Generators and Devices | 588,169,993 | 18,909,096 | 830,642 | 19,739,738 | 19,503,087 | (3,490,611) | 16,012,476 | (3,727,262) |
| 345.00 Accessory Electric Equipment | 86,274,192 | 2,405,635 | 112,836 | 2,518,471 | 2,361,735 | (97,652) | 2,264,083 | (254,388) |
| 346.00 Miscellaneous Power Plant Equipment | 14,711,421 | 430,245 | 22,159 | 452,404 | 493,373 | (22,998) | 470,375 | 17,971 |
| **Total Other Production Plant** | $1,463,239,055 | $42,186,781 | $1,762,317 | $43,949,098 | $42,704,133 | ($4,424,422) | $38,279,711 | ($5,669,387) |
| **TRANSMISSION PLANT** | | | | | | | | |
| 352.02 Structures and Improvements | $95,935 | $2,350 | | $2,350 | $2,561 | | $2,561 | $211 |
| 353.00 Station Equipment | 98,305,656 | 2,251,200 | | 2,251,200 | 2,270,861 | 108,136 | 2,378,997 | 127,797 |
| 354.00 Towers and Fixtures | 1,329,316 | 23,662 | | 23,662 | 24,459 | | 24,459 | 797 |
| 355.00 Poles and Fixtures | 1,370,085 | 27,813 | 5,480 | 33,293 | 25,484 | 5,069 | 30,553 | (2,740) |
| 356.00 Overhead Conductors and Devices | 1,947,677 | 33,500 | (6,427) | 27,073 | 34,084 | 6,427 | 40,511 | 13,438 |
| **Total Transmission Plant** | $103,048,669 | $2,338,525 | ($947) | $2,337,578 | $2,357,449 | $119,632 | $2,477,081 | $139,503 |
| **DISTRIBUTION PLANT** | | | | | | | | |
| 361.00 Structures and Improvements | $60,888,680 | $919,419 | $36,533 | $955,952 | $955,952 | $42,622 | $998,574 | $42,622 |
| 362.00 Station Equipment | 406,799,985 | 8,786,880 | (854,280) | 7,932,600 | 8,908,920 | (813,600) | 8,095,320 | 162,720 |
| 364.01 Poles, Towers and Fixtures - Wood | 310,263,864 | 7,011,963 | (124,106) | 6,887,857 | 7,105,042 | (62,053) | 7,042,989 | 155,132 |
| 364.02 Poles, Towers and Fixtures - Steel | 167,311,767 | 4,601,074 | 267,699 | 4,868,773 | 4,266,450 | 435,011 | 4,701,461 | (167,312) |
| 365.00 Overhead Conductors and Devices | 292,642,985 | 5,530,952 | (556,022) | 4,974,930 | 5,794,331 | (234,114) | 5,560,217 | 585,287 |
| 366.00 Underground Conduit | 620,488,170 | 9,059,127 | 434,342 | 9,493,469 | 9,741,664 | 496,391 | 10,238,055 | 744,586 |
| 367.00 Underground Conductors and Devices | 1,422,708,502 | 39,266,755 | 1,422,709 | 40,689,464 | 37,417,234 | 1,280,438 | 38,697,672 | (1,991,792) |

**ARIZONA PUBLIC SERVICE COMPANY**

Component Accruals

Current: VG Procedure / RL Technique

Proposed: VG Procedure / RL Technique

Statement B

| Account Description | 12/31/10 Investment | Current 2011 Annualized Accrual | | | Proposed 2011 Annualized Accrual | | | Difference |
|---|---|---|---|---|---|---|---|---|
| | | Investment | Net Salvage | Total | Investment | Net Salvage | Total | |
| A | B | C | D | E=C+D | F | G | H=F+G | I=H-E |
| 368.00 Line Transformers | 717,419,840 | 11,909,169 | 502,194 | 12,411,363 | 12,052,653 | 502,194 | 12,554,847 | 143,484 |
| 369.00 Services | 323,341,677 | 7,113,517 | | 7,113,517 | 7,113,517 | 323,342 | 7,436,859 | 323,342 |
| 370.01 Meters - Electronic | 62,207,543 | 2,289,238 | | 2,289,238 | 3,881,751 | (18,662) | 3,863,089 | 1,573,851 |
| 370.03 Meters - AMI | 117,715,566 | 4,496,735 | | 4,496,735 | 7,686,826 | | 7,686,826 | 3,190,091 |
| 371.00 Installations on Customers' Premises | 39,842,142 | 697,237 | 75,700 | 772,937 | 932,306 | 135,463 | 1,067,769 | 294,832 |
| 373.00 Street Lighting and Signal Systems | 73,702,827 | 1,083,432 | 95,814 | 1,179,246 | 1,267,689 | 95,814 | 1,363,503 | 184,257 |
| **Total Distribution Plant** | $4,615,333,548 | $102,765,498 | $1,300,583 | $104,066,081 | $107,124,335 | $2,182,846 | $109,307,181 | $5,241,100 |
| **GENERAL PLANT** | | | | | | | | |
| **Depreciable** | | | | | | | | |
| 390.00 Structures and Improvements | $107,643,854 | $2,206,699 | $118,408 | $2,325,107 | $2,357,400 | $139,937 | $2,497,337 | $172,230 |
| 391.CM Office Furn. and Equip. - Computer | 89,098,127 | 9,079,099 | 8,910 | 9,088,009 | 10,763,054 | 17,820 | 10,780,874 | 1,692,865 |
| 397.00 Communication Equipment | 152,910,098 | 7,217,357 | | 7,217,357 | 8,180,690 | | 8,180,690 | 963,333 |
| **Total Depreciable** | $349,652,079 | $18,503,155 | $127,318 | $18,630,473 | $21,301,144 | $157,757 | $21,458,901 | $2,828,428 |
| **Amortizable** | | | | | | | | |
| 391.FE Office Furn. and Equip. - Furniture | $49,130,094 | $2,456,505 | | $2,456,505 | $2,455,941 | | $2,455,941 | ($564) |
| 393.00 Stores Equipment | 256,764 | 12,838 | | 12,838 | 12,838 | | 12,838 | |
| 394.00 Tools, Shop and Garage Equipment | 28,424,012 | 1,421,201 | | 1,421,201 | 1,406,986 | | 1,406,986 | (14,215) |
| 395.00 Laboratory Equipment | 1,385,366 | 69,268 | | 69,268 | 58,318 | | 58,318 | (10,950) |
| 398.00 Miscellaneous Equipment | 5,909,111 | 246,213 | | 246,213 | 246,213 | | 246,213 | |
| **Total Amortizable** | $85,105,347 | $4,206,025 | | $4,206,025 | $4,180,296 | | $4,180,296 | ($25,729) |
| **Total General Plant** | $434,757,426 | $22,709,180 | $127,318 | $22,836,498 | $25,481,440 | $157,757 | $25,639,197 | $2,802,699 |
| **TOTAL UTILITY** | $11,009,502,913 | $294,418,991 | $10,949,424 | $305,368,415 | $259,134,857 | $4,932,539 | $264,067,396 | ($41,301,019) |
| **STEAM PRODUCTION (by Unit)** | | | | | | | | |
| **Cholla** | | | | | | | | |
| 311.00 Structures and Improvements | $72,335,187 | $1,181,541 | $127,512 | $1,309,053 | $2,072,612 | $104,385 | $2,176,997 | $867,944 |
| 312.00 Boiler Plant Equipment | 521,789,973 | 10,285,829 | 1,217,328 | 11,503,157 | 16,849,982 | 1,181,937 | 18,031,919 | 6,528,762 |
| 314.00 Turbogenerator Units | 125,558,183 | 2,774,769 | 266,509 | 3,041,278 | 4,241,938 | 220,063 | 4,462,001 | 1,420,723 |
| 315.00 Accessory Electric Equipment | 93,701,286 | 1,565,151 | 167,928 | 1,733,079 | 2,282,053 | 127,889 | 2,409,942 | 676,863 |
| 316.00 Miscellaneous Power Plant Equipment | 27,985,746 | 640,239 | 75,733 | 715,972 | 869,191 | 55,760 | 924,951 | 208,979 |
| **Total Cholla** | $841,370,375 | $16,447,529 | $1,855,010 | $18,302,539 | $26,315,776 | $1,690,034 | $28,005,810 | $9,703,271 |

**ARIZONA PUBLIC SERVICE COMPANY**

Component Accruals

Current: VG Procedure / RL Technique

Proposed: VG Procedure / RL Technique

Statement B

| Account Description | 12/31/10 Investment | Current 2011 Annualized Accrual | | | Proposed 2011 Annualized Accrual | | | Difference |
|---|---|---|---|---|---|---|---|---|
| | | Investment | Net Salvage | Total | Investment | Net Salvage | Total | |
| A | B | C | D | E=C+D | F | G | H=F+G | I=H-E |
| **Cholla Unit 1** | | | | | | | | |
| 311.00 Structures and Improvements | $4,372,274 | $100,125 | $8,745 | $108,870 | $157,402 | $7,433 | $164,835 | $55,965 |
| 312.00 Boiler Plant Equipment | 73,213,804 | 2,643,018 | 270,891 | 2,913,909 | 3,089,623 | 190,356 | 3,279,979 | 366,070 |
| 314.00 Turbogenerator Units | 25,640,590 | 369,224 | 33,333 | 402,557 | 1,176,903 | 61,537 | 1,238,440 | 835,883 |
| 315.00 Accessory Electric Equipment | 8,816,493 | 220,412 | 21,160 | 241,572 | 321,802 | 16,751 | 338,553 | 96,981 |
| 316.00 Miscellaneous Power Plant Equipment | 2,838,727 | 61,033 | 5,961 | 66,994 | 97,936 | 5,394 | 103,330 | 36,336 |
| **Total Cholla Unit 1** | $114,881,888 | $3,393,812 | $340,090 | $3,733,902 | $4,843,666 | $281,471 | $5,125,137 | $1,391,235 |
| **Cholla Unit 2** | | | | | | | | |
| 311.00 Structures and Improvements | $6,168,012 | $124,594 | $11,719 | $136,313 | $173,321 | $9,252 | $182,573 | $46,260 |
| 312.00 Boiler Plant Equipment | 162,323,693 | 2,629,644 | 275,950 | 2,905,594 | 4,074,325 | 275,950 | 4,350,275 | 1,444,681 |
| 314.00 Turbogenerator Units | 44,157,763 | 975,887 | 83,900 | 1,059,787 | 1,373,306 | 75,068 | 1,448,374 | 388,587 |
| 315.00 Accessory Electric Equipment | 46,110,434 | 691,657 | 64,555 | 756,212 | 1,060,540 | 59,944 | 1,120,484 | 364,272 |
| 316.00 Miscellaneous Power Plant Equipment | 8,714,396 | 179,517 | 18,300 | 197,817 | 283,218 | 17,429 | 300,647 | 102,830 |
| **Total Cholla Unit 2** | $267,474,298 | $4,601,299 | $454,424 | $5,055,723 | $6,964,710 | $437,643 | $7,402,353 | $2,346,630 |
| **Cholla Unit 3** | | | | | | | | |
| 311.00 Structures and Improvements | $9,984,226 | $153,757 | $18,970 | $172,727 | $218,655 | $9,984 | $228,639 | $55,912 |
| 312.00 Boiler Plant Equipment | 228,064,943 | 3,808,685 | 501,743 | 4,310,428 | 7,754,208 | 570,162 | 8,324,370 | 4,013,942 |
| 314.00 Turbogenerator Units | 54,849,058 | 1,409,621 | 148,092 | 1,557,713 | 1,667,411 | 82,274 | 1,749,685 | 191,972 |
| 315.00 Accessory Electric Equipment | 31,001,286 | 480,520 | 62,003 | 542,523 | 669,628 | 37,202 | 706,830 | 164,307 |
| 316.00 Miscellaneous Power Plant Equipment | 4,593,291 | 91,866 | 12,402 | 104,268 | 113,914 | 6,890 | 120,804 | 16,536 |
| **Total Cholla Unit 3** | $328,492,804 | $5,944,449 | $743,210 | $6,687,659 | $10,423,816 | $706,512 | $11,130,328 | $4,442,669 |
| **Cholla Common** | | | | | | | | |
| 311.00 Structures and Improvements | $51,810,675 | $803,065 | $88,078 | $891,143 | $1,523,234 | $77,716 | $1,600,950 | $709,807 |
| 312.00 Boiler Plant Equipment | 58,187,533 | 1,204,482 | 168,744 | 1,373,226 | 1,931,826 | 145,469 | 2,077,295 | 704,069 |
| 314.00 Turbogenerator Units | 910,772 | 20,037 | 1,184 | 21,221 | 24,318 | 1,184 | 25,502 | 4,281 |
| 315.00 Accessory Electric Equipment | 7,773,073 | 172,562 | 20,210 | 192,772 | 230,083 | 13,992 | 244,075 | 51,303 |
| 316.00 Miscellaneous Power Plant Equipment | 11,839,332 | 307,823 | 39,070 | 346,893 | 374,123 | 26,047 | 400,170 | 53,277 |
| **Total Cholla Common** | $130,521,385 | $2,507,969 | $317,286 | $2,825,255 | $4,083,584 | $264,408 | $4,347,992 | $1,522,737 |
| **Four Corners** | | | | | | | | |
| 311.00 Structures and Improvements | $57,549,016 | $3,059,759 | $361,500 | $3,421,259 | $391,557 | $209,285 | $600,842 | ($2,820,417) |
| 312.00 Boiler Plant Equipment | 375,402,116 | 16,604,192 | 2,169,866 | 18,774,058 | 3,057,517 | 1,892,823 | 4,950,340 | (13,823,718) |
| 314.00 Turbogenerator Units | 73,354,578 | 3,472,716 | 403,796 | 3,876,512 | 600,509 | 361,446 | 961,955 | (2,914,557) |
| 315.00 Accessory Electric Equipment | 40,063,953 | 1,675,100 | 207,694 | 1,882,794 | 370,390 | 193,629 | 564,019 | (1,318,775) |
| 316.00 Miscellaneous Power Plant Equipment | 25,722,887 | 1,411,061 | 189,065 | 1,600,126 | 352,051 | 120,272 | 472,323 | (1,127,803) |
| **Total Four Corners** | $572,092,550 | $26,222,828 | $3,331,921 | $29,554,749 | $4,772,024 | $2,777,455 | $7,549,479 | ($22,005,270) |

**ARIZONA PUBLIC SERVICE COMPANY**

Component Accruals

Current: VG Procedure / RL Technique

Proposed: VG Procedure / RL Technique

Statement B

| Account Description | 12/31/10 Investment | Current 2011 Annualized Accrual | | | Proposed 2011 Annualized Accrual | | | Difference |
|---|---|---|---|---|---|---|---|---|
| | | Investment | Net Salvage | Total | Investment | Net Salvage | Total | |
| A | B | C | D | E=C+D | F | G | H=F+G | I=H-E |
| **Four Corners Units 1-3** | | | | | | | | |
| 311.00 Structures and Improvements | $40,683,091 | $2,668,811 | $296,987 | $2,965,798 | | | | ($2,965,798) |
| 312.00 Boiler Plant Equipment | 242,101,914 | 14,066,121 | 1,718,924 | 15,785,045 | | | | (15,785,045) |
| 314.00 Turbogenerator Units | 50,183,693 | 2,960,838 | 321,176 | 3,282,014 | | | | (3,282,014) |
| 315.00 Accessory Electric Equipment | 24,333,485 | 1,321,308 | 148,434 | 1,469,742 | | | | (1,469,742) |
| 316.00 Miscellaneous Power Plant Equipment | 11,655,314 | 1,008,185 | 118,884 | 1,127,069 | | | | (1,127,069) |
| **Total Four Corners Units 1-3** | $368,957,497 | $22,025,263 | $2,604,405 | $24,629,668 | | | | ($24,629,668) |
| **Four Corners Units 4-5** | | | | | | | | |
| 311.00 Structures and Improvements | $11,882,266 | $251,904 | $41,588 | $293,492 | $280,421 | $185,363 | $465,784 | $172,292 |
| 312.00 Boiler Plant Equipment | 118,062,055 | 2,125,117 | 377,799 | 2,502,916 | 2,739,040 | 1,818,156 | 4,557,196 | 2,054,280 |
| 314.00 Turbogenerator Units | 21,183,385 | 468,153 | 76,260 | 544,413 | 567,715 | 355,881 | 923,596 | 379,183 |
| 315.00 Accessory Electric Equipment | 11,137,088 | 218,287 | 36,752 | 255,039 | 260,608 | 169,284 | 429,892 | 174,853 |
| 316.00 Miscellaneous Power Plant Equipment | 3,614,952 | 79,890 | 13,737 | 93,627 | 90,735 | 59,647 | 150,382 | 56,755 |
| **Total Four Corners Units 4-5** | $165,879,746 | $3,143,351 | $546,136 | $3,689,487 | $3,938,519 | $2,588,331 | $6,526,850 | $2,837,363 |
| **Four Corners Common** | | | | | | | | |
| 311.00 Structures and Improvements | $4,983,659 | $139,044 | $22,925 | $161,969 | $111,136 | $23,922 | $135,058 | ($26,911) |
| 312.00 Boiler Plant Equipment | 15,238,147 | 412,954 | 73,143 | 486,097 | 318,477 | 74,667 | 393,144 | (92,953) |
| 314.00 Turbogenerator Units | 1,987,500 | 43,725 | 6,360 | 50,085 | 32,794 | 5,565 | 38,359 | (11,726) |
| 315.00 Accessory Electric Equipment | 4,593,380 | 135,505 | 22,508 | 158,013 | 109,782 | 24,345 | 134,127 | (23,886) |
| 316.00 Miscellaneous Power Plant Equipment | 10,452,621 | 322,986 | 56,444 | 379,430 | 261,316 | 60,625 | 321,941 | (57,489) |
| **Total Four Corners Common** | $37,255,307 | $1,054,214 | $181,380 | $1,235,594 | $833,505 | $189,124 | $1,022,629 | ($212,965) |
| **Navajo Units 1-3** | | | | | | | | |
| 311.00 Structures and Improvements | $29,113,530 | $765,686 | $78,607 | $844,293 | $972,392 | $69,872 | $1,042,264 | $197,971 |
| 312.00 Boiler Plant Equipment | 166,003,214 | 4,648,090 | 531,210 | 5,179,300 | 5,677,310 | 464,809 | 6,142,119 | 962,819 |
| 314.00 Turbogenerator Units | 24,699,305 | 508,806 | 54,338 | 563,144 | 669,351 | 49,399 | 718,750 | 155,606 |
| 315.00 Accessory Electric Equipment | 21,491,344 | 470,660 | 51,579 | 522,239 | 629,696 | 45,132 | 674,828 | 152,589 |
| 316.00 Miscellaneous Power Plant Equipment | 17,228,597 | 554,761 | 62,023 | 616,784 | 646,072 | 49,963 | 696,035 | 79,251 |
| **Total Navajo Units 1-3** | $258,535,990 | $6,948,003 | $777,757 | $7,725,760 | $8,594,821 | $679,175 | $9,273,996 | $1,548,236 |
| **Ocotillo Units 1-2** | | | | | | | | |
| 311.00 Structures and Improvements | $4,759,658 | $170,872 | $48,549 | $219,421 | $233,699 | $41,885 | $275,584 | $56,163 |
| 312.00 Boiler Plant Equipment | 25,218,648 | 713,688 | 214,359 | 928,047 | 859,956 | 163,921 | 1,023,877 | 95,830 |
| 314.00 Turbogenerator Units | 20,161,583 | 532,266 | 159,277 | 691,543 | 955,659 | 177,422 | 1,133,081 | 441,538 |
| 315.00 Accessory Electric Equipment | 3,425,956 | 106,890 | 31,176 | 138,066 | 155,881 | 28,778 | 184,659 | 46,593 |
| 316.00 Miscellaneous Power Plant Equipment | 6,010,574 | 316,156 | 91,361 | 407,517 | 348,613 | 66,116 | 414,729 | 7,212 |
| **Total Ocotillo Units 1-2** | $59,576,419 | $1,839,872 | $544,722 | $2,384,594 | $2,553,808 | $478,122 | $3,031,930 | $647,336 |

**ARIZONA PUBLIC SERVICE COMPANY**

Component Accruals

Current: VG Procedure / RL Technique

Proposed: VG Procedure / RL Technique

Statement B

| Account Description | 12/31/10 Investment | Current 2011 Annualized Accrual | | | Proposed 2011 Annualized Accrual | | | Difference |
|---|---|---|---|---|---|---|---|---|
| | | Investment | Net Salvage | Total | Investment | Net Salvage | Total | |
| A | B | C | D | E=C+D | F | G | H=F+G | I=H-E |
| **Saguaro Units 1-2** | | | | | | | | |
| 311.00 Structures and Improvements | $4,311,317 | $121,148 | $34,491 | $155,639 | $237,554 | $43,544 | $281,098 | $125,459 |
| 312.00 Boiler Plant Equipment | 26,094,372 | 644,531 | 185,270 | 829,801 | 1,148,152 | 219,193 | 1,367,345 | 537,544 |
| 314.00 Turbogenerator Units | 16,513,563 | 336,877 | 97,430 | 434,307 | 544,948 | 100,733 | 645,681 | 211,374 |
| 315.00 Accessory Electric Equipment | 5,667,906 | 242,020 | 69,715 | 311,735 | 320,237 | 59,513 | 379,750 | 68,015 |
| 316.00 Miscellaneous Power Plant Equipment | 4,778,936 | 188,768 | 55,436 | 244,204 | 244,204 | 45,878 | 290,082 | 45,878 |
| **Total Saguaro Units 1-2** | $57,366,094 | $1,533,344 | $442,342 | $1,975,686 | $2,495,095 | $468,861 | $2,963,956 | $988,270 |
| **NUCLEAR PRODUCTION (by Unit)** | | | | | | | | |
| **Palo Verde** | | | | | | | | |
| 321.00 Structures and Improvements | $698,846,801 | $18,352,868 | $82,295 | $18,435,163 | $9,265,673 | $66,624 | $9,332,297 | ($9,102,866) |
| 322.00 Reactor Plant Equipment | 1,130,933,859 | 32,152,405 | 598,662 | 32,751,067 | 16,955,122 | 593,091 | 17,548,213 | (15,202,854) |
| 323.00 Turbogenerator Units | 354,174,138 | 9,754,391 | 44,384 | 9,798,775 | 5,113,500 | 63,385 | 5,176,885 | (4,621,890) |
| 324.00 Accessory Electric Equipment | 275,016,677 | 6,987,700 | 27,502 | 7,015,202 | 3,260,068 | 27,502 | 3,287,570 | (3,727,632) |
| 325.00 Miscellaneous Power Plant Equipment | 145,211,312 | 4,180,067 | 55,558 | 4,235,625 | 2,141,613 | 52,477 | 2,194,090 | (2,041,535) |
| **Total Palo Verde** | $2,604,182,787 | $71,427,431 | $808,401 | $72,235,832 | $36,735,976 | $803,079 | $37,539,055 | ($34,696,777) |
| **Palo Verde Unit 1** | | | | | | | | |
| 321.00 Structures and Improvements | $156,705,345 | $4,168,362 | $15,671 | $4,184,033 | $1,770,770 | | $1,770,770 | ($2,413,263) |
| 322.00 Reactor Plant Equipment | 454,207,200 | 14,352,948 | 181,683 | 14,534,631 | 6,586,004 | 181,683 | 6,767,687 | (7,766,944) |
| 323.00 Turbogenerator Units | 125,268,196 | 3,770,573 | 12,527 | 3,783,100 | 1,766,282 | 25,054 | 1,791,336 | (1,991,764) |
| 324.00 Accessory Electric Equipment | 114,860,792 | 3,032,325 | 11,486 | 3,043,811 | 1,274,955 | 11,486 | 1,286,441 | (1,757,370) |
| 325.00 Miscellaneous Power Plant Equipment | 30,801,758 | 880,930 | 9,241 | 890,171 | 397,343 | 6,160 | 403,503 | (486,668) |
| **Total Palo Verde Unit 1** | $881,843,291 | $26,205,138 | $230,608 | $26,435,746 | $11,795,354 | $224,383 | $12,019,737 | ($14,416,009) |
| **Palo Verde Unit 2** | | | | | | | | |
| 321.00 Structures and Improvements | $91,657,911 | $2,438,100 | $9,166 | $2,447,266 | $1,099,895 | $9,166 | $1,109,061 | ($1,338,205) |
| 322.00 Reactor Plant Equipment | 234,287,478 | 7,239,483 | 187,430 | 7,426,913 | 3,561,170 | 187,430 | 3,748,600 | (3,678,313) |
| 323.00 Turbogenerator Units | 78,612,699 | 2,303,352 | 15,723 | 2,319,075 | 1,108,439 | 7,861 | 1,116,300 | (1,202,775) |
| 324.00 Accessory Electric Equipment | 49,937,247 | 1,343,312 | 4,994 | 1,348,306 | 624,216 | 4,994 | 629,210 | (719,096) |
| 325.00 Miscellaneous Power Plant Equipment | 27,087,580 | 826,171 | 5,418 | 831,589 | 392,770 | 5,418 | 398,188 | (433,401) |
| **Total Palo Verde Unit 2** | $481,582,915 | $14,150,418 | $222,731 | $14,373,149 | $6,786,490 | $214,869 | $7,001,359 | ($7,371,790) |
| **Palo Verde Unit 3** | | | | | | | | |
| 321.00 Structures and Improvements | $163,192,491 | $3,818,704 | | $3,818,704 | $1,990,948 | | $1,990,948 | ($1,827,756) |
| 322.00 Reactor Plant Equipment | 414,451,923 | 9,863,956 | 207,226 | 10,071,182 | 6,465,450 | 207,226 | 6,672,676 | (3,398,506) |
| 323.00 Turbogenerator Units | 147,910,539 | 3,579,435 | 14,791 | 3,594,226 | 2,189,076 | 29,582 | 2,218,658 | (1,375,568) |
| 324.00 Accessory Electric Equipment | 90,837,828 | 2,125,605 | 9,084 | 2,134,689 | 1,126,389 | 9,084 | 1,135,473 | (999,216) |
| 325.00 Miscellaneous Power Plant Equipment | 28,712,249 | 720,677 | 5,742 | 726,419 | 390,487 | 5,742 | 396,229 | (330,190) |
| **Total Palo Verde Unit 3** | $845,105,030 | $20,108,377 | $236,843 | $20,345,220 | $12,162,350 | $251,634 | $12,413,984 | ($7,931,236) |

**ARIZONA PUBLIC SERVICE COMPANY**

Component Accruals

Current: VG Procedure / RL Technique

Proposed: VG Procedure / RL Technique

Statement B

| Account Description | 12/31/10 Investment | Current 2011 Annualized Accrual | | | Proposed 2011 Annualized Accrual | | | Difference |
|---|---|---|---|---|---|---|---|---|
| | | Investment | Net Salvage | Total | Investment | Net Salvage | Total | |
| A | B | C | D | E=C+D | F | G | H=F+G | I=H-E |
| **Palo Verde Water Reclamation** | | | | | | | | |
| 321.00 Structures and Improvements | $171,609,224 | $4,873,702 | $34,322 | $4,908,024 | $2,900,196 | $34,322 | $2,934,518 | ($1,973,506) |
| 322.00 Reactor Plant Equipment | 133,326 | 5,240 | 40 | 5,280 | 2,680 | 40 | 2,720 | (2,560) |
| 323.00 Turbogenerator Units | 217,756 | 6,206 | 44 | 6,250 | 3,157 | 22 | 3,179 | (3,071) |
| 324.00 Accessory Electric Equipment | | | | | | | | |
| 325.00 Miscellaneous Power Plant Equipment | 88,819 | 2,514 | 44 | 2,558 | 1,270 | 44 | 1,314 | (1,244) |
| **Total Palo Verde Water Reclamation** | $172,049,125 | $4,887,662 | $34,450 | $4,922,112 | $2,907,303 | $34,428 | $2,941,731 | ($1,980,381) |
| **Palo Verde Common** | | | | | | | | |
| 321.00 Structures and Improvements | $115,681,830 | $3,054,000 | $23,136 | $3,077,136 | $1,503,864 | $23,136 | $1,527,000 | ($1,550,136) |
| 322.00 Reactor Plant Equipment | 27,853,932 | 690,778 | 22,283 | 713,061 | 339,818 | 16,712 | 356,530 | (356,531) |
| 323.00 Turbogenerator Units | 2,164,948 | 94,825 | 1,299 | 96,124 | 46,546 | 866 | 47,412 | (48,712) |
| 324.00 Accessory Electric Equipment | 19,380,810 | 486,458 | 1,938 | 488,396 | 234,508 | 1,938 | 236,446 | (251,950) |
| 325.00 Miscellaneous Power Plant Equipment | 58,520,906 | 1,749,775 | 35,113 | 1,784,888 | 959,743 | 35,113 | 994,856 | (790,032) |
| **Total Palo Verde Common** | $223,602,426 | $6,075,836 | $83,769 | $6,159,605 | $3,084,479 | $77,765 | $3,162,244 | ($2,997,361) |
| **OTHER PRODUCTION (by Unit)** | | | | | | | | |
| **Douglas CT** | | | | | | | | |
| 341.00 Structures and Improvements | $49,075 | $2,915 | $142 | $3,057 | $2,518 | ($128) | $2,390 | ($667) |
| 342.00 Fuel Holders, Products and Accessories | 137,759 | 2,507 | 83 | 2,590 | 1,240 | (14) | 1,226 | (1,364) |
| 343.00 Prime Movers | 1,101,449 | 8,041 | 441 | 8,482 | (2,754) | 220 | (2,534) | (11,016) |
| 344.00 Generators and Devices | 551,765 | 3,862 | 166 | 4,028 | (1,545) | 55 | (1,490) | (5,518) |
| 345.00 Accessory Electric Equipment | 353,277 | 3,462 | 247 | 3,709 | 71 | 71 | 142 | (3,567) |
| 346.00 Miscellaneous Power Plant Equipment | 40,913 | 675 | 33 | 708 | 286 | (12) | 274 | (434) |
| **Total Douglas CT** | $2,234,238 | $21,462 | $1,112 | $22,574 | ($184) | $192 | $8 | ($22,566) |
| **Ocotillo CT Units 1-2** | | | | | | | | |
| 341.00 Structures and Improvements | $721,568 | $14,576 | $722 | $15,298 | $30,234 | ($1,443) | $28,791 | $13,493 |
| 342.00 Fuel Holders, Products and Accessories | 791,584 | 15,278 | 712 | 15,990 | 16,386 | (792) | 15,594 | (396) |
| 343.00 Prime Movers | 6,540,275 | 82,407 | 3,924 | 86,331 | 47,744 | (1,962) | 45,782 | (40,549) |
| 344.00 Generators and Devices | 7,596,314 | 247,640 | 9,875 | 257,515 | 261,313 | (46,338) | 214,975 | (42,540) |
| 345.00 Accessory Electric Equipment | 1,677,431 | 28,181 | 1,677 | 29,858 | 26,839 | (1,006) | 25,833 | (4,025) |
| 346.00 Miscellaneous Power Plant Equipment | 637,727 | 11,288 | 510 | 11,798 | 13,647 | (574) | 13,073 | 1,275 |
| **Total Octillo CT Units 1-2** | $17,964,899 | $399,370 | $17,420 | $416,790 | $396,163 | ($52,115) | $344,048 | ($72,742) |

**ARIZONA PUBLIC SERVICE COMPANY**

Component Accruals

Current: VG Procedure / RL Technique

Proposed: VG Procedure / RL Technique

Statement B

| Account Description | 12/31/10 Investment | Current 2011 Annualized Accrual | | | Proposed 2011 Annualized Accrual | | | Difference |
|---|---|---|---|---|---|---|---|---|
| | | Investment | Net Salvage | Total | Investment | Net Salvage | Total | |
| A | B | C | D | E=C+D | F | G | H=F+G | I=H-E |
| **Redhawk CC Units 1-2** | | | | | | | | |
| 341.00 Structures and Improvements | $22,197,402 | $668,142 | $93,229 | $761,371 | $694,779 | ($26,637) | $668,142 | ($93,229) |
| 342.00 Fuel Holders, Products and Accessories | 2,637,978 | 91,274 | 4,485 | 95,759 | 95,759 | (4,748) | 91,011 | (4,748) |
| 343.00 Prime Movers | 177,860,527 | 5,300,244 | 124,502 | 5,424,746 | 5,531,462 | (142,288) | 5,389,174 | (35,572) |
| 344.00 Generators and Devices | 279,212,258 | 8,432,210 | 335,055 | 8,767,265 | 9,297,768 | (2,317,462) | 6,980,306 | (1,786,959) |
| 345.00 Accessory Electric Equipment | 22,584,466 | 675,276 | 27,101 | 702,377 | 702,377 | (22,584) | 679,793 | (22,584) |
| 346.00 Miscellaneous Power Plant Equipment | 4,005,866 | 130,992 | 6,810 | 137,802 | 144,211 | (7,211) | 137,000 | (802) |
| **Total Redhawk CC Units 1-2** | $508,498,497 | $15,298,138 | $591,182 | $15,889,320 | $16,466,356 | ($2,520,930) | $13,945,426 | ($1,943,894) |
| **Saguaro** | | | | | | | | |
| 341.00 Structures and Improvements | $1,885,444 | $72,024 | $3,582 | $75,606 | $86,730 | ($4,148) | $82,582 | $6,976 |
| 342.00 Fuel Holders, Products and Accessories | 1,376,702 | 22,303 | 964 | 23,267 | 17,484 | (413) | 17,071 | (6,196) |
| 343.00 Prime Movers | 8,624,812 | 118,642 | 5,751 | 124,393 | 54,194 | (2,494) | 51,700 | (72,693) |
| 344.00 Generators and Devices | 32,512,372 | 1,007,027 | 50,115 | 1,057,142 | 949,491 | (62,572) | 886,919 | (170,223) |
| 345.00 Accessory Electric Equipment | 1,701,779 | 23,027 | 1,289 | 24,316 | 10,757 | (330) | 10,427 | (13,889) |
| 346.00 Miscellaneous Power Plant Equipment | 868,485 | 27,792 | 1,390 | 29,182 | 22,320 | (1,042) | 21,278 | (7,904) |
| **Total Saguaro** | $46,969,594 | $1,270,815 | $63,091 | $1,333,906 | $1,140,976 | ($70,999) | $1,069,977 | ($263,929) |
| **Saguaro CT Units 1-2** | | | | | | | | |
| 341.00 Structures and Improvements | $1,885,444 | $72,024 | $3,582 | $75,606 | $86,730 | ($4,148) | $82,582 | $6,976 |
| 342.00 Fuel Holders, Products and Accessories | 1,376,702 | 22,303 | 964 | 23,267 | 17,484 | (413) | 17,071 | (6,196) |
| 343.00 Prime Movers | 7,983,905 | 99,799 | 4,790 | 104,589 | 35,928 | (1,597) | 34,331 | (70,258) |
| 344.00 Generators and Devices | 4,487,988 | 183,110 | 8,078 | 191,188 | 150,796 | (23,338) | 127,458 | (63,730) |
| 345.00 Accessory Electric Equipment | 1,579,226 | 19,424 | 1,105 | 20,529 | 7,264 | (158) | 7,106 | (13,423) |
| 346.00 Miscellaneous Power Plant Equipment | 868,485 | 27,792 | 1,390 | 29,182 | 22,320 | (1,042) | 21,278 | (7,904) |
| **Total Saguaro CT Units 1-2** | $18,181,750 | $424,452 | $19,909 | $444,361 | $320,522 | ($30,696) | $289,826 | ($154,535) |
| **Saguaro CT Unit 3** | | | | | | | | |
| 341.00 Structures and Improvements | | | | | | | | |
| 342.00 Fuel Holders, Products and Accessories | | | | | | | | |
| 343.00 Prime Movers | 640,907 | 18,843 | 961 | 19,804 | 18,266 | (897) | 17,369 | (2,435) |
| 344.00 Generators and Devices | 28,024,384 | 823,917 | 42,037 | 865,954 | 798,695 | (39,234) | 759,461 | (106,493) |
| 345.00 Accessory Electric Equipment | 122,553 | 3,603 | 184 | 3,787 | 3,493 | (172) | 3,321 | (466) |
| 346.00 Miscellaneous Power Plant Equipment | | | | | | | | |
| **Total Saguaro CT Unit 3** | $28,787,844 | $846,363 | $43,182 | $889,545 | $820,454 | ($40,303) | $780,151 | ($109,394) |

**ARIZONA PUBLIC SERVICE COMPANY**

Component Accruals

Current: VG Procedure / RL Technique

Proposed: VG Procedure / RL Technique

Statement B

| Account Description | 12/31/10 Investment | Current 2011 Annualized Accrual | | | Proposed 2011 Annualized Accrual | | | Difference |
|---|---|---|---|---|---|---|---|---|
| | | Investment | Net Salvage | Total | Investment | Net Salvage | Total | |
| A | B | C | D | E=C+D | F | G | H=F+G | I=H-E |
| **Solar Units** | | | | | | | | |
| 341.00 Structures and Improvements | $418,403 | $2,176 | $84 | $2,260 | ($14,853) | $837 | ($14,016) | ($16,276) |
| 342.00 Fuel Holders, Products and Accessories | | | | | | | | |
| 343.00 Prime Movers | | | | | | | | |
| 344.00 Generators and Devices | 15,963,981 | 892,387 | 49,488 | 941,875 | 627,384 | (137,290) | 490,094 | (451,781) |
| 345.00 Accessory Electric Equipment | 728,283 | 39,036 | 1,966 | 41,002 | 53,966 | (2,695) | 51,271 | 10,269 |
| 346.00 Miscellaneous Power Plant Equipment | | | | | | | | |
| **Total Solar Units** | $17,110,667 | $933,599 | $51,538 | $985,137 | $666,497 | ($139,148) | $527,349 | ($457,788) |
| **Sundance** | | | | | | | | |
| 341.00 Structures and Improvements | $12,653,247 | $279,637 | $13,919 | $293,556 | $260,657 | ($12,653) | $248,004 | ($45,552) |
| 342.00 Fuel Holders, Products and Accessories | 4,325,769 | 94,734 | 4,758 | 99,492 | 88,678 | (4,326) | 84,352 | (15,140) |
| 343.00 Prime Movers | 229,732,211 | 5,054,109 | 252,705 | 5,306,814 | 4,686,537 | (252,705) | 4,433,832 | (872,982) |
| 344.00 Generators and Devices | 301,285 | 9,099 | 452 | 9,551 | 7,562 | (392) | 7,170 | (2,381) |
| 345.00 Accessory Electric Equipment | 26,408,712 | 578,351 | 29,050 | 607,401 | 541,379 | (26,409) | 514,970 | (92,431) |
| 346.00 Miscellaneous Power Plant Equipment | 2,028,889 | 44,433 | 2,232 | 46,665 | 50,519 | (2,435) | 48,084 | 1,419 |
| **Total Sun Dance** | $275,450,113 | $6,060,363 | $303,116 | $6,363,479 | $5,635,332 | ($298,920) | $5,336,412 | ($1,027,067) |
| **West Phoenix** | | | | | | | | |
| 341.00 Structures and Improvements | $27,606,161 | $700,155 | $40,562 | $740,717 | $840,081 | ($40,432) | $799,649 | $58,932 |
| 342.00 Fuel Holders, Products and Accessories | 28,090,344 | 990,209 | 50,137 | 1,040,346 | 1,037,207 | (47,166) | 990,041 | (50,305) |
| 343.00 Prime Movers | 164,651,195 | 4,896,967 | 190,232 | 5,087,199 | 4,762,834 | (165,600) | 4,597,234 | (489,965) |
| 344.00 Generators and Devices | 244,094,419 | 8,109,640 | 376,030 | 8,485,670 | 8,259,393 | (907,610) | 7,351,783 | (1,133,887) |
| 345.00 Accessory Electric Equipment | 29,569,013 | 980,088 | 47,816 | 1,027,904 | 992,802 | (43,228) | 949,574 | (78,330) |
| 346.00 Miscellaneous Power Plant Equipment | 6,447,142 | 198,892 | 10,433 | 209,325 | 254,815 | (11,315) | 243,500 | 34,175 |
| **Total West Phoenix** | $500,458,274 | $15,875,951 | $715,210 | $16,591,161 | $16,147,132 | ($1,215,351) | $14,931,781 | ($1,659,380) |
| **West Phoenix CC Units 1-3** | | | | | | | | |
| 341.00 Structures and Improvements | $1,710,485 | $68,590 | $3,250 | $71,840 | $85,524 | ($4,105) | $81,419 | $9,579 |
| 342.00 Fuel Holders, Products and Accessories | 22,517,702 | 844,414 | 42,784 | 887,198 | 905,212 | (40,532) | 864,680 | (22,518) |
| 343.00 Prime Movers | | | | | | | | |
| 344.00 Generators and Devices | 92,566,116 | 3,545,282 | 148,106 | 3,693,388 | 3,776,698 | (601,680) | 3,175,018 | (518,370) |
| 345.00 Accessory Electric Equipment | 13,561,670 | 511,275 | 24,411 | 535,686 | 543,823 | (20,343) | 523,480 | (12,206) |
| 346.00 Miscellaneous Power Plant Equipment | 4,722,353 | 140,726 | 7,556 | 148,282 | 196,922 | (8,500) | 188,422 | 40,140 |
| **Total West Phoenix CC Units 1-3** | $135,078,326 | $5,110,287 | $226,107 | $5,336,394 | $5,508,179 | ($675,160) | $4,833,019 | ($503,375) |

**ARIZONA PUBLIC SERVICE COMPANY**

Component Accruals

Current: VG Procedure / RL Technique

Proposed: VG Procedure / RL Technique

Statement B

| Account Description | 12/31/10 Investment | Current 2011 Annualized Accrual | | | Proposed 2011 Annualized Accrual | | | Difference |
|---|---|---|---|---|---|---|---|---|
| | | Investment | Net Salvage | Total | Investment | Net Salvage | Total | |
| A | B | C | D | E=C+D | F | G | H=F+G | I=H-E |
| **West Phoenix CC Unit 4** | | | | | | | | |
| 341.00 Structures and Improvements | $4,584,726 | $139,376 | $6,877 | $146,253 | $139,834 | ($6,877) | $132,957 | ($13,296) |
| 342.00 Fuel Holders, Products and Accessories | 4,135,109 | 123,226 | 6,203 | 129,429 | 123,226 | (6,203) | 117,023 | (12,406) |
| 343.00 Prime Movers | 54,680,534 | 1,629,480 | 82,021 | 1,711,501 | 1,629,480 | (82,021) | 1,547,459 | (164,042) |
| 344.00 Generators and Devices | 15,548,138 | 469,554 | 24,877 | 494,431 | 477,328 | (46,644) | 430,684 | (63,747) |
| 345.00 Accessory Electric Equipment | 2,569,550 | 83,510 | 4,111 | 87,621 | 91,733 | (4,625) | 87,108 | (513) |
| 346.00 Miscellaneous Power Plant Equipment | 315,741 | 10,072 | 505 | 10,577 | 11,746 | (537) | 11,209 | 632 |
| **Total West Phoenix CC Unit 4** | $81,833,798 | $2,455,218 | $124,594 | $2,579,812 | $2,473,347 | ($146,907) | $2,326,440 | ($253,372) |
| **West Phoenix CC Unit 5** | | | | | | | | |
| 341.00 Structures and Improvements | $10,865,036 | $328,124 | $17,384 | $345,508 | $317,259 | ($16,298) | $300,961 | ($44,547) |
| 342.00 Fuel Holders, Products and Accessories | | | | | | | | |
| 343.00 Prime Movers | 101,176,494 | 3,096,001 | 101,176 | 3,197,177 | 3,045,412 | (80,941) | 2,964,471 | (232,706) |
| 344.00 Generators and Devices | 131,363,010 | 3,980,299 | 197,045 | 4,177,344 | 3,901,481 | (249,590) | 3,651,891 | (525,453) |
| 345.00 Accessory Electric Equipment | 11,713,613 | 353,751 | 17,570 | 371,321 | 340,866 | (17,570) | 323,296 | (48,025) |
| 346.00 Miscellaneous Power Plant Equipment | 235,560 | 7,491 | 377 | 7,868 | 8,009 | (400) | 7,609 | (259) |
| **Total West Phoenix CC Unit 5** | $255,353,713 | $7,765,666 | $333,552 | $8,099,218 | $7,613,027 | ($364,799) | $7,248,228 | ($850,990) |
| **West Phoenix CT Units 1-2** | | | | | | | | |
| 341.00 Structures and Improvements | $880,435 | $11,974 | $616 | $12,590 | $33,457 | ($1,673) | $31,784 | $19,194 |
| 342.00 Fuel Holders, Products and Accessories | 1,437,533 | 22,569 | 1,150 | 23,719 | 8,769 | (431) | 8,338 | (15,381) |
| 343.00 Prime Movers | 8,794,167 | 171,486 | 7,035 | 178,521 | 87,942 | (2,638) | 85,304 | (93,217) |
| 344.00 Generators and Devices | 4,617,155 | 114,505 | 6,002 | 120,507 | 103,886 | (9,696) | 94,190 | (26,317) |
| 345.00 Accessory Electric Equipment | 1,724,180 | 31,552 | 1,724 | 33,276 | 16,380 | (690) | 15,690 | (17,586) |
| 346.00 Miscellaneous Power Plant Equipment | 1,173,488 | 40,603 | 1,995 | 42,598 | 38,138 | (1,878) | 36,260 | (6,338) |
| **Total West Phoenix CT Units 1-2** | $18,626,958 | $392,689 | $18,522 | $411,211 | $288,572 | ($17,006) | $271,566 | ($139,645) |
| **West Phoenix Common** | | | | | | | | |
| 341.00 Structures and Improvements | $9,565,479 | $152,091 | $12,435 | $164,526 | $264,007 | ($11,479) | $252,528 | $88,002 |
| 342.00 Fuel Holders, Products and Accessories | | | | | | | | |
| 343.00 Prime Movers | | | | | | | | |
| 344.00 Generators and Devices | | | | | | | | |
| 345.00 Accessory Electric Equipment | | | | | | | | |
| 346.00 Miscellaneous Power Plant Equipment | | | | | | | | |
| **Total West Phoenix Common** | $9,565,479 | $152,091 | $12,435 | $164,526 | $264,007 | ($11,479) | $252,528 | $88,002 |

**ARIZONA PUBLIC SERVICE COMPANY**

Component Accruals

Current: VG Procedure / RL Technique

Proposed: VG Procedure / RL Technique

Statement B

| Account Description | 12/31/10 Investment | Current 2011 Annualized Accrual | | | Proposed 2011 Annualized Accrual | | | Difference |
|---|---|---|---|---|---|---|---|---|
| | | Investment | Net Salvage | Total | Investment | Net Salvage | Total | |
| A | B | C | D | E=C+D | F | G | H=F+G | I=H-E |
| **Yucca** | | | | | | | | |
| 341.00 Structures and Improvements | $1,730,884 | $57,348 | $2,030 | $59,378 | $43,289 | ($1,761) | $41,528 | ($17,850) |
| 342.00 Fuel Holders, Products and Accessories | 4,819,210 | 67,734 | 1,327 | 69,061 | 48,273 | (2,254) | 46,019 | (23,042) |
| 343.00 Prime Movers | 76,131,450 | 1,900,383 | 2,389 | 1,902,772 | 2,017,459 | (102,254) | 1,915,205 | 12,433 |
| 344.00 Generators and Devices | 7,937,599 | 207,231 | 9,461 | 216,692 | 101,721 | (19,002) | 82,719 | (133,973) |
| 345.00 Accessory Electric Equipment | 3,251,231 | 78,214 | 3,690 | 81,904 | 33,544 | (1,471) | 32,073 | (49,831) |
| 346.00 Miscellaneous Power Plant Equipment | 682,399 | 16,173 | 751 | 16,924 | 7,575 | (409) | 7,166 | (9,758) |
| **Total Yucca** | $94,552,773 | $2,327,083 | $19,648 | $2,346,731 | $2,251,861 | ($127,151) | $2,124,710 | ($222,021) |
| **Yucca CT Units 1-4** | | | | | | | | |
| 341.00 Structures and Improvements | $1,193,877 | $42,741 | $2,030 | $44,771 | $27,340 | ($955) | $26,385 | ($18,386) |
| 342.00 Fuel Holders, Products and Accessories | 3,316,669 | 26,865 | 1,327 | 28,192 | 3,648 | | 3,648 | (24,544) |
| 343.00 Prime Movers | 7,962,254 | 46,181 | 2,389 | 48,570 | (7,166) | | (7,166) | (55,736) |
| 344.00 Generators and Devices | 7,883,898 | 205,770 | 9,461 | 215,231 | 100,126 | (18,921) | 81,205 | (134,026) |
| 345.00 Accessory Electric Equipment | 2,838,650 | 66,992 | 3,690 | 70,682 | 21,290 | (852) | 20,438 | (50,244) |
| 346.00 Miscellaneous Power Plant Equipment | 682,399 | 16,173 | 751 | 16,924 | 7,575 | (409) | 7,166 | (9,758) |
| **Total Yucca CT Units 1-4** | $23,877,747 | $404,722 | $19,648 | $424,370 | $152,813 | ($21,137) | $131,676 | ($292,694) |
| **Yucca CT Units 5-6** | | | | | | | | |
| 341.00 Structures and Improvements | $537,007 | $14,607 | | $14,607 | $15,949 | ($806) | $15,143 | $536 |
| 342.00 Fuel Holders, Products and Accessories | 1,502,541 | 40,869 | | 40,869 | 44,625 | (2,254) | 42,371 | 1,502 |
| 343.00 Prime Movers | 68,169,196 | 1,854,202 | | 1,854,202 | 2,024,625 | (102,254) | 1,922,371 | 68,169 |
| 344.00 Generators and Devices | 53,701 | 1,461 | | 1,461 | 1,595 | (81) | 1,514 | 53 |
| 345.00 Accessory Electric Equipment | 412,581 | 11,222 | | 11,222 | 12,254 | (619) | 11,635 | 413 |
| 346.00 Miscellaneous Power Plant Equipment | | | | | | | | |
| **Total Yucca CT Units 5-6** | $70,675,026 | $1,922,361 | | $1,922,361 | $2,099,048 | ($106,014) | $1,993,034 | $70,673 |

**ARIZONA PUBLIC SERVICE COMPANY**
Depreciation Reserve Summary
Vintage Group Procedure
December 31, 2010

Statement C

| Account Description | Plant Investment | Recorded Reserve Amount | Recorded Reserve Ratio | Computed Reserve Amount | Computed Reserve Ratio | Redistributed Reserve Amount | Redistributed Reserve Ratio |
|---|---|---|---|---|---|---|---|
| A | B | C | D=C/B | E | F=E/B | G | H=G/B |
| **STEAM PRODUCTION** | | | | | | | |
| 311.00 Structures and Improvements | $168,068,708 | $88,898,626 | 52.89% | $101,357,138 | 60.31% | $97,466,119 | 57.99% |
| 312.00 Boiler Plant Equipment | 1,114,508,323 | 598,114,849 | 53.67% | 631,396,335 | 56.65% | 606,430,932 | 54.41% |
| 314.00 Turbogenerator Units | 260,287,212 | 147,478,331 | 56.66% | 149,050,761 | 57.26% | 142,710,428 | 54.83% |
| 315.00 Accessory Electric Equipment | 164,350,445 | 108,884,358 | 66.25% | 103,007,971 | 62.68% | 97,962,586 | 59.61% |
| 316.00 Miscellaneous Power Plant Equipment | 81,726,740 | 42,315,482 | 51.78% | 43,140,737 | 52.79% | 41,121,581 | 50.32% |
| **Total Steam Production Plant** | $1,788,941,428 | $985,691,646 | 55.10% | $1,027,952,942 | 57.46% | $985,691,646 | 55.10% |
| **NUCLEAR PRODUCTION** | | | | | | | |
| 321.00 Structures and Improvements | $698,846,801 | $390,836,399 | 55.93% | $241,914,153 | 34.62% | $384,424,922 | 55.01% |
| 322.00 Reactor Plant Equipment | 1,130,933,859 | 556,209,183 | 49.18% | 353,970,046 | 31.30% | 561,119,881 | 49.62% |
| 323.00 Turbogenerator Units | 354,174,138 | 171,976,208 | 48.56% | 115,517,890 | 32.62% | 182,656,783 | 51.57% |
| 324.00 Accessory Electric Equipment | 275,016,677 | 169,883,421 | 61.77% | 104,821,257 | 38.11% | 166,763,875 | 60.64% |
| 325.00 Miscellaneous Power Plant Equipment | 145,211,312 | 77,544,578 | 53.40% | 44,088,269 | 30.36% | 71,484,329 | 49.23% |
| **Total Nuclear Production Plant** | $2,604,182,787 | $1,366,449,789 | 52.47% | $860,311,616 | 33.04% | $1,366,449,789 | 52.47% |
| **OTHER PRODUCTION** | | | | | | | |
| 341.00 Structures and Improvements | $67,262,184 | $19,276,175 | 28.66% | $14,551,236 | 21.63% | $20,097,831 | 29.88% |
| 342.00 Fuel Holders, Products and Accessories | 42,179,346 | 17,522,636 | 41.54% | 13,273,380 | 31.47% | 16,081,785 | 38.13% |
| 343.00 Prime Movers | 664,641,919 | 221,422,821 | 33.31% | 124,288,323 | 18.70% | 201,363,609 | 30.30% |
| 344.00 Generators and Devices | 588,169,993 | 166,810,837 | 28.36% | 183,668,979 | 31.23% | 189,354,954 | 32.19% |
| 345.00 Accessory Electric Equipment | 86,274,192 | 31,558,684 | 36.58% | 20,219,844 | 23.44% | 29,690,808 | 34.41% |
| 346.00 Miscellaneous Power Plant Equipment | 14,711,421 | 4,637,245 | 31.52% | 3,715,555 | 25.26% | 4,639,410 | 31.54% |
| **Total Other Production Plant** | $1,463,239,055 | $461,228,398 | 31.52% | $359,717,318 | 24.58% | $461,228,398 | 31.52% |
| **TRANSMISSION PLANT** | | | | | | | |
| 352.02 Structures and Improvements | $95,935 | $52,736 | 54.97% | $64,115 | 66.83% | $52,904 | 55.15% |
| 353.00 Station Equipment | 98,305,656 | 22,173,057 | 22.56% | 26,832,631 | 27.30% | 22,141,048 | 22.52% |
| 354.00 Towers and Fixtures | 1,329,316 | 448,155 | 33.71% | 510,240 | 38.38% | 421,027 | 31.67% |
| 355.00 Poles and Fixtures | 1,370,085 | 225,637 | 16.47% | 211,661 | 15.45% | 174,653 | 12.75% |
| 356.00 Overhead Conductors and Devices | 1,947,677 | 306,587 | 15.74% | 504,803 | 25.92% | 416,540 | 21.39% |
| **Total Transmission Plant** | $103,048,669 | $23,206,173 | 22.52% | $28,123,451 | 27.29% | $23,206,173 | 22.52% |

**ARIZONA PUBLIC SERVICE COMPANY**
Depreciation Reserve Summary
Vintage Group Procedure
December 31, 2010

Statement C

| Account Description | Plant Investment | Recorded Reserve Amount | Recorded Reserve Ratio | Computed Reserve Amount | Computed Reserve Ratio | Redistributed Reserve Amount | Redistributed Reserve Ratio |
|---|---|---|---|---|---|---|---|
| A | B | C | D=C/B | E | F=E/B | G | H=G/B |
| **DISTRIBUTION PLANT** | | | | | | | |
| 361.00 Structures and Improvements | $60,888,680 | $13,925,108 | 22.87% | $11,153,574 | 18.32% | $14,425,802 | 23.69% |
| 362.00 Station Equipment | 406,799,985 | 77,004,485 | 18.93% | 57,301,547 | 14.09% | 74,112,634 | 18.22% |
| 364.01 Poles, Towers and Fixtures - Wood | 310,263,864 | 106,919,214 | 34.46% | 83,765,803 | 27.00% | 108,340,954 | 34.92% |
| 364.02 Poles, Towers and Fixtures - Steel | 167,311,767 | 18,785,628 | 11.23% | 14,702,226 | 8.79% | 19,015,554 | 11.37% |
| 365.00 Overhead Conductors and Devices | 292,642,985 | 56,679,654 | 19.37% | 42,557,015 | 14.54% | 55,042,361 | 18.81% |
| 366.00 Underground Conduit | 620,488,170 | 115,499,013 | 18.61% | 105,266,915 | 16.97% | 136,150,047 | 21.94% |
| 367.00 Underground Conductors and Devices | 1,422,708,502 | 461,218,302 | 32.42% | 337,392,264 | 23.71% | 436,376,163 | 30.67% |
| 368.00 Line Transformers | 717,419,840 | 204,170,212 | 28.46% | 154,892,922 | 21.59% | 200,335,296 | 27.92% |
| 369.00 Services | 323,341,677 | 117,434,522 | 36.32% | 91,106,549 | 28.18% | 117,835,322 | 36.44% |
| 370.01 Meters - Electronic | 62,207,543 | 19,661,616 | 31.61% | 12,407,288 | 19.94% | 16,047,329 | 25.80% |
| 370.03 Meters - AMI | 117,715,566 | 5,454,950 | 4.63% | 6,965,881 | 5.92% | 9,009,526 | 7.65% |
| 371.00 Installations on Customers' Premises | 39,842,142 | 4,515,230 | 11.33% | 7,948,234 | 19.95% | 10,280,082 | 25.80% |
| 373.00 Street Lighting and Signal Systems | 73,702,827 | 15,510,350 | 21.04% | 15,314,314 | 20.78% | 19,807,216 | 26.87% |
| **Total Distribution Plant** | $4,615,333,548 | $1,216,778,286 | 26.36% | $940,774,532 | 20.38% | $1,216,778,286 | 26.36% |
| **GENERAL PLANT** | | | | | | | |
| **Depreciable** | | | | | | | |
| 390.00 Structures and Improvements | $107,643,854 | $41,645,555 | 38.69% | $26,639,445 | 24.75% | $27,863,799 | 25.89% |
| 391.CM Office Furn. and Equip. - Computer | 89,098,127 | 26,326,394 | 29.55% | 34,077,152 | 38.25% | 35,643,344 | 40.00% |
| 397.00 Communication Equipment | 152,910,098 | 53,478,093 | 34.97% | 62,059,040 | 40.59% | 64,911,285 | 42.45% |
| **Total Depreciable** | $349,652,079 | $121,450,043 | 34.73% | $122,775,638 | 35.11% | $128,418,428 | 36.73% |

**ARIZONA PUBLIC SERVICE COMPANY**
Depreciation Reserve Summary
Vintage Group Procedure
December 31, 2010

Statement C

| Account Description | Plant Investment | Recorded Reserve Amount | Recorded Reserve Ratio | Computed Reserve Amount | Computed Reserve Ratio | Redistributed Reserve Amount | Redistributed Reserve Ratio |
|---|---|---|---|---|---|---|---|
| A | B | C | D=C/B | E | F=E/B | G | H=G/B |
| **Amortizable** | | | | | | | |
| 391.FE Office Furn. and Equip. - Furniture | $49,130,094 | $16,581,836 | 33.75% | $14,343,161 | 29.19% | $14,343,161 | 29.19% |
| 393.00 Stores Equipment | 256,764 | 53,028 | 20.65% | 33,264 | 12.96% | 33,264 | 12.96% |
| 394.00 Tools, Shop and Garage Equipment | 28,424,012 | 15,220,425 | 53.55% | 11,518,585 | 40.52% | 11,518,585 | 40.52% |
| 395.00 Laboratory Equipment | 1,385,366 | 835,033 | 60.28% | 878,477 | 63.41% | 878,477 | 63.41% |
| 398.00 Miscellaneous Equipment | 5,909,111 | 2,242,021 | 37.94% | 1,190,470 | 20.15% | 1,190,470 | 20.15% |
| **Total Amortizable** | $85,105,347 | $34,932,343 | 41.05% | $27,963,957 | 32.86% | $27,963,957 | 32.86% |
| **Total General Plant** | $434,757,426 | $156,382,385 | 35.97% | $150,739,595 | 34.67% | $156,382,385 | 35.97% |
| **TOTAL UTILITY** | $11,009,502,913 | $4,209,736,678 | 38.24% | $3,367,619,454 | 30.59% | $4,209,736,678 | 38.24% |
| **STEAM PRODUCTION (by Unit)** | | | | | | | |
| **Cholla** | | | | | | | |
| 311.00 Structures and Improvements | $72,335,187 | $32,658,749 | 45.15% | $27,740,590 | 38.35% | $25,961,589 | 35.89% |
| 312.00 Boiler Plant Equipment | 521,789,973 | 199,546,630 | 38.24% | 165,902,051 | 31.79% | 155,262,773 | 29.76% |
| 314.00 Turbogenerator Units | 125,558,183 | 49,336,701 | 39.29% | 40,240,161 | 32.05% | 37,659,564 | 29.99% |
| 315.00 Accessory Electric Equipment | 93,701,286 | 64,122,005 | 68.43% | 49,240,217 | 52.55% | 46,082,448 | 49.18% |
| 316.00 Miscellaneous Power Plant Equipment | 27,985,746 | 13,003,913 | 46.47% | 9,520,688 | 34.02% | 8,910,127 | 31.84% |
| **Total Cholla** | $841,370,375 | $358,667,998 | 42.63% | $292,643,706 | 34.78% | $273,876,501 | 32.55% |
| **Cholla Unit 1** | | | | | | | |
| 311.00 Structures and Improvements | $4,372,274 | $2,485,697 | 56.85% | $1,891,795 | 43.27% | $1,770,475 | 40.49% |
| 312.00 Boiler Plant Equipment | 73,213,804 | 28,223,333 | 38.55% | 22,707,383 | 31.02% | 21,251,162 | 29.03% |
| 314.00 Turbogenerator Units | 25,640,590 | 6,606,429 | 25.77% | 6,245,198 | 24.36% | 5,844,694 | 22.79% |
| 315.00 Accessory Electric Equipment | 8,816,493 | 4,882,751 | 55.38% | 3,728,135 | 42.29% | 3,489,050 | 39.57% |
| 316.00 Miscellaneous Power Plant Equipment | 2,838,727 | 1,871,258 | 65.92% | 1,309,008 | 46.11% | 1,225,061 | 43.16% |
| **Total Cholla Unit 1** | $114,881,888 | $44,069,468 | 38.36% | $35,881,519 | 31.23% | $33,580,442 | 29.23% |
| **Cholla Unit 2** | | | | | | | |
| 311.00 Structures and Improvements | $6,168,012 | $3,411,030 | 55.30% | $2,686,370 | 43.55% | $2,514,093 | 40.76% |
| 312.00 Boiler Plant Equipment | 162,323,693 | 106,524,199 | 65.62% | 83,040,881 | 51.16% | 77,715,480 | 47.88% |
| 314.00 Turbogenerator Units | 44,157,763 | 18,673,370 | 42.29% | 16,165,636 | 36.61% | 15,128,936 | 34.26% |
| 315.00 Accessory Electric Equipment | 46,110,434 | 33,572,567 | 72.81% | 25,944,613 | 56.27% | 24,280,788 | 52.66% |
| 316.00 Miscellaneous Power Plant Equipment | 8,714,396 | 3,655,960 | 41.95% | 2,839,448 | 32.58% | 2,657,354 | 30.49% |
| **Total Cholla Unit 2** | $267,474,298 | $165,837,126 | 62.00% | $130,676,948 | 48.86% | $122,296,651 | 45.72% |

**ARIZONA PUBLIC SERVICE COMPANY**
Depreciation Reserve Summary
Vintage Group Procedure
December 31, 2010

Statement C

| Account Description | Plant Investment | Recorded Reserve Amount | Recorded Reserve Ratio | Computed Reserve Amount | Computed Reserve Ratio | Redistributed Reserve Amount | Redistributed Reserve Ratio |
|---|---|---|---|---|---|---|---|
| A | B | C | D=C/B | E | F=E/B | G | H=G/B |
| **Cholla Unit 3** | | | | | | | |
| 311.00 Structures and Improvements | $9,984,226 | $7,051,816 | 70.63% | $5,394,931 | 54.03% | $5,048,955 | 50.57% |
| 312.00 Boiler Plant Equipment | 228,064,943 | 49,009,037 | 21.49% | 46,827,913 | 20.53% | 43,824,844 | 19.22% |
| 314.00 Turbogenerator Units | 54,849,058 | 23,540,403 | 42.92% | 17,444,385 | 31.80% | 16,325,679 | 29.76% |
| 315.00 Accessory Electric Equipment | 31,001,286 | 22,409,000 | 72.28% | 16,990,227 | 54.80% | 15,900,645 | 51.29% |
| 316.00 Miscellaneous Power Plant Equipment | 4,593,291 | 2,817,643 | 61.34% | 2,115,521 | 46.06% | 1,979,853 | 43.10% |
| **Total Cholla Unit 3** | $328,492,804 | $104,827,899 | 31.91% | $88,772,977 | 27.02% | $83,079,977 | 25.29% |
| **Cholla Common** | | | | | | | |
| 311.00 Structures and Improvements | $51,810,675 | $19,710,205 | 38.04% | $17,767,493 | 34.29% | $16,628,066 | 32.09% |
| 312.00 Boiler Plant Equipment | 58,187,533 | 15,790,061 | 27.14% | 13,325,873 | 22.90% | 12,471,287 | 21.43% |
| 314.00 Turbogenerator Units | 910,772 | 516,499 | 56.71% | 384,942 | 42.27% | 360,255 | 39.55% |
| 315.00 Accessory Electric Equipment | 7,773,073 | 3,257,688 | 41.91% | 2,577,242 | 33.16% | 2,411,964 | 31.03% |
| 316.00 Miscellaneous Power Plant Equipment | 11,839,332 | 4,659,052 | 39.35% | 3,256,711 | 27.51% | 3,047,859 | 25.74% |
| **Total Cholla Common** | $130,521,385 | $43,933,506 | 33.66% | $37,312,262 | 28.59% | $34,919,431 | 26.75% |
| **Four Corners** | | | | | | | |
| 311.00 Structures and Improvements | $57,549,016 | $31,835,205 | 55.32% | $51,262,088 | 89.08% | $50,583,658 | 87.90% |
| 312.00 Boiler Plant Equipment | 375,402,116 | 249,976,472 | 66.59% | 332,878,015 | 88.67% | 327,056,555 | 87.12% |
| 314.00 Turbogenerator Units | 73,354,578 | 46,674,854 | 63.63% | 63,301,295 | 86.29% | 62,460,065 | 85.15% |
| 315.00 Accessory Electric Equipment | 40,063,953 | 23,152,430 | 57.79% | 34,187,081 | 85.33% | 33,555,171 | 83.75% |
| 316.00 Miscellaneous Power Plant Equipment | 25,722,887 | 11,914,370 | 46.32% | 18,479,812 | 71.84% | 18,042,158 | 70.14% |
| **Total Four Corners** | $572,092,550 | $363,553,331 | 63.55% | $500,108,290 | 87.42% | $491,697,606 | 85.95% |
| **Four Corners Units 1-3** | | | | | | | |
| 311.00 Structures and Improvements | $40,683,091 | $22,130,773 | 54.40% | $40,683,091 | 100.00% | $40,683,091 | 100.00% |
| 312.00 Boiler Plant Equipment | 242,101,914 | 166,321,891 | 68.70% | 242,101,914 | 100.00% | 242,101,914 | 100.00% |
| 314.00 Turbogenerator Units | 50,183,693 | 34,950,798 | 69.65% | 50,183,693 | 100.00% | 50,183,693 | 100.00% |
| 315.00 Accessory Electric Equipment | 24,333,485 | 14,311,157 | 58.81% | 24,333,485 | 100.00% | 24,333,485 | 100.00% |
| 316.00 Miscellaneous Power Plant Equipment | 11,655,314 | 5,718,804 | 49.07% | 11,655,314 | 100.00% | 11,655,314 | 100.00% |
| **Total Four Corners Units 1-3** | $368,957,497 | $243,433,422 | 65.98% | $368,957,497 | 100.00% | $368,957,497 | 100.00% |

**ARIZONA PUBLIC SERVICE COMPANY**
Depreciation Reserve Summary
Vintage Group Procedure
December 31, 2010

Statement C

| Account Description | Plant Investment | Recorded Reserve Amount | Recorded Reserve Ratio | Computed Reserve Amount | Computed Reserve Ratio | Redistributed Reserve Amount | Redistributed Reserve Ratio |
|---|---|---|---|---|---|---|---|
| A | B | C | D=C/B | E | F=E/B | G | H=G/B |
| **Four Corners Units 4-5** | | | | | | | |
| 311.00 Structures and Improvements | $11,882,266 | $7,361,654 | 61.95% | $7,890,704 | 66.41% | $7,384,675 | 62.15% |
| 312.00 Boiler Plant Equipment | 118,062,055 | 75,799,402 | 64.20% | 81,810,700 | 69.29% | 76,564,190 | 64.85% |
| 314.00 Turbogenerator Units | 21,183,385 | 10,435,941 | 49.26% | 11,584,172 | 54.69% | 10,841,280 | 51.18% |
| 315.00 Accessory Electric Equipment | 11,137,088 | 7,001,791 | 62.87% | 7,620,483 | 68.42% | 7,131,782 | 64.04% |
| 316.00 Miscellaneous Power Plant Equipment | 3,614,952 | 2,053,080 | 56.79% | 2,174,289 | 60.15% | 2,034,852 | 56.29% |
| **Total Four Corners Units 4-5** | $165,879,746 | $102,651,868 | 61.88% | $111,080,349 | 66.96% | $103,956,780 | 62.67% |
| **Four Corners Common** | | | | | | | |
| 311.00 Structures and Improvements | $4,983,659 | $2,342,778 | 47.01% | $2,688,292 | 53.94% | $2,515,892 | 50.48% |
| 312.00 Boiler Plant Equipment | 15,238,147 | 7,855,180 | 51.55% | 8,965,400 | 58.84% | 8,390,450 | 55.06% |
| 314.00 Turbogenerator Units | 1,987,500 | 1,288,114 | 64.81% | 1,533,431 | 77.15% | 1,435,092 | 72.21% |
| 315.00 Accessory Electric Equipment | 4,593,380 | 1,839,483 | 40.05% | 2,233,113 | 48.62% | 2,089,903 | 45.50% |
| 316.00 Miscellaneous Power Plant Equipment | 10,452,621 | 4,142,487 | 39.63% | 4,650,209 | 44.49% | 4,351,991 | 41.64% |
| **Total Four Corners Common** | $37,255,307 | $17,468,041 | 46.89% | $20,070,444 | 53.87% | $18,783,329 | 50.42% |
| **Navajo Units 1-3** | | | | | | | |
| 311.00 Structures and Improvements | $29,113,530 | $17,980,695 | 61.76% | $16,421,048 | 56.40% | $15,367,968 | 52.79% |
| 312.00 Boiler Plant Equipment | 166,003,214 | 100,903,604 | 60.78% | 91,281,962 | 54.99% | 85,428,061 | 51.46% |
| 314.00 Turbogenerator Units | 24,699,305 | 18,790,977 | 76.08% | 16,704,316 | 67.63% | 15,633,070 | 63.29% |
| 315.00 Accessory Electric Equipment | 21,491,344 | 15,279,119 | 71.09% | 13,685,439 | 63.68% | 12,807,794 | 59.60% |
| 316.00 Miscellaneous Power Plant Equipment | 17,228,597 | 9,325,019 | 54.13% | 8,484,627 | 49.25% | 7,940,509 | 46.09% |
| **Total Navajo Units 1-3** | $258,535,990 | $162,279,414 | 62.77% | $146,577,393 | 56.70% | $137,177,403 | 53.06% |
| **Ocotillo Units 1-2** | | | | | | | |
| 311.00 Structures and Improvements | $4,759,658 | $3,304,683 | 69.43% | $3,282,708 | 68.97% | $3,072,188 | 64.55% |
| 312.00 Boiler Plant Equipment | 25,218,648 | 23,841,573 | 94.54% | 21,849,542 | 86.64% | 20,448,334 | 81.08% |
| 314.00 Turbogenerator Units | 20,161,583 | 15,093,026 | 74.86% | 14,294,685 | 70.90% | 13,377,968 | 66.35% |
| 315.00 Accessory Electric Equipment | 3,425,956 | 2,585,027 | 75.45% | 2,503,962 | 73.09% | 2,343,383 | 68.40% |
| 316.00 Miscellaneous Power Plant Equipment | 6,010,574 | 3,863,288 | 64.27% | 3,493,484 | 58.12% | 3,269,448 | 54.39% |
| **Total Ocotillo Units 1-2** | $59,576,419 | $48,687,597 | 81.72% | $45,424,381 | 76.25% | $42,511,321 | 71.36% |

**ARIZONA PUBLIC SERVICE COMPANY**
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Statement C

| Account Description | Plant Investment | Recorded Reserve Amount | Recorded Reserve Ratio | Computed Reserve Amount | Computed Reserve Ratio | Redistributed Reserve Amount | Redistributed Reserve Ratio |
|---|---|---|---|---|---|---|---|
| A | B | C | D=C/B | E | F=E/B | G | H=G/B |
| **Saguaro Units 1-2** | | | | | | | |
| 311.00 Structures and Improvements | $4,311,317 | $3,119,294 | 72.35% | $2,650,705 | 61.48% | $2,480,715 | 57.54% |
| 312.00 Boiler Plant Equipment | 26,094,372 | 23,846,570 | 91.39% | 19,484,765 | 74.67% | 18,235,209 | 69.88% |
| 314.00 Turbogenerator Units | 16,513,563 | 17,582,774 | 106.47% | 14,510,305 | 87.87% | 13,579,761 | 82.23% |
| 315.00 Accessory Electric Equipment | 5,667,906 | 3,745,776 | 66.09% | 3,391,272 | 59.83% | 3,173,790 | 56.00% |
| 316.00 Miscellaneous Power Plant Equipment | 4,778,936 | 4,208,892 | 88.07% | 3,162,126 | 66.17% | 2,959,339 | 61.92% |
| **Total Saguaro Units 1-2** | $57,366,094 | $52,503,306 | 91.52% | $43,199,172 | 75.30% | $40,428,815 | 70.48% |
| **NUCLEAR PRODUCTION (by Unit)** | | | | | | | |
| **Palo Verde** | | | | | | | |
| 321.00 Structures and Improvements | $698,846,801 | $390,836,399 | 55.93% | $241,914,153 | 34.62% | $384,424,922 | 55.01% |
| 322.00 Reactor Plant Equipment | 1,130,933,859 | 556,209,183 | 49.18% | 353,970,046 | 31.30% | 561,119,881 | 49.62% |
| 323.00 Turbogenerator Units | 354,174,138 | 171,976,208 | 48.56% | 115,517,890 | 32.62% | 182,656,783 | 51.57% |
| 324.00 Accessory Electric Equipment | 275,016,677 | 169,883,421 | 61.77% | 104,821,257 | 38.11% | 166,763,875 | 60.64% |
| 325.00 Miscellaneous Power Plant Equipment | 145,211,312 | 77,544,578 | 53.40% | 44,088,269 | 30.36% | 71,484,329 | 49.23% |
| **Total Palo Verde** | $2,604,182,787 | $1,366,449,789 | 52.47% | $860,311,616 | 33.04% | $1,366,449,789 | 52.47% |
| **Palo Verde Unit 1** | | | | | | | |
| 321.00 Structures and Improvements | $156,705,345 | $100,876,428 | 64.37% | $63,267,866 | 40.37% | $100,610,842 | 64.20% |
| 322.00 Reactor Plant Equipment | 454,207,200 | 241,944,101 | 53.27% | 152,771,318 | 33.63% | 242,942,460 | 53.49% |
| 323.00 Turbogenerator Units | 125,268,196 | 68,240,082 | 54.48% | 43,041,449 | 34.36% | 68,446,065 | 54.64% |
| 324.00 Accessory Electric Equipment | 114,860,792 | 74,151,478 | 64.56% | 46,668,557 | 40.63% | 74,214,023 | 64.61% |
| 325.00 Miscellaneous Power Plant Equipment | 30,801,758 | 18,990,462 | 61.65% | 11,312,258 | 36.73% | 17,989,161 | 58.40% |
| **Total Palo Verde Unit 1** | $881,843,291 | $504,202,551 | 57.18% | $317,061,449 | 35.95% | $504,202,551 | 57.18% |
| **Palo Verde Unit 2** | | | | | | | |
| 321.00 Structures and Improvements | $91,657,911 | $56,731,380 | 61.89% | $36,063,237 | 39.35% | $55,579,960 | 60.64% |
| 322.00 Reactor Plant Equipment | 234,287,478 | 117,989,148 | 50.36% | 73,783,989 | 31.49% | 113,714,449 | 48.54% |
| 323.00 Turbogenerator Units | 78,612,699 | 34,734,451 | 44.18% | 27,286,159 | 34.71% | 42,052,898 | 53.49% |
| 324.00 Accessory Electric Equipment | 49,937,247 | 29,918,465 | 59.91% | 19,123,865 | 38.30% | 29,473,328 | 59.02% |
| 325.00 Miscellaneous Power Plant Equipment | 27,087,580 | 15,560,042 | 57.44% | 9,157,168 | 33.81% | 14,112,850 | 52.10% |
| **Total Palo Verde Unit 2** | $481,582,915 | $254,933,485 | 52.94% | $165,414,419 | 34.35% | $254,933,485 | 52.94% |

**ARIZONA PUBLIC SERVICE COMPANY**
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Statement C

| Account Description | Plant Investment | Recorded Reserve Amount | Recorded Reserve Ratio | Computed Reserve Amount | Computed Reserve Ratio | Redistributed Reserve Amount | Redistributed Reserve Ratio |
|---|---|---|---|---|---|---|---|
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| **Palo Verde Unit 3** | | | | | | | |
| 321.00 Structures and Improvements | $163,192,491 | $101,112,724 | 61.96% | $59,252,916 | 36.31% | $94,572,123 | 57.95% |
| 322.00 Reactor Plant Equipment | 414,451,923 | 180,296,659 | 43.50% | 118,151,189 | 28.51% | 188,578,209 | 45.50% |
| 323.00 Turbogenerator Units | 147,910,539 | 68,313,093 | 46.19% | 44,813,159 | 30.30% | 71,525,182 | 48.36% |
| 324.00 Accessory Electric Equipment | 90,837,828 | 54,944,448 | 60.49% | 32,458,800 | 35.73% | 51,806,693 | 57.03% |
| 325.00 Miscellaneous Power Plant Equipment | 28,712,249 | 16,887,577 | 58.82% | 9,443,346 | 32.89% | 15,072,292 | 52.49% |
| **Total Palo Verde Unit 3** | $845,105,030 | $421,554,500 | 49.88% | $264,119,411 | 31.25% | $421,554,500 | 49.88% |
| **Palo Verde Water Reclamation** | | | | | | | |
| 321.00 Structures and Improvements | $171,609,224 | $70,472,808 | 41.07% | $46,507,322 | 27.10% | $70,498,432 | 41.08% |
| 322.00 Reactor Plant Equipment | 133,326 | 50,006 | 37.51% | 26,845 | 20.14% | 40,694 | 30.52% |
| 323.00 Turbogenerator Units | 217,756 | 119,207 | 54.74% | 71,456 | 32.81% | 108,317 | 49.74% |
| 324.00 Accessory Electric Equipment | | | | | | | |
| 325.00 Miscellaneous Power Plant Equipment | 88,819 | 49,049 | 55.22% | 28,780 | 32.40% | 43,627 | 49.12% |
| **Total Palo Verde Water Reclamation** | $172,049,125 | $70,691,070 | 41.09% | $46,634,404 | 27.11% | $70,691,070 | 41.09% |
| **Palo Verde Common** | | | | | | | |
| 321.00 Structures and Improvements | $115,681,830 | $61,643,060 | 53.29% | $36,822,812 | 31.83% | $63,163,565 | 54.60% |
| 322.00 Reactor Plant Equipment | 27,853,932 | 15,929,270 | 57.19% | 9,236,704 | 33.16% | 15,844,069 | 56.88% |
| 323.00 Turbogenerator Units | 2,164,948 | 569,376 | 26.30% | 305,665 | 14.12% | 524,320 | 24.22% |
| 324.00 Accessory Electric Equipment | 19,380,810 | 10,869,029 | 56.08% | 6,570,036 | 33.90% | 11,269,831 | 58.15% |
| 325.00 Miscellaneous Power Plant Equipment | 58,520,906 | 26,057,448 | 44.53% | 14,146,717 | 24.17% | 24,266,399 | 41.47% |
| **Total Palo Verde Common** | $223,602,426 | $115,068,183 | 51.46% | $67,081,934 | 30.00% | $115,068,183 | 51.46% |
| **OTHER PRODUCTION (by Unit)** | | | | | | | |
| **Douglas CT** | | | | | | | |
| 341.00 Structures and Improvements | $49,075 | $17,696 | 36.06% | $18,844 | 38.40% | $24,163 | 49.24% |
| 342.00 Fuel Holders, Products and Accessories | 137,759 | 120,882 | 87.75% | 93,051 | 67.55% | 119,319 | 86.61% |
| 343.00 Prime Movers | 1,101,449 | 1,076,890 | 97.77% | 834,801 | 75.79% | 1,070,460 | 97.19% |
| 344.00 Generators and Devices | 551,765 | 535,119 | 96.98% | 419,498 | 76.03% | 537,919 | 97.49% |
| 345.00 Accessory Electric Equipment | 353,277 | 335,531 | 94.98% | 260,799 | 73.82% | 334,422 | 94.66% |
| 346.00 Miscellaneous Power Plant Equipment | 40,913 | 36,482 | 89.17% | 28,321 | 69.22% | 36,316 | 88.76% |
| **Total Douglas CT** | $2,234,238 | $2,122,600 | 95.00% | $1,655,314 | 74.09% | $2,122,600 | 95.00% |

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Statement C

| Account Description | Plant Investment | Recorded Reserve Amount | Recorded Reserve Ratio | Computed Reserve Amount | Computed Reserve Ratio | Redistributed Reserve Amount | Redistributed Reserve Ratio |
|---|---|---|---|---|---|---|---|
| A | B | C | D=C/B | E | F=E/B | G | H=G/B |
| **Ocotillo CT Units 1-2** | | | | | | | |
| 341.00 Structures and Improvements | $721,568 | $365,738 | 50.69% | $343,482 | 47.60% | $415,356 | 57.56% |
| 342.00 Fuel Holders, Products and Accessories | 791,584 | 624,258 | 78.86% | 501,158 | 63.31% | 606,027 | 76.56% |
| 343.00 Prime Movers | 6,540,275 | 6,067,636 | 92.77% | 4,783,565 | 73.14% | 5,784,541 | 88.44% |
| 344.00 Generators and Devices | 7,596,314 | 4,904,199 | 64.56% | 4,298,851 | 56.59% | 5,198,399 | 68.43% |
| 345.00 Accessory Electric Equipment | 1,677,431 | 1,386,807 | 82.67% | 1,116,793 | 66.58% | 1,350,485 | 80.51% |
| 346.00 Miscellaneous Power Plant Equipment | 637,727 | 489,648 | 76.78% | 399,815 | 62.69% | 483,477 | 75.81% |
| **Total Octillo CT Units 1-2** | $17,964,899 | $13,838,285 | 77.03% | $11,443,664 | 63.70% | $13,838,285 | 77.03% |
| **Redhawk CC Units 1-2** | | | | | | | |
| 341.00 Structures and Improvements | $22,197,402 | $3,560,250 | 16.04% | $4,045,668 | 18.23% | $3,951,957 | 17.80% |
| 342.00 Fuel Holders, Products and Accessories | 2,637,978 | 116,802 | 4.43% | 179,784 | 6.82% | 175,620 | 6.66% |
| 343.00 Prime Movers | 177,860,527 | 45,932,112 | 25.82% | 31,920,358 | 17.95% | 31,180,973 | 17.53% |
| 344.00 Generators and Devices | 279,212,258 | 70,242,249 | 25.16% | 88,204,328 | 31.59% | 86,161,211 | 30.86% |
| 345.00 Accessory Electric Equipment | 22,584,466 | 5,595,952 | 24.78% | 4,155,053 | 18.40% | 4,058,808 | 17.97% |
| 346.00 Miscellaneous Power Plant Equipment | 4,005,866 | 372,713 | 9.30% | 298,423 | 7.45% | 291,510 | 7.28% |
| **Total Redhawk CC Units 1-2** | $508,498,497 | $125,820,078 | 24.74% | $128,803,614 | 25.33% | $125,820,078 | 24.74% |
| **Saguaro** | | | | | | | |
| 341.00 Structures and Improvements | $1,885,444 | $981,183 | 52.04% | $815,125 | 43.23% | $1,016,029 | 53.89% |
| 342.00 Fuel Holders, Products and Accessories | 1,376,702 | 1,169,447 | 84.95% | 921,069 | 66.90% | 1,148,085 | 83.39% |
| 343.00 Prime Movers | 8,624,812 | 7,599,540 | 88.11% | 5,968,880 | 69.21% | 7,424,851 | 86.09% |
| 344.00 Generators and Devices | 32,512,372 | 10,086,665 | 31.02% | 8,775,823 | 26.99% | 10,275,001 | 31.60% |
| 345.00 Accessory Electric Equipment | 1,701,779 | 1,492,152 | 87.68% | 1,178,170 | 69.23% | 1,465,652 | 86.12% |
| 346.00 Miscellaneous Power Plant Equipment | 868,485 | 626,012 | 72.08% | 501,721 | 57.77% | 625,381 | 72.01% |
| **Total Saguaro** | $46,969,594 | $21,954,998 | 46.74% | $18,160,789 | 38.66% | $21,954,998 | 46.74% |
| **Saguaro CT Units 1-2** | | | | | | | |
| 341.00 Structures and Improvements | $1,885,444 | $981,183 | 52.04% | $815,125 | 43.23% | $1,016,029 | 53.89% |
| 342.00 Fuel Holders, Products and Accessories | 1,376,702 | 1,169,447 | 84.95% | 921,069 | 66.90% | 1,148,085 | 83.39% |
| 343.00 Prime Movers | 7,983,905 | 7,434,419 | 93.12% | 5,824,466 | 72.95% | 7,260,024 | 90.93% |
| 344.00 Generators and Devices | 4,487,988 | 2,879,784 | 64.17% | 2,461,151 | 54.84% | 3,067,752 | 68.35% |
| 345.00 Accessory Electric Equipment | 1,579,226 | 1,460,559 | 92.49% | 1,150,556 | 72.86% | 1,434,134 | 90.81% |
| 346.00 Miscellaneous Power Plant Equipment | 868,485 | 626,012 | 72.08% | 501,721 | 57.77% | 625,381 | 72.01% |
| **Total Saguaro CT Units 1-2** | $18,181,750 | $14,551,404 | 80.03% | $11,674,088 | 64.21% | $14,551,404 | 80.03% |

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Statement C

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|---|---|---|---|---|---|---|---|
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| **Saguaro CT Unit 3** | | | | | | | |
| 341.00 Structures and Improvements | | | | | | | |
| 342.00 Fuel Holders, Products and Accessories | | | | | | | |
| 343.00 Prime Movers | 640,907 | 165,120 | 25.76% | 144,414 | 22.53% | 164,827 | 25.72% |
| 344.00 Generators and Devices | 28,024,384 | 7,206,881 | 25.72% | 6,314,672 | 22.53% | 7,207,249 | 25.72% |
| 345.00 Accessory Electric Equipment | 122,553 | 31,593 | 25.78% | 27,615 | 22.53% | 31,518 | 25.72% |
| 346.00 Miscellaneous Power Plant Equipment | | | | | | | |
| **Total Saguaro CT Unit 3** | $28,787,844 | $7,403,594 | 25.72% | $6,486,701 | 22.53% | $7,403,594 | 25.72% |
| **Solar Units** | | | | | | | |
| 341.00 Structures and Improvements | $418,403 | $345,858 | 82.66% | $342,365 | 81.83% | $429,042 | 102.54% |
| 342.00 Fuel Holders, Products and Accessories | | | | | | | |
| 343.00 Prime Movers | | | | | | | |
| 344.00 Generators and Devices | 15,963,981 | 13,235,714 | 82.91% | 10,452,157 | 65.47% | 13,098,366 | 82.05% |
| 345.00 Accessory Electric Equipment | 728,283 | 196,423 | 26.97% | 199,962 | 27.46% | 250,587 | 34.41% |
| 346.00 Miscellaneous Power Plant Equipment | | | | | | | |
| **Total Solar Units** | $17,110,667 | $13,777,995 | 80.52% | $10,994,484 | 64.26% | $13,777,995 | 80.52% |
| **Sundance** | | | | | | | |
| 341.00 Structures and Improvements | $12,653,247 | $5,603,059 | 44.28% | $1,979,907 | 15.65% | $5,668,679 | 44.80% |
| 342.00 Fuel Holders, Products and Accessories | 4,325,769 | 1,948,218 | 45.04% | 680,227 | 15.72% | 1,947,560 | 45.02% |
| 343.00 Prime Movers | 229,732,211 | 104,718,058 | 45.58% | 36,480,728 | 15.88% | 104,448,094 | 45.47% |
| 344.00 Generators and Devices | 301,285 | 67,296 | 22.34% | 35,790 | 11.88% | 102,470 | 34.01% |
| 345.00 Accessory Electric Equipment | 26,408,712 | 11,833,373 | 44.81% | 4,152,768 | 15.72% | 11,889,803 | 45.02% |
| 346.00 Miscellaneous Power Plant Equipment | 2,028,889 | 583,235 | 28.75% | 243,314 | 11.99% | 696,634 | 34.34% |
| **Total Sun Dance** | $275,450,113 | $124,753,240 | 45.29% | $43,572,734 | 15.82% | $124,753,240 | 45.29% |
| **West Phoenix** | | | | | | | |
| 341.00 Structures and Improvements | $27,606,161 | $8,028,233 | 29.08% | $6,810,562 | 24.67% | $8,241,502 | 29.85% |
| 342.00 Fuel Holders, Products and Accessories | 28,090,344 | 10,287,133 | 36.62% | 9,248,768 | 32.93% | 8,941,789 | 31.83% |
| 343.00 Prime Movers | 164,651,195 | 43,377,427 | 26.35% | 35,863,165 | 21.78% | 38,925,794 | 23.64% |
| 344.00 Generators and Devices | 244,094,419 | 63,154,504 | 25.87% | 68,944,655 | 28.25% | 69,012,168 | 28.27% |
| 345.00 Accessory Electric Equipment | 29,569,013 | 8,531,885 | 28.85% | 8,079,177 | 27.32% | 8,254,821 | 27.92% |
| 346.00 Miscellaneous Power Plant Equipment | 6,447,142 | 2,077,953 | 32.23% | 2,027,036 | 31.44% | 2,081,061 | 32.28% |
| **Total West Phoenix** | $500,458,274 | $135,457,135 | 27.07% | $130,973,364 | 26.17% | $135,457,135 | 27.07% |

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Statement C

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| **West Phoenix CC Units 1-3** | | | | | | | |
| 341.00 Structures and Improvements | $1,710,485 | $132,833 | 7.77% | $252,378 | 14.75% | $231,985 | 13.56% |
| 342.00 Fuel Holders, Products and Accessories | 22,517,702 | 7,906,615 | 35.11% | 7,189,533 | 31.93% | 6,608,587 | 29.35% |
| 343.00 Prime Movers | | | | | | | |
| 344.00 Generators and Devices | 92,566,116 | 31,967,137 | 34.53% | 36,532,482 | 39.47% | 33,580,493 | 36.28% |
| 345.00 Accessory Electric Equipment | 13,561,670 | 4,298,346 | 31.69% | 4,283,559 | 31.59% | 3,937,428 | 29.03% |
| 346.00 Miscellaneous Power Plant Equipment | 4,722,353 | 1,314,748 | 27.84% | 1,372,056 | 29.05% | 1,261,187 | 26.71% |
| **Total West Phoenix CC Units 1-3** | $135,078,326 | $45,619,679 | 33.77% | $49,630,008 | 36.74% | $45,619,679 | 33.77% |
| **West Phoenix CC Unit 4** | | | | | | | |
| 341.00 Structures and Improvements | $4,584,726 | $1,106,157 | 24.13% | $1,077,578 | 23.50% | $1,080,513 | 23.57% |
| 342.00 Fuel Holders, Products and Accessories | 4,135,109 | 1,084,373 | 26.22% | 1,042,336 | 25.21% | 1,045,174 | 25.28% |
| 343.00 Prime Movers | 54,680,534 | 14,295,034 | 26.14% | 13,783,305 | 25.21% | 13,820,838 | 25.28% |
| 344.00 Generators and Devices | 15,548,138 | 3,605,752 | 23.19% | 4,130,977 | 26.57% | 4,142,226 | 26.64% |
| 345.00 Accessory Electric Equipment | 2,569,550 | 310,875 | 12.10% | 290,977 | 11.32% | 291,770 | 11.35% |
| 346.00 Miscellaneous Power Plant Equipment | 315,741 | 1,866 | 0.59% | 23,474 | 7.43% | 23,538 | 7.45% |
| **Total West Phoenix CC Unit 4** | $81,833,798 | $20,404,058 | 24.93% | $20,348,647 | 24.87% | $20,404,058 | 24.93% |
| **West Phoenix CC Unit 5** | | | | | | | |
| 341.00 Structures and Improvements | $10,865,036 | $2,253,755 | 20.74% | $2,144,466 | 19.74% | $2,335,341 | 21.49% |
| 342.00 Fuel Holders, Products and Accessories | | | | | | | |
| 343.00 Prime Movers | 101,176,494 | 21,250,703 | 21.00% | 16,112,985 | 15.93% | 17,547,170 | 17.34% |
| 344.00 Generators and Devices | 131,363,010 | 24,256,976 | 18.47% | 25,516,806 | 19.42% | 27,788,006 | 21.15% |
| 345.00 Accessory Electric Equipment | 11,713,613 | 2,446,192 | 20.88% | 2,327,714 | 19.87% | 2,534,899 | 21.64% |
| 346.00 Miscellaneous Power Plant Equipment | 235,560 | 19,526 | 8.29% | 19,960 | 8.47% | 21,737 | 9.23% |
| **Total West Phoenix CC Unit 5** | $255,353,713 | $50,227,152 | 19.67% | $46,121,932 | 18.06% | $50,227,152 | 19.67% |
| **West Phoenix CT Units 1-2** | | | | | | | |
| 341.00 Structures and Improvements | $880,435 | $480,418 | 54.57% | $425,221 | 48.30% | $538,595 | 61.17% |
| 342.00 Fuel Holders, Products and Accessories | 1,437,533 | 1,296,145 | 90.16% | 1,016,899 | 70.74% | 1,288,029 | 89.60% |
| 343.00 Prime Movers | 8,794,167 | 7,831,689 | 89.06% | 5,966,874 | 67.85% | 7,557,786 | 85.94% |
| 344.00 Generators and Devices | 4,617,155 | 3,324,639 | 72.01% | 2,764,391 | 59.87% | 3,501,444 | 75.84% |
| 345.00 Accessory Electric Equipment | 1,724,180 | 1,476,473 | 85.63% | 1,176,927 | 68.26% | 1,490,725 | 86.46% |
| 346.00 Miscellaneous Power Plant Equipment | 1,173,488 | 741,812 | 63.21% | 611,546 | 52.11% | 774,599 | 66.01% |
| **Total West Phoenix CT Units 1-2** | $18,626,958 | $15,151,177 | 81.34% | $11,961,858 | 64.22% | $15,151,177 | 81.34% |

**ARIZONA PUBLIC SERVICE COMPANY**
Depreciation Reserve Summary
Vintage Group Procedure
December 31, 2010

Statement C

| Account Description | Plant Investment | Recorded Reserve Amount | Recorded Reserve Ratio | Computed Reserve Amount | Computed Reserve Ratio | Redistributed Reserve Amount | Redistributed Reserve Ratio |
|---|---|---|---|---|---|---|---|
| A | B | C | D=C/B | E | F=E/B | G | H=G/B |
| **West Phoenix Common** | | | | | | | |
| 341.00 Structures and Improvements | $9,565,479 | $4,055,069 | 42.39% | $2,910,919 | 30.43% | $4,055,069 | 42.39% |
| 342.00 Fuel Holders, Products and Accessories | | | | | | | |
| 343.00 Prime Movers | | | | | | | |
| 344.00 Generators and Devices | | | | | | | |
| 345.00 Accessory Electric Equipment | | | | | | | |
| 346.00 Miscellaneous Power Plant Equipment | | | | | | | |
| **Total West Phoenix Common** | $9,565,479 | $4,055,069 | 42.39% | $2,910,919 | 30.43% | $4,055,069 | 42.39% |
| **Yucca** | | | | | | | |
| 341.00 Structures and Improvements | $1,730,884 | $374,159 | 21.62% | $195,283 | 11.28% | $351,103 | 20.28% |
| 342.00 Fuel Holders, Products and Accessories | 4,819,210 | 3,255,895 | 67.56% | 1,649,323 | 34.22% | 3,143,385 | 65.23% |
| 343.00 Prime Movers | 76,131,450 | 12,651,159 | 16.62% | 8,436,827 | 11.08% | 12,528,897 | 16.46% |
| 344.00 Generators and Devices | 7,937,599 | 4,585,091 | 57.76% | 2,537,877 | 31.97% | 4,969,421 | 62.61% |
| 345.00 Accessory Electric Equipment | 3,251,231 | 2,186,561 | 67.25% | 1,077,121 | 33.13% | 2,086,231 | 64.17% |
| 346.00 Miscellaneous Power Plant Equipment | 682,399 | 451,201 | 66.12% | 216,925 | 31.79% | 425,030 | 62.28% |
| **Total Yucca** | $94,552,773 | $23,504,066 | 24.86% | $14,113,356 | 14.93% | $23,504,066 | 24.86% |
| **Yucca CT Units 1-4** | | | | | | | |
| 341.00 Structures and Improvements | $1,193,877 | $336,710 | 28.20% | $160,084 | 13.41% | $313,660 | 26.27% |
| 342.00 Fuel Holders, Products and Accessories | 3,316,669 | 3,151,114 | 95.01% | 1,550,836 | 46.76% | 3,038,620 | 91.62% |
| 343.00 Prime Movers | 7,962,254 | 7,897,668 | 99.19% | 3,968,568 | 49.84% | 7,775,787 | 97.66% |
| 344.00 Generators and Devices | 7,883,898 | 4,581,346 | 58.11% | 2,534,357 | 32.15% | 4,965,676 | 62.99% |
| 345.00 Accessory Electric Equipment | 2,838,650 | 2,158,197 | 76.03% | 1,050,078 | 36.99% | 2,057,463 | 72.48% |
| 346.00 Miscellaneous Power Plant Equipment | 682,399 | 451,201 | 66.12% | 216,925 | 31.79% | 425,030 | 62.28% |
| **Total Yucca CT Units 1-4** | $23,877,747 | $18,576,237 | 77.80% | $9,480,848 | 39.71% | $18,576,237 | 77.80% |
| **Yucca CT Units 5-6** | | | | | | | |
| 341.00 Structures and Improvements | $537,007 | $37,449 | 6.97% | $35,199 | 6.55% | $37,443 | 6.97% |
| 342.00 Fuel Holders, Products and Accessories | 1,502,541 | 104,781 | 6.97% | 98,486 | 6.55% | 104,765 | 6.97% |
| 343.00 Prime Movers | 68,169,196 | 4,753,490 | 6.97% | 4,468,259 | 6.55% | 4,753,110 | 6.97% |
| 344.00 Generators and Devices | 53,701 | 3,745 | 6.97% | 3,520 | 6.55% | 3,744 | 6.97% |
| 345.00 Accessory Electric Equipment | 412,581 | 28,365 | 6.87% | 27,043 | 6.55% | 28,767 | 6.97% |
| 346.00 Miscellaneous Power Plant Equipment | | | | | | | |
| **Total Yucca CT Units 5-6** | $70,675,026 | $4,927,830 | 6.97% | $4,632,507 | 6.55% | $4,927,830 | 6.97% |

**ARIZONA PUBLIC SERVICE COMPANY**
Depreciation Reserve Components
Redistributed Reserve
December 31, 2010

Statement D

| Account Description | Plant Investment | Investment Reserve Amount | Investment Reserve Ratio | Net Salvage Reserve Amount | Net Salvage Reserve Ratio | Total Reserve Amount | Total Reserve Ratio |
|---|---|---|---|---|---|---|---|
| A | B | C | D=C/B | E | F=E/B | G=C+E | H=G/B |
| **STEAM PRODUCTION** | | | | | | | |
| 311.00 Structures and Improvements | $168,068,708 | $90,636,019 | 53.93% | $6,830,100 | 4.06% | $97,466,119 | 57.99% |
| 312.00 Boiler Plant Equipment | 1,114,508,323 | 556,790,163 | 49.96% | 49,640,770 | 4.45% | 606,430,932 | 54.41% |
| 314.00 Turbogenerator Units | 260,287,212 | 129,860,045 | 49.89% | 12,850,383 | 4.94% | 142,710,428 | 54.83% |
| 315.00 Accessory Electric Equipment | 164,350,445 | 90,544,133 | 55.09% | 7,418,453 | 4.51% | 97,962,586 | 59.61% |
| 316.00 Miscellaneous Power Plant Equipment | 81,726,740 | 37,582,478 | 45.99% | 3,539,103 | 4.33% | 41,121,581 | 50.32% |
| **Total Steam Production Plant** | $1,788,941,428 | $905,412,837 | 50.61% | $80,278,809 | 4.49% | $985,691,646 | 55.10% |
| **NUCLEAR PRODUCTION** | | | | | | | |
| 321.00 Structures and Improvements | $698,846,801 | $383,581,034 | 54.89% | $843,888 | 0.12% | $384,424,922 | 55.01% |
| 322.00 Reactor Plant Equipment | 1,130,933,859 | 566,004,611 | 50.05% | (4,884,730) | -0.43% | 561,119,881 | 49.62% |
| 323.00 Turbogenerator Units | 354,174,138 | 182,997,393 | 51.67% | (340,611) | -0.10% | 182,656,783 | 51.57% |
| 324.00 Accessory Electric Equipment | 275,016,677 | 166,169,883 | 60.42% | 593,992 | 0.22% | 166,763,875 | 60.64% |
| 325.00 Miscellaneous Power Plant Equipment | 145,211,312 | 72,567,826 | 49.97% | (1,083,497) | -0.75% | 71,484,329 | 49.23% |
| **Total Nuclear Production Plant** | $2,604,182,787 | $1,371,320,748 | 52.66% | ($4,870,958) | -0.19% | $1,366,449,789 | 52.47% |
| **OTHER PRODUCTION** | | | | | | | |
| 341.00 Structures and Improvements | $67,262,184 | $21,421,911 | 31.85% | ($1,324,080) | -1.97% | $20,097,831 | 29.88% |
| 342.00 Fuel Holders, Products and Accessories | 42,179,346 | 16,993,526 | 40.29% | (911,741) | -2.16% | 16,081,785 | 38.13% |
| 343.00 Prime Movers | 664,641,919 | 217,437,077 | 32.71% | (16,073,468) | -2.42% | 201,363,609 | 30.30% |
| 344.00 Generators and Devices | 588,169,993 | 138,974,256 | 23.63% | 50,380,698 | 8.57% | 189,354,954 | 32.19% |
| 345.00 Accessory Electric Equipment | 86,274,192 | 31,720,446 | 36.77% | (2,029,638) | -2.35% | 29,690,808 | 34.41% |
| 346.00 Miscellaneous Power Plant Equipment | 14,711,421 | 4,908,526 | 33.37% | (269,115) | -1.83% | 4,639,410 | 31.54% |
| **Total Other Production Plant** | $1,463,239,055 | $431,455,742 | 29.49% | $29,772,656 | 2.03% | $461,228,398 | 31.52% |
| **TRANSMISSION PLANT** | | | | | | | |
| 352.02 Structures and Improvements | $95,935 | $52,904 | 55.15% | | | $52,904 | 55.15% |
| 353.00 Station Equipment | 98,305,656 | 20,914,705 | 21.28% | 1,226,343 | 1.25% | 22,141,048 | 22.52% |
| 354.00 Towers and Fixtures | 1,329,316 | 421,027 | 31.67% | | | 421,027 | 31.67% |
| 355.00 Poles and Fixtures | 1,370,085 | 145,544 | 10.62% | 29,109 | 2.12% | 174,653 | 12.75% |
| 356.00 Overhead Conductors and Devices | 1,947,677 | 333,317 | 17.11% | 83,223 | 4.27% | 416,540 | 21.39% |
| **Total Transmission Plant** | $103,048,669 | $21,867,498 | 21.22% | $1,338,675 | 1.30% | $23,206,173 | 22.52% |

**ARIZONA PUBLIC SERVICE COMPANY**

Statement D

Depreciation Reserve Components
Redistributed Reserve
December 31, 2010

| Account Description | Plant Investment | Investment Reserve Amount | Investment Reserve Ratio | Net Salvage Reserve Amount | Net Salvage Reserve Ratio | Total Reserve Amount | Total Reserve Ratio |
|---|---|---|---|---|---|---|---|
| A | B | C | D=C/B | E | F=E/B | G=C+E | H=G/B |
| **DISTRIBUTION PLANT** | | | | | | | |
| 361.00 Structures and Improvements | $60,888,680 | $13,552,575 | 22.26% | $873,227 | 1.43% | $14,425,802 | 23.69% |
| 362.00 Station Equipment | 406,799,985 | 84,799,301 | 20.85% | (10,686,667) | -2.63% | 74,112,634 | 18.22% |
| 364.01 Poles, Towers and Fixtures - Wood | 310,263,864 | 91,375,643 | 29.45% | 16,965,311 | 5.47% | 108,340,954 | 34.92% |
| 364.02 Poles, Towers and Fixtures - Steel | 167,311,767 | 17,286,867 | 10.33% | 1,728,687 | 1.03% | 19,015,554 | 11.37% |
| 365.00 Overhead Conductors and Devices | 292,642,985 | 60,284,065 | 20.60% | (5,241,703) | -1.79% | 55,042,361 | 18.81% |
| 366.00 Underground Conduit | 620,488,170 | 129,025,281 | 20.79% | 7,124,765 | 1.15% | 136,150,047 | 21.94% |
| 367.00 Underground Conductors and Devices | 1,422,708,502 | 399,128,076 | 28.05% | 37,248,087 | 2.62% | 436,376,163 | 30.67% |
| 368.00 Line Transformers | 717,419,840 | 185,848,537 | 25.91% | 14,486,759 | 2.02% | 200,335,296 | 27.92% |
| 369.00 Services | 323,341,677 | 111,932,430 | 34.62% | 5,902,892 | 1.83% | 117,835,322 | 36.44% |
| 370.01 Meters - Electronic | 62,207,543 | 15,853,516 | 25.48% | 193,813 | 0.31% | 16,047,329 | 25.80% |
| 370.03 Meters - AMI | 117,715,566 | 9,009,526 | 7.65% | | | 9,009,526 | 7.65% |
| 371.00 Installations on Customers' Premises | 39,842,142 | 8,753,211 | 21.97% | 1,526,871 | 3.83% | 10,280,082 | 25.80% |
| 373.00 Street Lighting and Signal Systems | 73,702,827 | 16,865,318 | 22.88% | 2,941,898 | 3.99% | 19,807,216 | 26.87% |
| **Total Distribution Plant** | $4,615,333,548 | $1,143,714,346 | 24.78% | $73,063,940 | 1.58% | $1,216,778,286 | 26.36% |
| **GENERAL PLANT** | | | | | | | |
| **Depreciable** | | | | | | | |
| 390.00 Structures and Improvements | $107,643,854 | $27,025,896 | 25.11% | $837,903 | 0.78% | $27,863,799 | 25.89% |
| 391.CM Office Furn. and Equip. - Computer | 89,098,127 | 35,700,837 | 40.07% | (57,492) | -0.06% | 35,643,344 | 40.00% |
| 397.00 Communication Equipment | 152,910,098 | 64,911,285 | 42.45% | | | 64,911,285 | 42.45% |
| **Total Depreciable** | $349,652,079 | $127,638,017 | 36.50% | $780,411 | 0.22% | $128,418,428 | 36.73% |

**ARIZONA PUBLIC SERVICE COMPANY**
Depreciation Reserve Components
Redistributed Reserve
December 31, 2010

Statement D

| Account Description | Plant Investment | Investment Reserve Amount | Investment Reserve Ratio | Net Salvage Reserve Amount | Net Salvage Reserve Ratio | Total Reserve Amount | Total Reserve Ratio |
|---|---|---|---|---|---|---|---|
| A | B | C | D=C/B | E | F=E/B | G=C+E | H=G/B |
| **Amortizable** | | | | | | | |
| 391.FE Office Furn. and Equip. - Furniture | $49,130,094 | $14,343,161 | 29.19% | | | $14,343,161 | 29.19% |
| 393.00 Stores Equipment | 256,764 | 33,264 | 12.96% | | | 33,264 | 12.96% |
| 394.00 Tools, Shop and Garage Equipment | 28,424,012 | 11,518,585 | 40.52% | | | 11,518,585 | 40.52% |
| 395.00 Laboratory Equipment | 1,385,366 | 878,477 | 63.41% | | | 878,477 | 63.41% |
| 398.00 Miscellaneous Equipment | 5,909,111 | 1,190,470 | 20.15% | | | 1,190,470 | 20.15% |
| **Total Amortizable** | $85,105,347 | $27,963,957 | 32.86% | | | $27,963,957 | 32.86% |
| **Total General Plant** | $434,757,426 | $155,601,974 | 35.79% | $780,411 | 0.18% | $156,382,385 | 35.97% |
| **TOTAL UTILITY** | $11,009,502,913 | $4,029,373,145 | 36.60% | $180,363,533 | 1.64% | $4,209,736,678 | 38.24% |
| **STEAM PRODUCTION (by Unit)** | | | | | | | |
| **Cholla** | | | | | | | |
| 311.00 Structures and Improvements | $72,335,187 | $24,479,413 | 33.84% | $1,482,176 | 2.05% | $25,961,589 | 35.89% |
| 312.00 Boiler Plant Equipment | 521,789,973 | 150,404,763 | 28.82% | 4,858,009 | 0.93% | 155,262,773 | 29.76% |
| 314.00 Turbogenerator Units | 125,558,183 | 35,292,187 | 28.11% | 2,367,377 | 1.89% | 37,659,564 | 29.99% |
| 315.00 Accessory Electric Equipment | 93,701,286 | 43,751,882 | 46.69% | 2,330,566 | 2.49% | 46,082,448 | 49.18% |
| 316.00 Miscellaneous Power Plant Equipment | 27,985,746 | 8,545,568 | 30.54% | 364,559 | 1.30% | 8,910,127 | 31.84% |
| **Total Cholla** | $841,370,375 | $262,473,814 | 31.20% | $11,402,688 | 1.36% | $273,876,501 | 32.55% |
| **Cholla Unit 1** | | | | | | | |
| 311.00 Structures and Improvements | $4,372,274 | $1,681,575 | 38.46% | $88,899 | 2.03% | $1,770,475 | 40.49% |
| 312.00 Boiler Plant Equipment | 73,213,804 | 20,333,102 | 27.77% | 918,059 | 1.25% | 21,251,162 | 29.03% |
| 314.00 Turbogenerator Units | 25,640,590 | 5,510,173 | 21.49% | 334,522 | 1.30% | 5,844,694 | 22.79% |
| 315.00 Accessory Electric Equipment | 8,816,493 | 3,316,587 | 37.62% | 172,463 | 1.96% | 3,489,050 | 39.57% |
| 316.00 Miscellaneous Power Plant Equipment | 2,838,727 | 1,162,297 | 40.94% | 62,764 | 2.21% | 1,225,061 | 43.16% |
| **Total Cholla Unit 1** | $114,881,888 | $32,003,735 | 27.86% | $1,576,707 | 1.37% | $33,580,442 | 29.23% |
| **Cholla Unit 2** | | | | | | | |
| 311.00 Structures and Improvements | $6,168,012 | $2,385,288 | 38.67% | $128,806 | 2.09% | $2,514,093 | 40.76% |
| 312.00 Boiler Plant Equipment | 162,323,693 | 73,551,883 | 45.31% | 4,163,597 | 2.56% | 77,715,480 | 47.88% |
| 314.00 Turbogenerator Units | 44,157,763 | 14,144,366 | 32.03% | 984,570 | 2.23% | 15,128,936 | 34.26% |
| 315.00 Accessory Electric Equipment | 46,110,434 | 22,990,493 | 49.86% | 1,290,295 | 2.80% | 24,280,788 | 52.66% |
| 316.00 Miscellaneous Power Plant Equipment | 8,714,396 | 2,525,255 | 28.98% | 132,099 | 1.52% | 2,657,354 | 30.49% |
| **Total Cholla Unit 2** | $267,474,298 | $115,597,285 | 43.22% | $6,699,366 | 2.50% | $122,296,651 | 45.72% |

**ARIZONA PUBLIC SERVICE COMPANY**

Depreciation Reserve Components
Redistributed Reserve
December 31, 2010

Statement D

| Account Description | Plant Investment | Investment Reserve Amount | Investment Reserve Ratio | Net Salvage Reserve Amount | Net Salvage Reserve Ratio | Total Reserve Amount | Total Reserve Ratio |
|---|---|---|---|---|---|---|---|
| A | B | C | D=C/B | E | F=E/B | G=C+E | H=G/B |
| **Cholla Unit 3** | | | | | | | |
| 311.00 Structures and Improvements | $9,984,226 | $4,808,789 | 48.16% | $240,166 | 2.41% | $5,048,955 | 50.57% |
| 312.00 Boiler Plant Equipment | 228,064,943 | 44,142,614 | 19.36% | (317,770) | -0.14% | 43,824,844 | 19.22% |
| 314.00 Turbogenerator Units | 54,849,058 | 15,303,829 | 27.90% | 1,021,849 | 1.86% | 16,325,679 | 29.76% |
| 315.00 Accessory Electric Equipment | 31,001,286 | 15,127,881 | 48.80% | 772,765 | 2.49% | 15,900,645 | 51.29% |
| 316.00 Miscellaneous Power Plant Equipment | 4,593,291 | 1,888,063 | 41.10% | 91,790 | 2.00% | 1,979,853 | 43.10% |
| **Total Cholla Unit 3** | $328,492,804 | $81,271,177 | 24.74% | $1,808,800 | 0.55% | $83,079,977 | 25.29% |
| **Cholla Common** | | | | | | | |
| 311.00 Structures and Improvements | $51,810,675 | $15,603,761 | 30.12% | $1,024,305 | 1.98% | $16,628,066 | 32.09% |
| 312.00 Boiler Plant Equipment | 58,187,533 | 12,377,164 | 21.27% | 94,123 | 0.16% | 12,471,287 | 21.43% |
| 314.00 Turbogenerator Units | 910,772 | 333,819 | 36.65% | 26,436 | 2.90% | 360,255 | 39.55% |
| 315.00 Accessory Electric Equipment | 7,773,073 | 2,316,920 | 29.81% | 95,044 | 1.22% | 2,411,964 | 31.03% |
| 316.00 Miscellaneous Power Plant Equipment | 11,839,332 | 2,969,953 | 25.09% | 77,906 | 0.66% | 3,047,859 | 25.74% |
| **Total Cholla Common** | $130,521,385 | $33,601,617 | 25.74% | $1,317,814 | 1.01% | $34,919,431 | 26.75% |
| **Four Corners** | | | | | | | |
| 311.00 Structures and Improvements | $57,549,016 | $47,168,132 | 81.96% | $3,415,526 | 5.93% | $50,583,658 | 87.90% |
| 312.00 Boiler Plant Equipment | 375,402,116 | 294,235,287 | 78.38% | 32,821,268 | 8.74% | 327,056,555 | 87.12% |
| 314.00 Turbogenerator Units | 73,354,578 | 57,411,102 | 78.27% | 5,048,963 | 6.88% | 62,460,065 | 85.15% |
| 315.00 Accessory Electric Equipment | 40,063,953 | 30,226,932 | 75.45% | 3,328,238 | 8.31% | 33,555,171 | 83.75% |
| 316.00 Miscellaneous Power Plant Equipment | 25,722,887 | 16,396,859 | 63.74% | 1,645,299 | 6.40% | 18,042,158 | 70.14% |
| **Total Four Corners** | $572,092,550 | $445,438,313 | 77.86% | $46,259,293 | 8.09% | $491,697,606 | 85.95% |
| **Four Corners Units 1-3** | | | | | | | |
| 311.00 Structures and Improvements | $40,683,091 | $40,683,091 | 100.00% | | | $40,683,091 | 100.00% |
| 312.00 Boiler Plant Equipment | 242,101,914 | 242,101,914 | 100.00% | | | 242,101,914 | 100.00% |
| 314.00 Turbogenerator Units | 50,183,693 | 50,183,693 | 100.00% | | | 50,183,693 | 100.00% |
| 315.00 Accessory Electric Equipment | 24,333,485 | 24,333,485 | 100.00% | | | 24,333,485 | 100.00% |
| 316.00 Miscellaneous Power Plant Equipment | 11,655,314 | 11,655,314 | 100.00% | | | 11,655,314 | 100.00% |
| **Total Four Corners Units 1-3** | $368,957,497 | $368,957,497 | 100.00% | | | $368,957,497 | 100.00% |

**ARIZONA PUBLIC SERVICE COMPANY**
Depreciation Reserve Components
Redistributed Reserve
December 31, 2010

Statement D

| Account Description | Plant Investment | Investment Reserve Amount | Investment Reserve Ratio | Net Salvage Reserve Amount | Net Salvage Reserve Ratio | Total Reserve Amount | Total Reserve Ratio |
|---|---|---|---|---|---|---|---|
| A | B | C | D=C/B | E | F=E/B | G=C+E | H=G/B |
| **Four Corners Units 4-5** | | | | | | | |
| 311.00 Structures and Improvements | $11,882,266 | $4,444,578 | 37.41% | $2,940,097 | 24.74% | $7,384,675 | 62.15% |
| 312.00 Boiler Plant Equipment | 118,062,055 | 45,351,598 | 38.41% | 31,212,592 | 26.44% | 76,564,190 | 64.85% |
| 314.00 Turbogenerator Units | 21,183,385 | 6,104,744 | 28.82% | 4,736,536 | 22.36% | 10,841,280 | 51.18% |
| 315.00 Accessory Electric Equipment | 11,137,088 | 4,215,044 | 37.85% | 2,916,738 | 26.19% | 7,131,782 | 64.04% |
| 316.00 Miscellaneous Power Plant Equipment | 3,614,952 | 1,214,162 | 33.59% | 820,691 | 22.70% | 2,034,852 | 56.29% |
| **Total Four Corners Units 4-5** | $165,879,746 | $61,330,126 | 36.97% | $42,626,654 | 25.70% | $103,956,780 | 62.67% |
| **Four Corners Common** | | | | | | | |
| 311.00 Structures and Improvements | $4,983,659 | $2,040,463 | 40.94% | $475,429 | 9.54% | $2,515,892 | 50.48% |
| 312.00 Boiler Plant Equipment | 15,238,147 | 6,781,775 | 44.51% | 1,608,675 | 10.56% | 8,390,450 | 55.06% |
| 314.00 Turbogenerator Units | 1,987,500 | 1,122,665 | 56.49% | 312,427 | 15.72% | 1,435,092 | 72.21% |
| 315.00 Accessory Electric Equipment | 4,593,380 | 1,678,403 | 36.54% | 411,500 | 8.96% | 2,089,903 | 45.50% |
| 316.00 Miscellaneous Power Plant Equipment | 10,452,621 | 3,527,384 | 33.75% | 824,608 | 7.89% | 4,351,991 | 41.64% |
| **Total Four Corners Common** | $37,255,307 | $15,150,690 | 40.67% | $3,632,639 | 9.75% | $18,783,329 | 50.42% |
| **Navajo Units 1-3** | | | | | | | |
| 311.00 Structures and Improvements | $29,113,530 | $14,337,123 | 49.25% | $1,030,845 | 3.54% | $15,367,968 | 52.79% |
| 312.00 Boiler Plant Equipment | 166,003,214 | 79,671,764 | 47.99% | 5,756,297 | 3.47% | 85,428,061 | 51.46% |
| 314.00 Turbogenerator Units | 24,699,305 | 14,542,391 | 58.88% | 1,090,679 | 4.42% | 15,633,070 | 63.29% |
| 315.00 Accessory Electric Equipment | 21,491,344 | 11,936,434 | 55.54% | 871,360 | 4.05% | 12,807,794 | 59.60% |
| 316.00 Miscellaneous Power Plant Equipment | 17,228,597 | 7,410,835 | 43.01% | 529,674 | 3.07% | 7,940,509 | 46.09% |
| **Total Navajo Units 1-3** | $258,535,990 | $127,898,547 | 49.47% | $9,278,855 | 3.59% | $137,177,403 | 53.06% |
| **Ocotillo Units 1-2** | | | | | | | |
| 311.00 Structures and Improvements | $4,759,658 | $2,566,375 | 53.92% | $505,813 | 10.63% | $3,072,188 | 64.55% |
| 312.00 Boiler Plant Equipment | 25,218,648 | 17,154,643 | 68.02% | 3,293,691 | 13.06% | 20,448,334 | 81.08% |
| 314.00 Turbogenerator Units | 20,161,583 | 11,206,819 | 55.59% | 2,171,150 | 10.77% | 13,377,968 | 66.35% |
| 315.00 Accessory Electric Equipment | 3,425,956 | 1,964,010 | 57.33% | 379,373 | 11.07% | 2,343,383 | 68.40% |
| 316.00 Miscellaneous Power Plant Equipment | 6,010,574 | 2,740,284 | 45.59% | 529,164 | 8.80% | 3,269,448 | 54.39% |
| **Total Ocotillo Units 1-2** | $59,576,419 | $35,632,130 | 59.81% | $6,879,191 | 11.55% | $42,511,321 | 71.36% |

**ARIZONA PUBLIC SERVICE COMPANY**
Depreciation Reserve Components
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Statement D

| Account Description | Plant Investment | Investment Reserve Amount | Investment Reserve Ratio | Net Salvage Reserve Amount | Net Salvage Reserve Ratio | Total Reserve Amount | Total Reserve Ratio |
|---|---|---|---|---|---|---|---|
| A | B | C | D=C/B | E | F=E/B | G=C+E | H=G/B |
| **Saguaro Units 1-2** | | | | | | | |
| 311.00 Structures and Improvements | $4,311,317 | $2,084,975 | 48.36% | $395,740 | 9.18% | $2,480,715 | 57.54% |
| 312.00 Boiler Plant Equipment | 26,094,372 | 15,323,705 | 58.72% | 2,911,504 | 11.16% | 18,235,209 | 69.88% |
| 314.00 Turbogenerator Units | 16,513,563 | 11,407,546 | 69.08% | 2,172,214 | 13.15% | 13,579,761 | 82.23% |
| 315.00 Accessory Electric Equipment | 5,667,906 | 2,664,875 | 47.02% | 508,915 | 8.98% | 3,173,790 | 56.00% |
| 316.00 Miscellaneous Power Plant Equipment | 4,778,936 | 2,488,931 | 52.08% | 470,408 | 9.84% | 2,959,339 | 61.92% |
| **Total Saguaro Units 1-2** | $57,366,094 | $33,970,033 | 59.22% | $6,458,781 | 11.26% | $40,428,815 | 70.48% |
| **NUCLEAR PRODUCTION (by Unit)** | | | | | | | |
| **Palo Verde** | | | | | | | |
| 321.00 Structures and Improvements | $698,846,801 | $383,581,034 | 54.89% | $843,888 | 0.12% | $384,424,922 | 55.01% |
| 322.00 Reactor Plant Equipment | 1,130,933,859 | 566,004,611 | 50.05% | (4,884,730) | -0.43% | 561,119,881 | 49.62% |
| 323.00 Turbogenerator Units | 354,174,138 | 182,997,393 | 51.67% | (340,611) | -0.10% | 182,656,783 | 51.57% |
| 324.00 Accessory Electric Equipment | 275,016,677 | 166,169,883 | 60.42% | 593,992 | 0.22% | 166,763,875 | 60.64% |
| 325.00 Miscellaneous Power Plant Equipment | 145,211,312 | 72,567,826 | 49.97% | (1,083,497) | -0.75% | 71,484,329 | 49.23% |
| **Total Palo Verde** | $2,604,182,787 | $1,371,320,748 | 52.66% | ($4,870,958) | -0.19% | $1,366,449,789 | 52.47% |
| **Palo Verde Unit 1** | | | | | | | |
| 321.00 Structures and Improvements | $156,705,345 | $100,210,002 | 63.95% | $400,840 | 0.26% | $100,610,842 | 64.20% |
| 322.00 Reactor Plant Equipment | 454,207,200 | 243,605,126 | 53.63% | (662,666) | -0.15% | 242,942,460 | 53.49% |
| 323.00 Turbogenerator Units | 125,268,196 | 68,563,737 | 54.73% | (117,672) | -0.09% | 68,446,065 | 54.64% |
| 324.00 Accessory Electric Equipment | 114,860,792 | 73,918,349 | 64.35% | 295,673 | 0.26% | 74,214,023 | 64.61% |
| 325.00 Miscellaneous Power Plant Equipment | 30,801,758 | 18,071,429 | 58.67% | (82,267) | -0.27% | 17,989,161 | 58.40% |
| **Total Palo Verde Unit 1** | $881,843,291 | $504,368,642 | 57.19% | ($166,092) | -0.02% | $504,202,551 | 57.18% |
| **Palo Verde Unit 2** | | | | | | | |
| 321.00 Structures and Improvements | $91,657,911 | $55,303,443 | 60.34% | $276,517 | 0.30% | $55,579,960 | 60.64% |
| 322.00 Reactor Plant Equipment | 234,287,478 | 116,599,299 | 49.77% | (2,884,849) | -1.23% | 113,714,449 | 48.54% |
| 323.00 Turbogenerator Units | 78,612,699 | 42,121,517 | 53.58% | (68,618) | -0.09% | 42,052,898 | 53.49% |
| 324.00 Accessory Electric Equipment | 49,937,247 | 29,374,046 | 58.82% | 99,282 | 0.20% | 29,473,328 | 59.02% |
| 325.00 Miscellaneous Power Plant Equipment | 27,087,580 | 14,139,116 | 52.20% | (26,267) | -0.10% | 14,112,850 | 52.10% |
| **Total Palo Verde Unit 2** | $481,582,915 | $257,537,421 | 53.48% | ($2,603,935) | -0.54% | $254,933,485 | 52.94% |

**ARIZONA PUBLIC SERVICE COMPANY**
Depreciation Reserve Components
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Statement D

| Account Description | Plant Investment | Investment Reserve Amount | Investment Reserve Ratio | Net Salvage Reserve Amount | Net Salvage Reserve Ratio | Total Reserve Amount | Total Reserve Ratio |
|---|---|---|---|---|---|---|---|
| A | B | C | D=C/B | E | F=E/B | G=C+E | H=G/B |
| **Palo Verde Unit 3** | | | | | | | |
| 321.00 Structures and Improvements | $163,192,491 | $94,101,615 | 57.66% | $470,508 | 0.29% | $94,572,123 | 57.95% |
| 322.00 Reactor Plant Equipment | 414,451,923 | 189,696,851 | 45.77% | (1,118,642) | -0.27% | 188,578,209 | 45.50% |
| 323.00 Turbogenerator Units | 147,910,539 | 71,660,130 | 48.45% | (134,948) | -0.09% | 71,525,182 | 48.36% |
| 324.00 Accessory Electric Equipment | 90,837,828 | 51,641,827 | 56.85% | 164,867 | 0.18% | 51,806,693 | 57.03% |
| 325.00 Miscellaneous Power Plant Equipment | 28,712,249 | 15,119,524 | 52.66% | (47,232) | -0.16% | 15,072,292 | 52.49% |
| **Total Palo Verde Unit 3** | $845,105,030 | $422,219,947 | 49.96% | ($665,447) | -0.08% | $421,554,500 | 49.88% |
| **Palo Verde Water Reclamation** | | | | | | | |
| 321.00 Structures and Improvements | $171,609,224 | $70,713,132 | 41.21% | ($214,700) | -0.13% | $70,498,432 | 41.08% |
| 322.00 Reactor Plant Equipment | 133,326 | 40,132 | 30.10% | 562 | 0.42% | 40,694 | 30.52% |
| 323.00 Turbogenerator Units | 217,756 | 108,220 | 49.70% | 97 | 0.04% | 108,317 | 49.74% |
| 324.00 Accessory Electric Equipment | | | | | | | |
| 325.00 Miscellaneous Power Plant Equipment | 88,819 | 44,663 | 50.29% | (1,036) | -1.17% | 43,627 | 49.12% |
| **Total Palo Verde Water Reclamation** | $172,049,125 | $70,906,147 | 41.21% | ($215,077) | -0.13% | $70,691,070 | 41.09% |
| **Palo Verde Common** | | | | | | | |
| 321.00 Structures and Improvements | $115,681,830 | $63,252,842 | 54.68% | ($89,278) | -0.08% | $63,163,565 | 54.60% |
| 322.00 Reactor Plant Equipment | 27,853,932 | 16,063,204 | 57.67% | (219,135) | -0.79% | 15,844,069 | 56.88% |
| 323.00 Turbogenerator Units | 2,164,948 | 543,789 | 25.12% | (19,470) | -0.90% | 524,320 | 24.22% |
| 324.00 Accessory Electric Equipment | 19,380,810 | 11,235,661 | 57.97% | 34,169 | 0.18% | 11,269,831 | 58.15% |
| 325.00 Miscellaneous Power Plant Equipment | 58,520,906 | 25,193,094 | 43.05% | (926,695) | -1.58% | 24,266,399 | 41.47% |
| **Total Palo Verde Common** | $223,602,426 | $116,288,591 | 52.01% | ($1,220,408) | -0.55% | $115,068,183 | 51.46% |
| **OTHER PRODUCTION (by Unit)** | | | | | | | |
| **Douglas CT** | | | | | | | |
| 341.00 Structures and Improvements | $49,075 | $25,435 | 51.83% | ($1,272) | -2.59% | $24,163 | 49.24% |
| 342.00 Fuel Holders, Products and Accessories | 137,759 | 126,131 | 91.56% | (6,812) | -4.94% | 119,319 | 86.61% |
| 343.00 Prime Movers | 1,101,449 | 1,126,800 | 102.30% | (56,340) | -5.12% | 1,070,460 | 97.19% |
| 344.00 Generators and Devices | 551,765 | 566,231 | 102.62% | (28,312) | -5.13% | 537,919 | 97.49% |
| 345.00 Accessory Electric Equipment | 353,277 | 352,551 | 99.79% | (18,130) | -5.13% | 334,422 | 94.66% |
| 346.00 Miscellaneous Power Plant Equipment | 40,913 | 38,228 | 93.44% | (1,911) | -4.67% | 36,316 | 88.76% |
| **Total Douglas CT** | $2,234,238 | $2,235,376 | 100.05% | ($112,776) | -5.05% | $2,122,600 | 95.00% |

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Depreciation Reserve Components
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Statement D

| Account Description | Plant Investment | Investment Reserve Amount | Investment Reserve Ratio | Net Salvage Reserve Amount | Net Salvage Reserve Ratio | Total Reserve Amount | Total Reserve Ratio |
|---|---|---|---|---|---|---|---|
| A | B | C | D=C/B | E | F=E/B | G=C+E | H=G/B |
| **Ocotillo CT Units 1-2** | | | | | | | |
| 341.00 Structures and Improvements | $721,568 | $438,132 | 60.72% | ($22,775) | -3.16% | $415,356 | 57.56% |
| 342.00 Fuel Holders, Products and Accessories | 791,584 | 637,923 | 80.59% | (31,896) | -4.03% | 606,027 | 76.56% |
| 343.00 Prime Movers | 6,540,275 | 6,092,814 | 93.16% | (308,273) | -4.71% | 5,784,541 | 88.44% |
| 344.00 Generators and Devices | 7,596,314 | 5,144,430 | 67.72% | 53,969 | 0.71% | 5,198,399 | 68.43% |
| 345.00 Accessory Electric Equipment | 1,677,431 | 1,425,372 | 84.97% | (74,887) | -4.46% | 1,350,485 | 80.51% |
| 346.00 Miscellaneous Power Plant Equipment | 637,727 | 509,749 | 79.93% | (26,272) | -4.12% | 483,477 | 75.81% |
| **Total Octillo CT Units 1-2** | $17,964,899 | $14,248,419 | 79.31% | ($410,134) | -2.28% | $13,838,285 | 77.03% |
| **Redhawk CC Units 1-2** | | | | | | | |
| 341.00 Structures and Improvements | $22,197,402 | $4,378,540 | 19.73% | ($426,583) | -1.92% | $3,951,957 | 17.80% |
| 342.00 Fuel Holders, Products and Accessories | 2,637,978 | 184,863 | 7.01% | (9,243) | -0.35% | 175,620 | 6.66% |
| 343.00 Prime Movers | 177,860,527 | 36,294,403 | 20.41% | (5,113,430) | -2.87% | 31,180,973 | 17.53% |
| 344.00 Generators and Devices | 279,212,258 | 41,223,600 | 14.76% | 44,937,611 | 16.09% | 86,161,211 | 30.86% |
| 345.00 Accessory Electric Equipment | 22,584,466 | 4,603,215 | 20.38% | (544,407) | -2.41% | 4,058,808 | 17.97% |
| 346.00 Miscellaneous Power Plant Equipment | 4,005,866 | 306,853 | 7.66% | (15,343) | -0.38% | 291,510 | 7.28% |
| **Total Redhawk CC Units 1-2** | $508,498,497 | $86,991,473 | 17.11% | $38,828,605 | 7.64% | $125,820,078 | 24.74% |
| **Saguaro** | | | | | | | |
| 341.00 Structures and Improvements | $1,885,444 | $1,070,851 | 56.80% | ($54,822) | -2.91% | $1,016,029 | 53.89% |
| 342.00 Fuel Holders, Products and Accessories | 1,376,702 | 1,212,223 | 88.05% | (64,138) | -4.66% | 1,148,085 | 83.39% |
| 343.00 Prime Movers | 8,624,812 | 7,818,061 | 90.65% | (393,210) | -4.56% | 7,424,851 | 86.09% |
| 344.00 Generators and Devices | 32,512,372 | 10,659,190 | 32.79% | (384,189) | -1.18% | 10,275,001 | 31.60% |
| 345.00 Accessory Electric Equipment | 1,701,779 | 1,544,715 | 90.77% | (79,063) | -4.65% | 1,465,652 | 86.12% |
| 346.00 Miscellaneous Power Plant Equipment | 868,485 | 658,741 | 75.85% | (33,361) | -3.84% | 625,381 | 72.01% |
| **Total Saguaro** | $46,969,594 | $22,963,781 | 48.89% | ($1,008,783) | -2.15% | $21,954,998 | 46.74% |
| **Saguaro CT Units 1-2** | | | | | | | |
| 341.00 Structures and Improvements | $1,885,444 | $1,070,851 | 56.80% | ($54,822) | -2.91% | $1,016,029 | 53.89% |
| 342.00 Fuel Holders, Products and Accessories | 1,376,702 | 1,212,223 | 88.05% | (64,138) | -4.66% | 1,148,085 | 83.39% |
| 343.00 Prime Movers | 7,983,905 | 7,644,559 | 95.75% | (384,535) | -4.82% | 7,260,024 | 90.93% |
| 344.00 Generators and Devices | 4,487,988 | 3,072,612 | 68.46% | (4,860) | -0.11% | 3,067,752 | 68.35% |
| 345.00 Accessory Electric Equipment | 1,579,226 | 1,511,538 | 95.71% | (77,405) | -4.90% | 1,434,134 | 90.81% |
| 346.00 Miscellaneous Power Plant Equipment | 868,485 | 658,741 | 75.85% | (33,361) | -3.84% | 625,381 | 72.01% |
| **Total Saguaro CT Units 1-2** | $18,181,750 | $15,170,525 | 83.44% | ($619,120) | -3.41% | $14,551,404 | 80.03% |

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Depreciation Reserve Components
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Statement D

| Account Description | Plant Investment | Investment Reserve Amount | Investment Reserve Ratio | Net Salvage Reserve Amount | Net Salvage Reserve Ratio | Total Reserve Amount | Total Reserve Ratio |
|---|---|---|---|---|---|---|---|
| A | B | C | D=C/B | E | F=E/B | G=C+E | H=G/B |
| **Saguaro CT Unit 3** | | | | | | | |
| 341.00 Structures and Improvements | | | | | | | |
| 342.00 Fuel Holders, Products and Accessories | | | | | | | |
| 343.00 Prime Movers | 640,907 | 173,502 | 27.07% | (8,675) | -1.35% | 164,827 | 25.72% |
| 344.00 Generators and Devices | 28,024,384 | 7,586,578 | 27.07% | (379,329) | -1.35% | 7,207,249 | 25.72% |
| 345.00 Accessory Electric Equipment | 122,553 | 33,177 | 27.07% | (1,659) | -1.35% | 31,518 | 25.72% |
| 346.00 Miscellaneous Power Plant Equipment | | | | | | | |
| **Total Saguaro CT Unit 3** | $28,787,844 | $7,793,257 | 27.07% | ($389,663) | -1.35% | $7,403,594 | 25.72% |
| **Solar Units** | | | | | | | |
| 341.00 Structures and Improvements | $418,403 | $451,776 | 107.98% | ($22,734) | -5.43% | $429,042 | 102.54% |
| 342.00 Fuel Holders, Products and Accessories | | | | | | | |
| 343.00 Prime Movers | | | | | | | |
| 344.00 Generators and Devices | 15,963,981 | 13,315,955 | 83.41% | (217,589) | -1.36% | 13,098,366 | 82.05% |
| 345.00 Accessory Electric Equipment | 728,283 | 263,776 | 36.22% | (13,189) | -1.81% | 250,587 | 34.41% |
| 346.00 Miscellaneous Power Plant Equipment | | | | | | | |
| **Total Solar Units** | $17,110,667 | $14,031,507 | 82.00% | ($253,512) | -1.48% | $13,777,995 | 80.52% |
| **Sundance** | | | | | | | |
| 341.00 Structures and Improvements | $12,653,247 | $5,967,030 | 47.16% | ($298,352) | -2.36% | $5,668,679 | 44.80% |
| 342.00 Fuel Holders, Products and Accessories | 4,325,769 | 2,050,063 | 47.39% | (102,503) | -2.37% | 1,947,560 | 45.02% |
| 343.00 Prime Movers | 229,732,211 | 109,945,362 | 47.86% | (5,497,268) | -2.39% | 104,448,094 | 45.47% |
| 344.00 Generators and Devices | 301,285 | 107,863 | 35.80% | (5,393) | -1.79% | 102,470 | 34.01% |
| 345.00 Accessory Electric Equipment | 26,408,712 | 12,515,582 | 47.39% | (625,779) | -2.37% | 11,889,803 | 45.02% |
| 346.00 Miscellaneous Power Plant Equipment | 2,028,889 | 733,299 | 36.14% | (36,665) | -1.81% | 696,634 | 34.34% |
| **Total Sun Dance** | $275,450,113 | $131,319,200 | 47.67% | ($6,565,960) | -2.38% | $124,753,240 | 45.29% |
| **West Phoenix** | | | | | | | |
| 341.00 Structures and Improvements | $27,606,161 | $8,707,956 | 31.54% | ($466,454) | -1.69% | $8,241,502 | 29.85% |
| 342.00 Fuel Holders, Products and Accessories | 28,090,344 | 9,470,027 | 33.71% | (528,238) | -1.88% | 8,941,789 | 31.83% |
| 343.00 Prime Movers | 164,651,195 | 42,971,325 | 26.10% | (4,045,531) | -2.46% | 38,925,794 | 23.64% |
| 344.00 Generators and Devices | 244,094,419 | 63,175,259 | 25.88% | 5,836,908 | 2.39% | 69,012,168 | 28.27% |
| 345.00 Accessory Electric Equipment | 29,569,013 | 8,812,067 | 29.80% | (557,246) | -1.88% | 8,254,821 | 27.92% |
| 346.00 Miscellaneous Power Plant Equipment | 6,447,142 | 2,214,255 | 34.34% | (133,194) | -2.07% | 2,081,061 | 32.28% |
| **Total West Phoenix** | $500,458,274 | $135,350,890 | 27.05% | $106,245 | 0.02% | $135,457,135 | 27.07% |

**ARIZONA PUBLIC SERVICE COMPANY**
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Statement D

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|---|---|---|---|---|---|---|---|
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| **West Phoenix CC Units 1-3** | | | | | | | |
| 341.00 Structures and Improvements | $1,710,485 | $248,375 | 14.52% | ($16,390) | -0.96% | $231,985 | 13.56% |
| 342.00 Fuel Holders, Products and Accessories | 22,517,702 | 7,014,024 | 31.15% | (405,438) | -1.80% | 6,608,587 | 29.35% |
| 343.00 Prime Movers | | | | | | | |
| 344.00 Generators and Devices | 92,566,116 | 27,950,267 | 30.19% | 5,630,226 | 6.08% | 33,580,493 | 36.28% |
| 345.00 Accessory Electric Equipment | 13,561,670 | 4,265,508 | 31.45% | (328,080) | -2.42% | 3,937,428 | 29.03% |
| 346.00 Miscellaneous Power Plant Equipment | 4,722,353 | 1,349,606 | 28.58% | (88,418) | -1.87% | 1,261,187 | 26.71% |
| **Total West Phoenix CC Units 1-3** | $135,078,326 | $40,827,780 | 30.23% | $4,791,899 | 3.55% | $45,619,679 | 33.77% |
| **West Phoenix CC Unit 4** | | | | | | | |
| 341.00 Structures and Improvements | $4,584,726 | $1,137,382 | 24.81% | ($56,869) | -1.24% | $1,080,513 | 23.57% |
| 342.00 Fuel Holders, Products and Accessories | 4,135,109 | 1,100,183 | 26.61% | (55,009) | -1.33% | 1,045,174 | 25.28% |
| 343.00 Prime Movers | 54,680,534 | 14,548,250 | 26.61% | (727,413) | -1.33% | 13,820,838 | 25.28% |
| 344.00 Generators and Devices | 15,548,138 | 3,788,787 | 24.37% | 353,438 | 2.27% | 4,142,226 | 26.64% |
| 345.00 Accessory Electric Equipment | 2,569,550 | 307,126 | 11.95% | (15,356) | -0.60% | 291,770 | 11.35% |
| 346.00 Miscellaneous Power Plant Equipment | 315,741 | 25,696 | 8.14% | (2,158) | -0.68% | 23,538 | 7.45% |
| **Total West Phoenix CC Unit 4** | $81,833,798 | $20,907,424 | 25.55% | ($503,366) | -0.62% | $20,404,058 | 24.93% |
| **West Phoenix CC Unit 5** | | | | | | | |
| 341.00 Structures and Improvements | $10,865,036 | $2,458,254 | 22.63% | ($122,913) | -1.13% | $2,335,341 | 21.49% |
| 342.00 Fuel Holders, Products and Accessories | | | | | | | |
| 343.00 Prime Movers | 101,176,494 | 20,454,163 | 20.22% | (2,906,993) | -2.87% | 17,547,170 | 17.34% |
| 344.00 Generators and Devices | 131,363,010 | 27,794,607 | 21.16% | (6,601) | -0.01% | 27,788,006 | 21.15% |
| 345.00 Accessory Electric Equipment | 11,713,613 | 2,668,315 | 22.78% | (133,416) | -1.14% | 2,534,899 | 21.64% |
| 346.00 Miscellaneous Power Plant Equipment | 235,560 | 22,881 | 9.71% | (1,144) | -0.49% | 21,737 | 9.23% |
| **Total West Phoenix CC Unit 5** | $255,353,713 | $53,398,219 | 20.91% | ($3,171,067) | -1.24% | $50,227,152 | 19.67% |
| **West Phoenix CT Units 1-2** | | | | | | | |
| 341.00 Structures and Improvements | $880,435 | $566,942 | 64.39% | ($28,347) | -3.22% | $538,595 | 61.17% |
| 342.00 Fuel Holders, Products and Accessories | 1,437,533 | 1,355,820 | 94.32% | (67,791) | -4.72% | 1,288,029 | 89.60% |
| 343.00 Prime Movers | 8,794,167 | 7,968,912 | 90.62% | (411,126) | -4.67% | 7,557,786 | 85.94% |
| 344.00 Generators and Devices | 4,617,155 | 3,641,598 | 78.87% | (140,154) | -3.04% | 3,501,444 | 75.84% |
| 345.00 Accessory Electric Equipment | 1,724,180 | 1,571,119 | 91.12% | (80,394) | -4.66% | 1,490,725 | 86.46% |
| 346.00 Miscellaneous Power Plant Equipment | 1,173,488 | 816,073 | 69.54% | (41,474) | -3.53% | 774,599 | 66.01% |
| **Total West Phoenix CT Units 1-2** | $18,626,958 | $15,920,463 | 85.47% | ($769,286) | -4.13% | $15,151,177 | 81.34% |

**ARIZONA PUBLIC SERVICE COMPANY**

Depreciation Reserve Components
Redistributed Reserve
December 31, 2010

Statement D

| Account Description | Plant Investment | Investment Reserve Amount | Investment Reserve Ratio | Net Salvage Reserve Amount | Net Salvage Reserve Ratio | Total Reserve Amount | Total Reserve Ratio |
|---|---|---|---|---|---|---|---|
| A | B | C | D=C/B | E | F=E/B | G=C+E | H=G/B |
| **West Phoenix Common** | | | | | | | |
| 341.00 Structures and Improvements | $9,565,479 | $4,297,004 | 44.92% | ($241,935) | -2.53% | $4,055,069 | 42.39% |
| 342.00 Fuel Holders, Products and Accessories | | | | | | | |
| 343.00 Prime Movers | | | | | | | |
| 344.00 Generators and Devices | | | | | | | |
| 345.00 Accessory Electric Equipment | | | | | | | |
| 346.00 Miscellaneous Power Plant Equipment | | | | | | | |
| **Total West Phoenix Common** | $9,565,479 | $4,297,004 | 44.92% | ($241,935) | -2.53% | $4,055,069 | 42.39% |
| **Yucca** | | | | | | | |
| 341.00 Structures and Improvements | $1,730,884 | $382,191 | 22.08% | ($31,088) | -1.80% | $351,103 | 20.28% |
| 342.00 Fuel Holders, Products and Accessories | 4,819,210 | 3,312,297 | 68.73% | (168,911) | -3.50% | 3,143,385 | 65.23% |
| 343.00 Prime Movers | 76,131,450 | 13,188,313 | 17.32% | (659,416) | -0.87% | 12,528,897 | 16.46% |
| 344.00 Generators and Devices | 7,937,599 | 4,781,728 | 60.24% | 187,693 | 2.36% | 4,969,421 | 62.61% |
| 345.00 Accessory Electric Equipment | 3,251,231 | 2,203,167 | 67.76% | (116,936) | -3.60% | 2,086,231 | 64.17% |
| 346.00 Miscellaneous Power Plant Equipment | 682,399 | 447,400 | 65.56% | (22,370) | -3.28% | 425,030 | 62.28% |
| **Total Yucca** | $94,552,773 | $24,315,095 | 25.72% | ($811,029) | -0.86% | $23,504,066 | 24.86% |
| **Yucca CT Units 1-4** | | | | | | | |
| 341.00 Structures and Improvements | $1,193,877 | $342,777 | 28.71% | ($29,117) | -2.44% | $313,660 | 26.27% |
| 342.00 Fuel Holders, Products and Accessories | 3,316,669 | 3,202,018 | 96.54% | (163,397) | -4.93% | 3,038,620 | 91.62% |
| 343.00 Prime Movers | 7,962,254 | 8,185,039 | 102.80% | (409,252) | -5.14% | 7,775,787 | 97.66% |
| 344.00 Generators and Devices | 7,883,898 | 4,777,787 | 60.60% | 187,890 | 2.38% | 4,965,676 | 62.99% |
| 345.00 Accessory Electric Equipment | 2,838,650 | 2,172,886 | 76.55% | (115,422) | -4.07% | 2,057,463 | 72.48% |
| 346.00 Miscellaneous Power Plant Equipment | 682,399 | 447,400 | 65.56% | (22,370) | -3.28% | 425,030 | 62.28% |
| **Total Yucca CT Units 1-4** | $23,877,747 | $19,127,906 | 80.11% | ($551,669) | -2.31% | $18,576,237 | 77.80% |
| **Yucca CT Units 5-6** | | | | | | | |
| 341.00 Structures and Improvements | $537,007 | $39,414 | 7.34% | ($1,971) | -0.37% | $37,443 | 6.97% |
| 342.00 Fuel Holders, Products and Accessories | 1,502,541 | 110,279 | 7.34% | (5,514) | -0.37% | 104,765 | 6.97% |
| 343.00 Prime Movers | 68,169,196 | 5,003,274 | 7.34% | (250,164) | -0.37% | 4,753,110 | 6.97% |
| 344.00 Generators and Devices | 53,701 | 3,941 | 7.34% | (197) | -0.37% | 3,744 | 6.97% |
| 345.00 Accessory Electric Equipment | 412,581 | 30,281 | 7.34% | (1,514) | -0.37% | 28,767 | 6.97% |
| 346.00 Miscellaneous Power Plant Equipment | | | | | | | |
| **Total Yucca CT Units 5-6** | $70,675,026 | $5,187,189 | 7.34% | ($259,359) | -0.37% | $4,927,830 | 6.97% |

**ARIZONA PUBLIC SERVICE COMPANY**
Average Net Salvage

Statement E

| Account Description | Plant Investment | | | Salvage Rate | | Net Salvage | | | Average Rate |
|---|---|---|---|---|---|---|---|---|---|
| | Additions | Retirements | Survivors | Realized | Future | Realized | Future | Total | |
| A | B | C | D=B-C | E | F | G=E*C | H=F*D | I=G+H | J=I/B |
| **STEAM PRODUCTION** | | | | | | | | | |
| 311.00 Structures and Improvements | $178,569,299 | $10,500,591 | $168,068,708 | -1.3% | -9.8% | ($136,508) | ($16,518,367) | ($16,654,874) | -9.3% |
| 312.00 Boiler Plant Equipment | 1,206,247,872 | 91,739,549 | 1,114,508,323 | -20.1% | -12.3% | (18,439,649) | (136,617,735) | (155,057,385) | -12.9% |
| 314.00 Turbogenerator Units | 297,937,926 | 37,650,714 | 260,287,212 | -3.2% | -11.7% | (1,204,823) | (30,538,479) | (31,743,302) | -10.7% |
| 315.00 Accessory Electric Equipment | 169,852,137 | 5,501,692 | 164,350,445 | -10.9% | -10.3% | (599,684) | (16,861,794) | (17,461,479) | -10.3% |
| 316.00 Miscellaneous Power Plant Equipment | 85,846,998 | 4,120,258 | 81,726,740 | -16.5% | -12.0% | (679,843) | (9,798,157) | (10,477,999) | -12.2% |
| **Total Steam Production Plant** | $1,938,454,232 | $149,512,804 | $1,788,941,428 | -14.1% | -11.8% | ($21,060,507) | ($210,334,532) | ($231,395,039) | -11.9% |
| **NUCLEAR PRODUCTION** | | | | | | | | | |
| 321.00 Structures and Improvements | $727,309,483 | $28,462,682 | $698,846,801 | -4.3% | -0.5% | ($1,223,895) | ($3,337,529) | ($4,561,424) | -0.6% |
| 322.00 Reactor Plant Equipment | 1,207,856,362 | 76,922,503 | 1,130,933,859 | -17.7% | -1.3% | (13,615,283) | (15,144,579) | (28,759,862) | -2.4% |
| 323.00 Turbogenerator Units | 413,417,445 | 59,243,307 | 354,174,138 | -2.5% | -0.4% | (1,481,083) | (1,566,990) | (3,048,072) | -0.7% |
| 324.00 Accessory Electric Equipment | 283,285,283 | 8,268,606 | 275,016,677 | -2.7% | -0.5% | (223,252) | (1,260,223) | (1,483,475) | -0.5% |
| 325.00 Miscellaneous Power Plant Equipment | 184,562,340 | 39,351,028 | 145,211,312 | -4.7% | -0.5% | (1,849,498) | (668,167) | (2,517,666) | -1.4% |
| **Total Nuclear Production Plant** | $2,816,430,913 | $212,248,126 | $2,604,182,787 | -8.7% | -0.8% | ($18,393,012) | ($21,977,488) | ($40,370,499) | -1.4% |
| **OTHER PRODUCTION** | | | | | | | | | |
| 341.00 Structures and Improvements | $71,911,949 | $4,649,765 | $67,262,184 | -2.8% | 5.0% | ($130,193) | $3,363,109 | $3,232,916 | 4.5% |
| 342.00 Fuel Holders, Products and Accessories | 43,756,132 | 1,576,786 | 42,179,346 | -2.1% | 5.0% | (33,113) | 2,108,967 | 2,075,855 | 4.7% |
| 343.00 Prime Movers | 730,501,247 | 65,859,328 | 664,641,919 | -7.3% | 5.0% | (4,807,731) | 33,232,096 | 28,424,365 | 3.9% |
| 344.00 Generators and Devices | 737,042,178 | 148,872,185 | 588,169,993 | 72.2% | 5.0% | 107,485,718 | 29,408,500 | 136,894,217 | 18.6% |
| 345.00 Accessory Electric Equipment | 92,977,991 | 6,703,799 | 86,274,192 | -5.8% | 5.0% | (388,820) | 4,313,710 | 3,924,889 | 4.2% |
| 346.00 Miscellaneous Power Plant Equipment | 15,434,369 | 722,948 | 14,711,421 | -0.5% | 5.0% | (3,615) | 735,571 | 731,956 | 4.7% |
| **Total Other Production Plant** | $1,691,623,866 | $228,384,811 | $1,463,239,055 | 44.7% | 5.0% | $102,122,246 | $73,161,953 | $175,284,198 | 10.4% |
| **TRANSMISSION PLANT** | | | | | | | | | |
| 352.02 Structures and Improvements | $95,935 | | $95,935 | | | | | | |
| 353.00 Station Equipment | 101,228,038 | 2,922,382 | 98,305,656 | 5.5% | -5.0% | 160,731 | (4,915,283) | (4,754,552) | -4.7% |
| 354.00 Towers and Fixtures | 1,329,316 | | 1,329,316 | | | | | | |
| 355.00 Poles and Fixtures | 1,370,085 | | 1,370,085 | | -20.0% | | (274,017) | (274,017) | -20.0% |
| 356.00 Overhead Conductors and Devices | 2,086,319 | 138,642 | 1,947,677 | | -20.0% | | (389,535) | (389,535) | -18.7% |
| **Total Transmission Plant** | $106,109,693 | $3,061,024 | $103,048,669 | 5.3% | -5.4% | $160,731 | ($5,578,835) | ($5,418,104) | -5.1% |
| **DISTRIBUTION PLANT** | | | | | | | | | |
| 361.00 Structures and Improvements | $62,458,930 | $1,570,250 | $60,888,680 | 5.1% | -5.0% | $80,083 | ($3,044,434) | ($2,964,351) | -4.7% |
| 362.00 Station Equipment | 462,114,890 | 55,314,905 | 406,799,985 | 5.5% | 10.0% | 3,042,320 | 40,679,999 | 43,722,318 | 9.5% |
| 364.01 Poles, Towers and Fixtures - Wood | 420,599,219 | 110,335,355 | 310,263,864 | 10.3% | -5.0% | 11,364,542 | (15,513,193) | (4,148,652) | -1.0% |
| 364.02 Poles, Towers and Fixtures - Steel | 179,979,685 | 12,667,918 | 167,311,767 | -10.3% | -10.0% | (1,304,796) | (16,731,177) | (18,035,972) | -10.0% |
| 365.00 Overhead Conductors and Devices | 364,201,375 | 71,558,390 | 292,642,985 | 1.5% | 5.0% | 1,073,376 | 14,632,149 | 15,705,525 | 4.3% |
| 366.00 Underground Conduit | 649,562,771 | 29,074,601 | 620,488,170 | -3.6% | -5.0% | (1,046,686) | (31,024,409) | (32,071,094) | -4.9% |
| 367.00 Underground Conductors and Devices | 1,630,368,211 | 207,659,709 | 1,422,708,502 | 4.2% | -5.0% | 8,721,708 | (71,135,425) | (62,413,717) | -3.8% |
| 368.00 Line Transformers | 793,271,807 | 75,851,967 | 717,419,840 | 2.3% | -5.0% | 1,744,595 | (35,870,992) | (34,126,397) | -4.3% |
| 369.00 Services | 368,140,186 | 44,798,509 | 323,341,677 | -4.2% | -5.0% | (1,881,537) | (16,167,084) | (18,048,621) | -4.9% |
| 370.01 Meters - Electronic | 128,697,096 | 66,489,553 | 62,207,543 | 0.5% | | 332,448 | | 332,448 | 0.3% |

**ARIZONA PUBLIC SERVICE COMPANY**
Average Net Salvage

Statement E

| Account Description | Plant Investment | | | Salvage Rate | | Net Salvage | | | Average |
|---|---|---|---|---|---|---|---|---|---|
| | Additions | Retirements | Survivors | Realized | Future | Realized | Future | Total | Rate |
| A | B | C | D=B-C | E | F | G=E*C | H=F*D | I=G+H | J=I/B |
| 370.03 Meters - AMI | 118,648,206 | 932,640 | 117,715,566 | | | | | | |
| 371.00 Installations on Customers' Premises | 48,544,798 | 8,702,656 | 39,842,142 | -12.3% | -15.0% | (1,070,427) | (5,976,321) | (7,046,748) | -14.5% |
| 373.00 Street Lighting and Signal Systems | 86,926,219 | 13,223,392 | 73,702,827 | 0.6% | -10.0% | 79,340 | (7,370,283) | (7,290,942) | -8.4% |
| **Total Distribution Plant** | $5,313,513,393 | $698,179,845 | $4,615,333,548 | 3.0% | -3.2% | $21,134,966 | ($147,521,170) | ($126,386,204) | -2.4% |
| **GENERAL PLANT** | | | | | | | | | |
| **Depreciable** | | | | | | | | | |
| 390.00 Structures and Improvements | $130,079,520 | $22,435,666 | $107,643,854 | -8.2% | -5.0% | ($1,839,725) | ($5,382,193) | ($7,221,917) | -5.6% |
| 391.CM Office Furn. and Equip. - Computer | 255,865,944 | 166,767,817 | 89,098,127 | -0.2% | | (333,536) | | (333,536) | -0.1% |
| 397.00 Communication Equipment | 215,660,988 | 62,750,890 | 152,910,098 | 0.1% | | 62,751 | | 62,751 | |
| **Total Depreciable** | $601,606,452 | $251,954,373 | $349,652,079 | -0.8% | -1.5% | ($2,110,509) | ($5,382,193) | ($7,492,702) | -1.2% |
| **Amortizable** | | | | | | | | | |
| 391.FE Office Furn. and Equip. - Furniture | $78,701,437 | $29,571,343 | $49,130,094 | | | | | | |
| 393.00 Stores Equipment | 1,621,234 | 1,364,470 | 256,764 | | | | | | |
| 394.00 Tools, Shop and Garage Equipment | 41,668,206 | 13,244,194 | 28,424,012 | | | | | | |
| 395.00 Laboratory Equipment | 2,420,247 | 1,034,881 | 1,385,366 | | | | | | |
| 398.00 Miscellaneous Equipment | 7,518,954 | 1,609,843 | 5,909,111 | | | | | | |
| **Total Amortizable** | $131,930,078 | $46,824,731 | $85,105,347 | | | | | | |
| **Total General Plant** | $733,536,530 | $298,779,104 | $434,757,426 | -0.7% | -1.2% | ($2,110,509) | ($5,382,193) | ($7,492,702) | -1.0% |
| **TOTAL UTILITY** | $12,599,668,627 | $1,590,165,714 | $11,009,502,913 | 5.1% | -2.9% | $81,853,915 | ($317,632,264) | ($235,778,350) | -1.9% |
| **STEAM PRODUCTION (by Unit)** | | | | | | | | | |
| **Cholla** | | | | | | | | | |
| 311.00 Structures and Improvements | $81,486,004 | $9,150,817 | $72,335,187 | -1.3% | -5.2% | ($118,961) | ($3,786,879) | ($3,905,840) | -4.8% |
| 312.00 Boiler Plant Equipment | 570,277,432 | 48,487,459 | 521,789,973 | -20.1% | -6.0% | (9,745,979) | (31,234,973) | (40,980,952) | -7.2% |
| 314.00 Turbogenerator Units | 154,600,716 | 29,042,533 | 125,558,183 | -3.2% | -5.7% | (929,361) | (7,104,491) | (8,033,852) | -5.2% |
| 315.00 Accessory Electric Equipment | 96,531,398 | 2,830,112 | 93,701,286 | -10.9% | -5.5% | (308,482) | (5,134,111) | (5,442,594) | -5.6% |
| 316.00 Miscellaneous Power Plant Equipment | 29,964,877 | 1,979,131 | 27,985,746 | -16.5% | -5.8% | (326,557) | (1,618,592) | (1,945,149) | -6.5% |
| **Total Cholla** | $932,860,427 | $91,490,052 | $841,370,375 | -12.5% | -5.8% | ($11,429,340) | ($48,879,047) | ($60,308,387) | -6.5% |

**ARIZONA PUBLIC SERVICE COMPANY**
Average Net Salvage

Statement E

| Account Description | Plant Investment | | | Salvage Rate | | Net Salvage | | | Average Rate |
|---|---|---|---|---|---|---|---|---|---|
| | Additions | Retirements | Survivors | Realized | Future | Realized | Future | Total | |
| A | B | C | D=B-C | E | F | G=E*C | H=F*D | I=G+H | J=I/B |
| **Cholla Unit 1** | | | | | | | | | |
| 311.00 Structures and Improvements | $4,558,263 | $185,989 | $4,372,274 | -1.3% | -5.0% | ($2,418) | ($218,614) | ($221,032) | -4.8% |
| 312.00 Boiler Plant Equipment | 76,097,814 | 2,884,010 | 73,213,804 | -20.1% | -5.7% | (579,686) | (4,173,187) | (4,752,873) | -6.2% |
| 314.00 Turbogenerator Units | 28,570,183 | 2,929,593 | 25,640,590 | -3.2% | -5.4% | (93,747) | (1,384,592) | (1,478,339) | -5.2% |
| 315.00 Accessory Electric Equipment | 8,892,887 | 76,394 | 8,816,493 | -10.9% | -5.2% | (8,327) | (458,458) | (466,785) | -5.2% |
| 316.00 Miscellaneous Power Plant Equipment | 2,848,079 | 9,352 | 2,838,727 | -16.5% | -5.4% | (1,543) | (153,291) | (154,834) | -5.4% |
| **Total Cholla Unit 1** | $120,967,226 | $6,085,338 | $114,881,888 | -11.3% | -5.6% | ($685,721) | ($6,388,141) | ($7,073,862) | -5.8% |
| **Cholla Unit 2** | | | | | | | | | |
| 311.00 Structures and Improvements | $6,214,286 | $46,274 | $6,168,012 | -1.3% | -5.4% | ($602) | ($333,073) | ($333,674) | -5.4% |
| 312.00 Boiler Plant Equipment | 169,689,538 | 7,365,845 | 162,323,693 | -20.1% | -6.3% | (1,480,535) | (10,226,393) | (11,706,928) | -6.9% |
| 314.00 Turbogenerator Units | 53,219,332 | 9,061,569 | 44,157,763 | -3.2% | -6.0% | (289,970) | (2,649,466) | (2,939,436) | -5.5% |
| 315.00 Accessory Electric Equipment | 47,069,909 | 959,475 | 46,110,434 | -10.9% | -5.7% | (104,583) | (2,628,295) | (2,732,878) | -5.8% |
| 316.00 Miscellaneous Power Plant Equipment | 8,998,578 | 284,182 | 8,714,396 | -16.5% | -5.9% | (46,890) | (514,149) | (561,039) | -6.2% |
| **Total Cholla Unit 2** | $285,191,643 | $17,717,345 | $267,474,298 | -10.9% | -6.1% | ($1,922,579) | ($16,351,375) | ($18,273,955) | -6.4% |
| **Cholla Unit 3** | | | | | | | | | |
| 311.00 Structures and Improvements | $10,128,228 | $144,002 | $9,984,226 | -1.3% | -4.9% | ($1,872) | ($489,227) | ($491,099) | -4.8% |
| 312.00 Boiler Plant Equipment | 258,675,684 | 30,610,741 | 228,064,943 | -20.1% | -5.8% | (6,152,759) | (13,227,767) | (19,380,526) | -7.5% |
| 314.00 Turbogenerator Units | 71,090,033 | 16,240,975 | 54,849,058 | -3.2% | -5.5% | (519,711) | (3,016,698) | (3,536,409) | -5.0% |
| 315.00 Accessory Electric Equipment | 31,542,524 | 541,238 | 31,001,286 | -10.9% | -5.2% | (58,995) | (1,612,067) | (1,671,062) | -5.3% |
| 316.00 Miscellaneous Power Plant Equipment | 4,815,515 | 222,224 | 4,593,291 | -16.5% | -5.5% | (36,667) | (252,631) | (289,298) | -6.0% |
| **Total Cholla Unit 3** | $376,251,984 | $47,759,180 | $328,492,804 | -14.2% | -5.7% | ($6,770,004) | ($18,598,390) | ($25,368,394) | -6.7% |
| **Cholla Common** | | | | | | | | | |
| 311.00 Structures and Improvements | $60,585,227 | $8,774,552 | $51,810,675 | -1.3% | -5.3% | ($114,069) | ($2,745,966) | ($2,860,035) | -4.7% |
| 312.00 Boiler Plant Equipment | 65,814,396 | 7,626,863 | 58,187,533 | -20.1% | -6.2% | (1,532,999) | (3,607,627) | (5,140,627) | -7.8% |
| 314.00 Turbogenerator Units | 1,721,168 | 810,396 | 910,772 | -3.2% | -5.9% | (25,933) | (53,736) | (79,668) | -4.6% |
| 315.00 Accessory Electric Equipment | 9,026,078 | 1,253,005 | 7,773,073 | -10.9% | -5.6% | (136,578) | (435,292) | (571,870) | -6.3% |
| 316.00 Miscellaneous Power Plant Equipment | 13,302,705 | 1,463,373 | 11,839,332 | -16.5% | -5.9% | (241,457) | (698,521) | (939,977) | -7.1% |
| **Total Cholla Common** | $150,449,574 | $19,928,189 | $130,521,385 | -10.3% | -5.8% | ($2,051,035) | ($7,541,141) | ($9,592,176) | -6.4% |
| **Four Corners** | | | | | | | | | |
| 311.00 Structures and Improvements | $58,239,255 | $690,239 | $57,549,016 | -1.3% | -15.6% | ($8,973) | ($8,958,635) | ($8,967,608) | -15.4% |
| 312.00 Boiler Plant Equipment | 409,653,716 | 34,251,600 | 375,402,116 | -20.1% | -22.1% | (6,884,572) | (82,800,603) | (89,685,175) | -21.9% |
| 314.00 Turbogenerator Units | 81,000,802 | 7,646,224 | 73,354,578 | -3.2% | -19.9% | (244,679) | (14,609,614) | (14,854,293) | -18.3% |
| 315.00 Accessory Electric Equipment | 42,150,140 | 2,086,187 | 40,063,953 | -10.9% | -21.1% | (227,394) | (8,442,317) | (8,669,711) | -20.6% |
| 316.00 Miscellaneous Power Plant Equipment | 26,689,243 | 966,356 | 25,722,887 | -16.5% | -18.8% | (159,449) | (4,836,181) | (4,995,630) | -18.7% |
| **Total Four Corners** | $617,733,156 | $45,640,606 | $572,092,550 | -16.5% | -20.9% | ($7,525,067) | ($119,647,350) | ($127,172,417) | -20.6% |

**ARIZONA PUBLIC SERVICE COMPANY**
Average Net Salvage

Statement E

| Account Description | Plant Investment | | | Salvage Rate | | Net Salvage | | | Average Rate |
|---|---|---|---|---|---|---|---|---|---|
| | Additions | Retirements | Survivors | Realized | Future | Realized | Future | Total | |
| A | B | C | D=B-C | E | F | G=E*C | H=F*D | I=G+H | J=I/B |
| **Four Corners Units 1-3** | | | | | | | | | |
| 311.00 Structures and Improvements | $41,169,552 | $486,461 | $40,683,091 | -1.3% | | ($6,324) | | ($6,324) | |
| 312.00 Boiler Plant Equipment | 272,052,306 | 29,950,392 | 242,101,914 | -20.1% | | (6,020,029) | | (6,020,029) | -2.2% |
| 314.00 Turbogenerator Units | 54,983,581 | 4,799,888 | 50,183,693 | -3.2% | | (153,596) | | (153,596) | -0.3% |
| 315.00 Accessory Electric Equipment | 25,541,727 | 1,208,242 | 24,333,485 | -10.9% | | (131,698) | | (131,698) | -0.5% |
| 316.00 Miscellaneous Power Plant Equipment | 12,423,967 | 768,653 | 11,655,314 | -16.5% | | (126,828) | | (126,828) | -1.0% |
| **Total Four Corners Units 1-3** | $406,171,133 | $37,213,636 | $368,957,497 | -17.3% | | ($6,438,475) | | ($6,438,475) | -1.6% |
| **Four Corners Units 4-5** | | | | | | | | | |
| 311.00 Structures and Improvements | $11,904,152 | $21,886 | $11,882,266 | -1.3% | -66.0% | ($285) | ($7,842,296) | ($7,842,580) | -65.9% |
| 312.00 Boiler Plant Equipment | 121,163,055 | 3,101,000 | 118,062,055 | -20.1% | -67.1% | (623,301) | (79,219,639) | (79,842,940) | -65.9% |
| 314.00 Turbogenerator Units | 22,904,472 | 1,721,087 | 21,183,385 | -3.2% | -66.8% | (55,075) | (14,150,501) | (14,205,576) | -62.0% |
| 315.00 Accessory Electric Equipment | 11,536,586 | 399,498 | 11,137,088 | -10.9% | -66.4% | (43,545) | (7,395,026) | (7,438,572) | -64.5% |
| 316.00 Miscellaneous Power Plant Equipment | 3,652,142 | 37,190 | 3,614,952 | -16.5% | -66.7% | (6,136) | (2,411,173) | (2,417,309) | -66.2% |
| **Total Four Corners Units 4-5** | $171,160,407 | $5,280,661 | $165,879,746 | -13.8% | -66.9% | ($728,342) | ($111,018,635) | ($111,746,977) | -65.3% |
| **Four Corners Common** | | | | | | | | | |
| 311.00 Structures and Improvements | $5,165,551 | $181,892 | $4,983,659 | -1.3% | -22.4% | ($2,365) | ($1,116,340) | ($1,118,704) | -21.7% |
| 312.00 Boiler Plant Equipment | 16,438,355 | 1,200,208 | 15,238,147 | -20.1% | -23.5% | (241,242) | (3,580,965) | (3,822,206) | -23.3% |
| 314.00 Turbogenerator Units | 3,112,749 | 1,125,249 | 1,987,500 | -3.2% | -23.1% | (36,008) | (459,113) | (495,120) | -15.9% |
| 315.00 Accessory Electric Equipment | 5,071,827 | 478,447 | 4,593,380 | -10.9% | -22.8% | (52,151) | (1,047,291) | (1,099,441) | -21.7% |
| 316.00 Miscellaneous Power Plant Equipment | 10,613,134 | 160,513 | 10,452,621 | -16.5% | -23.2% | (26,485) | (2,425,008) | (2,451,493) | -23.1% |
| **Total Four Corners Common** | $40,401,616 | $3,146,309 | $37,255,307 | -11.4% | -23.2% | ($358,250) | ($8,628,715) | ($8,986,965) | -22.2% |
| **Navajo Units 1-3** | | | | | | | | | |
| 311.00 Structures and Improvements | $29,378,233 | $264,703 | $29,113,530 | -1.3% | -7.1% | ($3,441) | ($2,067,061) | ($2,070,502) | -7.0% |
| 312.00 Boiler Plant Equipment | 173,502,971 | 7,499,757 | 166,003,214 | -20.1% | -7.7% | (1,507,451) | (12,782,247) | (14,289,699) | -8.2% |
| 314.00 Turbogenerator Units | 24,801,608 | 102,303 | 24,699,305 | -3.2% | -7.5% | (3,274) | (1,852,448) | (1,855,722) | -7.5% |
| 315.00 Accessory Electric Equipment | 21,635,639 | 144,295 | 21,491,344 | -10.9% | -7.3% | (15,728) | (1,568,868) | (1,584,596) | -7.3% |
| 316.00 Miscellaneous Power Plant Equipment | 17,789,874 | 561,277 | 17,228,597 | -16.5% | -7.5% | (92,611) | (1,292,145) | (1,384,755) | -7.8% |
| **Total Navajo Units 1-3** | $267,108,325 | $8,572,335 | $258,535,990 | -18.9% | -7.6% | ($1,622,505) | ($19,562,769) | ($21,185,274) | -7.9% |
| **Ocotillo Units 1-2** | | | | | | | | | |
| 311.00 Structures and Improvements | $5,072,871 | $313,213 | $4,759,658 | -1.3% | -18.9% | ($4,072) | ($899,575) | ($903,647) | -17.8% |
| 312.00 Boiler Plant Equipment | 25,522,211 | 303,563 | 25,218,648 | -20.1% | -19.2% | (61,016) | (4,841,980) | (4,902,997) | -19.2% |
| 314.00 Turbogenerator Units | 20,642,999 | 481,416 | 20,161,583 | -3.2% | -19.1% | (15,405) | (3,850,862) | (3,866,268) | -18.7% |
| 315.00 Accessory Electric Equipment | 3,673,044 | 247,088 | 3,425,956 | -10.9% | -19.0% | (26,933) | (650,932) | (677,864) | -18.5% |
| 316.00 Miscellaneous Power Plant Equipment | 6,581,204 | 570,630 | 6,010,574 | -16.5% | -19.1% | (94,154) | (1,148,020) | (1,242,174) | -18.9% |
| **Total Ocotillo Units 1-2** | $61,492,329 | $1,915,910 | $59,576,419 | -10.5% | -19.1% | ($201,580) | ($11,391,369) | ($11,592,949) | -18.9% |

**ARIZONA PUBLIC SERVICE COMPANY**
Average Net Salvage

Statement E

| Account Description | Plant Investment | | | Salvage Rate | | Net Salvage | | | Average |
|---|---|---|---|---|---|---|---|---|---|
| | Additions | Retirements | Survivors | Realized | Future | Realized | Future | Total | Rate |
| A | B | C | D=B-C | E | F | G=E*C | H=F*D | I=G+H | J=I/B |
| **Saguaro Units 1-2** | | | | | | | | | |
| 311.00 Structures and Improvements | $4,392,936 | $81,619 | $4,311,317 | -1.3% | -18.7% | ($1,061) | ($806,216) | ($807,277) | -18.4% |
| 312.00 Boiler Plant Equipment | 27,291,542 | 1,197,170 | 26,094,372 | -20.1% | -19.0% | (240,631) | (4,957,931) | (5,198,562) | -19.0% |
| 314.00 Turbogenerator Units | 16,891,801 | 378,238 | 16,513,563 | -3.2% | -18.9% | (12,104) | (3,121,063) | (3,133,167) | -18.5% |
| 315.00 Accessory Electric Equipment | 5,861,916 | 194,010 | 5,667,906 | -10.9% | -18.8% | (21,147) | (1,065,566) | (1,086,713) | -18.5% |
| 316.00 Miscellaneous Power Plant Equipment | 4,821,800 | 42,864 | 4,778,936 | -16.5% | -18.9% | (7,073) | (903,219) | (910,291) | -18.9% |
| **Total Saguaro Units 1-2** | $59,259,995 | $1,893,901 | $57,366,094 | -14.9% | -18.9% | ($282,015) | ($10,853,996) | ($11,136,011) | -18.8% |
| **NUCLEAR PRODUCTION (by Unit)** | | | | | | | | | |
| **Palo Verde** | | | | | | | | | |
| 321.00 Structures and Improvements | $727,309,483 | $28,462,682 | $698,846,801 | -4.3% | -0.5% | ($1,223,895) | ($3,337,529) | ($4,561,424) | -0.6% |
| 322.00 Reactor Plant Equipment | 1,207,856,362 | 76,922,503 | 1,130,933,859 | -17.7% | -1.3% | (13,615,283) | (15,144,579) | (28,759,862) | -2.4% |
| 323.00 Turbogenerator Units | 413,417,445 | 59,243,307 | 354,174,138 | -2.5% | -0.4% | (1,481,083) | (1,566,990) | (3,048,072) | -0.7% |
| 324.00 Accessory Electric Equipment | 283,285,283 | 8,268,606 | 275,016,677 | -2.7% | -0.5% | (223,252) | (1,260,223) | (1,483,475) | -0.5% |
| 325.00 Miscellaneous Power Plant Equipment | 184,562,340 | 39,351,028 | 145,211,312 | -4.7% | -0.5% | (1,849,498) | (668,167) | (2,517,666) | -1.4% |
| **Total Palo Verde** | $2,816,430,913 | $212,248,126 | $2,604,182,787 | -8.7% | -0.8% | ($18,393,012) | ($21,977,488) | ($40,370,499) | -1.4% |
| **Palo Verde Unit 1** | | | | | | | | | |
| 321.00 Structures and Improvements | $158,549,759 | $1,844,414 | $156,705,345 | -4.3% | -0.4% | ($79,310) | ($626,821) | ($706,131) | -0.4% |
| 322.00 Reactor Plant Equipment | 476,577,165 | 22,369,965 | 454,207,200 | -17.7% | -1.3% | (3,959,484) | (5,904,694) | (9,864,177) | -2.1% |
| 323.00 Turbogenerator Units | 144,152,207 | 18,884,011 | 125,268,196 | -2.5% | -0.4% | (472,100) | (501,073) | (973,173) | -0.7% |
| 324.00 Accessory Electric Equipment | 116,985,487 | 2,124,695 | 114,860,792 | -2.7% | -0.4% | (57,367) | (459,443) | (516,810) | -0.4% |
| 325.00 Miscellaneous Power Plant Equipment | 35,114,067 | 4,312,309 | 30,801,758 | -4.7% | -0.4% | (202,679) | (123,207) | (325,886) | -0.9% |
| **Total Palo Verde Unit 1** | $931,378,685 | $49,535,394 | $881,843,291 | -9.6% | -0.9% | ($4,770,939) | ($7,615,238) | ($12,386,177) | -1.3% |
| **Palo Verde Unit 2** | | | | | | | | | |
| 321.00 Structures and Improvements | $92,433,785 | $775,874 | $91,657,911 | -4.3% | -0.5% | ($33,363) | ($458,290) | ($491,652) | -0.5% |
| 322.00 Reactor Plant Equipment | 263,630,088 | 29,342,610 | 234,287,478 | -17.7% | -1.3% | (5,193,642) | (3,045,737) | (8,239,379) | -3.1% |
| 323.00 Turbogenerator Units | 91,343,984 | 12,731,285 | 78,612,699 | -2.5% | -0.4% | (318,282) | (314,451) | (632,733) | -0.7% |
| 324.00 Accessory Electric Equipment | 52,298,306 | 2,361,059 | 49,937,247 | -2.7% | -0.5% | (63,749) | (249,686) | (313,435) | -0.6% |
| 325.00 Miscellaneous Power Plant Equipment | 29,386,233 | 2,298,653 | 27,087,580 | -4.7% | -0.4% | (108,037) | (108,350) | (216,387) | -0.7% |
| **Total Palo Verde Unit 2** | $529,092,396 | $47,509,481 | $481,582,915 | -12.0% | -0.9% | ($5,717,072) | ($4,176,514) | ($9,893,586) | -1.9% |
| **Palo Verde Unit 3** | | | | | | | | | |
| 321.00 Structures and Improvements | $164,694,826 | $1,502,335 | $163,192,491 | -4.3% | -0.5% | ($64,600) | ($815,962) | ($880,563) | -0.5% |
| 322.00 Reactor Plant Equipment | 437,104,524 | 22,652,601 | 414,451,923 | -17.7% | -1.4% | (4,009,510) | (5,802,327) | (9,811,837) | -2.2% |
| 323.00 Turbogenerator Units | 174,370,914 | 26,460,375 | 147,910,539 | -2.5% | -0.5% | (661,509) | (739,553) | (1,401,062) | -0.8% |
| 324.00 Accessory Electric Equipment | 93,473,730 | 2,635,902 | 90,837,828 | -2.7% | -0.5% | (71,169) | (454,189) | (525,358) | -0.6% |
| 325.00 Miscellaneous Power Plant Equipment | 31,555,474 | 2,843,225 | 28,712,249 | -4.7% | -0.5% | (133,632) | (143,561) | (277,193) | -0.9% |
| **Total Palo Verde Unit 3** | $901,199,468 | $56,094,438 | $845,105,030 | -8.8% | -0.9% | ($4,940,421) | ($7,955,592) | ($12,896,014) | -1.4% |

**ARIZONA PUBLIC SERVICE COMPANY**
Average Net Salvage

Statement E

| Account Description | Plant Investment | | | Salvage Rate | | Net Salvage | | | Average Rate |
|---|---|---|---|---|---|---|---|---|---|
| | Additions | Retirements | Survivors | Realized | Future | Realized | Future | Total | |
| A | B | C | D=B-C | E | F | G=E*C | H=F*D | I=G+H | J=I/B |
| **Palo Verde Water Reclamation** | | | | | | | | | |
| 321.00 Structures and Improvements | $186,745,934 | $15,136,710 | $171,609,224 | -4.3% | -0.5% | ($650,879) | ($858,046) | ($1,508,925) | -0.8% |
| 322.00 Reactor Plant Equipment | 133,326 | | 133,326 | -17.7% | -1.4% | | (1,867) | (1,867) | -1.4% |
| 323.00 Turbogenerator Units | 246,532 | 28,776 | 217,756 | -2.5% | -0.5% | (719) | (1,089) | (1,808) | -0.7% |
| 324.00 Accessory Electric Equipment | | | | | | | | | |
| 325.00 Miscellaneous Power Plant Equipment | 131,432 | 42,613 | 88,819 | -4.7% | -0.5% | (2,003) | (444) | (2,447) | -1.9% |
| **Total Palo Verde Water Reclamation** | $187,257,224 | $15,208,099 | $172,049,125 | -4.3% | -0.5% | ($653,601) | ($861,446) | ($1,515,046) | -0.8% |
| **Palo Verde Common** | | | | | | | | | |
| 321.00 Structures and Improvements | $124,885,179 | $9,203,349 | $115,681,830 | -4.3% | -0.5% | ($395,744) | ($578,409) | ($974,153) | -0.8% |
| 322.00 Reactor Plant Equipment | 30,411,259 | 2,557,327 | 27,853,932 | -17.7% | -1.4% | (452,647) | (389,955) | (842,602) | -2.8% |
| 323.00 Turbogenerator Units | 3,303,808 | 1,138,860 | 2,164,948 | -2.5% | -0.5% | (28,472) | (10,825) | (39,296) | -1.2% |
| 324.00 Accessory Electric Equipment | 20,527,760 | 1,146,950 | 19,380,810 | -2.7% | -0.5% | (30,968) | (96,904) | (127,872) | -0.6% |
| 325.00 Miscellaneous Power Plant Equipment | 88,375,134 | 29,854,228 | 58,520,906 | -4.7% | -0.5% | (1,403,149) | (292,605) | (1,695,753) | -1.9% |
| **Total Palo Verde Common** | $267,503,140 | $43,900,714 | $223,602,426 | -5.3% | -0.6% | ($2,310,979) | ($1,368,698) | ($3,679,676) | -1.4% |
| **OTHER PRODUCTION (by Unit)** | | | | | | | | | |
| **Douglas CT** | | | | | | | | | |
| 341.00 Structures and Improvements | $49,075 | | $49,075 | -2.8% | 5.0% | | $2,454 | $2,454 | 5.0% |
| 342.00 Fuel Holders, Products and Accessories | 160,633 | 22,874 | 137,759 | -2.1% | 5.0% | (480) | 6,888 | 6,408 | 4.0% |
| 343.00 Prime Movers | 1,101,449 | | 1,101,449 | -7.3% | 5.0% | | 55,072 | 55,072 | 5.0% |
| 344.00 Generators and Devices | 551,765 | | 551,765 | 72.2% | 5.0% | | 27,588 | 27,588 | 5.0% |
| 345.00 Accessory Electric Equipment | 369,401 | 16,124 | 353,277 | -5.8% | 5.0% | (935) | 17,664 | 16,729 | 4.5% |
| 346.00 Miscellaneous Power Plant Equipment | 40,913 | | 40,913 | -0.5% | 5.0% | | 2,046 | 2,046 | 5.0% |
| **Total Douglas CT** | $2,273,236 | $38,998 | $2,234,238 | -3.6% | 5.0% | ($1,416) | $111,712 | $110,296 | 4.9% |
| **Ocotillo CT Units 1-2** | | | | | | | | | |
| 341.00 Structures and Improvements | $744,373 | $22,805 | $721,568 | -2.8% | 5.0% | ($639) | $36,078 | $35,440 | 4.8% |
| 342.00 Fuel Holders, Products and Accessories | 791,584 | | 791,584 | -2.1% | 5.0% | | 39,579 | 39,579 | 5.0% |
| 343.00 Prime Movers | 6,636,736 | 96,461 | 6,540,275 | -7.3% | 5.0% | (7,042) | 327,014 | 319,972 | 4.8% |
| 344.00 Generators and Devices | 8,584,460 | 988,146 | 7,596,314 | 72.2% | 5.0% | 713,441 | 379,816 | 1,093,257 | 12.7% |
| 345.00 Accessory Electric Equipment | 1,771,355 | 93,924 | 1,677,431 | -5.8% | 5.0% | (5,448) | 83,872 | 78,424 | 4.4% |
| 346.00 Miscellaneous Power Plant Equipment | 668,202 | 30,475 | 637,727 | -0.5% | 5.0% | (152) | 31,886 | 31,734 | 4.7% |
| **Total Octillo CT Units 1-2** | $19,196,710 | $1,231,811 | $17,964,899 | 56.8% | 5.0% | $700,161 | $898,245 | $1,598,406 | 8.3% |
| **Redhawk CC Units 1-2** | | | | | | | | | |
| 341.00 Structures and Improvements | $26,241,141 | $4,043,739 | $22,197,402 | -2.8% | 5.0% | ($113,225) | $1,109,870 | $996,645 | 3.8% |
| 342.00 Fuel Holders, Products and Accessories | 2,637,978 | | 2,637,978 | -2.1% | 5.0% | | 131,899 | 131,899 | 5.0% |
| 343.00 Prime Movers | 221,649,524 | 43,788,997 | 177,860,527 | -7.3% | 5.0% | (3,196,597) | 8,893,026 | 5,696,430 | 2.6% |
| 344.00 Generators and Devices | 400,023,626 | 120,811,368 | 279,212,258 | 72.2% | 5.0% | 87,225,808 | 13,960,613 | 101,186,421 | 25.3% |
| 345.00 Accessory Electric Equipment | 26,990,534 | 4,406,068 | 22,584,466 | -5.8% | 5.0% | (255,552) | 1,129,223 | 873,671 | 3.2% |
| 346.00 Miscellaneous Power Plant Equipment | 4,005,866 | | 4,005,866 | -0.5% | 5.0% | | 200,293 | 200,293 | 5.0% |
| **Total Redhawk CC Units 1-2** | $681,548,669 | $173,050,172 | $508,498,497 | 48.3% | 5.0% | $83,660,434 | $25,424,925 | $109,085,359 | 16.0% |

**ARIZONA PUBLIC SERVICE COMPANY**
Average Net Salvage

Statement E

| Account Description | Plant Investment | | | Salvage Rate | | Net Salvage | | | Average Rate |
|---|---|---|---|---|---|---|---|---|---|
| | Additions | Retirements | Survivors | Realized | Future | Realized | Future | Total | |
| A | B | C | D=B-C | E | F | G=E*C | H=F*D | I=G+H | J=I/B |
| **Saguaro** | | | | | | | | | |
| 341.00 Structures and Improvements | $1,917,969 | $32,525 | $1,885,444 | -2.8% | 5.0% | ($911) | $94,272 | $93,362 | 4.9% |
| 342.00 Fuel Holders, Products and Accessories | 1,523,125 | 146,423 | 1,376,702 | -2.1% | 5.0% | (3,075) | 68,835 | 65,760 | 4.3% |
| 343.00 Prime Movers | 8,666,061 | 41,249 | 8,624,812 | -7.3% | 5.0% | (3,011) | 431,241 | 428,229 | 4.9% |
| 344.00 Generators and Devices | 32,947,021 | 434,649 | 32,512,372 | 72.2% | 5.0% | 313,817 | 1,625,619 | 1,939,435 | 5.9% |
| 345.00 Accessory Electric Equipment | 1,767,889 | 66,110 | 1,701,779 | -5.8% | 5.0% | (3,834) | 85,089 | 81,255 | 4.6% |
| 346.00 Miscellaneous Power Plant Equipment | 880,120 | 11,635 | 868,485 | -0.5% | 5.0% | (58) | 43,424 | 43,366 | 4.9% |
| **Total Saguaro** | $47,702,185 | $732,591 | $46,969,594 | 41.4% | 5.0% | $302,927 | $2,348,480 | $2,651,407 | 5.6% |
| **Saguaro CT Units 1-2** | | | | | | | | | |
| 341.00 Structures and Improvements | $1,917,969 | $32,525 | $1,885,444 | -2.8% | 5.0% | ($911) | $94,272 | $93,362 | 4.9% |
| 342.00 Fuel Holders, Products and Accessories | 1,523,125 | 146,423 | 1,376,702 | -2.1% | 5.0% | (3,075) | 68,835 | 65,760 | 4.3% |
| 343.00 Prime Movers | 8,025,154 | 41,249 | 7,983,905 | -7.3% | 5.0% | (3,011) | 399,195 | 396,184 | 4.9% |
| 344.00 Generators and Devices | 4,922,637 | 434,649 | 4,487,988 | 72.2% | 5.0% | 313,817 | 224,399 | 538,216 | 10.9% |
| 345.00 Accessory Electric Equipment | 1,645,336 | 66,110 | 1,579,226 | -5.8% | 5.0% | (3,834) | 78,961 | 75,127 | 4.6% |
| 346.00 Miscellaneous Power Plant Equipment | 880,120 | 11,635 | 868,485 | -0.5% | 5.0% | (58) | 43,424 | 43,366 | 4.9% |
| **Total Saguaro CT Units 1-2** | $18,914,341 | $732,591 | $18,181,750 | 41.4% | 5.0% | $302,927 | $909,088 | $1,212,015 | 6.4% |
| **Saguaro CT Unit 3** | | | | | | | | | |
| 341.00 Structures and Improvements | | | | | | | | | |
| 342.00 Fuel Holders, Products and Accessories | | | | | | | | | |
| 343.00 Prime Movers | 640,907 | | 640,907 | -7.3% | 5.0% | | 32,045 | 32,045 | 5.0% |
| 344.00 Generators and Devices | 28,024,384 | | 28,024,384 | 72.2% | 5.0% | | 1,401,219 | 1,401,219 | 5.0% |
| 345.00 Accessory Electric Equipment | 122,553 | | 122,553 | -5.8% | 5.0% | | 6,128 | 6,128 | 5.0% |
| 346.00 Miscellaneous Power Plant Equipment | | | | | | | | | |
| **Total Saguaro CT Unit 3** | $28,787,844 | | $28,787,844 | | 5.0% | | $1,439,392 | $1,439,392 | 5.0% |
| **Solar Units** | | | | | | | | | |
| 341.00 Structures and Improvements | $431,153 | $12,750 | $418,403 | -2.8% | 5.0% | ($357) | $20,920 | $20,563 | 4.8% |
| 342.00 Fuel Holders, Products and Accessories | | | | | | | | | |
| 343.00 Prime Movers | | | | | | | | | |
| 344.00 Generators and Devices | 17,736,803 | 1,772,822 | 15,963,981 | 72.2% | 5.0% | 1,279,977 | 798,199 | 2,078,177 | 11.7% |
| 345.00 Accessory Electric Equipment | 728,283 | | 728,283 | -5.8% | 5.0% | | 36,414 | 36,414 | 5.0% |
| 346.00 Miscellaneous Power Plant Equipment | | | | | | | | | |
| **Total Solar Units** | $18,896,239 | $1,785,572 | $17,110,667 | 71.7% | 5.0% | $1,279,620 | $855,533 | $2,135,154 | 11.3% |
| **Sundance** | | | | | | | | | |
| 341.00 Structures and Improvements | $12,671,247 | $18,000 | $12,653,247 | -2.8% | 5.0% | ($504) | $632,662 | $632,158 | 5.0% |
| 342.00 Fuel Holders, Products and Accessories | 4,325,769 | | 4,325,769 | -2.1% | 5.0% | | 216,288 | 216,288 | 5.0% |
| 343.00 Prime Movers | 230,018,750 | 286,539 | 229,732,211 | -7.3% | 5.0% | (20,917) | 11,486,611 | 11,465,693 | 5.0% |
| 344.00 Generators and Devices | 301,285 | | 301,285 | 72.2% | 5.0% | | 15,064 | 15,064 | 5.0% |
| 345.00 Accessory Electric Equipment | 26,442,312 | 33,600 | 26,408,712 | -5.8% | 5.0% | (1,949) | 1,320,436 | 1,318,487 | 5.0% |
| 346.00 Miscellaneous Power Plant Equipment | 2,026,889 | | 2,026,889 | -0.5% | 5.0% | | 101,444 | 101,444 | 5.0% |
| **Total Sun Dance** | $275,788,252 | $338,139 | $275,450,113 | -6.9% | 5.0% | ($23,370) | $13,772,506 | $13,749,136 | 5.0% |

**ARIZONA PUBLIC SERVICE COMPANY**
Average Net Salvage

Statement E

| Account Description | Plant Investment | | | Salvage Rate | | Net Salvage | | | Average |
|---|---|---|---|---|---|---|---|---|---|
| | Additions | Retirements | Survivors | Realized | Future | Realized | Future | Total | Rate |
| A | B | C | D=B-C | E | F | G=E*C | H=F*D | I=G+H | J=I/B |
| **West Phoenix** | | | | | | | | | |
| 341.00 Structures and Improvements | $28,030,775 | $424,614 | $27,606,161 | -2.8% | 5.0% | ($11,889) | $1,380,308 | $1,368,419 | 4.9% |
| 342.00 Fuel Holders, Products and Accessories | 29,454,913 | 1,364,569 | 28,090,344 | -2.1% | 5.0% | (28,656) | 1,404,517 | 1,375,861 | 4.7% |
| 343.00 Prime Movers | 186,297,277 | 21,646,082 | 164,651,195 | -7.3% | 5.0% | (1,580,164) | 8,232,560 | 6,652,396 | 3.6% |
| 344.00 Generators and Devices | 268,459,223 | 24,364,804 | 244,094,419 | 72.2% | 5.0% | 17,591,388 | 12,204,721 | 29,796,109 | 11.1% |
| 345.00 Accessory Electric Equipment | 31,615,986 | 2,046,973 | 29,569,013 | -5.8% | 5.0% | (118,724) | 1,478,451 | 1,359,726 | 4.3% |
| 346.00 Miscellaneous Power Plant Equipment | 7,127,980 | 680,838 | 6,447,142 | -0.5% | 5.0% | (3,404) | 322,357 | 318,953 | 4.5% |
| **Total West Phoenix** | $550,986,154 | $50,527,880 | $500,458,274 | 31.4% | 5.0% | $15,848,551 | $25,022,914 | $40,871,464 | 7.4% |
| **West Phoenix CC Units 1-3** | | | | | | | | | |
| 341.00 Structures and Improvements | $1,776,669 | $66,184 | $1,710,485 | -2.8% | 5.0% | ($1,853) | $85,524 | $83,671 | 4.7% |
| 342.00 Fuel Holders, Products and Accessories | 23,882,271 | 1,364,569 | 22,517,702 | -2.1% | 5.0% | (28,656) | 1,125,885 | 1,097,229 | 4.6% |
| 343.00 Prime Movers | | | | | | | | | |
| 344.00 Generators and Devices | 113,266,743 | 20,700,627 | 92,566,116 | 72.2% | 5.0% | 14,945,853 | 4,628,306 | 19,574,158 | 17.3% |
| 345.00 Accessory Electric Equipment | 15,554,341 | 1,992,671 | 13,561,670 | -5.8% | 5.0% | (115,575) | 678,084 | 562,509 | 3.6% |
| 346.00 Miscellaneous Power Plant Equipment | 5,366,074 | 643,721 | 4,722,353 | -0.5% | 5.0% | (3,219) | 236,118 | 232,899 | 4.3% |
| **Total West Phoenix CC Units 1-3** | $159,846,098 | $24,767,772 | $135,078,326 | 59.7% | 5.0% | $14,796,550 | $6,753,916 | $21,550,466 | 13.5% |
| **West Phoenix CC Unit 4** | | | | | | | | | |
| 341.00 Structures and Improvements | $4,584,726 | | $4,584,726 | -2.8% | 5.0% | | $229,236 | $229,236 | 5.0% |
| 342.00 Fuel Holders, Products and Accessories | 4,135,109 | | 4,135,109 | -2.1% | 5.0% | | 206,755 | 206,755 | 5.0% |
| 343.00 Prime Movers | 54,739,557 | 59,023 | 54,680,534 | -7.3% | 5.0% | (4,309) | 2,734,027 | 2,729,718 | 5.0% |
| 344.00 Generators and Devices | 16,699,190 | 1,151,052 | 15,548,138 | 72.2% | 5.0% | 831,060 | 777,407 | 1,608,466 | 9.6% |
| 345.00 Accessory Electric Equipment | 2,569,550 | | 2,569,550 | -5.8% | 5.0% | | 128,478 | 128,478 | 5.0% |
| 346.00 Miscellaneous Power Plant Equipment | 334,270 | 18,529 | 315,741 | -0.5% | 5.0% | (93) | 15,787 | 15,694 | 4.7% |
| **Total West Phoenix CC Unit 4** | $83,062,402 | $1,228,604 | $81,833,798 | 67.3% | 5.0% | $826,658 | $4,091,690 | $4,918,348 | 5.9% |
| **West Phoenix CC Unit 5** | | | | | | | | | |
| 341.00 Structures and Improvements | $10,865,036 | | $10,865,036 | -2.8% | 5.0% | | $543,252 | $543,252 | 5.0% |
| 342.00 Fuel Holders, Products and Accessories | | | | | | | | | |
| 343.00 Prime Movers | 122,437,292 | 21,260,798 | 101,176,494 | -7.3% | 5.0% | (1,552,038) | 5,058,825 | 3,506,786 | 2.9% |
| 344.00 Generators and Devices | 133,742,977 | 2,379,967 | 131,363,010 | 72.2% | 5.0% | 1,718,336 | 6,568,151 | 8,286,487 | 6.2% |
| 345.00 Accessory Electric Equipment | 11,713,613 | | 11,713,613 | -5.8% | 5.0% | | 585,681 | 585,681 | 5.0% |
| 346.00 Miscellaneous Power Plant Equipment | 235,560 | | 235,560 | -0.5% | 5.0% | | 11,778 | 11,778 | 5.0% |
| **Total West Phoenix CC Unit 5** | $278,994,478 | $23,640,765 | $255,353,713 | 0.7% | 5.0% | $166,298 | $12,767,686 | $12,933,984 | 4.6% |
| **West Phoenix CT Units 1-2** | | | | | | | | | |
| 341.00 Structures and Improvements | $880,435 | | $880,435 | -2.8% | 5.0% | | $44,022 | $44,022 | 5.0% |
| 342.00 Fuel Holders, Products and Accessories | 1,437,533 | | 1,437,533 | -2.1% | 5.0% | | 71,877 | 71,877 | 5.0% |
| 343.00 Prime Movers | 9,120,428 | 326,261 | 8,794,167 | -7.3% | 5.0% | (23,817) | 439,708 | 415,891 | 4.6% |
| 344.00 Generators and Devices | 4,750,313 | 133,158 | 4,617,155 | 72.2% | 5.0% | 96,140 | 230,858 | 326,998 | 6.9% |
| 345.00 Accessory Electric Equipment | 1,778,482 | 54,302 | 1,724,180 | -5.8% | 5.0% | (3,150) | 86,209 | 83,059 | 4.7% |
| 346.00 Miscellaneous Power Plant Equipment | 1,192,076 | 18,588 | 1,173,488 | -0.5% | 5.0% | (93) | 58,674 | 58,581 | 4.9% |
| **Total West Phoenix CT Units 1-2** | $19,159,267 | $532,309 | $18,626,958 | 13.0% | 5.0% | $69,081 | $931,348 | $1,000,428 | 5.2% |

**ARIZONA PUBLIC SERVICE COMPANY**
Average Net Salvage

Statement E

| Account Description | Plant Investment | | | Salvage Rate | | Net Salvage | | | Average Rate |
|---|---|---|---|---|---|---|---|---|---|
| | Additions | Retirements | Survivors | Realized | Future | Realized | Future | Total | |
| A | B | C | D=B-C | E | F | G=E*C | H=F*D | I=G+H | J=I/B |
| **West Phoenix Common** | | | | | | | | | |
| 341.00 Structures and Improvements | $9,923,909 | $358,430 | $9,565,479 | -2.8% | 5.0% | ($10,036) | $478,274 | $468,238 | 4.7% |
| 342.00 Fuel Holders, Products and Accessories | | | | | | | | | |
| 343.00 Prime Movers | | | | | | | | | |
| 344.00 Generators and Devices | | | | | | | | | |
| 345.00 Accessory Electric Equipment | | | | | | | | | |
| 346.00 Miscellaneous Power Plant Equipment | | | | | | | | | |
| **Total West Phoenix Common** | $9,923,909 | $358,430 | $9,565,479 | -2.8% | 5.0% | ($10,036) | $478,274 | $468,238 | 4.7% |
| **Yucca** | | | | | | | | | |
| 341.00 Structures and Improvements | $1,826,216 | $95,332 | $1,730,884 | -2.8% | 5.0% | ($2,669) | $86,544 | $83,875 | 4.6% |
| 342.00 Fuel Holders, Products and Accessories | 4,862,130 | 42,920 | 4,819,210 | -2.1% | 5.0% | (901) | 240,961 | 240,059 | 4.9% |
| 343.00 Prime Movers | 76,131,450 | | 76,131,450 | | 5.0% | | 3,806,573 | 3,806,573 | 5.0% |
| 344.00 Generators and Devices | 8,437,995 | 500,396 | 7,937,599 | 72.2% | 5.0% | 361,286 | 396,880 | 758,166 | 9.0% |
| 345.00 Accessory Electric Equipment | 3,292,231 | 41,000 | 3,251,231 | -5.8% | 5.0% | (2,378) | 162,562 | 160,184 | 4.9% |
| 346.00 Miscellaneous Power Plant Equipment | 682,399 | | 682,399 | | 5.0% | | 34,120 | 34,120 | 5.0% |
| **Total Yucca** | $95,232,421 | $679,648 | $94,552,773 | 52.3% | 5.0% | $355,337 | $4,727,639 | $5,082,976 | 5.3% |
| **Yucca CT Units 1-4** | | | | | | | | | |
| 341.00 Structures and Improvements | $1,289,209 | $95,332 | $1,193,877 | -2.8% | 5.0% | ($2,669) | $59,694 | $57,025 | 4.4% |
| 342.00 Fuel Holders, Products and Accessories | 3,359,589 | 42,920 | 3,316,669 | -2.1% | 5.0% | (901) | 165,833 | 164,932 | 4.9% |
| 343.00 Prime Movers | 7,962,254 | | 7,962,254 | -7.3% | 5.0% | | 398,113 | 398,113 | 5.0% |
| 344.00 Generators and Devices | 8,384,294 | 500,396 | 7,883,898 | 72.2% | 5.0% | 361,286 | 394,195 | 755,481 | 9.0% |
| 345.00 Accessory Electric Equipment | 2,879,650 | 41,000 | 2,838,650 | -5.8% | 5.0% | (2,378) | 141,933 | 139,555 | 4.8% |
| 346.00 Miscellaneous Power Plant Equipment | 682,399 | | 682,399 | -0.5% | 5.0% | | 34,120 | 34,120 | 5.0% |
| **Total Yucca CT Units 1-4** | $24,557,395 | $679,648 | $23,877,747 | 52.3% | 5.0% | $355,337 | $1,193,887 | $1,549,225 | 6.3% |
| **Yucca CT Units 5-6** | | | | | | | | | |
| 341.00 Structures and Improvements | $537,007 | | $537,007 | -2.8% | 5.0% | | $26,850 | $26,850 | 5.0% |
| 342.00 Fuel Holders, Products and Accessories | 1,502,541 | | 1,502,541 | -2.1% | 5.0% | | 75,127 | 75,127 | 5.0% |
| 343.00 Prime Movers | 68,169,196 | | 68,169,196 | -7.3% | 5.0% | | 3,408,460 | 3,408,460 | 5.0% |
| 344.00 Generators and Devices | 53,701 | | 53,701 | 72.2% | 5.0% | | 2,685 | 2,685 | 5.0% |
| 345.00 Accessory Electric Equipment | 412,581 | | 412,581 | -5.8% | 5.0% | | 20,629 | 20,629 | 5.0% |
| 346.00 Miscellaneous Power Plant Equipment | | | | | | | | | |
| **Total Yucca CT Units 5-6** | $70,675,026 | | $70,675,026 | | 5.0% | | $3,533,751 | $3,533,751 | 5.0% |

**ARIZONA PUBLIC SERVICE COMPANY**

Future Net Salvage
Steam Production

Statement F

| Account Description | 12/31/10 Plant Investment | Future Retirements | | Net Salvage Rate | | Future Net Salvage | | | Future Rate |
|---|---|---|---|---|---|---|---|---|---|
| | | Interim | Final | Interim | Final | Interim | Final | Total | |
| A | B | C | D=B-C | E | F | G=C*E | H=D*F | I=G+H | J=I/B |
| **STEAM PRODUCTION (by Unit)** | | | | | | | | | |
| **Cholla** | | | | | | | | | |
| 311.00 Structures and Improvements | $72,335,187 | $4,444,392 | $67,890,795 | -5.0% | -5.2% | ($222,220) | ($3,554,136) | ($3,776,355) | -5.2% |
| 312.00 Boiler Plant Equipment | 521,789,973 | 30,408,224 | 491,381,749 | -20.0% | -5.1% | (6,081,645) | (25,129,976) | (31,211,621) | -6.0% |
| 314.00 Turbogenerator Units | 125,558,183 | 7,127,529 | 118,430,654 | -15.0% | -5.1% | (1,069,129) | (6,039,116) | (7,108,245) | -5.7% |
| 315.00 Accessory Electric Equipment | 93,701,286 | 5,619,797 | 88,081,489 | -10.0% | -5.2% | (561,980) | (4,570,435) | (5,132,415) | -5.5% |
| 316.00 Miscellaneous Power Plant Equipment | 27,985,746 | 1,648,875 | 26,336,871 | -15.0% | -5.2% | (247,331) | (1,378,726) | (1,626,057) | -5.8% |
| **Total Cholla** | $841,370,375 | $49,248,817 | $792,121,558 | -16.6% | -5.1% | ($8,182,305) | ($40,672,389) | ($48,854,693) | -5.8% |
| **Cholla Unit 1** | | | | | | | | | |
| 311.00 Structures and Improvements | $4,372,274 | $196,148 | $4,176,126 | -5.0% | -5.0% | ($9,807) | ($208,806) | ($218,614) | -5.0% |
| 312.00 Boiler Plant Equipment | 73,213,804 | 3,210,974 | 70,002,830 | -20.0% | -5.0% | (642,195) | (3,500,142) | (4,142,336) | -5.7% |
| 314.00 Turbogenerator Units | 25,640,590 | 1,119,176 | 24,521,414 | -15.0% | -5.0% | (167,876) | (1,226,071) | (1,393,947) | -5.4% |
| 315.00 Accessory Electric Equipment | 8,816,493 | 394,231 | 8,422,262 | -10.0% | -5.0% | (39,423) | (421,113) | (460,536) | -5.2% |
| 316.00 Miscellaneous Power Plant Equipment | 2,838,727 | 125,992 | 2,712,735 | -15.0% | -5.0% | (18,899) | (135,637) | (154,536) | -5.4% |
| **Total Cholla Unit 1** | $114,881,888 | $5,046,520 | $109,835,368 | -17.4% | -5.0% | ($878,200) | ($5,491,768) | ($6,369,969) | -5.5% |
| **Cholla Unit 2** | | | | | | | | | |
| 311.00 Structures and Improvements | $6,168,012 | $357,565 | $5,810,447 | -5.0% | -5.4% | ($17,878) | ($313,764) | ($331,642) | -5.4% |
| 312.00 Boiler Plant Equipment | 162,323,693 | 9,547,962 | 152,775,731 | -20.0% | -5.4% | (1,909,592) | (8,249,889) | (10,159,482) | -6.3% |
| 314.00 Turbogenerator Units | 44,157,763 | 2,541,827 | 41,615,936 | -15.0% | -5.4% | (381,274) | (2,247,261) | (2,628,535) | -6.0% |
| 315.00 Accessory Electric Equipment | 46,110,434 | 2,735,742 | 43,374,692 | -10.0% | -5.4% | (273,574) | (2,342,233) | (2,615,808) | -5.7% |
| 316.00 Miscellaneous Power Plant Equipment | 8,714,396 | 498,472 | 8,215,924 | -15.0% | -5.4% | (74,771) | (443,660) | (518,431) | -5.9% |
| **Total Cholla Unit 2** | $267,474,298 | $15,681,567 | $251,792,731 | -16.9% | -5.4% | ($2,657,090) | ($13,596,807) | ($16,253,897) | -6.1% |
| **Cholla Unit 3** | | | | | | | | | |
| 311.00 Structures and Improvements | $9,984,226 | $644,618 | $9,339,608 | -5.0% | -4.9% | ($32,231) | ($457,641) | ($489,872) | -4.9% |
| 312.00 Boiler Plant Equipment | 228,064,943 | 14,059,017 | 214,005,926 | -20.0% | -4.9% | (2,811,803) | (10,486,290) | (13,298,094) | -5.8% |
| 314.00 Turbogenerator Units | 54,849,058 | 3,408,856 | 51,440,202 | -15.0% | -4.9% | (511,328) | (2,520,570) | (3,031,898) | -5.5% |
| 315.00 Accessory Electric Equipment | 31,001,286 | 2,003,329 | 28,997,957 | -10.0% | -4.9% | (200,333) | (1,420,900) | (1,621,233) | -5.2% |
| 316.00 Miscellaneous Power Plant Equipment | 4,593,291 | 291,848 | 4,301,443 | -15.0% | -4.9% | (43,777) | (210,771) | (254,548) | -5.5% |
| **Total Cholla Unit 3** | $328,492,804 | $20,407,669 | $308,085,135 | -17.6% | -4.9% | ($3,599,473) | ($15,096,172) | ($18,695,645) | -5.7% |
| **Cholla Common** | | | | | | | | | |
| 311.00 Structures and Improvements | $51,810,675 | $3,246,060 | $48,564,615 | -5.0% | -5.3% | ($162,303) | ($2,573,925) | ($2,736,228) | -5.3% |
| 312.00 Boiler Plant Equipment | 58,187,533 | 3,590,271 | 54,597,262 | -20.0% | -5.3% | (718,054) | (2,893,655) | (3,611,709) | -6.2% |
| 314.00 Turbogenerator Units | 910,772 | 57,671 | 853,101 | -15.0% | -5.3% | (8,651) | (45,214) | (53,865) | -5.9% |
| 315.00 Accessory Electric Equipment | 7,773,073 | 486,495 | 7,286,578 | -10.0% | -5.3% | (48,650) | (386,189) | (434,838) | -5.6% |
| 316.00 Miscellaneous Power Plant Equipment | 11,839,332 | 732,563 | 11,106,769 | -15.0% | -5.3% | (109,884) | (588,659) | (698,543) | -5.9% |
| **Total Cholla Common** | $130,521,385 | $8,113,060 | $122,408,325 | -12.9% | -5.3% | ($1,047,542) | ($6,487,641) | ($7,535,183) | -5.8% |

**ARIZONA PUBLIC SERVICE COMPANY**

Future Net Salvage
Steam Production

Statement F

| Account Description | 12/31/10 Plant Investment | Future Retirements | | Net Salvage Rate | | Future Net Salvage | | | Future Rate |
|---|---|---|---|---|---|---|---|---|---|
| | | Interim | Final | Interim | Final | Interim | Final | Total | |
| A | B | C | D=B-C | E | F | G=C*E | H=D*F | I=G+H | J=I/B |
| **Four Corners** | | | | | | | | | |
| 311.00 Structures and Improvements | $57,549,016 | $1,316,207 | $56,232,809 | -4.6% | -15.8% | ($60,558) | ($8,899,884) | ($8,960,442) | -15.6% |
| 312.00 Boiler Plant Equipment | 375,402,116 | 10,195,716 | 365,206,400 | -18.8% | -22.1% | (1,912,071) | (80,856,576) | (82,768,647) | -22.0% |
| 314.00 Turbogenerator Units | 73,354,578 | 1,783,918 | 71,570,660 | -13.9% | -20.1% | (247,578) | (14,353,990) | (14,601,567) | -19.9% |
| 315.00 Accessory Electric Equipment | 40,063,953 | 1,194,264 | 38,869,689 | -9.5% | -21.4% | (113,085) | (8,324,078) | (8,437,163) | -21.1% |
| 316.00 Miscellaneous Power Plant Equipment | 25,722,887 | 1,025,498 | 24,697,389 | -14.6% | -19.0% | (149,372) | (4,686,051) | (4,835,424) | -18.8% |
| **Total Four Corners** | $572,092,550 | $15,515,602 | $556,576,948 | -16.0% | -21.0% | ($2,482,663) | ($117,120,580) | ($119,603,242) | -20.9% |
| **Four Corners Units 1-3** | | | | | | | | | |
| 311.00 Structures and Improvements | $40,683,091 | $105,056 | $40,578,035 | | | | | | |
| 312.00 Boiler Plant Equipment | 242,101,914 | 635,363 | 241,466,551 | | | | | | |
| 314.00 Turbogenerator Units | 50,183,693 | 133,400 | 50,050,293 | | | | | | |
| 315.00 Accessory Electric Equipment | 24,333,485 | 63,417 | 24,270,068 | | | | | | |
| 316.00 Miscellaneous Power Plant Equipment | 11,655,314 | 29,684 | 11,625,630 | | | | | | |
| **Total Four Corners Units 1-3** | $368,957,497 | $966,920 | $367,990,577 | | | | | | |
| **Four Corners Units 4-5** | | | | | | | | | |
| 311.00 Structures and Improvements | $11,882,266 | $850,181 | $11,032,085 | -5.0% | -70.7% | ($42,509) | ($7,799,684) | ($7,842,193) | -66.0% |
| 312.00 Boiler Plant Equipment | 118,062,055 | 8,453,329 | 109,608,726 | -20.0% | -70.7% | (1,690,666) | (77,493,369) | (79,184,035) | -67.1% |
| 314.00 Turbogenerator Units | 21,183,385 | 1,498,647 | 19,684,738 | -15.0% | -70.7% | (224,797) | (13,917,110) | (14,141,907) | -66.8% |
| 315.00 Accessory Electric Equipment | 11,137,088 | 797,284 | 10,339,804 | -10.0% | -70.7% | (79,728) | (7,310,241) | (7,389,970) | -66.4% |
| 316.00 Miscellaneous Power Plant Equipment | 3,614,952 | 256,801 | 3,358,151 | -15.0% | -70.7% | (38,520) | (2,374,213) | (2,412,733) | -66.7% |
| **Total Four Corners Units 4-5** | $165,879,746 | $11,856,242 | $154,023,504 | -17.5% | -70.7% | ($2,076,220) | ($108,894,617) | ($110,970,838) | -66.9% |
| **Four Corners Common** | | | | | | | | | |
| 311.00 Structures and Improvements | $4,983,659 | $360,969 | $4,622,690 | -5.0% | -23.8% | ($18,048) | ($1,100,200) | ($1,118,249) | -22.4% |
| 312.00 Boiler Plant Equipment | 15,238,147 | 1,107,023 | 14,131,124 | -20.0% | -23.8% | (221,405) | (3,363,207) | (3,584,612) | -23.5% |
| 314.00 Turbogenerator Units | 1,987,500 | 151,870 | 1,835,630 | -15.0% | -23.8% | (22,781) | (436,880) | (459,660) | -23.1% |
| 315.00 Accessory Electric Equipment | 4,593,380 | 333,563 | 4,259,817 | -10.0% | -23.8% | (33,356) | (1,013,836) | (1,047,193) | -22.8% |
| 316.00 Miscellaneous Power Plant Equipment | 10,452,621 | 739,014 | 9,713,607 | -15.0% | -23.8% | (110,852) | (2,311,839) | (2,422,691) | -23.2% |
| **Total Four Corners Common** | $37,255,307 | $2,692,440 | $34,562,867 | -15.1% | -23.8% | ($406,442) | ($8,225,962) | ($8,632,404) | -23.2% |
| **Navajo Units 1-3** | | | | | | | | | |
| 311.00 Structures and Improvements | $29,113,530 | $1,152,915 | $27,960,615 | -5.0% | -7.2% | ($57,646) | ($2,013,164) | ($2,070,810) | -7.1% |
| 312.00 Boiler Plant Equipment | 166,003,214 | 6,563,943 | 159,439,271 | -20.0% | -7.2% | (1,312,789) | (11,479,628) | (12,792,416) | -7.7% |
| 314.00 Turbogenerator Units | 24,699,305 | 999,965 | 23,699,340 | -15.0% | -7.2% | (149,995) | (1,706,352) | (1,856,347) | -7.5% |
| 315.00 Accessory Electric Equipment | 21,491,344 | 865,701 | 20,625,643 | -10.0% | -7.2% | (86,570) | (1,485,046) | (1,571,616) | -7.3% |
| 316.00 Miscellaneous Power Plant Equipment | 17,228,597 | 674,320 | 16,554,277 | -15.0% | -7.2% | (101,148) | (1,191,908) | (1,293,056) | -7.5% |
| **Total Navajo Units 1-3** | $258,535,990 | $10,256,844 | $248,279,146 | -16.7% | -7.2% | ($1,708,147) | ($17,876,099) | ($19,584,246) | -7.6% |

**ARIZONA PUBLIC SERVICE COMPANY**

Statement F

Future Net Salvage
Steam Production

| Account Description | 12/31/10 Plant Investment | Future Retirements | | Net Salvage Rate | | Future Net Salvage | | | Future Rate |
|---|---|---|---|---|---|---|---|---|---|
| | | Interim | Final | Interim | Final | Interim | Final | Total | |
| A | B | C | D=B-C | E | F | G=C*E | H=D*F | I=G+H | J=I/B |
| **Ocotillo Units 1-2** | | | | | | | | | |
| 311.00 Structures and Improvements | $4,759,658 | $112,764 | $4,646,894 | -5.0% | -19.2% | ($5,638) | ($892,204) | ($897,842) | -18.9% |
| 312.00 Boiler Plant Equipment | 25,218,648 | 619,855 | 24,598,793 | -20.0% | -19.2% | (123,971) | (4,722,968) | (4,846,939) | -19.2% |
| 314.00 Turbogenerator Units | 20,161,583 | 490,682 | 19,670,901 | -15.0% | -19.2% | (73,602) | (3,776,813) | (3,850,415) | -19.1% |
| 315.00 Accessory Electric Equipment | 3,425,956 | 83,505 | 3,342,451 | -10.0% | -19.2% | (8,351) | (641,751) | (650,101) | -19.0% |
| 316.00 Miscellaneous Power Plant Equipment | 6,010,574 | 139,130 | 5,871,444 | -15.0% | -19.2% | (20,869) | (1,127,317) | (1,148,187) | -19.1% |
| **Total Ocotillo Units 1-2** | $59,576,419 | $1,445,935 | $58,130,484 | -16.1% | -19.2% | ($232,431) | ($11,161,053) | ($11,393,484) | -19.1% |
| **Saguaro Units 1-2** | | | | | | | | | |
| 311.00 Structures and Improvements | $4,311,317 | $102,569 | $4,208,748 | -5.0% | -19.0% | ($5,128) | ($799,662) | ($804,791) | -18.7% |
| 312.00 Boiler Plant Equipment | 26,094,372 | 632,826 | 25,461,546 | -20.0% | -19.0% | (126,565) | (4,837,694) | (4,964,259) | -19.0% |
| 314.00 Turbogenerator Units | 16,513,563 | 406,572 | 16,106,991 | -15.0% | -19.0% | (60,986) | (3,060,328) | (3,121,314) | -18.9% |
| 315.00 Accessory Electric Equipment | 5,667,906 | 134,335 | 5,533,571 | -10.0% | -19.0% | (13,434) | (1,051,378) | (1,064,812) | -18.8% |
| 316.00 Miscellaneous Power Plant Equipment | 4,778,936 | 111,735 | 4,667,201 | -15.0% | -19.0% | (16,760) | (886,768) | (903,528) | -18.9% |
| **Total Saguaro Units 1-2** | $57,366,094 | $1,388,037 | $55,978,057 | -16.1% | -19.0% | ($222,873) | ($10,635,831) | ($10,858,704) | -18.9% |
| **NUCLEAR PRODUCTION (by Unit)** | | | | | | | | | |
| **Palo Verde** | | | | | | | | | |
| 321.00 Structures and Improvements | $698,846,801 | $64,639,936 | $634,206,865 | -5.0% | | ($3,231,997) | | ($3,231,997) | -0.5% |
| 322.00 Reactor Plant Equipment | 1,130,933,859 | 102,004,842 | 1,028,929,017 | -15.0% | | (15,300,726) | | (15,300,726) | -1.4% |
| 323.00 Turbogenerator Units | 354,174,138 | 32,132,580 | 322,041,558 | -5.0% | | (1,606,629) | | (1,606,629) | -0.5% |
| 324.00 Accessory Electric Equipment | 275,016,677 | 25,062,524 | 249,954,153 | -5.0% | | (1,253,126) | | (1,253,126) | -0.5% |
| 325.00 Miscellaneous Power Plant Equipment | 145,211,312 | 13,348,201 | 131,863,111 | -5.0% | | (667,410) | | (667,410) | -0.5% |
| **Total Palo Verde** | $2,604,182,787 | $237,188,084 | $2,366,994,703 | -9.3% | | ($22,059,888) | | ($22,059,888) | -0.8% |
| **Palo Verde Unit 1** | | | | | | | | | |
| 321.00 Structures and Improvements | $156,705,345 | $13,747,569 | $142,957,776 | -5.0% | | ($687,378) | | ($687,378) | -0.4% |
| 322.00 Reactor Plant Equipment | 454,207,200 | 39,422,061 | 414,785,139 | -15.0% | | (5,913,309) | | (5,913,309) | -1.3% |
| 323.00 Turbogenerator Units | 125,268,196 | 10,895,310 | 114,372,886 | -5.0% | | (544,766) | | (544,766) | -0.4% |
| 324.00 Accessory Electric Equipment | 114,860,792 | 10,080,165 | 104,780,627 | -5.0% | | (504,008) | | (504,008) | -0.4% |
| 325.00 Miscellaneous Power Plant Equipment | 30,801,758 | 2,693,325 | 28,108,433 | -5.0% | | (134,666) | | (134,666) | -0.4% |
| **Total Palo Verde Unit 1** | $881,843,291 | $76,838,430 | $805,004,861 | -10.1% | | ($7,784,128) | | ($7,784,128) | -0.9% |
| **Palo Verde Unit 2** | | | | | | | | | |
| 321.00 Structures and Improvements | $91,657,911 | $8,278,376 | $83,379,535 | -5.0% | | ($413,919) | | ($413,919) | -0.5% |
| 322.00 Reactor Plant Equipment | 234,287,478 | 20,925,924 | 213,361,554 | -15.0% | | (3,138,889) | | (3,138,889) | -1.3% |
| 323.00 Turbogenerator Units | 78,612,699 | 7,054,872 | 71,557,827 | -5.0% | | (352,744) | | (352,744) | -0.4% |
| 324.00 Accessory Electric Equipment | 49,937,247 | 4,500,499 | 45,436,748 | -5.0% | | (225,025) | | (225,025) | -0.5% |
| 325.00 Miscellaneous Power Plant Equipment | 27,087,580 | 2,422,656 | 24,664,924 | -5.0% | | (121,133) | | (121,133) | -0.4% |
| **Total Palo Verde Unit 2** | $481,582,915 | $43,182,328 | $438,400,587 | -9.8% | | ($4,251,709) | | ($4,251,709) | -0.9% |

**ARIZONA PUBLIC SERVICE COMPANY**

Future Net Salvage
Steam Production

Statement F

| Account Description | 12/31/10 Plant Investment | Future Retirements | | Net Salvage Rate | | Future Net Salvage | | | Future Rate |
|---|---|---|---|---|---|---|---|---|---|
| | | Interim | Final | Interim | Final | Interim | Final | Total | |
| A | B | C | D=B-C | E | F | G=C*E | H=D*F | I=G+H | J=I/B |
| **Palo Verde Unit 3** | | | | | | | | | |
| 321.00 Structures and Improvements | $163,192,491 | $15,537,725 | $147,654,766 | -5.0% | | ($776,886) | | ($776,886) | -0.5% |
| 322.00 Reactor Plant Equipment | 414,451,923 | 39,000,560 | 375,451,363 | -15.0% | | (5,850,084) | | (5,850,084) | -1.4% |
| 323.00 Turbogenerator Units | 147,910,539 | 13,963,005 | 133,947,534 | -5.0% | | (698,150) | | (698,150) | -0.5% |
| 324.00 Accessory Electric Equipment | 90,837,828 | 8,641,800 | 82,196,028 | -5.0% | | (432,090) | | (432,090) | -0.5% |
| 325.00 Miscellaneous Power Plant Equipment | 28,712,249 | 2,723,889 | 25,988,360 | -5.0% | | (136,194) | | (136,194) | -0.5% |
| **Total Palo Verde Unit 3** | $845,105,030 | $79,866,979 | $765,238,051 | -9.9% | | ($7,893,405) | | ($7,893,405) | -0.9% |
| **Palo Verde Water Reclamation** | | | | | | | | | |
| 321.00 Structures and Improvements | $171,609,224 | $16,126,075 | $155,483,149 | -5.0% | | ($806,304) | | ($806,304) | -0.5% |
| 322.00 Reactor Plant Equipment | 133,326 | 12,289 | 121,037 | -15.0% | | (1,843) | | (1,843) | -1.4% |
| 323.00 Turbogenerator Units | 217,756 | 20,661 | 197,095 | -5.0% | | (1,033) | | (1,033) | -0.5% |
| 324.00 Accessory Electric Equipment | | | | | | | | | |
| 325.00 Miscellaneous Power Plant Equipment | 88,819 | 8,405 | 80,414 | -5.0% | | (420) | | (420) | -0.5% |
| **Total Palo Verde Water Reclamation** | $172,049,125 | $16,167,430 | $155,881,695 | -5.0% | | ($809,600) | | ($809,600) | -0.5% |
| **Palo Verde Common** | | | | | | | | | |
| 321.00 Structures and Improvements | $115,681,830 | $10,950,191 | $104,731,639 | -5.0% | | ($547,510) | | ($547,510) | -0.5% |
| 322.00 Reactor Plant Equipment | 27,853,932 | 2,644,008 | 25,209,924 | -15.0% | | (396,601) | | (396,601) | -1.4% |
| 323.00 Turbogenerator Units | 2,164,948 | 198,732 | 1,966,216 | -5.0% | | (9,937) | | (9,937) | -0.5% |
| 324.00 Accessory Electric Equipment | 19,380,810 | 1,840,061 | 17,540,749 | -5.0% | | (92,003) | | (92,003) | -0.5% |
| 325.00 Miscellaneous Power Plant Equipment | 58,520,906 | 5,499,926 | 53,020,980 | -5.0% | | (274,996) | | (274,996) | -0.5% |
| **Total Palo Verde Common** | $223,602,426 | $21,132,917 | $202,469,509 | -6.3% | | ($1,321,047) | | ($1,321,047) | -0.6% |

**ARIZONA PUBLIC SERVICE COMPANY** Statement G

Dismantlement Costs

Steam Production

| Unit | Capacity (MW) | Cost per kW | 2009 Cost | Plant | Distributed Cost | Inflation Rate | Year Spent | Trended Cost | Accrual Rate |
|---|---|---|---|---|---|---|---|---|---|
| A | B | C | D=B*C*1000 | E | F | G | H | I | J=I/E |
| **Cholla** | | | | | | | | | |
| 1 | 110 | 40.00 | $4,400,000 | $109,835,368 | $3,720,058 | 2.00% | 2028 | $5,527,811 | 5.0% |
| 2 | 245 | 40.00 | 9,800,000 | 251,792,731 | 8,285,584 | 2.00% | 2033 | 13,593,379 | 5.4% |
| 3 | 260 | 40.00 | 10,400,000 | 308,085,135 | 8,792,865 | 2.00% | 2035 | 15,008,422 | 4.9% |
| C | | | | 122,408,325 | 3,801,493 | 2.00% | 2035 | 6,488,717 | 5.3% |
| | 615 | | $24,600,000 | $792,121,558 | $24,600,000 | | | $40,618,329 | 5.1% |
| | Allocated to Common: | | 3,801,493 | | | | | | |
| | Allocated to Units: | | $20,798,507 | | | | | | |
| **Four Corners** | | | | | | | | | |
| 1-3 | 550 | | $50,993,709 | | | 2.00% | 2012 | | |
| 4-5 | 224 | | 9,151,548 | 522,014,081 | 60,145,257 | 2.00% | 2038 | 108,944,808 | 20.9% |
| C | | | 4,534,879 | 34,562,867 | 4,534,879 | 2.00% | 2038 | 8,214,306 | 23.8% |
| | 774 | | $64,680,136 | $556,576,948 | $64,680,136 | | | $117,159,114 | 21.0% |
| | Allocated to Common: | | | | | | | | |
| | Allocated to Units: | | $64,680,136 | | | | | | |
| **Navajo** | | | | | | | | | |
| 1-3 | 315 | 40.00 | $12,600,000 | $248,279,146 | $12,600,000 | 2.00% | 2026 | $17,995,903 | 7.2% |
| C | | | | | | | | | |
| | 315 | | $12,600,000 | $248,279,146 | $12,600,000 | | | $17,995,903 | 7.2% |
| | Allocated to Common: | | | | | | | | |
| | Allocated to Units: | | $12,600,000 | | | | | | |
| **Ocotillo** | | | | | | | | | |
| 1-2 | 220 | 40.00 | $8,800,000 | $58,130,484 | $8,800,000 | 2.00% | 2020 | $11,160,528 | 19.2% |
| C | | | | | | | | | |
| | 220 | | $8,800,000 | $58,130,484 | $8,800,000 | | | $11,160,528 | 19.2% |
| | Allocated to Common: | | | | | | | | |
| | Allocated to Units: | | $8,800,000 | | | | | | |
| **Saguaro** | | | | | | | | | |
| 1-2 | 210 | 40.00 | $8,400,000 | $55,978,057 | $8,400,000 | 2.00% | 2020 | $10,653,231 | 19.0% |
| C | | | | | | | | | |
| | 210 | | $8,400,000 | $55,978,057 | $8,400,000 | | | $10,653,231 | 19.0% |
| | Allocated to Common: | | | | | | | | |
| | Allocated to Units: | | $8,400,000 | | | | | | |

**ARIZONA PUBLIC SERVICE COMPANY**
Current and Proposed Parameters
Vintage Group Procedure

Statement H

| Account Description | Current Parameters P-Life/ AYFR | Curve Shape | VG ASL | Rem. Life | Avg. Sal. | Fut. Sal. | Proposed Parameters (at December 31, 2010) P-Life/ AYFR | Curve Shape | VG ASL | Rem. Life | Avg. Sal. | Fut. Sal. |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A | B | C | D | E | F | G | H | I | J | K | L | M |
| **STEAM PRODUCTION** | | | | | | | | | | | | |
| 311.00 Structures and Improvements | | | | | | | | | 17.74 | 7.81 | -9.3 | -9.8 |
| 312.00 Boiler Plant Equipment | | | | | | | | | 23.74 | 11.42 | -12.9 | -12.3 |
| 314.00 Turbogenerator Units | | | | | | | | | 24.09 | 11.56 | -10.7 | -11.7 |
| 315.00 Accessory Electric Equipment | | | | | | | | | 23.95 | 10.10 | -10.3 | -10.3 |
| 316.00 Miscellaneous Power Plant Equipment | | | | | | | | | 20.72 | 10.74 | -12.2 | -12.0 |
| **Total Steam Production Plant** | | | | | | | | | 22.92 | 10.85 | -11.9 | -11.8 |
| **NUCLEAR PRODUCTION** | | | | | | | | | | | | |
| 321.00 Structures and Improvements | | | | | | | | | 51.83 | 33.93 | -0.6 | |
| 322.00 Reactor Plant Equipment | | | | | | | | | 48.64 | 33.28 | -2.4 | |
| 323.00 Turbogenerator Units | | | | | | | | | 49.58 | 33.38 | -0.7 | |
| 324.00 Accessory Electric Equipment | | | | | | | | | 53.64 | 33.27 | -0.5 | |
| 325.00 Miscellaneous Power Plant Equipment | | | | | | | | | 48.94 | 33.87 | -1.4 | |
| **Total Nuclear Production Plant** | | | | | | | | | 50.11 | 33.50 | -1.4 | -0.8 |
| **OTHER PRODUCTION** | | | | | | | | | | | | |
| 341.00 Structures and Improvements | | | | | | | | | 29.91 | 22.98 | 4.5 | |
| 342.00 Fuel Holders, Products and Accessories | | | | | | | | | 29.22 | 19.50 | 4.7 | |
| 343.00 Prime Movers | | | | | | | | | 32.38 | 25.74 | 3.9 | |
| 344.00 Generators and Devices | | | | | | | | | 28.82 | 22.37 | 18.6 | |
| 345.00 Accessory Electric Equipment | | | | | | | | | 30.76 | 23.00 | 4.2 | |
| 346.00 Miscellaneous Power Plant Equipment | | | | | | | | | 26.52 | 19.42 | 4.7 | |
| **Total Other Production Plant** | | | | | | | | | 30.49 | 23.76 | 10.4 | 5.0 |
| **TRANSMISSION PLANT** | | | | | | | | | | | | |
| 352.02 Structures and Improvements | 50.00 | R4 | 50.38 | 19.18 | | | 50.00 | R4 | 50.62 | 16.79 | | |
| 353.00 Station Equipment | 45.00 | S0.5 | 45.98 | 33.50 | | | 45.00 | S0.5 | 45.96 | 34.11 | -4.7 | -5.0 |
| 354.00 Towers and Fixtures | 60.00 | R3 | 60.18 | 39.78 | | | 60.00 | R3 | 60.26 | 37.13 | | |
| 355.00 Poles and Fixtures | 50.00 | R1.5 | 50.08 | 45.43 | -20.00 | -20.0 | 55.00 | R1.5 | 55.15 | 48.05 | -20.0 | -20.0 |
| 356.00 Overhead Conductors and Devices | 60.00 | R3 | 59.90 | 50.16 | 18.7 | 20.0 | 60.00 | R3 | 59.74 | 47.35 | -18.7 | -20.0 |
| **Total Transmission Plant** | | | | | | | | | 46.41 | 34.48 | -5.1 | -5.4 |

**ARIZONA PUBLIC SERVICE COMPANY**
Current and Proposed Parameters
Vintage Group Procedure

Statement H

| Account Description | Current Parameters P-Life/ AYFR | Curve Shape | VG ASL | Rem. Life | Avg. Sal. | Fut. Sal. | Proposed Parameters (at December 31, 2010) P-Life/ AYFR | Curve Shape | VG ASL | Rem. Life | Avg. Sal. | Fut. Sal. |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A | B | C | D | E | F | G | H | I | J | K | L | M |
| **DISTRIBUTION PLANT** | | | | | | | | | | | | |
| 361.00 Structures and Improvements | 60.00 | R3 | 59.87 | 47.22 | -4.6 | -5.0 | 60.00 | R3 | 59.91 | 49.60 | -4.7 | -5.0 |
| 362.00 Station Equipment | 43.00 | L0.5 | 43.08 | 36.31 | 10.0 | 10.0 | 43.00 | L0.5 | 43.06 | 36.12 | 9.5 | 10.0 |
| 364.01 Poles, Towers and Fixtures - Wood | 40.00 | L0 | 39.92 | 31.55 | -0.5 | -5.0 | 40.00 | L0 | 39.92 | 30.83 | -1.0 | -5.0 |
| 364.02 Poles, Towers and Fixtures - Steel | 35.00 | L0.5 | 35.08 | 31.88 | -5.7 | -5.0 | 38.00 | SC | 38.18 | 35.13 | -10.0 | -10.0 |
| 365.00 Overhead Conductors and Devices | 50.00 | SC | 49.97 | 43.42 | 10.2 | 10.0 | 48.00 | L0 | 47.78 | 40.17 | 4.3 | 5.0 |
| 366.00 Underground Conduit | 65.00 | L1 | 64.94 | 56.80 | -5.0 | -5.0 | 60.00 | L1 | 59.96 | 50.32 | -4.9 | -5.0 |
| 367.00 Underground Conductors and Devices | 33.00 | L1 | 32.94 | 26.28 | -4.2 | -5.0 | 35.00 | L1 | 34.90 | 27.33 | -3.8 | -5.0 |
| 368.00 Line Transformers | 55.00 | L1 | 55.14 | 44.80 | -4.3 | -5.0 | 55.00 | L1 | 55.12 | 44.08 | -4.3 | -5.0 |
| 369.00 Services | 40.00 | L1 | 40.47 | 31.15 | | | 40.00 | L1 | 40.65 | 29.77 | -4.9 | -5.0 |
| 370.01 Meters - Electronic | 26.00 | R1.5 | | | | | 15.00 | R0.5 | 14.87 | 11.94 | 0.3 | |
| 370.03 Meters - AMI | 26.00 | R1.5 | 26.00 | 25.47 | | | 15.00 | R0.5 | 15.04 | 14.15 | | |
| 371.00 Installations on Customers' Premises | 55.00 | SC | 54.77 | 49.26 | -10.6 | -10.0 | 40.00 | L0 | 40.15 | 33.33 | -14.5 | -15.0 |
| 373.00 Street Lighting and Signal Systems | 65.00 | L0 | 64.65 | 57.06 | -9.1 | -10.0 | 55.00 | L0.5 | 54.60 | 44.94 | -8.4 | -10.0 |
| **Total Distribution Plant** | | | | | | | | | 40.07 | 32.39 | -2.4 | -3.2 |
| **GENERAL PLANT** | | | | | | | | | | | | |
| **Depreciable** | | | | | | | | | | | | |
| 390.00 Structures and Improvements | 45.00 | L1 | 45.03 | 34.14 | -5.3 | -5.0 | 45.00 | L1 | 44.91 | 34.13 | -5.6 | -5.0 |
| 391.CM Office Furn. and Equip. - Computer | 8.00 | L3 | 8.09 | 4.69 | -0.1 | | 8.00 | L3 | 8.04 | 4.96 | -0.1 | |
| 397.00 Communication Equipment | 18.00 | S1.5 | 18.04 | 11.17 | | | 18.00 | S1.5 | 18.11 | 10.76 | | |
| **Total Depreciable** | | | | | | | | | 15.95 | 10.38 | -1.2 | -1.5 |

**ARIZONA PUBLIC SERVICE COMPANY**
Current and Proposed Parameters
Vintage Group Procedure

Statement H

| Account Description | Current Parameters P-Life/ AYFR | Curve Shape | VG ASL | Rem. Life | Avg. Sal. | Fut. Sal. | Proposed Parameters (at December 31, 2010) P-Life/ AYFR | Curve Shape | VG ASL | Rem. Life | Avg. Sal. | Fut. Sal. |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A | B | C | D | E | F | G | H | I | J | K | L | M |
| **Amortizable** | | | | | | | | | | | | |
| 391.FE Office Furn. and Equip. - Furniture | 20.00 | SQ | 20.00 | 11.65 | | | 20.00 | SQ | 20.00 | 14.16 | | |
| 393.00 Stores Equipment | 20.00 | SQ | 20.00 | 2.73 | | | 20.00 | SQ | 20.00 | 17.41 | | |
| 394.00 Tools, Shop and Garage Equipment | 20.00 | SQ | 20.00 | 12.39 | | | 20.00 | SQ | 20.00 | 11.90 | | |
| 395.00 Laboratory Equipment | 20.00 | SQ | 20.00 | 7.31 | | | 20.00 | SQ | 20.00 | 7.32 | | |
| 398.00 Miscellaneous Equipment | 24.00 | SQ | 24.00 | 19.34 | | | 24.00 | SQ | 24.00 | 19.16 | | |
| **Total Amortizable** | | | | | | | | | 20.23 | 13.59 | | |
| **Total General Plant** | | | | | | | | | 16.64 | 10.90 | -1.0 | -1.2 |
| **TOTAL UTILITY** | | | | | | | | | 34.24 | 24.32 | -1.9 | -2.9 |
| **STEAM PRODUCTION (by Unit)** | | | | | | | | | | | | |
| **Cholla** | | | | | | | | | | | | |
| 311.00 Structures and Improvements | | | 46.39 | 25.69 | -11.0 | | | | 36.14 | 23.07 | -4.8 | -5.2 |
| 312.00 Boiler Plant Equipment | | | 39.52 | 23.80 | -11.5 | | | | 31.90 | 22.07 | -7.2 | -6.0 |
| 314.00 Turbogenerator Units | | | 36.92 | 25.19 | -10.2 | | | | 30.41 | 21.27 | -5.2 | -5.7 |
| 315.00 Accessory Electric Equipment | | | 45.73 | 24.80 | -11.0 | | | | 43.68 | 21.89 | -5.6 | -5.5 |
| 316.00 Miscellaneous Power Plant Equipment | | | 37.20 | 25.30 | -11.9 | | | | 33.22 | 22.38 | -6.5 | -5.8 |
| **Total Cholla** | | | | | | | | | 33.02 | 22.02 | -6.5 | -5.8 |
| **Cholla Unit 1** | | | | | | | | | | | | |
| 311.00 Structures and Improvements | 2028 | 200-SC | 32.37 | 19.96 | -9.1 | -9.4 | 2028 | 200-SC | 29.03 | 17.10 | -4.8 | -5.0 |
| 312.00 Boiler Plant Equipment | 2028 | 200-SC | 24.87 | 19.97 | -10.2 | -9.9 | 2028 | 200-SC | 24.33 | 17.11 | -6.2 | -5.7 |
| 314.00 Turbogenerator Units | 2028 | 200-SC | 40.13 | 19.94 | -9.7 | -9.9 | 2028 | 200-SC | 22.21 | 17.11 | -5.2 | -5.4 |
| 315.00 Accessory Electric Equipment | 2028 | 200-SC | 30.87 | 19.96 | -9.6 | -9.6 | 2028 | 200-SC | 28.61 | 17.11 | -5.2 | -5.2 |
| 316.00 Miscellaneous Power Plant Equipment | 2028 | 200-SC | 33.42 | 19.96 | -9.9 | -9.9 | 2028 | 200-SC | 30.40 | 17.10 | -5.4 | -5.4 |
| **Total Cholla Unit 1** | | | | | | | | | 24.36 | 17.11 | -5.8 | -5.6 |

**ARIZONA PUBLIC SERVICE COMPANY**
Current and Proposed Parameters
Vintage Group Procedure

Statement H

| Account Description | Current Parameters P-Life/ AYFR | Curve Shape | VG ASL | Rem. Life | Avg. Sal. | Fut. Sal. | Proposed Parameters (at December 31, 2010) P-Life/ AYFR | Curve Shape | VG ASL | Rem. Life | Avg. Sal. | Fut. Sal. |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A | B | C | D | E | F | G | H | I | J | K | L | M |
| **Cholla Unit 2** | | | | | | | | | | | | |
| 311.00 Structures and Improvements | 2033 | 200-SC | 40.34 | 24.65 | -9.3 | -9.4 | 2033 | 200-SC | 37.22 | 21.84 | -5.4 | -5.4 |
| 312.00 Boiler Plant Equipment | 2033 | 200-SC | 46.13 | 24.64 | -10.4 | -10.1 | 2033 | 200-SC | 42.32 | 21.83 | -6.9 | -6.3 |
| 314.00 Turbogenerator Units | 2033 | 200-SC | 38.06 | 24.66 | -9.1 | -10.0 | 2033 | 200-SC | 33.22 | 21.85 | -5.5 | -6.0 |
| 315.00 Accessory Electric Equipment | 2033 | 200-SC | 48.20 | 24.63 | -9.7 | -9.7 | 2033 | 200-SC | 46.70 | 21.82 | -5.8 | -5.7 |
| 316.00 Miscellaneous Power Plant Equipment | 2033 | 200-SC | 39.88 | 24.65 | -10.3 | -10.0 | 2033 | 200-SC | 31.65 | 21.85 | -6.2 | -5.9 |
| **Total Cholla Unit 2** | | | | | | | | | 40.57 | 21.83 | -6.4 | -6.1 |
| **Cholla Unit 3** | | | | | | | | | | | | |
| 311.00 Structures and Improvements | 2035 | 200-SC | 50.03 | 26.49 | -12.5 | -12.5 | 2035 | 200-SC | 48.83 | 23.70 | -4.8 | -4.9 |
| 312.00 Boiler Plant Equipment | 2035 | 200-SC | 47.58 | 26.50 | -13.4 | -13.2 | 2035 | 200-SC | 29.93 | 23.74 | -7.5 | -5.8 |
| 314.00 Turbogenerator Units | 2035 | 200-SC | 35.50 | 26.53 | -11.2 | -13.2 | 2035 | 200-SC | 33.81 | 23.73 | -5.0 | -5.5 |
| 315.00 Accessory Electric Equipment | 2035 | 200-SC | 49.74 | 26.49 | -12.9 | -12.9 | 2035 | 200-SC | 49.50 | 23.69 | -5.3 | -5.2 |
| 316.00 Miscellaneous Power Plant Equipment | 2035 | 200-SC | 42.25 | 26.51 | -13.4 | -13.2 | 2035 | 200-SC | 42.28 | 23.71 | -6.0 | -5.5 |
| **Total Cholla Unit 3** | | | | | | | | | 32.26 | 23.73 | -6.7 | -5.7 |
| **Cholla Common** | | | | | | | | | | | | |
| 311.00 Structures and Improvements | 2035 | 200-SC | 48.54 | 26.49 | -11.0 | -11.1 | 2035 | 200-SC | 34.99 | 23.73 | -4.7 | -5.3 |
| 312.00 Boiler Plant Equipment | 2035 | 200-SC | 40.70 | 26.51 | -13.2 | -11.8 | 2035 | 200-SC | 30.71 | 23.73 | -7.8 | -6.2 |
| 314.00 Turbogenerator Units | 2035 | 200-SC | 39.11 | 26.52 | -8.1 | -11.8 | 2035 | 200-SC | 38.99 | 23.72 | -4.6 | -5.9 |
| 315.00 Accessory Electric Equipment | 2035 | 200-SC | 38.82 | 26.52 | -11.6 | -11.5 | 2035 | 200-SC | 34.82 | 23.73 | -6.3 | -5.6 |
| 316.00 Miscellaneous Power Plant Equipment | 2035 | 200-SC | 34.87 | 26.53 | -12.4 | -11.8 | 2035 | 200-SC | 32.42 | 23.73 | -7.1 | -5.9 |
| **Total Cholla Common** | | | | | | | | | 32.73 | 23.73 | -6.4 | -5.8 |
| **Four Corners** | | | | | | | | | | | | |
| 311.00 Structures and Improvements | | | 19.89 | 10.73 | -12.9 | | | | 9.39 | 1.62 | -15.4 | -15.6 |
| 312.00 Boiler Plant Equipment | | | 22.76 | 10.92 | -13.9 | | | | 15.98 | 3.30 | -21.9 | -22.1 |
| 314.00 Turbogenerator Units | | | 21.14 | 10.46 | -12.2 | | | | 15.47 | 3.26 | -18.3 | -19.9 |
| 315.00 Accessory Electric Equipment | | | 25.35 | 12.24 | -13.7 | | | | 10.83 | 2.55 | -20.6 | -21.1 |
| 316.00 Miscellaneous Power Plant Equipment | | | 18.51 | 2.26 | -14.7 | | | | 13.30 | 4.65 | -18.7 | -18.8 |
| **Total Four Corners** | | | | | | | | | 14.30 | 3.04 | -20.6 | -20.9 |

**ARIZONA PUBLIC SERVICE COMPANY**
Current and Proposed Parameters
Vintage Group Procedure

Statement H

| Account Description | Current Parameters P-Life/ AYFR | Curve Shape | VG ASL | Rem. Life | Avg. Sal. | Fut. Sal. | Proposed Parameters (at December 31, 2010) P-Life/ AYFR | Curve Shape | VG ASL | Rem. Life | Avg. Sal. | Fut. Sal. |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A | B | C | D | E | F | G | H | I | J | K | L | M |
| **Four Corners Units 1-3** | | | | | | | | | | | | |
| 311.00 Structures and Improvements | 2016 | 200-SC | 16.00 | 8.41 | -11.1 | -11.2 | 2012 | 200-SC | 7.07 | | | |
| 312.00 Boiler Plant Equipment | 2016 | 200-SC | 18.33 | 8.41 | -12.3 | -11.4 | 2012 | 200-SC | 11.77 | | -2.2 | |
| 314.00 Turbogenerator Units | 2016 | 200-SC | 18.04 | 8.41 | -10.8 | -11.4 | 2012 | 200-SC | 12.07 | | -0.3 | |
| 315.00 Accessory Electric Equipment | 2016 | 200-SC | 19.82 | 8.41 | -11.4 | -11.3 | 2012 | 200-SC | 7.28 | | -0.5 | |
| 316.00 Miscellaneous Power Plant Equipment | 2016 | 200-SC | 11.82 | 8.41 | -11.8 | -11.4 | 2012 | 200-SC | 7.31 | | -1.0 | |
| **Total Four Corners Units 1-3** | | | | | | | | | 10.42 | | -1.6 | |
| **Four Corners Units 4-5** | | | | | | | | | | | | |
| 311.00 Structures and Improvements | 2031 | 200-SC | 39.25 | 22.78 | -16.7 | -16.7 | 2038 | 200-SC | 44.16 | 26.51 | -65.9 | -66.0 |
| 312.00 Boiler Plant Equipment | 2031 | 200-SC | 43.59 | 22.77 | -17.3 | -17.3 | 2038 | 200-SC | 44.95 | 26.50 | -65.9 | -67.1 |
| 314.00 Turbogenerator Units | 2031 | 200-SC | 38.14 | 22.78 | -16.6 | -17.3 | 2038 | 200-SC | 38.32 | 26.52 | -62.0 | -66.8 |
| 315.00 Accessory Electric Equipment | 2031 | 200-SC | 41.28 | 22.77 | -16.9 | -17.0 | 2038 | 200-SC | 44.51 | 26.51 | -64.5 | -66.4 |
| 316.00 Miscellaneous Power Plant Equipment | 2031 | 200-SC | 38.12 | 22.78 | -17.3 | -17.3 | 2038 | 200-SC | 41.35 | 26.51 | -66.2 | -66.7 |
| **Total Four Corners Units 4-5** | | | | | | | | | 43.81 | 26.50 | -65.3 | -66.9 |
| **Four Corners Common** | | | | | | | | | | | | |
| 311.00 Structures and Improvements | 2031 | 200-SC | 42.23 | 22.77 | -16.2 | -16.7 | 2038 | 200-SC | 47.11 | 26.50 | -21.7 | -22.4 |
| 312.00 Boiler Plant Equipment | 2031 | 200-SC | 44.03 | 22.77 | -17.5 | -17.3 | 2038 | 200-SC | 50.51 | 26.49 | -23.3 | -23.5 |
| 314.00 Turbogenerator Units | 2031 | 200-SC | 61.58 | 22.73 | -12.5 | -17.3 | 2038 | 200-SC | 66.67 | 26.43 | -15.9 | -23.1 |
| 315.00 Accessory Electric Equipment | 2031 | 200-SC | 38.90 | 22.78 | -16.5 | -17.0 | 2038 | 200-SC | 43.49 | 26.51 | -21.7 | -22.8 |
| 316.00 Miscellaneous Power Plant Equipment | 2031 | 200-SC | 36.42 | 22.78 | -17.4 | -17.4 | 2038 | 200-SC | 41.46 | 26.51 | -23.1 | -23.2 |
| **Total Four Corners Common** | | | | | | | | | 46.86 | 26.50 | -22.2 | -23.2 |
| **Navajo Units 1-3** | | | | | | | | | | | | |
| 311.00 Structures and Improvements | 2026 | 200-SC | 33.77 | 18.05 | -10.4 | -10.4 | 2026 | 200-SC | 32.06 | 15.19 | -7.0 | -7.1 |
| 312.00 Boiler Plant Equipment | 2026 | 200-SC | 32.09 | 18.06 | -11.2 | -10.9 | 2026 | 200-SC | 31.18 | 15.19 | -8.2 | -7.7 |
| 314.00 Turbogenerator Units | 2026 | 200-SC | 40.76 | 18.05 | -10.9 | -10.9 | 2026 | 200-SC | 40.93 | 15.18 | -7.5 | -7.5 |
| 315.00 Accessory Electric Equipment | 2026 | 200-SC | 38.85 | 18.05 | -10.7 | -10.7 | 2026 | 200-SC | 37.34 | 15.18 | -7.3 | -7.3 |
| 316.00 Miscellaneous Power Plant Equipment | 2026 | 200-SC | 28.67 | 18.06 | -11.1 | -10.9 | 2026 | 200-SC | 28.11 | 15.19 | -7.8 | -7.5 |
| **Total Navajo Units 1-3** | | | | | | | | | 32.22 | 15.19 | -7.9 | -7.6 |

**ARIZONA PUBLIC SERVICE COMPANY**
Current and Proposed Parameters
Vintage Group Procedure

Statement H

| Account Description | Current Parameters P-Life/ AYFR | Curve Shape | VG ASL | Rem. Life | Avg. Sal. | Fut. Sal. | Proposed Parameters (at December 31, 2010) P-Life/ AYFR | Curve Shape | VG ASL | Rem. Life | Avg. Sal. | Fut. Sal. |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A | B | C | D | E | F | G | H | I | J | K | L | M |
| **Ocotillo Units 1-2** | | | | | | | | | | | | |
| 311.00 Structures and Improvements | 2020 | 200-SC | 28.48 | 12.30 | -28.4 | -29.8 | 2020 | 200-SC | 22.13 | 9.38 | -17.8 | -18.9 |
| 312.00 Boiler Plant Equipment | 2020 | 200-SC | 36.48 | 12.29 | -30.0 | -30.1 | 2020 | 200-SC | 34.34 | 9.38 | -19.2 | -19.2 |
| 314.00 Turbogenerator Units | 2020 | 200-SC | 39.20 | 12.29 | -29.9 | -30.1 | 2020 | 200-SC | 23.10 | 9.38 | -18.7 | -19.1 |
| 315.00 Accessory Electric Equipment | 2020 | 200-SC | 32.94 | 12.29 | -29.1 | 29.9 | 2020 | 200-SC | 24.21 | 9.38 | -18.5 | -19.0 |
| 316.00 Miscellaneous Power Plant Equipment | 2020 | 200-SC | 19.18 | 12.30 | -28.9 | -30.1 | 2020 | 200-SC | 18.29 | 9.38 | -18.9 | -19.1 |
| **Total Ocotillo Units 1-2** | | | | | | | | | 25.99 | 9.38 | -18.9 | -19.1 |
| **Saguaro Units 1-2** | | | | | | | | | | | | |
| 311.00 Structures and Improvements | 2020 | 200-SC | 28.81 | 12.30 | -28.7 | -29.2 | 2020 | 200-SC | 19.41 | 9.38 | -18.4 | -18.7 |
| 312.00 Boiler Plant Equipment | 2020 | 200-SC | 31.48 | 12.29 | -29.1 | -29.5 | 2020 | 200-SC | 25.18 | 9.38 | -19.0 | -19.0 |
| 314.00 Turbogenerator Units | 2020 | 200-SC | 35.65 | 12.29 | -28.9 | -29.5 | 2020 | 200-SC | 35.82 | 9.38 | -18.5 | -18.9 |
| 315.00 Accessory Electric Equipment | 2020 | 200-SC | 21.05 | 12.30 | -29.0 | -29.4 | 2020 | 200-SC | 18.85 | 9.38 | -18.5 | -18.8 |
| 316.00 Miscellaneous Power Plant Equipment | 2020 | 200-SC | 22.35 | 12.30 | -29.3 | -29.5 | 2020 | 200-SC | 21.15 | 9.38 | -18.9 | -18.9 |
| **Total Saguaro Units 1-2** | | | | | | | | | 25.54 | 9.38 | -18.8 | -18.9 |
| **NUCLEAR PRODUCTION (by Unit)** | | | | | | | | | | | | |
| **Palo Verde** | | | | | | | | | | | | |
| 321.00 Structures and Improvements | | | 53.62 | 36.57 | -0.3 | | | | 51.83 | 33.93 | -0.6 | -0.5 |
| 322.00 Reactor Plant Equipment | | | 51.30 | 35.85 | -1.8 | | | | 48.64 | 33.28 | -2.4 | -1.3 |
| 323.00 Turbogenerator Units | | | 52.13 | 36.08 | -0.5 | | | | 49.58 | 33.38 | -0.7 | -0.4 |
| 324.00 Accessory Electric Equipment | | | 54.15 | 35.97 | -0.3 | | | | 53.64 | 33.27 | -0.5 | -0.5 |
| 325.00 Miscellaneous Power Plant Equipment | | | 50.53 | 36.53 | -1.2 | | | | 48.94 | 33.87 | -1.4 | -0.5 |
| **Total Palo Verde** | | | | | | | | | 50.11 | 33.50 | -1.4 | -0.8 |
| **Palo Verde Unit 1** | | | | | | | | | | | | |
| 321.00 Structures and Improvements | 2024 | 200-SC | 36.00 | 16.14 | -0.3 | -0.2 | 2044 | 200-SC | 53.54 | 32.01 | -0.4 | -0.4 |
| 322.00 Reactor Plant Equipment | 2024 | 200-SC | 30.70 | 16.15 | -1.4 | -0.6 | 2044 | 200-SC | 48.33 | 32.03 | -2.1 | -1.3 |
| 323.00 Turbogenerator Units | 2024 | 200-SC | 32.10 | 16.14 | -0.5 | -0.2 | 2044 | 200-SC | 48.84 | 32.03 | -0.7 | -0.4 |
| 324.00 Accessory Electric Equipment | 2024 | 200-SC | 36.20 | 16.14 | -0.3 | -0.2 | 2044 | 200-SC | 53.77 | 32.01 | -0.4 | -0.4 |
| 325.00 Miscellaneous Power Plant Equipment | 2024 | 200-SC | 33.60 | 16.14 | -0.8 | -0.2 | 2044 | 200-SC | 50.74 | 32.02 | -0.9 | -0.4 |
| **Total Palo Verde Unit 1** | | | | | | | | | 50.01 | 32.02 | -1.3 | -0.9 |

**ARIZONA PUBLIC SERVICE COMPANY**
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Vintage Group Procedure

Statement H

| Account Description | Current Parameters P-Life/ AYFR | Curve Shape | VG ASL | Rem. Life | Avg. Sal. | Fut. Sal. | Proposed Parameters (at December 31, 2010) P-Life/ AYFR | Curve Shape | VG ASL | Rem. Life | Avg. Sal. | Fut. Sal. |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A | B | C | D | E | F | G | H | I | J | K | L | M |
| **Palo Verde Unit 2** | | | | | | | | | | | | |
| 321.00 Structures and Improvements | 2025 | 200-SC | 36.57 | 17.10 | -0.2 | -0.2 | 2045 | 200-SC | 54.10 | 32.92 | -0.5 | -0.5 |
| 322.00 Reactor Plant Equipment | 2025 | 200-SC | 31.73 | 17.10 | -2.7 | -0.7 | 2045 | 200-SC | 48.65 | 32.94 | -3.1 | -1.3 |
| 323.00 Turbogenerator Units | 2025 | 200-SC | 33.34 | 17.10 | -0.6 | -0.2 | 2045 | 200-SC | 50.48 | 32.93 | -0.7 | -0.4 |
| 324.00 Accessory Electric Equipment | 2025 | 200-SC | 36.15 | 17.10 | -0.3 | -0.2 | 2045 | 200-SC | 53.24 | 32.92 | -0.6 | -0.5 |
| 325.00 Miscellaneous Power Plant Equipment | 2025 | 200-SC | 32.11 | 17.10 | -0.6 | -0.2 | 2045 | 200-SC | 49.81 | 32.94 | -0.7 | -0.4 |
| **Total Palo Verde Unit 2** | | | | | | | | | 50.43 | 32.93 | -1.9 | -0.9 |
| **Palo Verde Unit 3** | | | | | | | | | | | | |
| 321.00 Structures and Improvements | 2027 | 200-SC | 37.18 | 19.00 | -0.2 | -0.2 | 2047 | 200-SC | 54.39 | 34.74 | -0.5 | -0.5 |
| 322.00 Reactor Plant Equipment | 2027 | 200-SC | 36.61 | 19.00 | -1.6 | -0.7 | 2047 | 200-SC | 48.75 | 34.77 | -2.2 | -1.4 |
| 323.00 Turbogenerator Units | 2027 | 200-SC | 36.19 | 19.00 | -0.3 | -0.2 | 2047 | 200-SC | 49.91 | 34.76 | -0.8 | -0.5 |
| 324.00 Accessory Electric Equipment | 2027 | 200-SC | 37.11 | 19.00 | -0.3 | -0.2 | 2047 | 200-SC | 53.96 | 34.74 | -0.6 | -0.5 |
| 325.00 Miscellaneous Power Plant Equipment | 2027 | 200-SC | 35.13 | 19.00 | -0.6 | -0.2 | 2047 | 200-SC | 51.86 | 34.75 | -0.9 | -0.5 |
| **Total Palo Verde Unit 3** | | | | | | | | | 50.60 | 34.76 | -1.4 | -0.9 |
| **Palo Verde Water Reclamation** | | | | | | | | | | | | |
| 321.00 Structures and Improvements | 2027 | 200-SC | 34.15 | 19.00 | -0.5 | -0.2 | 2047 | 200-SC | 47.75 | 34.77 | -0.8 | -0.5 |
| 322.00 Reactor Plant Equipment | 2027 | 200-SC | 25.15 | 19.02 | -0.7 | -0.7 | 2047 | 200-SC | 43.41 | 34.79 | -1.4 | -1.4 |
| 323.00 Turbogenerator Units | 2027 | 200-SC | 34.08 | 19.00 | -0.6 | -0.2 | 2047 | 200-SC | 51.70 | 34.75 | -0.7 | -0.5 |
| 324.00 Accessory Electric Equipment | | | | | | | | | | | | |
| 325.00 Miscellaneous Power Plant Equipment | 2027 | 200-SC | 34.30 | 19.00 | -1.7 | -0.2 | 2047 | 200-SC | 52.00 | 34.75 | -1.9 | -0.5 |
| **Total Palo Verde Water Reclamation** | | | | | | | | | 47.75 | 34.77 | -0.8 | -0.5 |
| **Palo Verde Common** | | | | | | | | | | | | |
| 321.00 Structures and Improvements | 2027 | 200-SC | 34.28 | 19.00 | -0.5 | -0.2 | 2047 | 200-SC | 51.01 | 34.75 | -0.8 | -0.5 |
| 322.00 Reactor Plant Equipment | 2027 | 200-SC | 36.09 | 19.00 | -2.7 | -0.7 | 2047 | 200-SC | 52.35 | 34.75 | -2.8 | -1.4 |
| 323.00 Turbogenerator Units | 2027 | 200-SC | 22.36 | 19.02 | -1.3 | -2.0 | 2047 | 200-SC | 40.77 | 34.80 | -1.2 | -0.5 |
| 324.00 Accessory Electric Equipment | 2027 | 200-SC | 35.75 | 19.00 | -0.4 | -2.0 | 2047 | 200-SC | 52.49 | 34.75 | -0.6 | -0.5 |
| 325.00 Miscellaneous Power Plant Equipment | 2027 | 200-SC | 30.99 | 19.01 | -1.8 | -2.0 | 2047 | 200-SC | 46.42 | 34.77 | -1.9 | -0.5 |
| **Total Palo Verde Common** | | | | | | | | | 49.88 | 34.76 | -1.4 | -0.6 |

**ARIZONA PUBLIC SERVICE COMPANY**
Current and Proposed Parameters
Vintage Group Procedure

Statement H

| Account Description | Current Parameters P-Life/ AYFR | Curve Shape | VG ASL | Rem. Life | Avg. Sal. | Fut. Sal. | Proposed Parameters (at December 31, 2010) P-Life/ AYFR | Curve Shape | VG ASL | Rem. Life | Avg. Sal. | Fut. Sal. |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A | B | C | D | E | F | G | H | I | J | K | L | M |
| **OTHER PRODUCTION (by Unit)** | | | | | | | | | | | | |
| **Douglas CT** | | | | | | | | | | | | |
| 341.00 Structures and Improvements | 2020 | 200-SC | 15.72 | 12.30 | -5.0 | -5.0 | 2020 | 200-SC | 15.76 | 9.39 | 5.0 | 5.0 |
| 342.00 Fuel Holders, Products and Accessories | 2020 | 200-SC | 32.83 | 12.29 | -4.3 | -5.0 | 2020 | 200-SC | 32.80 | 9.38 | 4.0 | 5.0 |
| 343.00 Prime Movers | 2020 | 200-SC | 46.12 | 12.29 | -5.0 | -5.0 | 2020 | 200-SC | 46.39 | 9.38 | 5.0 | 5.0 |
| 344.00 Generators and Devices | 2020 | 200-SC | 46.70 | 12.29 | -5.0 | -5.0 | 2020 | 200-SC | 46.97 | 9.38 | 5.0 | 5.0 |
| 345.00 Accessory Electric Equipment | 2020 | 200-SC | 42.17 | 12.29 | -5.5 | -5.0 | 2020 | 200-SC | 42.30 | 9.38 | 4.5 | 5.0 |
| 346.00 Miscellaneous Power Plant Equipment | 2020 | 200-SC | 34.39 | 12.29 | -5.0 | -5.0 | 2020 | 200-SC | 34.57 | 9.38 | 5.0 | 5.0 |
| **Total Douglas CT** | | | | | | | | | 42.69 | 9.38 | 4.9 | 5.0 |
| **Ocotillo CT Units 1-2** | | | | | | | | | | | | |
| 341.00 Structures and Improvements | 2020 | 200-SC | 32.43 | 12.29 | -5.0 | -5.0 | 2020 | 200-SC | 18.84 | 9.38 | 4.8 | 5.0 |
| 342.00 Fuel Holders, Products and Accessories | 2020 | 200-SC | 33.24 | 12.29 | -5.0 | -5.0 | 2020 | 200-SC | 28.12 | 9.38 | 5.0 | 5.0 |
| 343.00 Prime Movers | 2020 | 200-SC | 40.66 | 12.29 | -4.9 | -5.0 | 2020 | 200-SC | 40.85 | 9.38 | 4.8 | 5.0 |
| 344.00 Generators and Devices | 2020 | 200-SC | 24.36 | 12.30 | -4.4 | -5.0 | 2020 | 200-SC | 21.32 | 9.38 | 12.7 | 5.0 |
| 345.00 Accessory Electric Equipment | 2020 | 200-SC | 35.70 | 12.29 | -5.7 | -5.0 | 2020 | 200-SC | 31.55 | 9.38 | 4.4 | 5.0 |
| 346.00 Miscellaneous Power Plant Equipment | 2020 | 200-SC | 34.75 | 12.29 | -4.8 | -5.0 | 2020 | 200-SC | 27.67 | 9.38 | 4.7 | 5.0 |
| **Total Octillo CT Units 1-2** | | | | | | | | | 27.26 | 9.38 | 8.3 | 5.0 |
| **Redhawk CC Units 1-2** | | | | | | | | | | | | |
| 341.00 Structures and Improvements | 2037 | 200-SC | 32.73 | 28.40 | -13.0 | -5.0 | 2037 | 200-SC | 32.09 | 25.61 | 3.8 | 5.0 |
| 342.00 Fuel Holders, Products and Accessories | 2037 | 200-SC | 28.88 | 28.41 | -5.0 | -5.0 | 2037 | 200-SC | 27.60 | 25.62 | 5.0 | 5.0 |
| 343.00 Prime Movers | 2037 | 200-SC | 33.06 | 28.40 | -2.8 | -5.0 | 2037 | 200-SC | 32.36 | 25.60 | 2.6 | 5.0 |
| 344.00 Generators and Devices | 2037 | 200-SC | 32.63 | 28.40 | -4.2 | -5.0 | 2037 | 200-SC | 30.17 | 25.61 | 25.3 | 5.0 |
| 345.00 Accessory Electric Equipment | 2037 | 200-SC | 32.92 | 28.40 | -4.2 | -5.0 | 2037 | 200-SC | 32.35 | 25.60 | 3.2 | 5.0 |
| 346.00 Miscellaneous Power Plant Equipment | 2037 | 200-SC | 30.34 | 28.41 | -5.0 | -5.0 | 2037 | 200-SC | 27.80 | 25.62 | 5.0 | 5.0 |
| **Total Redhawk CC Units 1-2** | | | | | | | | | 31.04 | 25.61 | 16.0 | 5.0 |

**ARIZONA PUBLIC SERVICE COMPANY**
Current and Proposed Parameters
Vintage Group Procedure

Statement H

| Account Description | Current Parameters P-Life/ AYFR | Curve Shape | VG ASL | Rem. Life | Avg. Sal. | Fut. Sal. | Proposed Parameters (at December 31, 2010) P-Life/ AYFR | Curve Shape | VG ASL | Rem. Life | Avg. Sal. | Fut. Sal. |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A | B | C | D | E | F | G | H | I | J | K | L | M |
| **Saguaro** | | | | | | | | | | | | |
| 341.00 Structures and Improvements | | | 21.77 | 12.30 | -5.0 | | | | 17.25 | 9.39 | 4.9 | |
| 342.00 Fuel Holders, Products and Accessories | | | 35.77 | 12.29 | -4.5 | | | | 31.95 | 9.38 | 4.3 | |
| 343.00 Prime Movers | | | 39.66 | 13.71 | -5.0 | | | | 39.85 | 10.81 | 4.9 | |
| 344.00 Generators and Devices | | | 30.90 | 25.10 | -4.9 | | | | 30.94 | 22.27 | 5.9 | |
| 345.00 Accessory Electric Equipment | | | 39.91 | 13.67 | -5.4 | | | | 39.82 | 10.77 | 4.6 | |
| 346.00 Miscellaneous Power Plant Equipment | | | 24.45 | 12.30 | -4.9 | | | | 23.96 | 9.38 | 4.9 | |
| **Total Saguaro** | | | | | | | | | 31.34 | 18.67 | 5.6 | 5.0 |
| **Saguaro CT Units 1-2** | | | | | | | | | | | | |
| 341.00 Structures and Improvements | 2020 | 200-SC | 21.77 | 12.30 | -5.0 | -5.0 | 2020 | 200-SC | 17.25 | 9.39 | 4.9 | 5.0 |
| 342.00 Fuel Holders, Products and Accessories | 2020 | 200-SC | 35.77 | 12.29 | -4.5 | -5.0 | 2020 | 200-SC | 31.95 | 9.38 | 4.3 | 5.0 |
| 343.00 Prime Movers | 2020 | 200-SC | 40.25 | 12.29 | -5.0 | -5.0 | 2020 | 200-SC | 40.46 | 9.38 | 4.9 | 5.0 |
| 344.00 Generators and Devices | 2020 | 200-SC | 20.79 | 12.30 | -4.6 | -5.0 | 2020 | 200-SC | 20.81 | 9.38 | 10.9 | 5.0 |
| 345.00 Accessory Electric Equipment | 2020 | 200-SC | 40.51 | 12.29 | -5.4 | -5.0 | 2020 | 200-SC | 40.41 | 9.38 | 4.6 | 5.0 |
| 346.00 Miscellaneous Power Plant Equipment | 2020 | 200-SC | 24.45 | 12.30 | -4.9 | -5.0 | 2020 | 200-SC | 23.96 | 9.38 | 4.9 | 5.0 |
| **Total Saguaro CT Units 1-2** | | | | | | | | | 28.38 | 9.38 | 6.4 | 5.0 |
| **Saguaro CT Unit 3** | | | | | | | | | | | | |
| 341.00 Structures and Improvements | | | | | | | | | | | | |
| 342.00 Fuel Holders, Products and Accessories | | | | | | | | | | | | |
| 343.00 Prime Movers | 2037 | 200-SC | 33.51 | 28.40 | -5.0 | -5.0 | 2037 | 200-SC | 33.56 | 25.60 | 5.0 | 5.0 |
| 344.00 Generators and Devices | 2037 | 200-SC | 33.51 | 28.40 | -5.0 | -5.0 | 2037 | 200-SC | 33.56 | 25.60 | 5.0 | 5.0 |
| 345.00 Accessory Electric Equipment | 2037 | 200-SC | 33.51 | 28.40 | -5.0 | -5.0 | 2037 | 200-SC | 33.56 | 25.60 | 5.0 | 5.0 |
| 346.00 Miscellaneous Power Plant Equipment | | | | | | | | | | | | |
| **Total Saguaro CT Unit 3** | | | | | | | | | 33.56 | 25.60 | 5.0 | 5.0 |

**ARIZONA PUBLIC SERVICE COMPANY**
Current and Proposed Parameters
Vintage Group Procedure

Statement H

| Account Description | Current Parameters P-Life/ AYFR | Curve Shape | VG ASL | Rem. Life | Avg. Sal. | Fut. Sal. | Proposed Parameters (at December 31, 2010) P-Life/ AYFR | Curve Shape | VG ASL | Rem. Life | Avg. Sal. | Fut. Sal. |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A | B | C | D | E | F | G | H | I | J | K | L | M |
| **Solar Units** | | | | | | | | | | | | |
| 341.00 Structures and Improvements | 12.00 | S3 | 14.32 | 3.20 | -4.9 | -5.0 | 12.00 | S3 | 16.26 | 2.25 | 4.8 | 5.0 |
| 342.00 Fuel Holders, Products and Accessories | | | | | | | | | | | | |
| 343.00 Prime Movers | | | | | | | | | | | | |
| 344.00 Generators and Devices | 12.00 | S3 | 12.12 | 5.48 | -5.3 | -5.0 | 12.00 | S3 | 12.62 | 4.22 | 11.7 | 5.0 |
| 345.00 Accessory Electric Equipment | 12.00 | S3 | 12.06 | 5.18 | -5.0 | -5.0 | 12.00 | S3 | 12.11 | 8.61 | 5.0 | 5.0 |
| 346.00 Miscellaneous Power Plant Equipment | | | | | | | | | | | | |
| **Total Solar Units** | | | | | | | | | 12.67 | 4.38 | 11.3 | 5.0 |
| **Sundance** | | | | | | | | | | | | |
| 341.00 Structures and Improvements | 2037 | 200-SC | 30.70 | 28.41 | -5.0 | -5.0 | 2037 | 200-SC | 30.66 | 25.61 | 5.0 | 5.0 |
| 342.00 Fuel Holders, Products and Accessories | 2037 | 200-SC | 30.73 | 28.41 | -5.0 | -5.0 | 2037 | 200-SC | 30.69 | 25.61 | 5.0 | 5.0 |
| 343.00 Prime Movers | 2037 | 200-SC | 30.72 | 28.41 | -5.0 | -5.0 | 2037 | 200-SC | 30.75 | 25.61 | 5.0 | 5.0 |
| 344.00 Generators and Devices | 2037 | 200-SC | 29.25 | 28.41 | -5.0 | -5.0 | 2037 | 200-SC | 29.27 | 25.61 | 5.0 | 5.0 |
| 345.00 Accessory Electric Equipment | 2037 | 200-SC | 30.73 | 28.41 | -5.0 | -5.0 | 2037 | 200-SC | 30.69 | 25.61 | 5.0 | 5.0 |
| 346.00 Miscellaneous Power Plant Equipment | 2037 | 200-SC | 30.73 | 28.41 | -5.0 | -5.0 | 2037 | 200-SC | 29.31 | 25.61 | 5.0 | 5.0 |
| **Total Sun Dance** | | | | | | | | | 30.73 | 25.61 | 5.0 | 5.0 |
| **West Phoenix** | | | | | | | | | | | | |
| 341.00 Structures and Improvements | | | 33.13 | 25.94 | -5.3 | | | | 30.03 | 22.21 | 4.9 | |
| 342.00 Fuel Holders, Products and Accessories | | | 27.72 | 20.61 | -5.0 | | | | 27.21 | 17.72 | 4.7 | |
| 343.00 Prime Movers | | | 33.20 | 27.79 | -3.7 | | | | 32.93 | 25.02 | 3.6 | |
| 344.00 Generators and Devices | | | 29.85 | 24.56 | -4.7 | | | | 29.47 | 21.91 | 11.1 | |
| 345.00 Accessory Electric Equipment | | | 29.10 | 22.78 | -4.9 | | | | 29.17 | 20.65 | 4.3 | |
| 346.00 Miscellaneous Power Plant Equipment | | | 29.54 | 17.41 | -5.3 | | | | 24.20 | 16.09 | 4.5 | |
| **Total West Phoenix** | | | | | | | | | 30.30 | 22.43 | 7.4 | 5.0 |

**ARIZONA PUBLIC SERVICE COMPANY**
Current and Proposed Parameters
Vintage Group Procedure

Statement H

| Account Description | Current Parameters P-Life/ AYFR | Curve Shape | VG ASL | Rem. Life | Avg. Sal. | Fut. Sal. | Proposed Parameters (at December 31, 2010) P-Life/ AYFR | Curve Shape | VG ASL | Rem. Life | Avg. Sal. | Fut. Sal. |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A | B | C | D | E | F | G | H | I | J | K | L | M |
| **West Phoenix CC Units 1-3** | | | | | | | | | | | | |
| 341.00 Structures and Improvements | 2028 | 200-SC | 24.76 | 19.97 | -4.9 | -5.0 | 2028 | 200-SC | 20.32 | 17.11 | 4.7 | 5.0 |
| 342.00 Fuel Holders, Products and Accessories | 2028 | 200-SC | 26.40 | 19.97 | -5.0 | -5.0 | 2028 | 200-SC | 25.88 | 17.11 | 4.6 | 5.0 |
| 343.00 Prime Movers | | | | | | | | | | | | |
| 344.00 Generators and Devices | 2028 | 200-SC | 25.85 | 19.97 | -4.2 | -5.0 | 2028 | 200-SC | 25.48 | 17.11 | 17.3 | 5.0 |
| 345.00 Accessory Electric Equipment | 2028 | 200-SC | 26.26 | 19.97 | -4.8 | -5.0 | 2028 | 200-SC | 26.01 | 17.11 | 3.6 | 5.0 |
| 346.00 Miscellaneous Power Plant Equipment | 2028 | 200-SC | 32.86 | 19.96 | -5.4 | -5.0 | 2028 | 200-SC | 24.83 | 17.11 | 4.3 | 5.0 |
| **Total West Phoenix CC Units 1-3** | | | | | | | | | 25.49 | 17.11 | 13.5 | 5.0 |
| **West Phoenix CC Unit 4** | | | | | | | | | | | | |
| 341.00 Structures and Improvements | 2036 | 200-SC | 32.84 | 27.47 | -5.0 | -5.0 | 2036 | 200-SC | 32.78 | 24.67 | 5.0 | 5.0 |
| 342.00 Fuel Holders, Products and Accessories | 2036 | 200-SC | 33.52 | 27.47 | -5.0 | -5.0 | 2036 | 200-SC | 33.58 | 24.67 | 5.0 | 5.0 |
| 343.00 Prime Movers | 2036 | 200-SC | 33.52 | 27.47 | -5.0 | -5.0 | 2036 | 200-SC | 33.58 | 24.67 | 5.0 | 5.0 |
| 344.00 Generators and Devices | 2036 | 200-SC | 33.01 | 27.47 | -5.2 | -5.0 | 2036 | 200-SC | 32.59 | 24.67 | 9.6 | 5.0 |
| 345.00 Accessory Electric Equipment | 2036 | 200-SC | 30.76 | 27.48 | -5.0 | -5.0 | 2036 | 200-SC | 28.02 | 24.68 | 5.0 | 5.0 |
| 346.00 Miscellaneous Power Plant Equipment | 2036 | 200-SC | 31.27 | 27.47 | -5.0 | -5.0 | 2036 | 200-SC | 26.86 | 24.68 | 4.7 | 5.0 |
| **Total West Phoenix CC Unit 4** | | | | | | | | | 33.11 | 24.67 | 5.9 | 5.0 |
| **West Phoenix CC Unit 5** | | | | | | | | | | | | |
| 341.00 Structures and Improvements | 2038 | 200-SC | 33.49 | 29.32 | -5.0 | -5.0 | 2038 | 200-SC | 33.50 | 26.54 | 5.0 | 5.0 |
| 342.00 Fuel Holders, Products and Accessories | | | | | | | | | | | | |
| 343.00 Prime Movers | 2038 | 200-SC | 33.06 | 29.32 | -3.1 | -5.0 | 2038 | 200-SC | 32.59 | 26.54 | 2.9 | 5.0 |
| 344.00 Generators and Devices | 2038 | 200-SC | 33.48 | 29.32 | -5.0 | -5.0 | 2038 | 200-SC | 32.94 | 26.54 | 6.2 | 5.0 |
| 345.00 Accessory Electric Equipment | 2038 | 200-SC | 33.52 | 29.32 | -5.0 | -5.0 | 2038 | 200-SC | 33.56 | 26.54 | 5.0 | 5.0 |
| 346.00 Miscellaneous Power Plant Equipment | 2038 | 200-SC | 31.63 | 29.33 | -5.0 | -5.0 | 2038 | 200-SC | 29.15 | 26.55 | 5.0 | 5.0 |
| **Total West Phoenix CC Unit 5** | | | | | | | | | 32.85 | 26.54 | 4.6 | 5.0 |

**ARIZONA PUBLIC SERVICE COMPANY**
Current and Proposed Parameters
Vintage Group Procedure

Statement H

| Account Description | Current Parameters P-Life/ AYFR | Curve Shape | VG ASL | Rem. Life | Avg. Sal. | Fut. Sal. | Proposed Parameters (at December 31, 2010) P-Life/ AYFR | Curve Shape | VG ASL | Rem. Life | Avg. Sal. | Fut. Sal. |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A | B | C | D | E | F | G | H | I | J | K | L | M |
| **West Phoenix CT Units 1-2** | | | | | | | | | | | | |
| 341.00 Structures and Improvements | 2020 | 200-SC | 39.03 | 12.29 | -5.0 | -5.0 | 2020 | 200-SC | 19.08 | 9.38 | 5.0 | 5.0 |
| 342.00 Fuel Holders, Products and Accessories | 2020 | 200-SC | 36.53 | 12.29 | -5.0 | -5.0 | 2020 | 200-SC | 36.73 | 9.38 | 5.0 | 5.0 |
| 343.00 Prime Movers | 2020 | 200-SC | 32.86 | 12.29 | -4.8 | -5.0 | 2020 | 200-SC | 32.96 | 9.38 | 4.6 | 5.0 |
| 344.00 Generators and Devices | 2020 | 200-SC | 28.71 | 12.30 | -5.0 | -5.0 | 2020 | 200-SC | 24.86 | 9.38 | 6.9 | 5.0 |
| 345.00 Accessory Electric Equipment | 2020 | 200-SC | 33.95 | 12.29 | -5.4 | -5.0 | 2020 | 200-SC | 33.43 | 9.38 | 4.7 | 5.0 |
| 346.00 Miscellaneous Power Plant Equipment | 2020 | 200-SC | 23.33 | 12.30 | -5.0 | -5.0 | 2020 | 200-SC | 20.80 | 9.38 | 4.9 | 5.0 |
| **Total West Phoenix CT Units 1-2** | | | | | | | | | 28.84 | 9.38 | 5.2 | 5.0 |
| **West Phoenix Common** | | | | | | | | | | | | |
| 341.00 Structures and Improvements | 2031 | 200-SC | 42.59 | 22.77 | -6.5 | -5.0 | 2031 | 200-SC | 29.46 | 19.96 | 4.7 | 5.0 |
| 342.00 Fuel Holders, Products and Accessories | | | | | | | | | | | | |
| 343.00 Prime Movers | | | | | | | | | | | | |
| 344.00 Generators and Devices | | | | | | | | | | | | |
| 345.00 Accessory Electric Equipment | | | | | | | | | | | | |
| 346.00 Miscellaneous Power Plant Equipment | | | | | | | | | | | | |
| **Total West Phoenix Common** | | | | | | | | | 29.46 | 19.96 | 4.7 | 5.0 |
| **Yucca** | | | | | | | | | | | | |
| 341.00 Structures and Improvements | | | | | | | | | 35.51 | 31.16 | 4.6 | |
| 342.00 Fuel Holders, Products and Accessories | | | | | | | | | 48.66 | 31.11 | 4.9 | |
| 343.00 Prime Movers | | | | | | | | | 35.28 | 31.16 | 5.0 | |
| 344.00 Generators and Devices | | | | | | | | | 44.96 | 31.13 | 9.0 | |
| 345.00 Accessory Electric Equipment | | | | | | | | | 47.85 | 31.11 | 4.9 | |
| 346.00 Miscellaneous Power Plant Equipment | | | | | | | | | 46.77 | 31.12 | 5.0 | |
| **Total Yucca** | | | | | | | | | 36.86 | 31.16 | 5.3 | 5.0 |

**ARIZONA PUBLIC SERVICE COMPANY**
Current and Proposed Parameters
Vintage Group Procedure

Statement H

| Account Description | Current Parameters P-Life/ AYFR | Curve Shape | VG ASL | Rem. Life | Avg. Sal. | Fut. Sal. | Proposed Parameters (at December 31, 2010) P-Life/ AYFR | Curve Shape | VG ASL | Rem. Life | Avg. Sal. | Fut. Sal. |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A | B | C | D | E | F | G | H | I | J | K | L | M |
| **Yucca CT Units 1-4** | | | | | | | | | | | | |
| 341.00 Structures and Improvements | 2020 | 200-SC | 21.94 | 12.30 | -4.9 | -5.0 | 2043 | 200-SC | 36.51 | 31.16 | 4.4 | 5.0 |
| 342.00 Fuel Holders, Products and Accessories | 2020 | 200-SC | 41.81 | 12.29 | -4.9 | -5.0 | 2043 | 200-SC | 61.23 | 31.06 | 4.9 | 5.0 |
| 343.00 Prime Movers | 2020 | 200-SC | 45.24 | 12.29 | -5.0 | -5.0 | 2043 | 200-SC | 65.30 | 31.04 | 5.0 | 5.0 |
| 344.00 Generators and Devices | 2020 | 200-SC | 26.33 | 12.30 | -4.9 | -5.0 | 2043 | 200-SC | 45.07 | 31.13 | 9.0 | 5.0 |
| 345.00 Accessory Electric Equipment | 2020 | 200-SC | 27.75 | 12.30 | -5.2 | -5.0 | 2043 | 200-SC | 51.04 | 31.10 | 4.8 | 5.0 |
| 346.00 Miscellaneous Power Plant Equipment | 2020 | 200-SC | 27.71 | 12.30 | -5.0 | -5.0 | 2043 | 200-SC | 46.77 | 31.12 | 5.0 | 5.0 |
| **Total Yucca CT Units 1-4** | | | | | | | | | 52.60 | 31.10 | 6.3 | 5.0 |
| **Yucca CT Units 5-6** | | | | | | | | | | | | |
| 341.00 Structures and Improvements | | | | | | | 2043 | 200-SC | 33.48 | 31.17 | 5.0 | 5.0 |
| 342.00 Fuel Holders, Products and Accessories | | | | | | | 2043 | 200-SC | 33.48 | 31.17 | 5.0 | 5.0 |
| 343.00 Prime Movers | | | | | | | 2043 | 200-SC | 33.48 | 31.17 | 5.0 | 5.0 |
| 344.00 Generators and Devices | | | | | | | 2043 | 200-SC | 33.48 | 31.17 | 5.0 | 5.0 |
| 345.00 Accessory Electric Equipment | | | | | | | 2043 | 200-SC | 33.48 | 31.17 | 5.0 | 5.0 |
| 346.00 Miscellaneous Power Plant Equipment | | | | | | | | | | | | |
| **Total Yucca CT Units 5-6** | | | | | | | | | 33.48 | 31.17 | 5.0 | 5.0 |

# ANALYSIS

## INTRODUCTION

This section provides an explanation of the supporting schedules developed in the APS depreciation study to estimate appropriate projection curves, projection lives and net salvage statistics for each rate category. The form and content of the schedules developed for an account depend upon the method of analysis adopted for the category.

This section also includes an example of the supporting schedules developed for Account 362.00 – Station Equipment. Documentation for all other plant accounts is contained in the study work papers. Supporting schedules developed in the APS study include:

Schedule A – Generation Arrangement;

Schedule B – Age Distribution;

Schedule C – Plant History;

Schedule D – Actuarial Life Analysis;

Schedule E – Graphics Analysis; and

Schedule F – Historical Net Salvage Analysis.

The format and content of these schedules are briefly described below.

### SCHEDULE A – GENERATION ARRANGEMENT

The purpose of this schedule is to obtain appropriate weighted–average life statistics for a rate category. A weighted–average remaining–life is the sum of Column H divided by the sum of Column I. A weighted average life is the sum of Column C divided by the sum of Column I.

It should be noted that the generation arrangement does not include parameters for net salvage. Computed Net Plant (Column C) and Accruals (Column I) must be adjusted for net salvage to obtain a correct measurement of theoretical reserves and annualized depreciation accruals.

The following table provides a description of each column in the generation arrangement.

| Column | Title | Description |
|---|---|---|
| A | Vintage | Vintage or placement year of surviving plant. |
| B | Age | Age of surviving plant at beginning of study year. |
| C | Surviving Plant | Actual dollar amount of surviving plant. |
| D | Average Life | Estimated average life of each vintage. This *statistic* is the sum of the realized life and the unrealized life, which is the product of the remaining life (Column E) and the theoretical proportion surviving. |
| E | Remaining Life | Estimated remaining life of each vintage. |
| F | Net Plant Ratio | Theoretical net plant ratio of each vintage. |
| G | Allocation Factor | A pivotal ratio which determines the amortization period of the difference between the recorded and computed reserve. |
| H | Computed Net Plant | Plant in service less theoretical reserve for each vintage. |
| I | Accrual | Ratio of computed net plant (Column H) and remaining life (Column E). |

**Table 2. Generation Arrangement**

## SCHEDULE B – AGE DISTRIBUTION

This schedule provides the age distribution and realized life of surviving plant shown in Column C of the Generation Arrangement (Schedule A). The format of the schedule depends upon the availability of either aged or unaged data. Derived additions for vintage years older than the earliest activity year in an account for unaged data are obtained from the age distribution of surviving plant at the beginning of the earliest activity year. The amount surviving from these vintages is shown in Column D. The realized life (Column G) is derived from the dollar years of service provided by a vintage over the period of years the vintage has been in service. Plant additions for vintages older than the earliest activity year in an account are represented by the opening balances shown in Column D.

The computed proportion surviving (Column D) for unaged data is derived from a computed mortality analysis. The average service life displayed in the title block is the life statistic derived for the most recent activity year, given the derived age distribution at the start of the year and the specified retirement dispersion. The realized life (Column F) is obtained by finding the slope of an SC retirement dispersion, which connects the computed survivors of a vintage (Column E) to the recorded vintage addition (Column B). The realized life is the area bounded by the SC dispersion, the computed proportion surviving and the age of the vintage.

### SCHEDULE C – PLANT HISTORY

An Unadjusted Plant History schedule provides a summary of recorded plant data extracted from the continuing property records maintained by the Company. Activity year total amounts shown on this schedule for aged data are obtained from a historical arrangement of the database in which all plant accounting transactions are identified by vintage and activity year. Activity year totals for unaged data are obtained from a transaction file without vintage identification. Information displayed in the unadjusted plant history is consistent with regulated investments reported internally by the Company.

An Adjusted Plant History schedule provides a summary of recorded plant data extracted from the continuing property records maintained by the Company with sales, transfers, and adjustments appropriately aged for depreciation study purposes. Activity year total amounts shown on this schedule for aged data are obtained from a historical arrangement of the data base in which all plant accounting transactions are identified by vintage and activity year. Ageing of adjusting transactions is achieved using transaction codes that identify an adjusting year associated with the dollar amount of a transaction. Adjusting transactions processed in the adjusted plant history are not aged in the Company's records or in the unadjusted plant history.

### SCHEDULE D – ACTUARIAL LIFE ANALYSIS

These schedules provide a summary of the dispersion and life indications obtained from an actuarial life analysis for a specified placement band. The observation band (Column A) is specified to produce a rolling–band, shrinking–band, or progressive–band analysis depending upon the movement of the end points of the band. The degree of censoring (or point of truncation) of the observed life table is shown in Column B for each observation band. The estimated average service life, best fitting Iowa dispersion, and a statistical measure of the goodness of fit are shown for each degree polynomial (First, Second, and Third) fitted to the estimated hazard rates. Options available in the analysis include the width and location of both the placement and observation bands; the interval of years included in a selected rolling, shrinking, or progressive band analysis; the estimator of the hazard rate (actuarial, conditional proportion retired, or maximum likelihood); the elements to include on the diagonal of a weight matrix (exposures, inverse of age, inverse of variance, or unweighted); and the age at which an observed life table is truncated.

Estimated projection lives (Columns C, F, and I) are flagged with an asterisk if negative hazard rates are indicated by the fitted polynomial. All negative hazard rates are set equal to zero in the calculation of the graduated survivor curve. The Conformance Index (Columns E, H, and K) is the square root of the mean sum–

of–squared differences between the graduated survivor curve and the best fitting Iowa curve. A Conformance Index of zero would indicate a perfect fit.

### SCHEDULE E – GRAPHICS ANALYSIS

This schedule provides a graphics plot of a) the observed proportion surviving for a selected placement and observation band; b) the statistically best fitting Iowa dispersion and derived average service life; and c) the projection curve and projection life selected to describe future forces of mortality.

The graphics analysis also provides a plot of the observed hazard rates and graduated hazard function for a selected placement and observation band. The estimator of the hazard rates and weighting used in fitting orthogonal polynomials to the observed data are displayed in the title block of the displayed graph.

### SCHEDULE F – HISTORICAL NET SALVAGE ANALYSIS

This schedule provides a moving average analysis of the ratio of realized net salvage (Column I) to the associated retirements (Column B). The schedule also provides a moving average analysis of the components of net salvage related to retirements. The ratio of gross salvage to retirements is shown in Column D and the ratio of cost of removal to retirements is shown in Column G.

## ARIZONA PUBLIC SERVICE COMPANY

**Distribution Plant**
**Account: 362.00 Station Equipment**

**Dispersion: 43 - L0.5**
**Procedure: Vintage Group**

**Generation Arrangement**

| | December 31, 2010 | | | | Net | | | |
|---|---|---|---|---|---|---|---|---|
| Vintage | Age | Surviving Plant | Avg. Life | Rem. Life | Plant Ratio | Alloc. Factor | Computed Net Plant | Accrual |
| A | B | C | D | E | F | G | H=C*F*G | I=H/E |
| 2010 | 0.5 | 20,702,095 | 43.00 | 42.55 | 0.9895 | 1.0000 | 20,484,455 | 481,439 |
| 2009 | 1.5 | 28,443,020 | 43.00 | 41.69 | 0.9696 | 1.0000 | 27,578,821 | 661,473 |
| 2008 | 2.5 | 44,214,526 | 43.01 | 40.88 | 0.9505 | 1.0000 | 42,024,898 | 1,028,030 |
| 2007 | 3.5 | 20,078,730 | 43.01 | 40.10 | 0.9324 | 1.0000 | 18,721,265 | 466,892 |
| 2006 | 4.5 | 34,459,322 | 43.01 | 39.34 | 0.9148 | 1.0000 | 31,523,301 | 801,204 |
| 2005 | 5.5 | 36,386,765 | 42.98 | 38.62 | 0.8986 | 1.0000 | 32,696,212 | 846,677 |
| 2004 | 6.5 | 16,946,211 | 42.90 | 37.91 | 0.8838 | 1.0000 | 14,977,110 | 395,034 |
| 2003 | 7.5 | 16,711,457 | 43.03 | 37.23 | 0.8652 | 1.0000 | 14,459,118 | 388,339 |
| 2002 | 8.5 | 18,137,055 | 43.06 | 36.57 | 0.8495 | 1.0000 | 15,406,727 | 421,239 |
| 2001 | 9.5 | 19,817,265 | 43.15 | 35.94 | 0.8329 | 1.0000 | 16,506,076 | 459,293 |
| 2000 | 10.5 | 13,804,427 | 42.94 | 35.32 | 0.8225 | 1.0000 | 11,354,638 | 321,448 |
| 1999 | 11.5 | 19,147,511 | 43.18 | 34.73 | 0.8043 | 1.0000 | 15,399,716 | 443,425 |
| 1998 | 12.5 | 11,133,907 | 43.36 | 34.16 | 0.7877 | 1.0000 | 8,769,831 | 256,763 |
| 1997 | 13.5 | 6,976,698 | 43.07 | 33.60 | 0.7802 | 1.0000 | 5,443,360 | 161,992 |
| 1996 | 14.5 | 7,113,394 | 43.00 | 33.07 | 0.7691 | 1.0000 | 5,471,191 | 165,447 |
| 1995 | 15.5 | 3,867,810 | 42.62 | 32.55 | 0.7639 | 1.0000 | 2,954,494 | 90,755 |
| 1994 | 16.5 | 2,939,364 | 42.90 | 32.06 | 0.7473 | 1.0000 | 2,196,568 | 68,516 |
| 1993 | 17.5 | 4,518,641 | 43.19 | 31.58 | 0.7311 | 1.0000 | 3,303,740 | 104,611 |
| 1992 | 18.5 | 3,299,401 | 43.05 | 31.12 | 0.7229 | 1.0000 | 2,385,241 | 76,647 |
| 1991 | 19.5 | 3,878,592 | 42.07 | 30.67 | 0.7291 | 1.0000 | 2,827,785 | 92,187 |
| 1990 | 20.5 | 4,299,549 | 41.87 | 30.24 | 0.7224 | 1.0000 | 3,105,922 | 102,698 |
| 1989 | 21.5 | 4,429,694 | 44.07 | 29.83 | 0.6768 | 1.0000 | 2,998,146 | 100,508 |
| 1988 | 22.5 | 9,548,697 | 43.45 | 29.44 | 0.6775 | 1.0000 | 6,468,994 | 219,758 |
| 1987 | 23.5 | 5,504,471 | 44.78 | 29.05 | 0.6487 | 1.0000 | 3,570,722 | 122,921 |
| 1986 | 24.5 | 6,245,626 | 42.80 | 28.67 | 0.6697 | 1.0000 | 4,182,676 | 145,911 |
| 1985 | 25.5 | 6,804,962 | 43.77 | 28.29 | 0.6463 | 1.0000 | 4,398,253 | 155,482 |
| 1984 | 26.5 | 4,259,757 | 41.65 | 27.91 | 0.6702 | 1.0000 | 2,855,039 | 102,278 |
| 1983 | 27.5 | 3,369,708 | 42.83 | 27.55 | 0.6432 | 1.0000 | 2,167,349 | 78,680 |
| 1982 | 28.5 | 3,867,435 | 40.27 | 27.18 | 0.6750 | 1.0000 | 2,610,602 | 96,038 |
| 1981 | 29.5 | 2,197,584 | 43.62 | 26.82 | 0.6150 | 1.0000 | 1,351,428 | 50,381 |
| 1980 | 30.5 | 1,815,309 | 42.03 | 26.47 | 0.6298 | 1.0000 | 1,143,280 | 43,191 |
| 1979 | 31.5 | 3,672,304 | 44.11 | 26.12 | 0.5922 | 1.0000 | 2,174,792 | 83,259 |
| 1978 | 32.5 | 2,089,710 | 42.33 | 25.78 | 0.6089 | 1.0000 | 1,272,421 | 49,365 |
| 1977 | 33.5 | 1,373,571 | 44.02 | 25.44 | 0.5778 | 1.0000 | 793,591 | 31,200 |
| 1976 | 34.5 | 647,653 | 42.35 | 25.10 | 0.5927 | 1.0000 | 383,833 | 15,293 |
| 1975 | 35.5 | 804,184 | 46.43 | 24.77 | 0.5334 | 1.0000 | 428,947 | 17,319 |

## ARIZONA PUBLIC SERVICE COMPANY

**Distribution Plant**
**Account: 362.00 Station Equipment**

**Dispersion: 43 - L0.5**
**Procedure: Vintage Group**

**Generation Arrangement**

| Vintage | December 31, 2010 Age | Surviving Plant | Avg. Life | Rem. Life | Net Plant Ratio | Alloc. Factor | Computed Net Plant | Accrual |
|---|---|---|---|---|---|---|---|---|
| A | B | C | D | E | F | G | H=C*F*G | I=H/E |
| 1974 | 36.5 | 1,927,649 | 39.39 | 24.44 | 0.6204 | 1.0000 | 1,195,883 | 48,932 |
| 1973 | 37.5 | 1,243,097 | 45.51 | 24.12 | 0.5299 | 1.0000 | 658,746 | 27,316 |
| 1972 | 38.5 | 1,835,496 | 40.28 | 23.80 | 0.5908 | 1.0000 | 1,084,453 | 45,571 |
| 1971 | 39.5 | 657,693 | 43.97 | 23.48 | 0.5341 | 1.0000 | 351,243 | 14,958 |
| 1970 | 40.5 | 1,717,869 | 44.13 | 23.17 | 0.5251 | 1.0000 | 902,003 | 38,929 |
| 1969 | 41.5 | 760,378 | 44.81 | 22.86 | 0.5103 | 1.0000 | 387,996 | 16,970 |
| 1968 | 42.5 | 442,261 | 46.24 | 22.56 | 0.4879 | 1.0000 | 215,785 | 9,565 |
| 1967 | 43.5 | 318,764 | 45.70 | 22.26 | 0.4871 | 1.0000 | 155,258 | 6,975 |
| 1966 | 44.5 | 431,631 | 48.25 | 21.97 | 0.4553 | 1.0000 | 196,508 | 8,946 |
| 1965 | 45.5 | 182,048 | 42.75 | 21.67 | 0.5069 | 1.0000 | 92,285 | 4,258 |
| 1964 | 46.5 | 187,919 | 48.25 | 21.39 | 0.4432 | 1.0000 | 83,291 | 3,895 |
| 1963 | 47.5 | 328,083 | 43.43 | 21.10 | 0.4858 | 1.0000 | 159,383 | 7,553 |
| 1962 | 48.5 | 836,090 | 47.96 | 20.82 | 0.4341 | 1.0000 | 362,952 | 17,433 |
| 1961 | 49.5 | 105,433 | 42.85 | 20.54 | 0.4794 | 1.0000 | 50,546 | 2,461 |
| 1960 | 50.5 | 403,593 | 50.06 | 20.27 | 0.4049 | 1.0000 | 163,405 | 8,062 |
| 1959 | 51.5 | 116,498 | 43.69 | 20.00 | 0.4578 | 1.0000 | 53,330 | 2,667 |
| 1958 | 52.5 | 236,828 | 43.23 | 19.73 | 0.4564 | 1.0000 | 108,097 | 5,478 |
| 1957 | 53.5 | 144,058 | 43.23 | 19.47 | 0.4503 | 1.0000 | 64,869 | 3,332 |
| 1956 | 54.5 | 236,693 | 47.39 | 19.21 | 0.4053 | 1.0000 | 95,939 | 4,995 |
| 1955 | 55.5 | 263,209 | 48.36 | 18.95 | 0.3919 | 1.0000 | 103,155 | 5,443 |
| 1954 | 56.5 | 155,912 | 47.13 | 18.70 | 0.3967 | 1.0000 | 61,854 | 3,308 |
| 1953 | 57.5 | 97,574 | 44.91 | 18.45 | 0.4108 | 1.0000 | 40,079 | 2,172 |
| 1952 | 58.5 | 130,534 | 46.33 | 18.20 | 0.3929 | 1.0000 | 51,281 | 2,817 |
| 1951 | 59.5 | 29,426 | 44.63 | 17.96 | 0.4024 | 1.0000 | 11,841 | 659 |
| 1950 | 60.5 | 68,513 | 62.63 | 17.72 | 0.2829 | 1.0000 | 19,384 | 1,094 |
| 1949 | 61.5 | 74,709 | 58.77 | 17.48 | 0.2975 | 1.0000 | 22,223 | 1,271 |
| 1948 | 62.5 | 167,271 | 62.61 | 17.25 | 0.2755 | 1.0000 | 46,077 | 2,672 |
| 1946 | 64.5 | 3,742 | 66.24 | 16.79 | 0.2534 | 1.0000 | 948 | 56 |
| 1945 | 65.5 | 45,852 | 67.61 | 16.56 | 0.2450 | 1.0000 | 11,234 | 678 |
| 1943 | 67.5 | 124 | 64.02 | 16.12 | 0.2519 | 1.0000 | 31 | 2 |
| 1942 | 68.5 | 103,074 | 68.46 | 15.91 | 0.2324 | 1.0000 | 23,949 | 1,506 |
| 1941 | 69.5 | 921 | 68.39 | 15.69 | 0.2295 | 1.0000 | 211 | 13 |
| 1940 | 70.5 | 1,053 | 44.39 | 15.49 | 0.3488 | 1.0000 | 367 | 24 |
| 1939 | 71.5 | 4,690 | 71.45 | 15.28 | 0.2138 | 1.0000 | 1,003 | 66 |
| 1935 | 75.5 | 29,425 | 76.88 | 14.48 | 0.1884 | 1.0000 | 5,543 | 383 |
| 1929 | 81.5 | 5,471 | 81.22 | 13.38 | 0.1647 | 1.0000 | 901 | 67 |
| Total | 10.7 | $406,799,985 | 43.06 | 36.12 | 0.8387 | 1.0000 | $341,172,593 | $9,446,217 |

## ARIZONA PUBLIC SERVICE COMPANY

**Distribution Plant**

**Account: 362.00 Station Equipment**

**Age Distribution**

| Vintage | Age as of 12/31/2010 | Derived Additions | 1971 Opening Balance | Experience to 12/31/2010 Amount Surviving | Proportion Surviving | Realized Life |
|---|---|---|---|---|---|---|
| A | B | C | D | E | F=E/(C+D) | G |
| 2010 | 0.5 | 20,702,095 | | 20,702,095 | 1.0000 | 0.5000 |
| 2009 | 1.5 | 28,515,638 | | 28,443,020 | 0.9975 | 1.4962 |
| 2008 | 2.5 | 44,259,532 | | 44,214,526 | 0.9990 | 2.4989 |
| 2007 | 3.5 | 20,260,272 | | 20,078,730 | 0.9910 | 3.4833 |
| 2006 | 4.5 | 35,013,016 | | 34,459,322 | 0.9842 | 4.4702 |
| 2005 | 5.5 | 37,234,267 | | 36,386,765 | 0.9772 | 5.4129 |
| 2004 | 6.5 | 18,625,320 | | 16,946,211 | 0.9098 | 6.3039 |
| 2003 | 7.5 | 17,460,275 | | 16,711,457 | 0.9571 | 7.4001 |
| 2002 | 8.5 | 18,540,699 | | 18,137,055 | 0.9782 | 8.3760 |
| 2001 | 9.5 | 20,246,280 | | 19,817,265 | 0.9788 | 9.4103 |
| 2000 | 10.5 | 15,902,384 | | 13,804,427 | 0.8681 | 10.1413 |
| 1999 | 11.5 | 19,989,956 | | 19,147,511 | 0.9579 | 11.3010 |
| 1998 | 12.5 | 11,456,939 | | 11,133,907 | 0.9718 | 12.3950 |
| 1997 | 13.5 | 7,606,332 | | 6,976,698 | 0.9172 | 13.0012 |
| 1996 | 14.5 | 8,065,812 | | 7,113,394 | 0.8819 | 13.8168 |
| 1995 | 15.5 | 5,462,633 | | 3,867,810 | 0.7080 | 14.3157 |
| 1994 | 16.5 | 3,640,568 | | 2,939,364 | 0.8074 | 15.4606 |
| 1993 | 17.5 | 5,461,100 | | 4,518,641 | 0.8274 | 16.6038 |
| 1992 | 18.5 | 4,333,603 | | 3,299,401 | 0.7614 | 17.2905 |
| 1991 | 19.5 | 5,404,322 | | 3,878,592 | 0.7177 | 17.1375 |
| 1990 | 20.5 | 5,397,653 | | 4,299,549 | 0.7966 | 17.7358 |
| 1989 | 21.5 | 4,852,251 | | 4,429,694 | 0.9129 | 20.7330 |
| 1988 | 22.5 | 11,582,781 | | 9,548,697 | 0.8244 | 20.8852 |
| 1987 | 23.5 | 6,089,217 | | 5,504,471 | 0.9040 | 22.9735 |
| 1986 | 24.5 | 8,857,497 | | 6,245,626 | 0.7051 | 21.7401 |
| 1985 | 25.5 | 8,450,138 | | 6,804,962 | 0.8053 | 23.4293 |
| 1984 | 26.5 | 6,301,017 | | 4,259,757 | 0.6760 | 22.0226 |
| 1983 | 27.5 | 4,296,972 | | 3,369,708 | 0.7842 | 23.8970 |
| 1982 | 28.5 | 6,977,975 | | 3,867,435 | 0.5542 | 22.0180 |
| 1981 | 29.5 | 3,178,217 | | 2,197,584 | 0.6915 | 26.0312 |
| 1980 | 30.5 | 3,310,288 | | 1,815,309 | 0.5484 | 25.0893 |
| 1979 | 31.5 | 5,432,311 | | 3,672,304 | 0.6760 | 27.7985 |
| 1978 | 32.5 | 3,817,195 | | 2,089,710 | 0.5474 | 26.6399 |
| 1977 | 33.5 | 2,345,255 | | 1,373,571 | 0.5857 | 28.9335 |
| 1976 | 34.5 | 1,292,464 | | 647,653 | 0.5011 | 27.8451 |
| 1975 | 35.5 | 1,131,156 | | 804,184 | 0.7109 | 32.4983 |
| 1974 | 36.5 | 4,358,605 | | 1,927,649 | 0.4423 | 26.0143 |

## ARIZONA PUBLIC SERVICE COMPANY

**Distribution Plant**

**Account: 362.00 Station Equipment**

**Age Distribution**

| Vintage | Age as of 12/31/2010 | Derived Additions | 1971 Opening Balance | Experience to 12/31/2010 Amount Surviving | Proportion Surviving | Realized Life |
|---|---|---|---|---|---|---|
| A | B | C | D | E | F=E/(C+D) | G |
| 1973 | 37.5 | 2,168,175 | | 1,243,097 | 0.5733 | 32.6685 |
| 1972 | 38.5 | 4,168,498 | | 1,835,496 | 0.4403 | 27.9625 |
| 1971 | 39.5 | 1,198,504 | | 657,693 | 0.5488 | 32.1640 |
| 1970 | 40.5 | | 3,261,971 | 1,717,869 | 0.5266 | 32.8187 |
| 1969 | 41.5 | | 1,506,880 | 760,378 | 0.5046 | 33.9778 |
| 1968 | 42.5 | | 815,711 | 442,261 | 0.5422 | 35.8759 |
| 1967 | 43.5 | | 662,909 | 318,764 | 0.4809 | 35.7943 |
| 1966 | 44.5 | | 655,699 | 431,631 | 0.6583 | 38.7746 |
| 1965 | 45.5 | | 527,904 | 182,048 | 0.3449 | 33.7074 |
| 1964 | 46.5 | | 482,393 | 187,919 | 0.3896 | 39.6121 |
| 1963 | 47.5 | | 896,787 | 328,083 | 0.3658 | 35.1953 |
| 1962 | 48.5 | | 1,476,615 | 836,090 | 0.5662 | 40.1052 |
| 1961 | 49.5 | | 453,274 | 105,433 | 0.2326 | 35.3652 |
| 1960 | 50.5 | | 664,089 | 403,593 | 0.6077 | 42.9353 |
| 1959 | 51.5 | | 527,014 | 116,498 | 0.2211 | 36.9058 |
| 1958 | 52.5 | | 862,125 | 236,828 | 0.2747 | 36.7817 |
| 1957 | 53.5 | | 727,325 | 144,058 | 0.1981 | 37.1069 |
| 1956 | 54.5 | | 668,974 | 236,693 | 0.3538 | 41.5710 |
| 1955 | 55.5 | | 861,024 | 263,209 | 0.3057 | 42.8371 |
| 1954 | 56.5 | | 591,941 | 155,912 | 0.2634 | 41.8970 |
| 1953 | 57.5 | | 387,431 | 97,574 | 0.2518 | 39.9524 |
| 1952 | 58.5 | | 651,617 | 130,534 | 0.2003 | 41.6343 |
| 1951 | 59.5 | | 240,909 | 29,426 | 0.1221 | 40.1844 |
| 1950 | 60.5 | | 141,579 | 68,513 | 0.4839 | 58.4225 |
| 1949 | 61.5 | | 288,531 | 74,709 | 0.2589 | 54.7982 |
| 1948 | 62.5 | | 305,066 | 167,271 | 0.5483 | 58.8614 |
| 1947 | 63.5 | | 38,715 | | 0.0000 | 60.2396 |
| 1946 | 64.5 | | 10,283 | 3,742 | 0.3639 | 62.9096 |
| 1945 | 65.5 | | 80,545 | 45,852 | 0.5693 | 64.4672 |
| 1943 | 67.5 | | 5,970 | 124 | 0.0208 | 61.2440 |
| 1942 | 68.5 | | 143,577 | 103,074 | 0.7179 | 65.8544 |
| 1941 | 69.5 | | 5,369 | 921 | 0.1716 | 65.9414 |
| 1940 | 70.5 | | 723,683 | 1,053 | 0.0015 | 42.0967 |
| 1939 | 71.5 | | 12,143 | 4,690 | 0.3862 | 69.2960 |
| 1938 | 72.5 | | 1,270 | | 0.0000 | 69.0000 |
| 1937 | 73.5 | | 1,991 | | 0.0000 | 56.0000 |
| 1935 | 75.5 | | 35,712 | 29,425 | 0.8239 | 75.2359 |

**ARIZONA PUBLIC SERVICE COMPANY**
**Distribution Plant**
**Account: 362.00 Station Equipment**

**Age Distribution**

| Vintage | Age as of 12/31/2010 | Derived Additions | 1971 Opening Balance | Experience to 12/31/2010 Amount Surviving | Proportion Surviving | Realized Life |
|---|---|---|---|---|---|---|
| A | B | C | D | E | F=E/(C+D) | G |
| 1929 | 81.5 | | 10,650 | 5,471 | 0.5137 | 80.1481 |
| Total | 10.7 | $443,387,214 | $18,727,676 | $406,799,985 | 0.8803 | |

## ARIZONA PUBLIC SERVICE COMPANY

**Distribution Plant**

**Account: 362.00 Station Equipment**

**Unadjusted Plant History**

| Year | Beginning Balance | Additions | Retirements | Sales, Transfers & Adjustments | Ending Balance |
|---|---|---|---|---|---|
| A | B | C | D | E | F=B+C-D+E |
| 1971 | (197,326) | (315,403) | | | (512,729) |
| 1972 | (512,729) | 4,293,454 | 267,313 | 20,268,903 | 23,782,315 |
| 1973 | 23,782,315 | 1,811,938 | 156,258 | (1) | 25,437,995 |
| 1974 | 25,437,995 | 3,836,944 | 200,589 | | 29,074,349 |
| 1975 | 29,074,349 | 1,723,973 | 289,499 | | 30,508,823 |
| 1976 | 30,508,823 | 1,457,810 | 328,724 | | 31,637,910 |
| 1977 | 31,637,910 | 2,228,384 | 122,868 | | 33,743,426 |
| 1978 | 33,743,426 | 3,599,800 | 221,922 | | 37,121,304 |
| 1979 | 37,121,304 | 5,333,750 | 141,915 | | 42,313,139 |
| 1980 | 42,313,139 | 3,217,662 | 195,943 | 18,957 | 45,353,814 |
| 1981 | 45,353,814 | 3,025,619 | 285,113 | 3,499 | 48,097,819 |
| 1982 | 48,097,819 | 6,814,111 | 553,733 | (20,659) | 54,337,538 |
| 1983 | 54,337,538 | 4,115,031 | 788,796 | 15,653 | 57,679,426 |
| 1984 | 57,679,426 | 5,352,720 | 540,334 | 172,655 | 62,664,467 |
| 1985 | 62,664,467 | 7,981,730 | 530,996 | 6,483 | 70,121,683 |
| 1986 | 70,121,683 | 6,729,114 | 488,282 | (612,394) | 75,750,122 |
| 1987 | 75,750,122 | 5,853,890 | 1,214,438 | (48,594) | 80,340,980 |
| 1988 | 80,340,980 | 10,646,542 | 2,585,562 | 1,425 | 88,403,386 |
| 1989 | 88,403,386 | 5,111,358 | 4,949,595 | (22,258) | 88,542,890 |
| 1990 | 88,542,890 | 5,281,728 | 1,077,929 | 57,545 | 92,804,234 |
| 1991 | 92,804,234 | 4,600,648 | 1,204,353 | (81,832) | 96,118,697 |
| 1992 | 96,118,697 | 5,551,769 | 704,500 | (242) | 100,965,724 |
| 1993 | 100,965,724 | 5,349,721 | 1,679,689 | 55,344 | 104,691,100 |
| 1994 | 104,691,100 | 4,265,607 | 663,584 | 5,105,806 | 113,398,930 |
| 1995 | 113,398,930 | 5,500,420 | 63,199 | 26,780 | 118,862,931 |
| 1996 | 118,862,931 | 9,201,675 | | | 128,064,606 |
| 1997 | 128,064,606 | 7,558,209 | | (1,237,571) | 134,385,244 |
| 1998 | 134,385,244 | 11,400,750 | 870,741 | | 144,915,254 |
| 1999 | 144,915,254 | 19,156,586 | 5,015,699 | | 159,056,141 |
| 2000 | 159,056,141 | 14,750,178 | 729,953 | | 173,076,366 |
| 2001 | 173,076,366 | 22,297,098 | 1,094,340 | | 194,279,123 |
| 2002 | 194,279,123 | 19,710,942 | 1,585,452 | | 212,404,613 |
| 2003 | 212,404,613 | 13,840,098 | 312,803 | | 225,931,908 |
| 2004 | 225,931,908 | 20,644,519 | 3,956,064 | | 242,620,363 |
| 2005 | 242,620,363 | 36,908,827 | 3,549,091 | (931,135) | 275,048,964 |
| 2006 | 275,048,964 | 37,921,966 | 5,074,017 | (1,372,215) | 306,524,699 |
| 2007 | 306,524,699 | 21,411,660 | 3,277,891 | (35,705) | 324,622,763 |
| 2008 | 324,622,763 | 58,498,010 | 4,869,485 | (56,151) | 378,195,137 |
| 2009 | 378,195,137 | 19,320,926 | 3,899,219 | 230,597 | 393,847,441 |
| 2010 | 393,847,441 | 14,249,796 | 1,825,016 | 527,764 | 406,799,985 |

## ARIZONA PUBLIC SERVICE COMPANY

**Distribution Plant**

**Account: 362.00 Station Equipment**

**Adjusted Plant History**

| Year | Beginning Balance | Additions | Retirements | Sales, Transfers & Adjustments | Ending Balance |
|---|---|---|---|---|---|
| A | B | C | D | E | F=B+C-D+E |
| 1971 | 18,609,402 | 1,186,414 | | | 19,795,816 |
| 1972 | 19,795,816 | 4,189,415 | 267,313 | | 23,717,918 |
| 1973 | 23,717,918 | 2,252,423 | 156,258 | | 25,814,083 |
| 1974 | 25,814,083 | 4,307,788 | 194,414 | | 29,927,457 |
| 1975 | 29,927,457 | 1,132,059 | 295,674 | | 30,763,843 |
| 1976 | 30,763,843 | 1,291,776 | 328,724 | | 31,726,895 |
| 1977 | 31,726,895 | 2,302,955 | 122,868 | | 33,906,982 |
| 1978 | 33,906,982 | 3,825,953 | 221,922 | | 37,511,013 |
| 1979 | 37,511,013 | 5,435,532 | 141,915 | | 42,804,630 |
| 1980 | 42,804,630 | 3,173,386 | 195,943 | 18,957 | 45,801,029 |
| 1981 | 45,801,029 | 3,106,164 | 296,730 | 3,499 | 48,613,963 |
| 1982 | 48,613,963 | 6,867,579 | 581,445 | (20,659) | 54,879,437 |
| 1983 | 54,879,437 | 4,250,895 | 640,321 | 15,653 | 58,505,664 |
| 1984 | 58,505,664 | 6,104,416 | 526,751 | 172,655 | 64,255,985 |
| 1985 | 64,255,985 | 6,788,866 | 430,968 | 6,483 | 70,620,365 |
| 1986 | 70,620,365 | 8,464,109 | 412,710 | (659,121) | 78,012,643 |
| 1987 | 78,012,643 | 5,290,500 | 1,257,429 | (48,593) | 81,997,121 |
| 1988 | 81,997,121 | 10,580,905 | 2,149,202 | 1,620 | 90,430,444 |
| 1989 | 90,430,444 | 4,577,494 | 5,527,381 | (22,258) | 89,458,300 |
| 1990 | 89,458,300 | 5,231,070 | 1,207,750 | 57,545 | 93,539,164 |
| 1991 | 93,539,164 | 5,316,499 | 1,204,353 | | 97,651,311 |
| 1992 | 97,651,311 | 4,546,303 | 688,591 | | 101,509,023 |
| 1993 | 101,509,023 | 5,306,989 | 1,679,689 | 55,344 | 105,191,667 |
| 1994 | 105,191,667 | 3,429,665 | 663,584 | 5,105,806 | 113,063,554 |
| 1995 | 113,063,554 | 5,462,633 | 63,199 | 26,780 | 118,489,768 |
| 1996 | 118,489,768 | 9,303,383 | | | 127,793,152 |
| 1997 | 127,793,152 | 7,606,332 | 36,998 | (1,237,571) | 134,124,915 |
| 1998 | 134,124,915 | 11,456,939 | 870,741 | | 144,711,114 |
| 1999 | 144,711,114 | 19,989,956 | 5,015,699 | | 159,685,371 |
| 2000 | 159,685,371 | 15,902,384 | 729,953 | | 174,857,802 |
| 2001 | 174,857,802 | 21,514,557 | 1,094,340 | | 195,278,019 |
| 2002 | 195,278,019 | 18,540,699 | 1,585,452 | | 212,233,266 |
| 2003 | 212,233,266 | 17,251,309 | 312,803 | | 229,171,772 |
| 2004 | 229,171,772 | 18,692,168 | 3,975,898 | | 243,888,043 |
| 2005 | 243,888,043 | 38,096,362 | 3,940,520 | (931,135) | 277,112,750 |
| 2006 | 277,112,750 | 35,096,624 | 4,625,757 | (1,372,215) | 306,211,402 |
| 2007 | 306,211,402 | 20,203,450 | 3,277,891 | (35,705) | 323,101,256 |
| 2008 | 323,101,256 | 44,372,505 | 4,869,485 | (56,151) | 362,548,125 |
| 2009 | 362,548,125 | 28,515,638 | 3,899,219 | 230,597 | 387,395,141 |
| 2010 | 387,395,141 | 20,702,095 | 1,825,016 | 527,764 | 406,799,985 |

## ARIZONA PUBLIC SERVICE COMPANY

**Distribution Plant**

**Account: 362.00 Station Equipment**

T-Cut: None
Placement Band: 1929-2010
Hazard Function: Proportion Retired
Weighting: Exposures

**Rolling Band Life Analysis**

| Observation Band | Censoring | First Degree | | | Second Degree | | | Third Degree | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | Average Life | Dispersion | Conf. Index | Average Life | Dispersion | Conf. Index | Average Life | Dispersion | Conf. Index |
| A | B | C | D | E | F | G | H | I | J | K |
| 1971-1975 | 62.5 | 43.8 | L1 * | 7.83 | 39.1 | S1 | 10.18 | 37.0 | R2 | 11.46 |
| 1972-1976 | 57.3 | 41.9 | L1 | 7.58 | 37.5 | S0.5 | 10.05 | 36.5 | R1.5 | 10.59 |
| 1973-1977 | 63.9 | 48.2 | L1 | 6.72 | 42.4 | S0.5 | 8.76 | 41.2 | R1.5 | 9.11 |
| 1974-1978 | 62.0 | 47.8 | L1 | 6.53 | 42.5 | S0.5 | 8.59 | 42.2 | S0.5 | 8.66 |
| 1975-1979 | 64.0 | 51.1 | L1 | 5.88 | 46.0 | S0.5 | 7.40 | 46.5 | S0.5 | 7.34 |
| 1976-1980 | 69.1 | 58.0 | L1 | 5.15 | 51.7 | S0.5 | 6.37 | 75.2 | O3 * | 6.04 |
| 1977-1981 | 69.1 | 58.0 | L1 | 5.45 | 56.6 | L1 | 5.66 | 51.6 | S0.5 | 6.09 |
| 1978-1982 | 59.5 | 51.0 | L1 | 5.77 | 49.2 | L1 | 6.22 | 44.6 | R1.5 | 7.35 |
| 1979-1983 | 50.7 | 46.9 | L1 | 5.40 | 44.0 | S0.5 | 6.78 | 42.2 | R1.5 | 7.54 |
| 1980-1984 | 46.8 | 44.5 | L1 | 5.95 | 43.6 | L1 | 6.34 | 41.1 | S0.5 | 7.31 |
| 1981-1985 | 44.1 | 43.6 | L1 | 5.89 | 42.7 | L1.5 | 6.35 | 41.0 | S0.5 | 7.03 |
| 1982-1986 | 43.4 | 44.1 | L1 * | 5.72 | 43.5 | L1 | 6.03 | 42.1 | S0 | 6.48 |
| 1983-1987 | 28.8 | 39.6 | L1.5 * | 4.12 | 38.1 | S0.5 | 5.58 | 37.9 | S0.5 | 5.72 |
| 1984-1988 | 20.8 | 36.1 | L1 | 3.62 | 35.0 | L1 | 4.37 | 34.5 | S0 | 4.82 |
| 1985-1989 | 1.2 | 25.5 | L0.5 | 3.91 | 25.6 | L0.5 | 3.98 | 25.5 | L0.5 | 3.56 |
| 1986-1990 | 1.8 | 25.6 | L0.5 | 3.67 | 25.9 | L0.5 | 3.77 | 25.6 | L0.5 | 3.30 |
| 1987-1991 | 7.1 | 25.7 | L0.5 | 3.29 | 25.9 | L0.5 | 3.14 | 25.7 | L0.5 | 3.27 |
| 1988-1992 | 10.1 | 27.8 | L0 | 3.33 | 28.7 | L0 * | 2.86 | 28.0 | L0 | 3.07 |
| 1989-1993 | 10.4 | 29.5 | L0 | 2.80 | 30.8 | L0 * | 2.35 | 29.7 | L0 | 2.51 |
| 1990-1994 | 42.6 | 48.8 | L0 | 4.80 | 46.1 | L0.5 | 5.98 | 97.7 | O4 * | 1.79 |
| 1991-1995 | 50.2 | 56.4 | L0.5 | 4.71 | 50.4 | S0 | 7.07 | 111.3 | O3 * | 1.95 |
| 1992-1996 | 56.0 | 66.9 | L0.5 | 3.27 | 65.3 | L0.5 | 3.51 | 131.1 | SC * | 2.45 |
| 1993-1997 | 65.1 | 82.0 | L0.5 | 2.59 | 84.9 | L0.5 | 2.42 | 145.9 | SC * | 2.24 |
| 1994-1998 | 76.9 | 81.2 | L1 * | 6.81 | 151.1 | SC * | 2.59 | 159.3 | R1 * | 1.14 |
| 1995-1999 | 51.7 | 49.0 | L1 | 12.12 | 117.0 | O3 * | 1.86 | 117.0 | O3 * | 1.86 |
| 1996-2000 | 48.4 | 48.3 | L0.5 | 11.15 | 111.6 | O3 * | 1.62 | 111.2 | O3 * | 1.54 |
| 1997-2001 | 34.2 | 45.9 | L0.5 | 7.51 | 97.7 | O4 * | 3.27 | 52.8 | L0 * | 2.04 |
| 1998-2002 | 28.4 | 43.8 | L0.5 | 7.38 | 94.3 | O4 * | 3.82 | 47.5 | L0 * | 2.10 |
| 1999-2003 | 30.7 | 48.0 | L0.5 | 6.47 | 106.1 | O4 * | 5.89 | 49.5 | SC * | 2.61 |
| 2000-2004 | 31.9 | 54.8 | L0.5 | 3.28 | 76.6 | O3 * | 2.90 | 52.5 | R0.5 | 3.67 |
| 2001-2005 | 23.3 | 46.3 | L0.5 | 3.90 | 79.7 | O4 * | 3.46 | 46.9 | S-.5 | 3.08 |
| 2002-2006 | 17.3 | 41.1 | L0.5 | 4.01 | 65.2 | O4 * | 2.25 | 42.3 | L0 | 2.38 |
| 2003-2007 | 8.2 | 39.2 | L0.5 | 1.53 | 40.5 | L0.5 * | 1.33 | 39.5 | L0.5 | 1.32 |
| 2004-2008 | 3.7 | 35.9 | L0.5 | 1.70 | 35.8 | L1 | 1.64 | 35.5 | L1 | 1.47 |
| 2005-2009 | 3.0 | 37.4 | L0.5 | 1.96 | 37.1 | L1 | 1.81 | 36.8 | L1 | 1.62 |
| 2006-2010 | 2.1 | 40.9 | L1 | 3.20 | 39.7 | S0 | 1.82 | 39.4 | S0 | 1.73 |

## ARIZONA PUBLIC SERVICE COMPANY

**Distribution Plant**

**Account: 362.00 Station Equipment**

T-Cut: None
Placement Band: 1929-2010
Hazard Function: Proportion Retired
Weighting: Exposures

**Shrinking Band Life Analysis**

| Observation Band | Censoring | First Degree | | | Second Degree | | | Third Degree | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | Average Life | Dispersion | Conf. Index | Average Life | Dispersion | Conf. Index | Average Life | Dispersion | Conf. Index |
| A | B | C | D | E | F | G | H | I | J | K |
| 1971-2010 | 6.1 | 42.3 | L0.5 | 1.26 | 43.1 | L0.5 | 1.41 | 41.4 | S-.5 | 1.74 |
| 1973-2010 | 6.1 | 42.3 | L0.5 | 1.26 | 43.1 | L0.5 | 1.43 | 41.4 | S-.5 | 1.74 |
| 1975-2010 | 6.1 | 42.3 | L0.5 | 1.26 | 43.1 | L0.5 | 1.43 | 41.4 | S-.5 | 1.74 |
| 1977-2010 | 6.1 | 42.3 | L0.5 | 1.27 | 43.2 | L0.5 | 1.46 | 41.4 | S-.5 | 1.76 |
| 1979-2010 | 6.1 | 42.2 | L0.5 | 1.27 | 43.1 | L0.5 | 1.46 | 41.3 | S-.5 | 1.75 |
| 1981-2010 | 6.1 | 42.0 | L0.5 | 1.28 | 43.0 | L0.5 | 1.44 | 41.2 | S-.5 | 1.74 |
| 1983-2010 | 6.1 | 41.9 | L0.5 | 1.31 | 43.0 | L0.5 | 1.46 | 41.1 | S-.5 | 1.75 |
| 1985-2010 | 6.1 | 41.9 | L0.5 | 1.34 | 43.0 | L0.5 | 1.48 | 41.1 | S-.5 | 1.77 |
| 1987-2010 | 6.1 | 41.8 | L0.5 | 1.33 | 42.9 | L0.5 | 1.49 | 41.0 | S-.5 | 1.77 |
| 1989-2010 | 6.3 | 42.5 | L0.5 | 1.42 | 43.9 | L0.5 | 1.70 | 41.6 | S-.5 | 1.84 |
| 1991-2010 | 7.0 | 44.8 | L0.5 | 1.53 | 45.2 | L0.5 | 1.65 | 43.4 | S-.5 | 1.81 |
| 1993-2010 | 6.9 | 44.6 | L0.5 | 1.55 | 45.3 | L0.5 | 1.77 | 43.2 | S-.5 | 1.94 |
| 1995-2010 | 6.8 | 44.6 | L0.5 | 1.59 | 45.3 | L0.5 | 1.82 | 43.2 | S-.5 | 1.97 |
| 1997-2010 | 6.2 | 43.0 | L0.5 | 1.51 | 44.0 | L0.5 | 1.77 | 41.9 | S-.5 | 1.90 |
| 1999-2010 | 5.5 | 41.6 | L0.5 | 1.47 | 42.7 | L0.5 | 1.71 | 40.7 | S-.5 | 1.86 |
| 2001-2010 | 5.2 | 42.8 | L0.5 | 1.80 | 42.3 | L1 | 1.49 | 41.3 | S0 | 1.88 |
| 2003-2010 | 4.7 | 41.4 | L0.5 | 1.72 | 40.8 | L1 | 1.44 | 40.2 | S0 | 1.80 |
| 2005-2010 | 2.3 | 39.9 | L1 | 2.31 | 39.3 | L1 | 1.72 | 38.9 | S0 | 1.40 |
| 2007-2010 | 2.2 | 43.1 | L1 | 4.63 | 41.1 | S0.5 | 1.81 | 40.9 | R1 | 1.88 |
| 2009-2010 | 0.5 | 50.8 | L1 | 9.09 | 48.3 | S0 | 6.96 | 46.7 | R1 | 5.07 |

## ARIZONA PUBLIC SERVICE COMPANY

**Distribution Plant**

**Account: 362.00 Station Equipment**

T-Cut: None
Placement Band: 1929-2010
Hazard Function: Proportion Retired
Weighting: Exposures

**Progressing Band Life Analysis**

| Observation Band | Censoring | First Degree | | | Second Degree | | | Third Degree | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | Average Life | Dispersion | Conf. Index | Average Life | Dispersion | Conf. Index | Average Life | Dispersion | Conf. Index |
| A | B | C | D | E | F | G | H | I | J | K |
| 1971-1972 | 77.9 | 46.7 | L1 * | 10.72 | 39.6 | S1 | 13.54 | 37.5 | R2 | 14.46 |
| 1971-1974 | 71.3 | 47.9 | L1 | 8.29 | 41.7 | S0.5 | 10.42 | 39.1 | R2 | 11.42 |
| 1971-1976 | 59.5 | 45.0 | L1 | 6.35 | 39.2 | S0.5 | 9.06 | 37.9 | R1.5 | 9.81 |
| 1971-1978 | 57.7 | 47.8 | L1 | 4.62 | 42.2 | S0.5 | 6.86 | 41.2 | R1.5 | 7.26 |
| 1971-1980 | 57.6 | 51.0 | L1 | 3.66 | 46.0 | S0.5 | 5.19 | 45.7 | S0.5 | 5.25 |
| 1971-1982 | 51.0 | 49.6 | L1 | 2.86 | 45.5 | S0.5 | 4.18 | 43.5 | S0.5 | 4.97 |
| 1971-1984 | 43.7 | 46.8 | L1 | 2.72 | 44.0 | L1.5 | 3.88 | 42.0 | S0.5 | 4.90 |
| 1971-1986 | 41.8 | 47.4 | L1 | 2.69 | 44.9 | L1.5 | 3.69 | 43.7 | S0.5 | 4.21 |
| 1971-1988 | 23.2 | 41.1 | L1 | 2.86 | 38.8 | S0 | 2.76 | 37.8 | S0.5 | 3.58 |
| 1971-1990 | 6.7 | 33.8 | L0.5 | 4.08 | 33.6 | L1 | 3.89 | 32.5 | S0 | 2.91 |
| 1971-1992 | 14.5 | 35.6 | L0.5 | 2.63 | 35.2 | L1 | 2.63 | 34.3 | S-.5 | 3.05 |
| 1971-1994 | 16.5 | 36.8 | L0.5 | 2.55 | 36.5 | L0.5 | 2.61 | 35.9 | L1 | 2.91 |
| 1971-1996 | 23.2 | 40.8 | L0.5 | 3.11 | 40.7 | L0.5 | 3.19 | 44.0 | L0.5 * | 2.93 |
| 1971-1998 | 32.2 | 43.8 | L0.5 | 5.12 | 44.3 | L0.5 | 4.87 | 70.7 | O4 * | 3.08 |
| 1971-2000 | 30.9 | 41.7 | L0.5 | 6.52 | 60.7 | O4 * | 3.37 | 76.1 | O4 * | 1.92 |
| 1971-2002 | 25.6 | 43.4 | L0.5 | 5.24 | 67.2 | O4 * | 1.69 | 66.0 | O4 * | 1.73 |
| 1971-2004 | 27.0 | 44.3 | L0.5 | 5.67 | 69.5 | O4 * | 1.61 | 70.3 | O4 * | 1.57 |
| 1971-2006 | 19.8 | 42.1 | L0.5 | 4.21 | 61.6 | O4 * | 0.94 | 45.5 | L0 | 1.38 |
| 1971-2008 | 10.9 | 41.2 | L0.5 | 1.68 | 42.3 | L0.5 | 1.49 | 40.7 | L0.5 | 2.03 |
| 1971-2010 | 6.1 | 42.3 | L0.5 | 1.26 | 43.1 | L0.5 | 1.41 | 41.4 | S-.5 | 1.74 |

## ARIZONA PUBLIC SERVICE COMPANY

**Distribution Plant**

**Account: 362.00 Station Equipment**

T-Cut: None

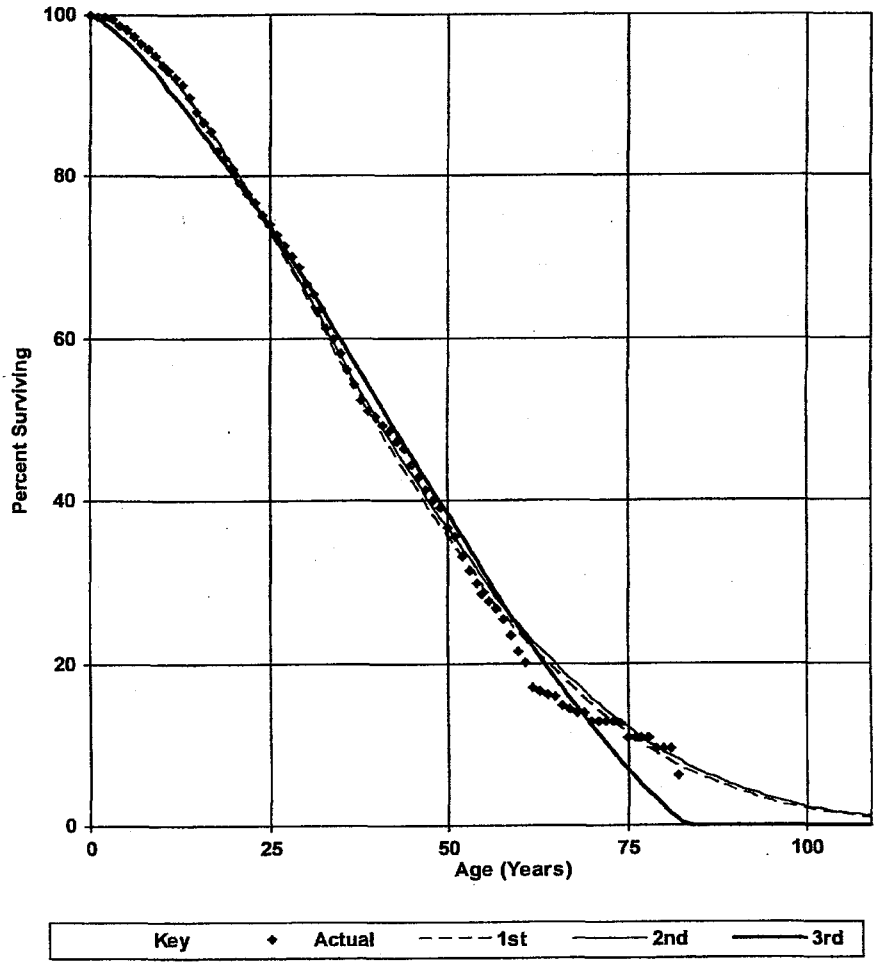
Placement Band: 1929-2010 Observation Band: 1971-2010

Hazard Function: Proportion Retired

Weighting: Exposures

**Graphics Analysis**

1st: 42.3-L0.5 2nd: 43.1-L0.5 3rd: 41.4-S-.5



## ARIZONA PUBLIC SERVICE COMPANY

**Distribution Plant**

**Account: 362.00 Station Equipment**

T-Cut: None

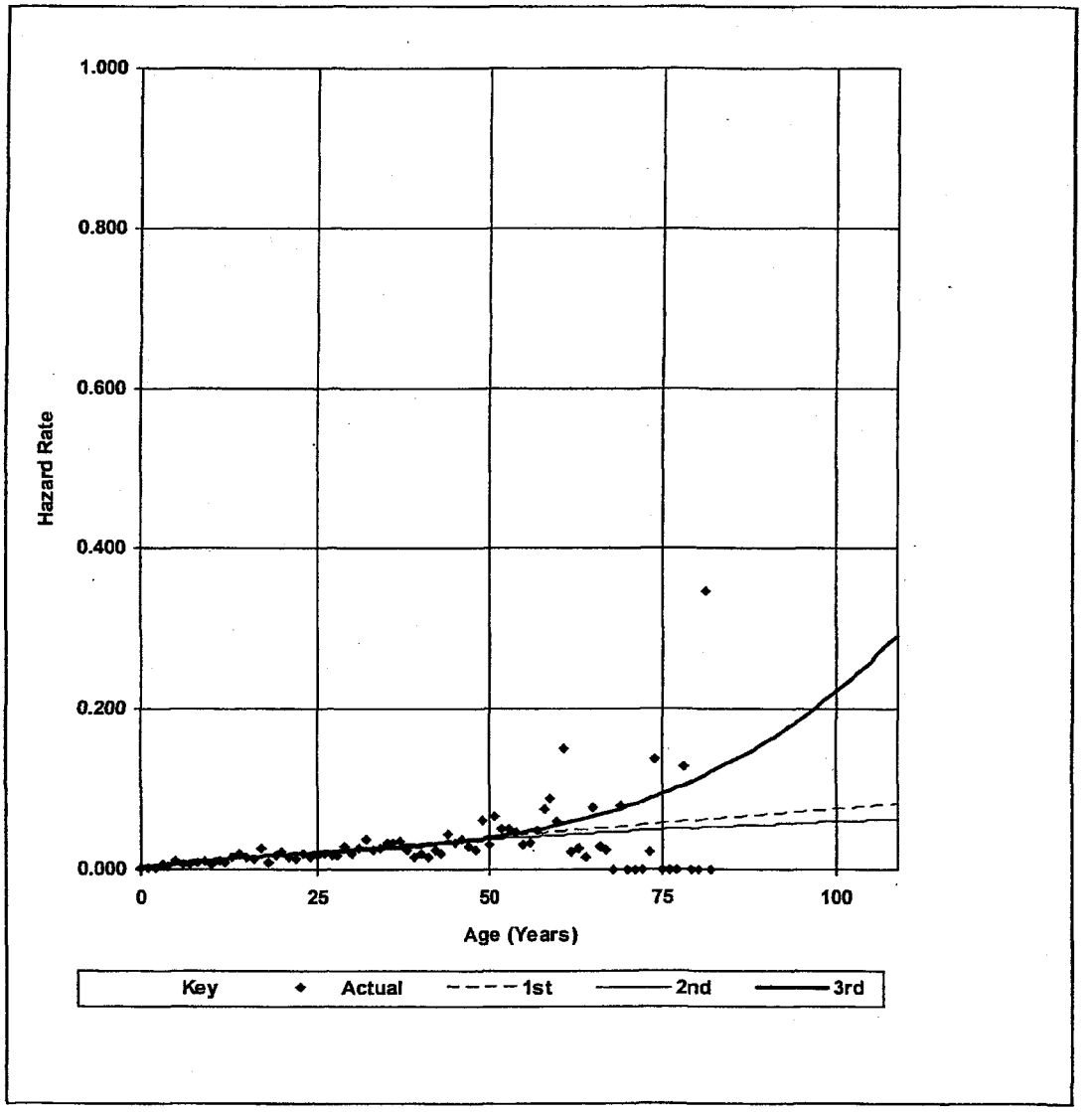
Placement Band: 1929-2010 Observation Band: 1971-2010

Hazard Function: Proportion Retired

Weighting: Exposures

***Polynomial Hazard Function***

1st: 42.3-L0.5 2nd: 43.1-L0.5 3rd: 41.4-S-.5



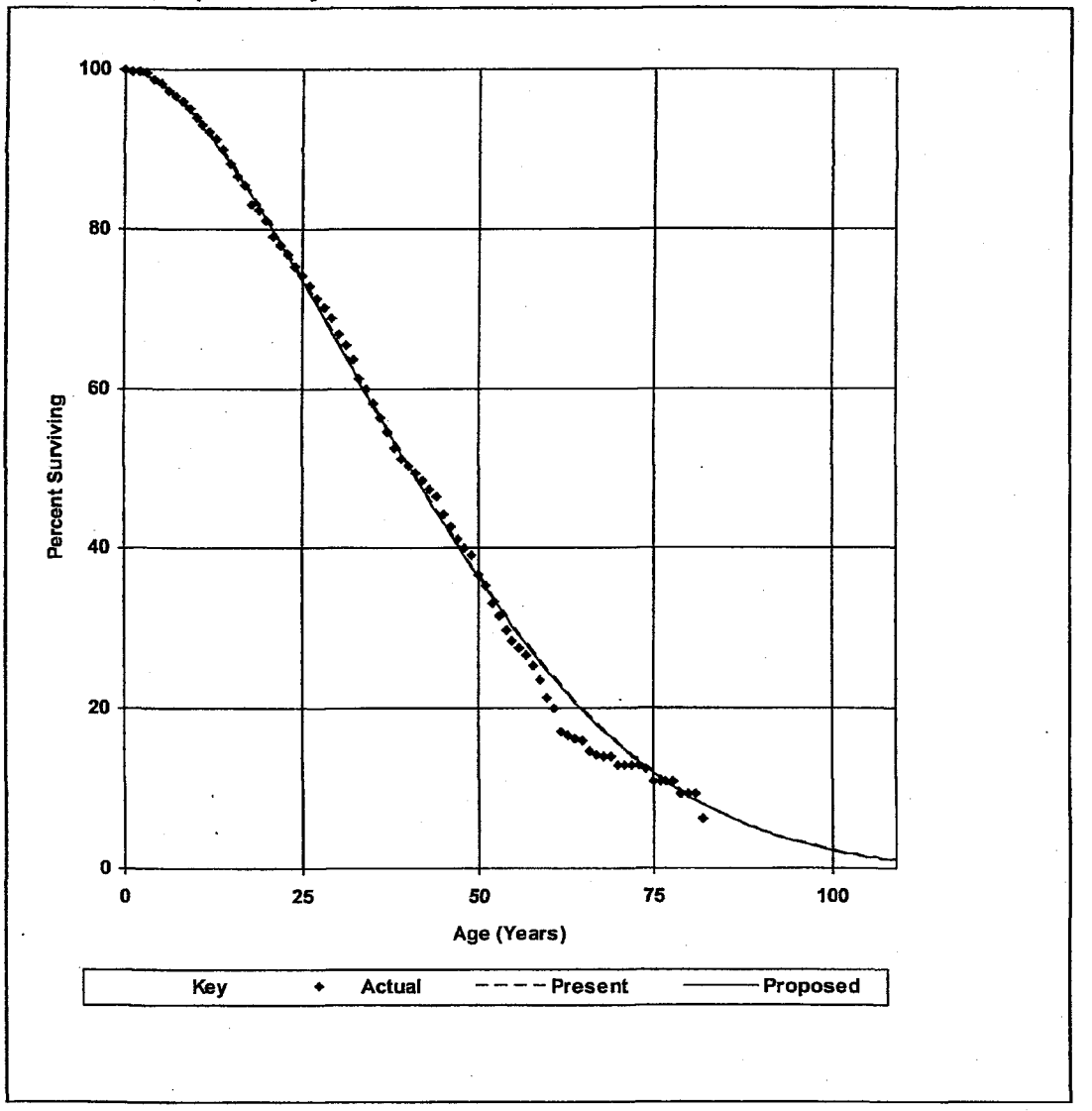
## ARIZONA PUBLIC SERVICE COMPANY

**Distribution Plant**

**Account: 362.00 Station Equipment**

T-Cut: None
Placement Band: 1929-2010
Observation Band: 1971-2010

**Present and Proposed Projection Life Curves** Present: 43.0-L0.5 Proposed: 43.0-L0.5



# ARIZONA PUBLIC SERVICE COMPANY

**Distribution Plant**

**Account: 362.00 Station Equipment**

**Unadjusted Net Salvage History**

| | | Gross Salvage | | | Cost of Retiring | | | Net Salvage | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Year | Retirements | Amount | Pct. | 5-Yr Avg. | Amount | Pct. | 5-Yr Avg. | Amount | Pct. | 5-Yr Avg. |
| A | B | C | D=C/B | E | F | G=F/B | H | I=C-F | J=I/B | K |
| 1980 | 195,943 | 23,940 | 12.2 | | 44,600 | 22.8 | | (20,660) | -10.5 | |
| 1981 | 285,113 | 14,271 | 5.0 | | 114,846 | 40.3 | | (100,575) | -35.3 | |
| 1982 | 553,733 | 101,079 | 18.3 | | 158,044 | 28.5 | | (56,965) | -10.3 | |
| 1983 | 788,796 | 145,734 | 18.5 | | 119,423 | 15.1 | | 26,311 | 3.3 | |
| 1984 | 540,334 | 131,469 | 24.3 | 17.6 | 144,531 | 26.7 | 24.6 | (13,062) | -2.4 | -7.0 |
| 1985 | 530,996 | 146,551 | 27.6 | 20.0 | 106,927 | 20.1 | 23.9 | 39,624 | 7.5 | -3.9 |
| 1986 | 488,282 | 16,662 | 3.4 | 18.7 | 60,520 | 12.4 | 20.3 | (43,858) | -9.0 | -1.7 |
| 1987 | 1,214,438 | 36,980 | 3.0 | 13.4 | 160,911 | 13.2 | 16.6 | (123,931) | -10.2 | -3.2 |
| 1988 | 2,585,562 | 2,309,201 | 89.3 | 49.3 | 246,124 | 9.5 | 13.4 | 2,063,077 | 79.8 | 35.9 |
| 1989 | 4,949,595 | 269,663 | 5.4 | 28.4 | 206,957 | 4.2 | 8.0 | 62,706 | 1.3 | 20.4 |
| 1990 | 1,077,929 | 445,162 | 41.3 | 29.8 | 131,454 | 12.2 | 7.8 | 313,708 | 29.1 | 22.0 |
| 1991 | 1,204,353 | 553,850 | 46.0 | 32.8 | 157,459 | 13.1 | 8.2 | 396,391 | 32.9 | 24.6 |
| 1992 | 704,500 | 239,226 | 34.0 | 36.3 | 215,787 | 30.6 | 9.1 | 23,439 | 3.3 | 27.2 |
| 1993 | 1,679,689 | 343,438 | 20.4 | 19.3 | 219,066 | 13.0 | 9.7 | 124,371 | 7.4 | 9.6 |
| 1994 | 663,584 | 124,296 | 18.7 | 32.0 | 98,392 | 14.8 | 15.4 | 25,904 | 3.9 | 16.6 |
| 1995 | 63,199 | 12,802 | 20.3 | 29.5 | 7,090 | 11.2 | 16.2 | 5,712 | 9.0 | 13.3 |
| 1996 | | | 0.0 | 23.1 | | 0.0 | 17.4 | | 0.0 | 5.8 |
| 1997 | | | 0.0 | 20.0 | | 0.0 | 13.5 | | 0.0 | 6.5 |
| 1998 | 870,741 | 282,808 | 32.5 | 26.3 | 16,340 | 1.9 | 7.6 | 266,468 | 30.6 | 18.7 |
| 1999 | 5,015,699 | 1,105,255 | 22.0 | 23.5 | 243,050 | 4.8 | 4.5 | 862,205 | 17.2 | 19.1 |
| 2000 | 729,953 | 200,673 | 27.5 | 24.0 | 54,063 | 7.4 | 4.7 | 146,610 | 20.1 | 19.3 |
| 2001 | 1,094,340 | 214,293 | 19.6 | 23.4 | 191,215 | 17.5 | 6.5 | 23,078 | 2.1 | 16.8 |
| 2002 | 1,585,452 | 184,970 | 11.7 | 21.4 | 1,317,557 | 83.1 | 19.6 | (1,132,587) | -71.4 | 1.8 |
| 2003 | 312,803 | 990,085 | 316.5 | 30.8 | 676,647 | 216.3 | 28.4 | 313,438 | 100.2 | 2.4 |
| 2004 | 3,956,064 | (273,543) | -6.9 | 17.1 | 157,777 | 4.0 | 31.2 | (431,320) | -10.9 | -14.1 |
| 2005 | 3,549,091 | (27,246) | -0.8 | 10.4 | 222,288 | 6.3 | 24.4 | (249,534) | -7.0 | -14.1 |
| 2006 | 5,074,017 | 2,911,829 | 57.4 | 26.2 | 500,211 | 9.9 | 19.9 | 2,411,618 | 47.5 | 6.3 |
| 2007 | 3,277,891 | 119,477 | 3.6 | 23.0 | 588,630 | 18.0 | 13.3 | (469,153) | -14.3 | 9.7 |
| 2008 | 4,869,485 | 107,233 | 2.2 | 13.7 | 863,196 | 17.7 | 11.3 | (755,963) | -15.5 | 2.4 |
| 2009 | 3,899,219 | 605,278 | 15.5 | 18.0 | 1,107,953 | 28.4 | 15.9 | (502,675) | -12.9 | 2.1 |
| 2010 | 1,825,016 | 112,006 | 6.1 | 20.4 | 379,706 | 20.8 | 18.2 | (267,700) | -14.7 | 2.2 |
| Total | 53,585,817 | 11,447,443 | 21.4 | | 8,510,763 | 15.9 | | 2,936,679 | 5.5 | |

## ARIZONA PUBLIC SERVICE COMPANY

**Distribution Plant**

**Account: 362.00 Station Equipment**

**Adjusted Net Salvage History**

| | | Gross Salvage | | | Cost of Retiring | | | Net Salvage | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Year | Retirements | Amount | Pct. | 5-Yr Avg. | Amount | Pct. | 5-Yr Avg. | Amount | Pct. | 5-Yr Avg. |
| A | B | C | D=C/B | E | F | G=F/B | H | I=C-F | J=I/B | K |
| 1980 | 195,943 | 23,940 | 12.2 | | 44,600 | 22.8 | | (20,660) | -10.5 | |
| 1981 | 296,730 | 14,271 | 4.8 | | 114,846 | 38.7 | | (100,575) | -33.9 | |
| 1982 | 581,445 | 101,079 | 17.4 | | 158,044 | 27.2 | | (56,965) | -9.8 | |
| 1983 | 640,321 | 145,734 | 22.8 | | 119,423 | 18.7 | | 26,311 | 4.1 | |
| 1984 | 526,751 | 131,469 | 25.0 | 18.6 | 144,531 | 27.4 | 25.9 | (13,062) | -2.5 | -7.4 |
| 1985 | 430,968 | 146,551 | 34.0 | 21.8 | 106,927 | 24.8 | 26.0 | 39,624 | 9.2 | -4.2 |
| 1986 | 412,710 | 16,662 | 4.0 | 20.9 | 60,520 | 14.7 | 22.7 | (43,858) | -10.6 | -1.8 |
| 1987 | 1,257,429 | 36,980 | 2.9 | 14.6 | 160,911 | 12.8 | 18.1 | (123,931) | -9.9 | -3.5 |
| 1988 | 2,149,202 | 2,309,201 | 107.4 | 55.3 | 246,124 | 11.5 | 15.1 | 2,063,077 | 96.0 | 40.2 |
| 1989 | 5,527,381 | 269,663 | 4.9 | 28.4 | 206,957 | 3.7 | 8.0 | 62,706 | 1.1 | 20.4 |
| 1990 | 1,207,750 | 445,162 | 36.9 | 29.2 | 131,454 | 10.9 | 7.6 | 313,708 | 26.0 | 21.5 |
| 1991 | 1,204,353 | 553,850 | 46.0 | 31.9 | 157,459 | 13.1 | 8.0 | 396,391 | 32.9 | 23.9 |
| 1992 | 688,591 | 239,226 | 34.7 | 35.4 | 215,787 | 31.3 | 8.9 | 23,439 | 3.4 | 26.5 |
| 1993 | 1,679,689 | 343,438 | 20.4 | 18.0 | 219,066 | 13.0 | 9.0 | 124,371 | 7.4 | 8.9 |
| 1994 | 663,584 | 124,296 | 18.7 | 31.3 | 98,392 | 14.8 | 15.1 | 25,904 | 3.9 | 16.2 |
| 1995 | 63,199 | 12,802 | 20.3 | 29.6 | 7,090 | 11.2 | 16.2 | 5,712 | 9.0 | 13.4 |
| 1996 | | | 0.0 | 23.3 | | 0.0 | 17.5 | | 0.0 | 5.8 |
| 1997 | 36,998 | | 0.0 | 19.7 | | 0.0 | 13.3 | | 0.0 | 6.4 |
| 1998 | 870,741 | 282,808 | 32.5 | 25.7 | 16,340 | 1.9 | 7.5 | 266,468 | 30.6 | 18.2 |
| 1999 | 5,015,699 | 1,105,255 | 22.0 | 23.4 | 243,050 | 4.8 | 4.5 | 862,205 | 17.2 | 18.9 |
| 2000 | 729,953 | 200,673 | 27.5 | 23.9 | 54,063 | 7.4 | 4.7 | 146,610 | 20.1 | 19.2 |
| 2001 | 1,094,340 | 214,293 | 19.6 | 23.3 | 191,215 | 17.5 | 6.5 | 23,078 | 2.1 | 16.8 |
| 2002 | 1,585,452 | 184,970 | 11.7 | 21.4 | 1,317,557 | 83.1 | 19.6 | (1,132,587) | -71.4 | 1.8 |
| 2003 | 312,803 | 990,085 | 316.5 | 30.8 | 676,647 | 216.3 | 28.4 | 313,438 | 100.2 | 2.4 |
| 2004 | 3,975,898 | (273,543) | -6.9 | 17.1 | 157,777 | 4.0 | 31.1 | (431,320) | -10.8 | -14.0 |
| 2005 | 3,940,520 | (27,246) | -0.7 | 10.0 | 222,288 | 5.6 | 23.5 | (249,534) | -6.3 | -13.5 |
| 2006 | 4,625,757 | 2,911,829 | 62.9 | 26.2 | 500,211 | 10.8 | 19.9 | 2,411,618 | 52.1 | 6.3 |
| 2007 | 3,277,891 | 119,477 | 3.6 | 23.1 | 588,630 | 18.0 | 13.3 | (469,153) | -14.3 | 9.8 |
| 2008 | 4,869,485 | 107,233 | 2.2 | 13.7 | 863,196 | 17.7 | 11.3 | (755,963) | -15.5 | 2.4 |
| 2009 | 3,899,219 | 605,278 | 15.5 | 18.0 | 1,107,953 | 28.4 | 15.9 | (502,675) | -12.9 | 2.1 |
| 2010 | 1,825,016 | 112,006 | 6.1 | 20.8 | 379,706 | 20.8 | 18.6 | (267,700) | -14.7 | 2.2 |
| Total | 53,585,817 | 11,447,443 | 21.4 | | 8,510,763 | 15.9 | | 2,936,679 | 5.5 | |

# TESTIMONY OF PETER M. EWEN

**On Behalf of Arizona Public Service Company**

**Docket No. E-01345A-11-_____**

June 1, 2011

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**TESTIMONY OF PETE M. EWEN**
**ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY**
**(Docket No. E-01345A-11-_____)**

I. INTRODUCTION

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

A. My name is Peter M. Ewen. My business address is 400 N. 5th Street, Phoenix, Arizona, 85004. I am the Director of Financial Planning and Forecasting for Arizona Public Service Company ("APS" or "Company"). In that capacity, among other responsibilities, I oversee the preparation of the Company's fuel and purchased power expense forecasts and the Company's Power Supply Adjustment ("PSA") filings with the Arizona Corporation Commission ("Commission").

**Q. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?**

A. I received Bachelors and Masters degrees in Economics from Arizona State University in 1985 and 1988, respectively. I have analyzed and forecasted electric energy and demand growth since 1988, first as a Staff member of the Commission and, since 1990, as an employee for APS. I have specifically analyzed the dispatch of our generating units in combination with market purchases to serve native load demand since 1998, and assumed full responsibility for making the optimal dispatch and associated fuel cost projections in 2000. I was formerly President of the Arizona Economic Round Table, a group of Arizona-based economists that specialize in studying the Arizona economy, and I am still a member of that organization. I also serve on the Joint Legislative Budget Committee's Finance Advisory Committee. This advisory committee consists of a group of state economists who advise the Joint Legislative Budget Committee staff on the adequacy of the economic projections underlying their state revenue projections.

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

A. My testimony discusses the system average cost of fuel for generation and purchased power. In particular, I sponsor the Company's Base Fuel and Purchased Power pro forma, which sets forth the base rate level of fuel and purchased power expenses.[1] This requested base fuel rate reflects conditions expected to exist at the time the requested rates are likely to be in effect, which, in this proceeding, represents a decrease from the current authorized rate. My testimony explains the reasons for this decrease.

In addition, I sponsor the "Total Company" column for several pro forma adjustments to the 2010 Test Year ending December 31, 2010 ("Test Year" or "TY") set forth in SFR Schedule C-2, including:

- Base Fuel and Purchased Power;
- Remove Test Year PSA Revenue and Deferred Fuel Amortization; and
- Remove Test Year PSA Deferrals and Mark-to-Market Accruals.

The Base Fuel and Purchased Power pro forma has been prepared under two alternate resource plans reflecting the fact that the Company's proposed acquisition of Southern California Edison's ("SCE") share of Four Corners Units 4 and 5 has not yet been approved and completed. My testimony discusses the method used for each.

I will also discuss two modifications to the PSA Plan of Administration ("POA"). Specifically, I will explain why the removal of the 90/10 sharing provision and the inclusion of environmental chemical costs in the PSA are appropriate.

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

**Q. WERE YOU THE COMPANY'S WITNESS ON THESE SAME MATTERS IN THE PREVIOUS THREE APS RATE PROCEEDINGS?**

A. Yes.

II. SUMMARY

**Q. PLEASE SUMMARIZE YOUR TESTIMONY.**

A. APS's current base fuel recovery amount of 3.76¢ per kilowatt-hour ("kWh"), established in Decision No. 71448 (December 30, 2009), was premised on expected 2009 cost levels at the time of the settlement in that case. Since then, the system average fuel cost has continued to decrease primarily because of lower prices for natural gas and wholesale power purchases, as well as a lower reliance on higher-cost natural gas and purchased power relative to other generation sources. During the Test Year, APS's fuel costs had fallen to 3.35¢ per kWh and are expected to decline even further into 2012.

Given the decrease in fuel costs that has occurred since fuel rates were last set, the Company proposes that the base fuel recovery rate be set at 3.24¢/kWh, which rate reflects normalized levels of power plant performance, expected 2012 fuel and purchased power prices, and a credit for anticipated off-system sales margins. This rate will allow the Company to recover fuel costs incurred during the Test Year, adjusted to reflect the conditions the Company expects to experience during 2012 when the rates requested in this proceeding are expected to become effective. Attachment PME-1 shows these changes and their respective impact on the Company's overall fuel costs.

The method by which I calculated this new base fuel rate is consistent with the one used by the Company and accepted by the Commission in the Company's last two rate cases. If the Company's proposed acquisition of incremental ownership interests of Four Corners 4 and 5 is more certain at the time of the decision in this case, then I propose that the base fuel recovery be set at

3.13¢/kWh, which reflects the lower costs of generation which will result from that transaction.

APS is the only utility in Arizona that has a cost sharing element in its PSA. Although this is currently benefiting the Company, the provision is still unfair and unnecessary to protect APS customers from imprudent acts on the part of the Company.

Certain chemicals such as lime, ammonia, and sulfur are necessary to operate certain of the Company's power plants in order to comply with environmental emissions rules. Their use is directly proportional to unit output every bit as much as fuel itself and thus should also be recoverable through the PSA.

## III. BASE FUEL AND PURCHASED POWER PRO FORMA

**Q. ARE YOU PROPOSING TO ADJUST THE COMPANY'S AUTHORIZED BASE FUEL RATE?**

A. Yes, I am proposing to decrease the base fuel rate from 3.76¢/kWh (authorized by the Commission in Decision No. 71448) to 3.24¢/kWh. 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, which APS is proposing to remove in this proceeding, 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 decrease 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. WHAT FACTORS ARE BEHIND YOUR PROPOSED ADJUSTMENT?**

A. The dramatic decline in natural gas prices and the associated decline in wholesale power prices since the last update to the base fuel rate is the largest single reason for the adjustment. By themselves, these changes in commodity prices account for $133 million of the $144 million reduction in base fuel expense. Additionally, the combination of lower retail sales and greater availability of baseload nuclear and coal generating units is leading to a lower reliance on natural gas-fired generation and wholesale power market purchases. Since natural gas and wholesale power are more costly on a variable fuel basis than nuclear and coal generation, a lower share of natural gas generation and wholesale purchases leads to a lower average cost. I have quantified the impact of this change at $60 million of the overall reduction described above.

There are several items that are offsetting these cost reductions. The most prominent are increased capacity costs and higher prices for nuclear fuel. The higher capacity costs are primarily related to having additional capacity under contract and amount to a $32 million increase. Higher uranium prices are the primary driver of higher nuclear fuel costs, which total just under $22 million of an increase.

Each of these factors represents changes in conditions since the last time the Company's base fuel rate was set (at 3.76¢/kWh). At that time, the Company relied on forward market expectations from November 2008 for the year 2009. The current estimates are based on March 2011 expectations for the year 2012. A summary of the quantification of these factors can be seen in Attachment PME-1.

Attachment PME-2 shows the average fuel cost for the Company's major resource types embedded in the current authorized and proposed base fuel rates.

**Q. DO THESE PROPOSED ADJUSTMENTS REQUIRE NORMALIZATION OF CONDITIONS EXPERIENCED IN THE TEST YEAR?**

A. Yes, the adjustments described above reflect both changes in prices and operations from the last time the Base Fuel Rate was set for the current Test Year, and known and measurable changes to Test Year conditions which are more representative of conditions that will be present when the Company's new rates are likely to take effect. Specifically, I am proposing to normalize actual Test Year fuel expenses and off-system sales margins for:

- Increased electricity sales due to customer growth;
- lower commodity market prices for natural gas and power;
- higher coal and nuclear prices due to standard contract escalators;
- normalized maintenance and unplanned outage times;
- the cancellation by Salt River Project ("SRP") of a capacity power contract with APS;
- additional renewable resources consistent with the Company's Renewable Energy Standard ("RES") requirements; and
- other miscellaneous items, such as broker fees, third-party wheeling expenses, and short-term and long-term capacity costs.

Of the total proposed adjustment, $113.7 million reflects costs that are already reflected in the Test Year and the remaining $29.8 million is for costs that are normalized to 2012 levels, the time when rates from this request are likely to take effect. For the Test Year ending December 31, 2010, the Company's actual

average base fuel and purchased power expense, excluding the impact of the period's non-cash fuel cost deferrals, was 3.35¢/kWh. Attachment PME-3, page 1 of 4, shows the components that make up this cost level.

**Q. ARE YOU PROPOSING TO NORMALIZE FUEL EXPENSES FOR THE COMPANY'S PROPOSED ACQUISITION OF SCE'S OWNERSHIP SHARE OF FOUR CORNERS UNITS 4 AND 5?**

A. I have prepared a proposed base fuel rate both with and without the planned transaction. While the company is planning for the acquisition of SCE's share of Four Corners 4 and 5 in the latter half of 2012, the resolution of the transaction is yet to be determined. Given this uncertainty, I have followed a two-step approach to determining the appropriate base fuel rate. In the first step, I have made all of the typical and necessary normalizing adjustments to test year fuel expenses and calculated the resulting average cost of fuel as if there is no change in ownership at Four Corners. This results in a base fuel rate of 3.24¢/kWh and the components of this cost level can be seen in attachment PME-3, page 2 of 4. The normalizing adjustments are described in more detail in my testimony below.

In the second step, the additional generation capacity from SCE's share of Four Corners 4 and 5 is added to the Company's available resources. This additional lower-cost generation displaces higher-cost natural gas generation and wholesale market power purchases and results in a lower proposed Base Fuel Rate of 3.13¢/kWh. This result can be seen in Attachment PME-3, page 3 of 4.

In the event that the proposed acquisition of Four Corners 4 and 5 is, for whatever reason, delayed or cancelled or otherwise uncertain at the time of a decision in this case, then the Base Fuel Rate of 3.24¢/kWh would be the appropriate rate to adopt in this proceeding. On the other hand, if the Four Corners transaction has received all necessary approvals, then it may be appropriate to adopt the Base Fuel Rate of 3.13¢/kWh. The following section of my testimony discusses the

development and implementation of the normalizing adjustments aside from those relating to the acquisition of Four Corners 4 and 5.

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

A. I developed the pro forma for fuel expense net of off-system sales margins using the approach used by the Company and accepted by the Commission for establishing the Company's base fuel rate in the last two rate cases. Under that approach, I simulated the impacts of the adjustments I mentioned above using the Company's production cost simulation tool RTSim. This computer model replicates the dispatch of the APS system and is the primary fuel expense and off-system sales forecasting tool APS uses to prepare its annual budgets, long-range fuel forecasts, and near-term operational plans. The vast majority of the input assumptions I have used in the proposed base fuel adjustment are the same as or consistent with the expected levels in the Company's operating plans prepared for internal use. Most importantly, the estimated fuel expense is based on the March 31, 2011 forward curve for natural gas and power prices and the corresponding valuation of the Company's hedges.

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

A. The model simulates the dispatch of the APS generating units on a daily and hourly basis. It takes into account the APS system load shape, fuel prices (including wholesale market prices for power) and characteristics of APS-owned generating plants (such as heat rates, overhaul cycles, unplanned outage rates, start-up costs and ramp rates, among others), along with commitments for purchases and sales of power. The model also simulates necessary market purchases for those times when load exceeds generating capacity, and likewise

simulates market sales during those times when the system is not fully utilized but generating units are economic.

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

**Q. DO THESE RESULTS FLOW DIRECTLY INTO YOUR PROPOSED FUEL PRO FORMA?**

A. No. The process I have used captures the impacts of the relevant factors on the Company's *average* base fuel cost. The change in the average cost from the Company's Test Year amounts applied to the adjusted Test Year retail sales amounts produces the appropriate adjustment for the Test Year pro forma. This calculation is shown on Attachment PME-4. Attachment PME-3 shows the major components of the proposed base fuel rate of 3.24¢/kWh, the realized Test Year fuel costs of 3.35¢/kWh, and the current authorized level of 3.76¢/kWh. This base fuel rate results in a pro forma to Test Year fuel and purchased power costs of $(29,810,000) (see SFR Schedule C-2, page 10, column 28). The alternate base fuel rate, which includes the acquisition of SCE's share of Four Corners 4 and 5, produces an additional reduction in normalized fuel costs of $31.1 million ((3.1298¢/kWh – 3.2415¢/kWh) x 27,833,756 MWh = -$31,090,305).

**Q. CAN YOU DESCRIBE THE NORMALIZING ADJUSTMENTS RELATED TO FUEL PRICES?**

A. Yes. Commodity prices for natural gas and wholesale market power have decreased from the levels included in the current base fuel rate and translate into a decrease in fuel expense of $133 million net of the value of the Company's hedge contracts. At the close of the market on March 31, 2011, delivered natural gas prices for calendar year 2012 averaged $5.21/MMBTU. These prices represent a 21% decrease from the delivered prices the Company is currently recovering in base rates.

In addition, because natural gas is the marginal fuel source for most wholesale power transactions, power prices have decreased in concert with gas prices. Prices for on-peak power delivered at Palo Verde for calendar year 2012 averaged under $44/MWh on March 31, 2011, a 25.7% decrease from the level currently being recovered in base rates. The weighted average of the on-peak and off-peak 2012 power prices the Company expects to pay is $28.73/MWh.

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

A. Yes. The Company's coal contracts have standard contract escalators which will lead to steady upward pressure on those fuel prices. The Test Year average cost (on a production basis) for the combined coal fleet was $17.45/MWh. Excluding a one-time credit for settlement of prior year contract issues, the average production cost was $18.45/MWh. (These one-time credits were credited to the PSA in 2010 and are being refunded to customers through the 2011 Historical Component.) In 2012, the average production cost is expected to be $19.51/MWh, equating to a 6% increase in delivered coal prices over two years. This increase reflects the escalation rates specific to each contract, but the dominant component having the greatest impact on the overall contract escalation is the price of petroleum products used in coal mining.

Nuclear fuel costs are also increasing into 2012. Production costs averaged $7.62/MWh in 2010, but are projected to increase to $8.97/MWh in 2012, an 18% increase. Most of these cost increases have already been realized as a result of the lengthy nuclear fuel cycle. Nuclear fuel is procured in several steps leading up to the time the nuclear fuel assemblies are installed during a refueling outage, beginning with the purchase of uranium, followed by conversion and enrichment processes and ending with the fabrication of the nuclear fuel into assemblies. These assemblies are then shipped to the plant prior to each unit's next refueling outage and installed during the outage. Typically only 1/2 to 1/3 of the existing fuel assemblies are replaced during any one outage. The lead time for the start of this procurement process is 15-18 months prior to the outage. This timing element means that between 85% and 90% of the cost for any particular year has already been set with a high degree of certainty six months prior to the start of that year. These costs are then recorded as fuel expense as the plant consumes the fuel while generating electricity through the course of the year. The cost increases expected to be recorded in 2012 principally reflect the much higher world-wide prices for uranium in recent years.

**Q. ARE ANY RESOURCE CHANGES EXPECTED TO IMPACT FUEL COSTS?**

A. Yes, the resources used to meet the Company's native load demand are dynamic, and the proposed fuel costs reflect several normalizing adjustments. First, the Company is continuing to acquire energy from renewable resources in line with its commitments to meet the requirements of the RES and the 2009 Settlement Agreement. In terms of contribution to total generated and purchased energy, renewables will have doubled by 2012 compared to the amount included in the current authorized base fuel rate of 3.76¢/kWh, from 2.0% of the total to 4.1% of

the total. These new resources are predominantly displacing natural gas generation and market power purchases.

Second, there are differences in the capacity available to the Company under long term contracts in 2012 compared to the Test Year and the amounts included in the current authorized base fuel rate. In 2010, the Company added a new 10-year 560 MW tolling contract with the Arlington combined cycle natural gas-fired power plant west of Phoenix. During 2010, this capacity was available for the months of June through September. In 2012 (and future years), the capacity is available for the months of May through October. Also in mid-2010, SRP terminated a long-term capacity and energy contract which resulted in the loss of almost 240 MW of capacity year-round. The net effect of these capacity changes, when put on an average cost basis and applied to 2010 Test Year normalized sales, is an increase of $32 million as can be seen in Attachment PME-1.

Finally, changes in planned and unplanned outage time for each of the Company's generating resources are being reflected in the normalized fuel cost. Planned outage time has been normalized in a manner consistent with the normalization of maintenance expense for these plants and consistent with the procedures used in previous rate cases. The planned outage time is adjusted to match the historical average planned outage time for each plant, with the exception of the nuclear plant. Because of the recent improvements at Palo Verde, including the installation of the Rapid Refueling Package at each unit, the projected 2012 refueling outage days were adopted as the normalized level. Also consistent with past practice, the projected unplanned outage time for 2012 was used as the normalized level for developing the fuel cost estimates. The projected effective forced outage factors ("EFOF") are consistent with the factors used by the Company in its internal financial and business planning. The EFOF levels

used in the normalized fuel cost calculation are displayed and compared to the EFOF levels used for the current authorized base fuel rate in Attachment PME-5.

IV. OTHER ADJUSTMENTS TO TEST YEAR FUEL REVENUE AND EXPENSE

**Q. DURING THE TEST YEAR, THE COMPANY RECOVERED PRIOR PERIOD FUEL COSTS THROUGH THE PSA. HAVE YOU REMOVED THESE REVENUES?**

A. Yes. Attachment PME-6 is a pro forma that removes revenues related to prior period fuel expense collected through the PSA from the Test Year. In addition, it removes the related prior period amortization of deferred fuel and the amortization of deferred $SO_2$ emission allowance sales margins. Together, these items have no impact on pre-tax operating income. This pro forma is included in SFR Schedule C-2 on page 10, column 29.

**Q. WHAT OTHER CHANGES TO TEST YEAR FUEL EXPENSE ARE YOU PROPOSING?**

A. In addition to the changes described above, I have included a pro forma that removes the PSA fuel deferrals and non-cash mark-to-market accounting entries from Test Year expense. These non-cash accounting adjustments have no bearing on the Company's anticipated fuel expenses in 2012 and beyond. The combined pre-tax impact of these adjustments is approximately $102 million as shown on Attachment PME-7 and in SFR Schedule C-2, page 10, column 30.

V. PSA PLAN OF ADMINISTRATION ("POA") MODIFICATIONS

**Q. IS THE COMPANY PROPOSING ANY MODIFICATIONS IN THE PSA POA IN THIS PROCEEDING?**

A. Yes. The Company is proposing two modifications to the PSA POA. The first is to remove the 90/10 sharing provision which was approved in Decision No. 69663 (June 28, 2007) and the second is to include the cost associated with environmental chemical costs, primarily lime, in the PSA. Each modification is discussed below.

**Q. STARTING WITH THE 90/10 SHARING PROVISION, PLEASE EXPLAIN WHY THE COMPANY IS REQUESTING ITS REMOVAL IN THIS CASE.**

A. The Company is the only Arizona utility to have a 90/10 sharing provision. The 90/10 sharing provision was established by the Commission in 2005 as a method to encourage APS to prudently procure fuel. Since then, the Commission, through an audit of the Company's fuel procurement practices conducted by Liberty Consulting Group in 2006, evaluated APS's hedging and procurement practices and deemed them to be sound. This was recently confirmed in the 2010 Liberty benchmarking study. Further, the Commission, through the recent adoption of the new Integrated Resource Planning Rules ("IRP"), will effectively approve the Company's proposed resource mix. The combination of the good outcomes of the two Liberty studies and the Commission's review of the Company's resource mix, the only variables that exist are fuel and purchased power market prices – something entirely outside of APS's control – and power plant operations, which can be and have been effectively reviewed in prudence determinations.

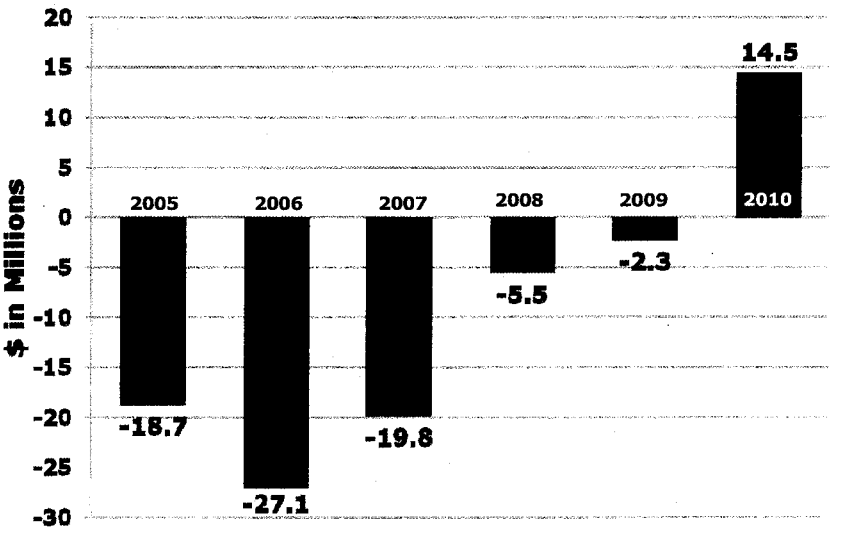
Another benefit from the removal of the 90/10 sharing provision is it will also facilitate resetting base fuel rates without controversy. Because gas generation and purchased power costs vary depending on market conditions, with the 90/10 sharing provision in place, if a lower base fuel rate were established in the case, and gas and power prices increased dramatically, the Company would be penalized for higher prices and would only be able to recover 90% of those costs. On the other hand, if a higher base fuel rate were set and then fuel and purchased power costs continued to decrease, APS would receive the benefit of this scenario and be able to keep 10% of the over-collection. Because market prices are so

variable and are not something APS can control, removing the 90/10 sharing provision in this case is reasonable and prudent.

**Q. PLEASE EXPLAIN HOW THE 90/10 SHARING PROVISION WORKS.**

A. Under the 90/10 sharing provision, the Company can only recover from customers 90% of most fuel expenses above the amounts recovered through the Base Fuel Rate. This mechanism also allows the Company to keep 10% of any fuel reductions below the Base Fuel Rate, which has worked to the Company's benefit with the lower than usual price of natural gas over the recent past. The chart below shows the annual and cumulative totals resulting from the provision. As is evidenced from the chart, since the provision has been in effect, it has been to the detriment of the Company by $59M. The chart also shows that the swings in benefit or penalty can be quite sizable, are driven primarily by market forces beyond the Company's influence, and will not be controlled any better by any changes in Company procurement practices.

**CHART 1: PRE-TAX INCOME EFFECT OF 90/10 SHARING FEATURE IN PSA**



**Q. THE COMPANY IS ALSO REQUESTING TO INCLUDE CHEMICAL COSTS IN THE PSA. PLEASE EXPLAIN.**

A. The Company is proposing to include in the PSA environmental chemical costs that directly correlate to the use of fuel. Chemicals, such as lime, ammonia, and sulfur are used to scrub the emissions from a coal plant and are dependent upon the amount of fuel burned. As production from the power plants varies, so too does the amount of chemicals used. The Company therefore 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.

**Q. PLEASE EXPLAIN HOW THE CHEMICAL COSTS WILL RUN THROUGH THE PSA.**

A. The Company is proposing that chemical costs be treated in the PSA in a similar fashion to how $SO_2$ emission allowance sales margins are treated. The chemical costs incurred in the Test Year will be converted to an average cost per kWh based on the normalized Test Year sales, and that average cost will be established as the Base Cost for Allowable Chemicals. Upon approval in this proceeding, the Company will begin deferring any difference between the actual chemical costs incurred each month and the amount recovered in base rates through the Base Cost for Allowable Chemicals. These differences can be positive or negative, and the deferrals will apply to the Company's Operations and Maintenance ("O&M") Expenses. Prior to the beginning of each PSA Year, in accordance with the established procedures for setting new PSA rates, the Company will provide a forecast of anticipated chemical costs and chemical cost base rate recovery, and the difference in under- or over-recovery will be converted to an average rate per kWh and added to the Forward Component of the PSA. Similarly, any remaining under- or over-recovery from the previous year will be converted to an average rate per kWh and added to the PSA Historical Component.

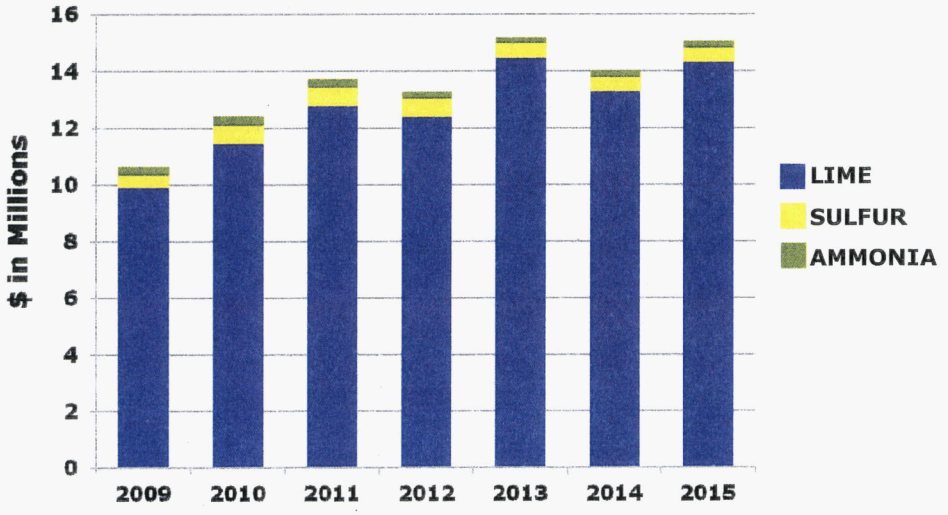
**Q. WHAT IS THE PROPOSED BASE COST FOR ALLOWABLE CHEMICALS?**

A. The Company incurred $12.4 million in power production-related chemical costs during the Test Year. Over 90% of this amount (almost $11.5 million) was for lime used at the Four Corners, Cholla and Navajo coal-fired generating stations. Another $600,000 was incurred for sulfur at the coal plants, and just over $300,000 was accounted for by ammonia nitrate, which is primarily used at the West Phoenix and Red Hawk combined cycle gas-fired plants. These amounts divided by the Test Year native load sales of 28,075 GWh yields an average Base Cost of Allowable Chemicals of 0.0442¢/kWh.

**Q. DOES THE COMPANY HAVE A PROJECTION OF WHAT CHEMICAL COSTS WILL BE OVER THE NEXT FIVE YEARS?**

A. Yes, the chart below shows that the Company expects these chemical costs to increase to as much as $15 million in the next several years, and that the amount of the chemical costs will vary considerably with the production levels of the Company's coal plants.

**CHART 2: PRODUCTION-RELATED CHEMICAL COSTS**



**Q. IS THE COMPANY PROPOSING ANY ADDITIONAL MODIFICATIONS TO THE PSA IN THIS PROCEEDING?**

A. Yes. The Company is proposing that the exemptions for customers on the E3, E4 and Solar 2 rate riders be discontinued. APS witness Charles Miessner discusses the reasons for these changes. Otherwise, the only changes would relate to updating the base rates for fuel and for the Test Year levels of $SO_2$ emission allowance sales margins. The new Base Net Margins on the Sale of Emission Allowances will be (0.0001)¢/kWh, as the sales of these allowances in the Test Year were *de minimus*. Attached as Attachment PME-8 is a redlined PSA POA showing the proposed changes from the current version and attached as PME-9 is a clean version of the PSA POA.

VI. CONCLUSION

**Q. DO YOU HAVE ANY CONCLUDING REMARKS?**

A. The decline in market prices for natural gas and wholesale power has substantially reduced the Company's cost of fuel, and it is appropriate to reduce the Company's Base Fuel Rate to 3.2415¢/kWh. The determination of this rate is consistent with the approach accepted by the Commission in prior proceedings. It would also be appropriate to make a corresponding and offsetting adjustment to the PSA Forward Component simultaneously with the change in the Base Fuel Rate. With sufficient clarity around the successful completion of the Company's acquisition of the additional share of Four Corners Units 4 and 5 and the recovery of related fixed costs, it would be appropriate to establish the Company's Base Fuel Rate at 3.1298¢/kWh.

The Company is the only utility in Arizona with a sharing provision as part of its PSA mechanism, so the 90/10 sharing provision should be eliminated. Certain chemical costs at the power plants (lime, sulfur, ammonia) vary directly with the generation of electricity and are therefore volatile much like fuel costs.

Differences between actual chemical expenses and the amounts in the Test Year should be recovered or refunded through the PSA. Base rates in the PSA POA should be updated to adjusted Test Year levels, and the exemptions applied to certain rate riders in the PSA should be eliminated.

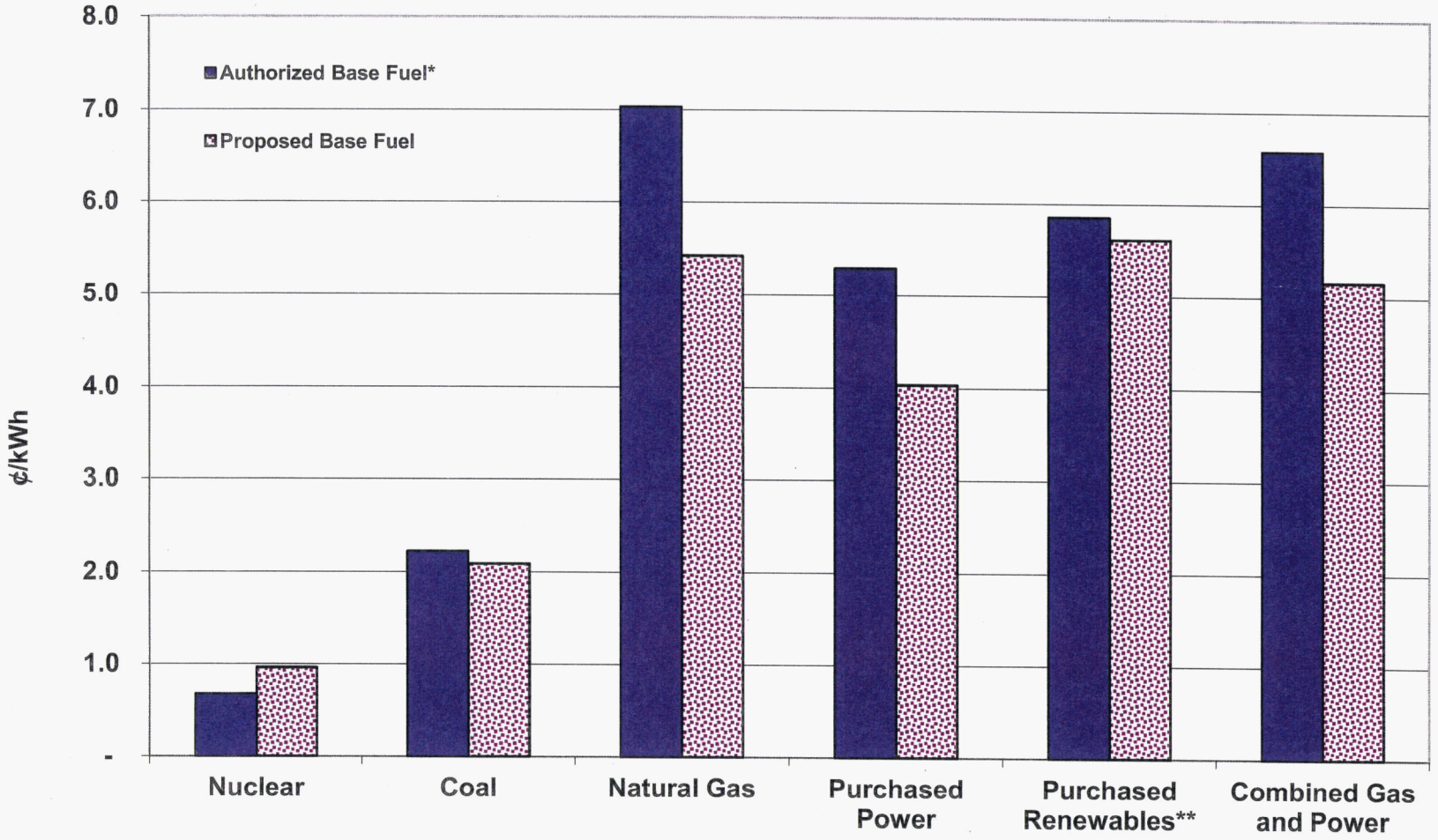
**Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

A. Yes.

# Summary of Base Fuel Cost Changes

| | Current Authorized Level (2009 Conditions) | Proposed Proforma Level (2012 Conditions) | Proforma vs. Current Authorized |
|---|---|---|---|
| Base Fuel Cost (¢/kWh) | 3.7571 | 3.2415 | (0.5156) |
| Test Year Period Normalized Sales (GWh) | 27,834 | 27,834 | |
| Base Fuel Expense ($000,000) | 1,045.7 | 902.2 | **(143.5)** |
| Change in Future PSA Revenues ($000,000) | | | 122.8 |
| Net Change in Revenues From Customers ($000,000) | | | **(20.7)** |
| **Reasons for Change ($000,000)** | | | |
| Prices for Hedged Natural Gas, Purchased Power | | | (132.6) |
| Reduced Share of Natural Gas, Market Purchased Power | | | (59.8) |
| Coal Price | | | (14.5) |
| Gas Transportation | | | 7.8 |
| Nuclear Price | | | 21.7 |
| Capacity Costs | | | 31.9 |
| All Other Items | | | 2.0 |
| Total | | | **(143.5)** |

# Arizona Public Service Company
# Average Fuel Cost by Type of Resource




* Authorized in Decision No. 71448
** Excludes above-market premium.

# 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 | 8,388 | 29.9% | 0.82 | 0.25 |
| Coal [2] | 195,673 | 11,210 | 10,357 | 36.9% | 1.89 | 0.70 |
| Natural Gas [3] | 386,676 | 6,984 | 6,452 | 23.0% | 5.99 | 1.38 |
| Purchased Power [4] | 221,949 | 2,409 | 2,225 | 7.9% | 9.97 | 0.79 |
| Renewable [5, 6] | 37,421 | 706 | 653 | 2.3% | 5.73 | 0.13 |
| Fixed Gas Transport and Fuel Handling | 63,081 | - | - | 0.0% | | 0.22 |
| Total Native Load | 973,997 | 30,388 | 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.

# Components of APS Base Fuel Rate
## Proposed Rate Using 3/31/11 Market Prices
### Excluding the Effects of Acquiring SCE Share of Four Corners Units 4 & 5

| | Fuel Expense ($000) | Production (GWH) | Native Load Sales (GWH) | Share of Production % | Average Cost Not Weighted (¢/kWh) | Average Cost Weighted (¢/kWh) |
|---|---|---|---|---|---|---|
| Nuclear [1] | 83,119 | 9,264 | 8,641 | 30% | 0.96 | 0.2900 |
| Coal [2] | 246,710 | 12,648 | 11,798 | 41% | 2.09 | 0.8609 |
| Natural Gas [3] | 286,846 | 5,667 | 5,287 | 18% | 5.43 | 1.0009 |
| Purchased Power [4, 5] | 185,504 | 1,680 | 1,567 | 5% | 11.84 | 0.6473 |
| Renewable [6, 7] | 66,610 | 1,463 | 1,365 | 5% | 4.88 | 0.2324 |
| Fixed Gas Transport and Fuel Handling | 77,128 | - | - | 0% | | 0.2691 |
| Total | 945,916 | 30,721 | 28,658 | 100% | | 3.3006 |
| Off System Margin Credit | (16,931) | | 28,658 | | | (0.0591) |
| **Net Retail Fuel Cost** | 928,986 | | 28,658 | | | **3.2415** |

**Native Load Sales**

| | |
|---|---|
| Retail Sales | 28,186 |
| Sales for Resale | 421 |
| Pacificorp Supplemental Sales | 51 |
| Total Native Load Sales | 28,658 |

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 - Includes fixed capacity contract costs.
6 - Excludes costs for above market purchase premiums which are recovered through RES.
7 - Includes generation associated with company owned facilities.

## Components of APS Base Fuel Rate
## Proposed Rate Using 3/31/11 Market Prices
### Including the Effects of Acquiring SCE Share of Four Corners Units 4 & 5

| | Fuel Expense ($000) | Production (GWH) | Native Load Sales (GWH) | Share of Production % | Average Cost Not Weighted (¢/kWh) | Average Cost Weighted (¢/kWh) |
|---|---|---|---|---|---|---|
| Nuclear [1] | 83,119 | 9,264 | 8,641 | 30% | 0.96 | 0.2900 |
| Coal [2] | 253,448 | 13,564 | 12,653 | 44% | 2.00 | 0.8844 |
| Natural Gas [3] | 258,572 | 4,969 | 4,635 | 16% | 5.58 | 0.9023 |
| Purchased Power [4, 5] | 178,544 | 1,462 | 1,363 | 5% | 13.10 | 0.6230 |
| Renewable [6, 7] | 66,610 | 1,463 | 1,365 | 5% | 4.88 | 0.2324 |
| Fixed Gas Transport and Fuel Handling | 77,128 | - | - | 0% | | 0.2691 |
| Total | 917,422 | 30,721 | 28,658 | 100% | | 3.2012 |
| Off System Margin Credit | (20,459) | | 28,658 | | | (0.0714) |
| **Net Retail Fuel Cost** | 896,963 | | 28,658 | | | **3.1298** |

**Native Load Sales**

| | |
|---|---|
| Retail Sales | 28,186 |
| Sales for Resale | 421 |
| Pacificorp Supplemental Sales | 51 |
| Total Native Load Sales | 28,658 |

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 - Includes fixed capacity contract costs.
6 - Excludes costs for above market purchase premiums which are recovered through RES.
7 - Includes generation associated with company owned facilities.

## Components of APS Base Fuel Rate
## Current Authorized Rates From 2009 Rate Case Settlement

| | Fuel Expense ($000) | Production (GWH) | Native Load Sales (GWH) | Share of Production % | Average Cost Not Weighted (¢/kWh) | Average Cost Weighted (¢/kWh) |
|---|---|---|---|---|---|---|
| Nuclear [1] | 53,288 | 8,827 | 7,917 | 27% | 0.67 | 0.18 |
| Coal [2] | 250,241 | 12,530 | 11,238 | 38% | 2.23 | 0.85 |
| Natural Gas [3] | 479,802 | 7,607 | 6,823 | 23% | 7.03 | 1.63 |
| Purchased Power [4, 5] | 233,210 | 3,092 | 2,773 | 9% | 8.41 | 0.79 |
| Renewable [6, 7] | 35,221 | 670 | 601 | 2% | 5.86 | 0.12 |
| Fixed Gas Transport and Fuel Handling | 69,212 | - | - | 0% | | 0.24 |
| Total Native Load | 1,120,974 | 32,726 | 29,353 | 100% | | 3.8189 |
| Off System Margin Credit | (18,143) | | 29,353 | | | (0.0618) |
| **Net Retail Fuel Cost** | 1,102,831 | | 29,353 | | | **3.7571** |

**Native Load Sales**

| | |
|---|---|
| Billed Retail Sales | 29,343 |
| Traditional Sales for Resale | 343 |
| Pacificorp Supplemental Sales | 172 |
| E-3 and E-4 Customers | (505) |
| Total Native Load Sales | 29,353 |

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 - Includes fixed capacity contract costs.
6 - Excludes costs for above market purchase premiums which are recovered through RES.
7 - Includes generation associated with company owned facilities.

**ARIZONA PUBLIC SERVICE COMPANY**
**Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2, page 10, column 28**
**Total Company**
**(Thousands of Dollars)**

**Pro Forma Adjustment:** **Base Fuel and Purchased Power**
**Adjustment to Test Year Operations to include 2012 base fuel and purchased power ¢/kWh costs at adjusted Test Year consumption**

| Line No. | Description | | Amount |
|---|---|---|---|
| | **ADJUSTED TEST YEAR FUEL AND PURCHASED POWER COSTS (¢/kWh)** | | |
| 1. | Normalized 2012 Fuel and Purchased Power Costs (¢/kWh) | 3.2415 | |
| 2. | Test Year Fuel and Purchased Power Costs (¢/kWh) | 3.3486 | |
| 3. | Adjustment to Fuel and Purchased Power Costs (¢/kWh) | (0.1071) | |
| | **ADJUSTED TEST YEAR RETAIL SALES (MWh)** | | |
| 4. | Test Year Retail Sales (MWh) | 27,709,463 | |
| 5. | Pro Forma Adjustments to Test Year Billed Retail Sales (MWh) | | |
| 6. | To Adjust to Normal Weather | 116,749 | |
| 7. | To Annualize to December 31, 2010 Customer Level | 7,544 | |
| 8. | Adjusted Test Year Retail Sales (MWh) | 27,833,756 | |
| 9. | Pro Forma Adjustment to Fuel and Purchased Power Expenses (Line 3 x Line 8) | | $ (29,810) |
| 10. | **Operating Income (before income tax)** | | **$ 29,810** |
| 11. | Current Income Tax Rate - 39.51% | | 11,778 |
| 12. | **Operating Income After Tax** | | **$ 18,032** |

# Arizona Public Service Company
## Comparison of Generating Unit Effective Forced Outage Factors (EFOF)
## Proposed Base Rate Level vs. Current Authorized Base Rate Level
## (%)

| | Current Authorized Level (2009 Conditions) | Proposed Level (2012 Conditions) |
|---|---|---|
| Nuclear | 2.5 | 2.0 |
| Four Corners | 7.7 | 6.0 |
| Cholla | 5.3 | 4.1 |
| Navajo | 5.0 | 5.0 |
| West Phoenix CC 1-3 | 7.0 | 6.3 |
| West Phoenix CC 4 | 7.0 | 3.7 |
| West Phoenix CC 5 | 10.0 | 6.8 |
| Redhawk | 7.5 | 6.6 |
| Gila | 3.7 | 2.7 |
| Arlington | N/A | 4.0 |
| Steam Plants | 6.5 | 6.0 |
| Gas Turbines | 6.5 | 2.3 |

**ARIZONA PUBLIC SERVICE COMPANY**
**Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2, page 10, column 29**
**Total Company**
**(Thousands of Dollars)**

**Pro Forma Adjustment:** **Test Year PSA Revenue and Deferred Fuel Amortization**
**Adjustment to Test Year retail operating revenues and fuel and purchased power expense to remove retail PSA revenue and amortization of deferred fuel related to prior periods**

| Line No. | Description | Total Company Amount |
|---|---|---|
| | **Revenues** | |
| 1 | Remove Test Year PSA Billed and Unbilled Revenue | $ 121,231 |
| | **Expenses** | |
| 2 | Remove Test Year PSA Fuel Expense Deferral Amortization | 127,728 |
| 3 | Operating Revenues less Fuel and Purchased Power Costs | $ (6,497) |
| | **Operations & Maintenance** | |
| 4. | Remove Test Year PSA SO2 Margin Deferral Amortization | $ (6,497) |
| 5. | **Operating Income (before income tax)** | **$ -** |
| 6. | Current Income Tax Rate - 39.51% | - |
| 7. | **Operating Income After Tax** | **$ -** |

**ARIZONA PUBLIC SERVICE COMPANY**
**Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2, page 10, column 30**
**Total Company**
**(Thousands of Dollars)**

**Pro Forma Adjustment:** **Test Year Retail Deferred Fuel Expense and Non-Cash Mark-to-Market Accruals**
**Adjustment to Test Year retail fuel and purchased power costs to remove retail PSA deferred fuel and non-cash mark-to-market accruals**

| Line No. | Description | | Total Company |
|---|---|---|---|
| | **Fuel and Purchased Power Costs** | | |
| 1. | Current Period Retail PSA Fuel Expense Deferral | $ (99,349) | |
| 2. | Deferred Mark to Market on Native Load Hedge | 35,686 | |
| 3. | Total Test Year PSA Fuel Expense Deferral | (63,663) | |
| 4. | Non-Cash Hedge-Related MTM Accruals | (38,127) | |
| 5. | Pro Forma Adjustment to Fuel and Purchased Power Costs | | (101,790) |
| 6. | **Operating Income (before income tax)** | | **101,790** |
| 7. | Current Income Tax Rate - 39.51% | | 40,217 |
| 8. | **Operating Income After Tax** | | **$ 61,573** |

# Power Supply Adjustment
# Plan of Administration

## *Table of Contents*

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2. PSA Components ..... 1 2
3. Calculation of the PSA Rate ..... 5 4
4. Filing and Procedural Deadlines ..... 5
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6. Definitions ..... 6
7. Calculations Schedules ..... 8
8. Compliance Reports ..... 9
9. Allowable Costs ..... 10

## *1. General Description*

This document describes the plan for administering the Power Supply Adjustment mechanism ("PSA") approved for Arizona Public Service Company ("APS") by the Commission on June 28, 2007 in Decision No. 69663 and amended by the Commission on 71448 in Decision No. 71448. December 30, 2009 in Decision No. 71448 and as further amended by the Commission on [insert date] in Decision No. xxxxx. 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 ($0.037571032415 per kWh) authorized in Decision No. 71448xxxxx, from January 1, 2010. [insert date]. It also provides for refund or recovery of the net margins from sales of emission allowances, to the extent the actual sales margins deviate from the base rate amount of ((($0.000242) per kWh)[1]. ($0.000001) per kWh[1]. Lastly, it provides for the refund or recovery of Allowable Chemical costs, to the extent that actual Allowable Chemical costs deviate from the base rate amount of $0.000442 per kWh[2].

The PSA described in this Plan of Administration ("POA") uses a forward-looking estimate of fuel and purchased power costs and, net margins on the sales of emission allowances, and environmental chemical costs ("PSA Costs") to set a rate that is then reconciled to actual costs experienced. This PSA includes a 90/10 sharing mechanism under which APS absorbs 10 percent of the deviations between actual fuel and purchased power costs and the amount recovered through base rates. The demand component of long-term purchased power agreements (duration of three years or longer) acquired via a competitive procurement process, renewable energy costs not recovered through other mechanisms, and net margins from the sales of emission allowances are exempt from the 90/10 sharing.

[1] *($0.000001) per kWh is the result of the following: (2010 net gains from sales of $SO_2$ allowances of $21,178)/(2010 test year native load sales of 28,075,248 MWh)/1000.*
[2] *$0.000442 per kWh is the result of the following: (2010 Allowable Chemical costs of $12,400,620)/(2010 test year sales of 28,075,248 MWh)/1000.*


[1] *($0.000242) per kWh is the result of the following: (Normalized gains from SO2 allowances of ($7,044,934))/(ACC jurisdictional test year sales of 29,133,753 MWh)/1000.*

This PSA includes a limit of $0.004 per kilowatt-hour (kWh) on the amount the PSA rate may change in any one year. This PSA also provides a mechanism for mid-year rate adjustment in the event that conditions change sufficiently to cause extraordinarily high balances to accrue under application of this PSA.

## *2. PSA Components*

The PSA Rate will consist of three components designed to provide for the recovery of actual, prudently incurred PSA Costs. Those components are:

1. The Forward Component, which recovers or refunds differences between expected PSA Year (each February 1 through January 31 period shall constitute a PSA Year) PSA Costs and those embedded in base rates.
2. The Historical Component, which tracks the differences between the PSA Year's actual fuel and purchased power costs and those recovered through the combination of base rates and the Forward Component, and which provides for their recovery during the next PSA Year.
3. The Transition Component, which provides for:
    a. The opportunity to seek a mid-year change in the PSA rate in cases where variances between the anticipated recovery of fuel and purchased power costs for the PSA Year under the combination of base rates and the Forward Component become so large as to warrant recovery, should the Commission deem such an adjustment to be appropriate.
    b. The tracking of balances resulting from the application of the Transition Components, in order to provide a basis for the refund or recovery of any such balances.

Except for circumstances when the Commission approves new base rates, a PSA Year begins on February 1 and ends on the ensuing January 31. In the event that new base rates become effective on a date other than February 1, the Commission may, at its discretion, adjust any or all of the PSA components to reflect the new base rates.

On or before September 30 of each year, APS will submit a PSA Rate filing, which shall include a ~~proposed~~ calculation of the three components of the proposed PSA Rate. This filing shall be accompanied by such supporting information as Staff determines to be required. APS will supplement this filing with Historical Component and Transition Component filings on or before December 31 in order to replace estimated balances with actual balances, as explained below.

### a. Forward Component Description

The Forward Component is intended to refund or recover the difference between: (1) PSA Costs embedded in base rates and (2) the forecast PSA Costs over a PSA Year that begins on February 1 and ends on the ensuing January 31. APS will submit, on or before September 30 of each year, a forecast for the upcoming calendar year (January 1-December 31) of its PSA Costs. It will also



[1] ~~($0.000242) per kWh is the result of the following: (Normalized gains from SO2 allowances of ($7,044,934))/(ACC jurisdictional test year sales of 29,133,753 MWh)/1000.~~

submit a forecast of kWh sales for the same calendar year, and divide the forecast costs by the forecast sales to produce the cents/kWh unit rate required to collect those costs over those sales. The result of subtracting the Base PSA Costs from this unit rate shall be the Forward Component.

APS shall maintain and report monthly the balances in a Forward Component Tracking Account, which will record APS' over/under-recovery of its actual PSA Costs as compared to the Base PSA Costs recovered in revenue. ~~The over/under recovery of costs is divided into two separate calculations to allow the application of the 90/10 sharing mechanism on those costs to which it applies.~~ The balance calculated as a result of these steps is then reduced by the current month's collection of Forward Component revenue. This account will operate on a PSA Year basis (i.e.; February to January), and its balances will be used to administer this PSA's Historical Component, which is described immediately below.

**b. Historical Component Description**

The Historical Component in any current PSA Year is intended to refund or recover the balances accumulated in the Forward Component Tracking Account (described above) and Historical Component Tracking Account (described below) during the immediately preceding PSA Year. The sum of the projected Forward Component Tracking Account balance on January 31 of the following calendar year and the projected Historical Component Tracking Account balance on January 31 of the following calendar year is divided by the forecast kWh sales used to set the Forward Component for the coming PSA Year. That result comprises the proposed Historical Component for the coming PSA year.

APS shall maintain and report monthly the balances in a Historical Component Tracking Account, which will reflect monthly collections under the Historical Component and the amounts approved for use in calculating the Historical Component.

Each annual September 30 APS filing will include an accumulation of Forward Component Tracking Account balances and Historical Component Tracking Account balances for the preceding February through August and an estimate of the balances for September through January (the remaining five months of the current PSA Year). The APS filing shall use these balances to calculate a preliminary Historical Component for the coming PSA Year[3]. On or before December 31, APS will submit a supplemental filing that recalculates the preliminary Historical Component. This recalculation shall replace estimated monthly balances with those actual monthly balances that have become available since the September 30 filing.

The September 30 filing's use of estimated balances for September through January (with supporting workpapers) is required to allow the PSA review process to begin in a way that will support its completion and a Commission decision, if necessary, prior to February 1. The December 31 updating will allow for the use of the most current balance information available prior to the time when a Commission decision, if necessary, is expected. In addition to the

[3] For example, the September 30, 2008 filing would include actual balances for February through August of 2008 and estimated balances for September 2008 through January 2009.

December 31 update filing, APS monthly filings (for the months of September through December) of Forward Component Tracking Account balance information and Historical Component Tracking Account balance information will include a recalculation (replacing estimated balances with actual balances as they become known) of the projected Historical Component unit rate required for the next PSA Year.[4]

The Historical Component Tracking Account will measure the changes each month in the Historical Component balance used to establish the current Historical Component as a result of collections under the Historical Component in effect. It will subtract each month's Historical Component collections from the Historical Component balance. The Historical Component Account will also include Applicable Interest on any balances. APS shall file the amounts and supporting calculations and workpapers for this account each month.

**c. Transition Component Description**

The Transition Component will be used as the method for incorporating any future, approved mid-year changes to the PSA rate. APS, Staff, or the Commission on its own motion retain the ability to request at any time a change in the PSA rate through an adjustment to the Transition Component to address a significant imbalance between anticipated collections and costs for the PSA Year under the Forward Component element of this PSA. After the review of such request, the Commission may provide for the refund or collection of such balance (through a change to the Transition Component Balance) over such period as the Commission determines appropriate through a unit rate ($/kWh) imposed as part of the Transition Component.

A Transition Component Tracking Account will measure the changes each month in the Transition Component balance. APS, Staff, or the Commission on its own motion may request that the balance in any Transition Component Tracking Account at the end of the period set for recovery be included in the establishment of the Transition Component for the coming PSA Year.

The Transition Component Account will also include Applicable Interest as determined by the Commission. APS shall file the amounts and supporting calculations and workpapers for this account each month.

As it must do for the Historical Component filing, APS shall file on or before September 30 of each year an accumulation of Transition Component Tracking Account balances for the preceding February through August and an estimate of the balances for September through January (the remaining five months of the prior PSA Year). Those balances will form the basis for setting the preliminary Transition Component for the coming PSA Year. On or before December 31, APS will submit a supplemental filing to update the Transition Component calculation in the same manner as required for the Historical Component.

[4] This updating to replace estimated with actual information will allow for the Commission to use the latest available balance information in determining what Historical Component is appropriate to establish for the coming PSA Year.

## *3. Calculation of the PSA Rate*

The PSA rate is the sum of the three components; *i.e.,* Forward Component, Historical Component, and Transition Component. The PSA rate shall be applied to customer bills. Unless the Commission has otherwise acted on a new PSA rate by February 1, the proposed PSA rate (as amended by the updated December 31 filing) shall go into effect. However, the PSA rate may not change from the prior year's PSA rate by more than plus or minus $0.004 per kWh~~.~~ without an offsetting change in the Base Cost of Fuel and Purchased Power. The PSA rate shall be applicable to APS' retail electric rate schedules (with the exception of ~~Solar 2, E 3, E 4,~~ E-36, Direct Access service and any other rate that is exempt from the PSA) and is adjusted annually. The PSA Rate shall be applied to the customer's bill as a monthly kWh charge that is the same for all customer classes.

The PSA rate shall be reset on February 1 of each year, and shall be effective with the first February billing cycle unless suspended by the Commission. It is not prorated.

## *4. Filing and Procedural Deadlines*

### a. September 30 Filing

APS shall file the PSA rate with all Component calculations for the PSA year beginning on the next February 1, including all supporting data, with the Commission on or before September 30 of each year. That calculation shall use a forecast of kWh sales and of PSA Costs for the coming calendar year, with all inputs and assumptions being the most current available for the Forward Component. The filing will also include the Historical Component calculation for the year beginning on the next February 1, with all supporting data. That calculation shall use the same forecast of sales used for the Forward Component calculation. The Transition Component filing shall also include a proposed method for addressing the over or under recovery of any Transition Component balances that result from changes in the sales forecasts or recovery periods set or any additions to or subtractions from Transition Component balances reviewed or approved by the Commission since the last February 1 resetting of the new PSA.[5]

### b. December 31 Filing

APS shall by December 31 update the September 30 filing. This update shall replace estimated Forward Component Tracking Account balances, the Historical Component Tracking Account balances, and the Transition Component Tracking Account balances with actual balances and with more current estimates for those months (December and January) for which actual data are not available. Unless the Commission has otherwise acted on the APS calculation by February 1, the PSA rate proposed by APS shall go into effect with the first February billing cycle.[6]

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[5] This method assumes that the Commission defers the recovery of any approved Transition Component Balance changes until the next February 1 PSA resetting. The Commission may also, as part of the approval of any such Transition Component Balance change, make a PSA change effective on dates and across periods as it determines to be appropriate when it approves such a Transition Component Balance change.

[6] No reference in this plan to effectiveness in the absence of Commission action shall be interpreted as precluding the normal application of the balance reconciliation provisions generally established for the PSA.

**c. Additional Filings**

APS shall also file with the Commission any additional information that the Staff determines it requires to verify the component calculations, account balances, and any other matter pertinent to the PSA.

**d. Review Process**

The Commission Staff and interested parties shall have an opportunity to review the September 30 and December 31 forecast, balances, and supporting data on which the calculations of the three PSA components have been based. Any objections to the September 30 calculations shall be filed within 45 days of the APS filing. Any objections to the December 31 calculations shall be filed within 15 days of the APS filing.

## *5. Verification and Audit*

The amounts charged through the PSA shall be subject to periodic audit to assure their completeness and accuracy and to assure that all fuel and purchased power costs were incurred reasonably and prudently. The Commission may, after notice and opportunity for hearing, make such adjustments to existing balances or to already recovered amounts as it finds necessary to correct any accounting or calculation errors or to address any costs found to be unreasonable or imprudent. Such adjustments, with appropriate interest, shall be recovered or refunded through the Transition Component.

## *6. Definitions*

Allowable Chemical Costs - Costs associated with reagent (lime), sulfur and ammonia used in the production of electricity.

Applicable Interest - Based 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.

Cost of Allowable Chemicals - An amount generally expressed as a rate per kWh, which reflects the cost of Allowable Chemicals embedded in base rates as approved by the Commission in APS' most recent rate case. The Base Cost for Allowable Chemicals is set at $0.000442 per kWh effective on [insert date].

Base Cost of Fuel and Purchased Power - An amount generally expressed as a rate per kWh, which reflects the fuel and purchased power cost ~~and net margins from the sales of emission allowances~~ embedded in the base rates as approved by the Commission in APS' most recent rate case. The Base ~~PSA Costs~~Cost of Fuel and Purchased Power recovered in base revenue is the approved rate per kWh times the applicable sales volumes. Decision No. ~~71448~~xxxxx set the base cost at $0.~~037571~~032415 per kWh effective on ~~January 1, 2010.~~[insert date].

Base Net Margins on the Sale of Emission Allowances~~—~~ - An amount generally expressed as a rate per kWh, which reflects the net margins on sales of $SO_2$ emission allowances embedded in

the base rates as approved by the Commission in APS' most recent rate case. The Base Net Margins on the Sale of Emission Allowances is set at ~~(~~($0.~~000242~~000001) per kWh~~)~~ effective on ~~January 1, 2010.~~[insert date].

Base PSA Costs - An amount generally expressed as a rate per kWh, which reflects the fuel and purchased power cost, net margins from the sales of emission allowances, and allowable chemical costs embedded in the base rates as approved by the Commission in APS' most recent rate case. The Base PSA Costs recovered in base revenue is the approved rate per kWh times the applicable sales volumes.

PSA Costs - The combination of System Book Fuel and Purchased Power Costs net of the System Book Off-System Sales Revenues plus the Net Margins on the Sales of Emission Allowances and Allowable Chemical Costs.

Forward Component - An amount generally expressed as a rate per kWh charge that is updated annually on February 1 of each year and effective with the first billing cycle in February. The Forward Component for the PSA Year will adjust for the difference between the forecast PSA Costs generally expressed as a rate per kWh less the Base PSA Costs generally expressed as a rate per kWh embedded in APS' base rates. The result of this calculation will equal the Forward Component, generally expressed as a rate per kWh.

Forward Component Tracking Account - An account that records on a monthly basis APS' over/under-recovery of its actual PSA Costs as compared to the actual Base PSA Costs recovered in revenue and Forward Component revenue; plus Applicable Interest. The balance of this account as of the end of each PSA Year is, subject to periodic audit, reflected in the next Historical Component calculation. APS files the balances and supporting details underlying this Account with the Commission on a monthly basis.

Historical Component - An amount generally expressed as a rate per kWh charge that is updated annually on February 1 of each year and effective with the first billing cycle in February unless suspended by the Commission. The purpose of this charge is to provide for a true-up mechanism to reconcile any over or under-recovered amounts from the preceding PSA Year tracking account balances to be refunded/collected from customers in the coming year's PSA rate.

Historical Component Tracking Account - An account that records on a monthly basis the account balance to be collected via the Historical Component rate as compared to the actual Historical Component revenues; plus Applicable Interest; the balance of which at the close of the preceding PSA Year is, subject to periodic audit, then reflected in the next Historical Component calculation. APS files the balances and supporting details underlying this Account with the Commission on a monthly basis.

ISFSI - Costs associated with the Independent Spent Fuel Storage Installation that stores spent nuclear fuel.

Mark-to-Market Accounting - Recording the value of qualifying commodity contracts to reflect their current market value relative to their actual cost.

Native Load - Native load includes customer load in the APS control area for which APS has a generation service obligation and PacifiCorp Supplemental Sales.

Net Margins on the Sale of Emission Allowances - Revenues incurred from the sale of emission allowances net of the costs incurred to produce the excess allowances.

PacifiCorp Supplemental Sales - The PacifiCorp Supplemental Sales agreement is a long-term contract from 1990~~,~~ which requires APS to offer a certain amount of energy to PacifiCorp each year. It is a component of the set of agreements that led to the sale of Cholla Unit 4 to PacifiCorp and the establishment of the seasonal diversity exchange with PacifiCorp.

PSA - The Power Supply Adjustment mechanism approved by the Commission in Decision No. 69663 and amended by the Commission in Decision No. ~~71448~~71448 and further amended by the commission in Decision No. xxxxx, which 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.

PSA Year - A consecutive 12-month period generally beginning each February 1.

Preference Power - Power allocated to APS wholesale customers by federal power agencies such as the Western Area Power Administration.

System Book Fuel and Purchased Power Costs - The costs recorded for the fuel and purchased power used by APS to serve both Native Load and off-system sales, less the costs associated with applicable special contracts, E-36~~,~~ AG -1 RCDAC-1, ISFSI, and Mark-to-Market Accounting adjustments. Wheeling costs are included; broker fees are included up to the level in the Base Cost of Fuel and Purchased Power authorized in Decision No. ~~71448~~xxxxx.

System Book Off-System Sales Revenue - The revenue recorded from sales made to non-Native Load customers, for the purpose of optimizing the APS system, using APS-owned or contracted generation and purchased power, less Mark-to-Market Accounting adjustments.

Traditional Sales-for-Resale - The portion of load from Native Load wholesale customers that is served by APS, excluding the load served with Preference Power.

Transition Component - An amount generally expressed as a rate per kWh charge to be applied when necessary to provide for significant changes between estimated and actual costs under the Forward Component.

Transition Component Tracking Account - An account that records on a monthly basis the account balance to be collected via the Transition Component as compared to the actual Transition Component revenues, plus applicable interest; the balance of which upon Commission

consideration may then be reflected in the next Transition Component calculation. APS files the balances and supporting details underlying this Account with the Commission on a monthly basis.

Wheeling Costs (FERC Account 565, Transmission of Electricity by Others) - Amounts payable to others for the transmission of APS' electricity over transmission facilities owned by others.

## *7. Schedules*

Samples of the following schedules are attached to this Plan of Administration

| | |
|---|---|
| Schedule 1 | Power Supply Adjustment (PSA) Rate Calculation ~~Effective February 1, 2010~~ |
| Schedule 2 | PSA Forward Component Rate Calculation ~~Effective February 1, 2010~~ |
| Schedule 3 | PSA Year Forward Component Tracking Account ~~(in effect February 1, 2010 January 31, 2011)~~ |
| Schedule 4 | PSA Historical Component Rate Calculation ~~Effective February 1, 2010~~ |
| Schedule 5 | Historical Component Tracking Account ~~(in effect February 1, 2010 January 31, 2011)~~ |
| Schedule 6 | PSA Transition Component Rate Calculation |
| Schedule 7 | PSA Transition Tracking Account ~~(in effect XX 1, 20XX XX 31, 20XX)~~ |

## *8. Compliance Reports*

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 Corporations 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.

The publicly available reports will include at a minimum:

1. The PSA Rate Calculation (Schedule 1); Forward Component, Historical Component, and Transition Component Calculations (Schedules 2, 4, and 6); Annual Forward Component, Historical Component, and Transition Component Tracking Account Balances (Schedules 3, 5, and 7). Additional information will provide other relative inputs and outputs such as:
    a. ~~a.~~ Total power and fuel costs.
    b. ~~b.~~ Margins on the sale of excess emission allowances.
    c. ~~c.~~ Costs of allowable chemicals.
    d. Customer sales in both MWh and thousands of dollars by customer class.
    e. ~~d.~~ Number of customers by customer class.
    f. ~~e.~~ A detailed listing of all items excluded from the PSA calculations.
    g. ~~f.~~ A detailed listing of any adjustments to the adjustor reports.
    h. ~~g.~~ Total off-system sales revenues.
    i. ~~h.~~ System losses in MW and MWh.

j. ~~i.~~ Monthly maximum retail demand in MW.

2. Identification of a contact person and phone number from APS for questions.

APS shall provide to Commission Staff monthly reports containing the information listed below. These reports shall be due within 30 days of the end of the reporting period. All of these additional reports will be provided confidentially.

A. Information for each generating unit shall include the following items:

1. Net generation, in MWh per month, and 12 months cumulatively.
2. Average heat rate, both monthly and 12-month average.
3. Equivalent forced-outage rate, both monthly and 12-month average.
4. Outage information for each month including, but not limited to, event type, start date and time, end date and time, and a description.
5. Total fuel costs per month.
6. The fuel cost per kWh per month.

B. Information on power purchases shall include the following items per seller (information on economy interchange purchases may be aggregated):

1. The quantity purchased in MWh.
2. The demand purchased in MW to the extent specified in the contract.
3. The total cost for demand to the extent specified in the contract.
4. The total cost of energy.

C. Information on off-system sales shall include the following items:

1. An itemization of off-system sales margins per buyer.
2. Details on negative off-system sales margins.

D. Fuel purchase information shall include the following items:

1. Natural gas interstate pipeline costs, itemized by pipeline and by individual cost components, such as reservation charge, usage, surcharges and fuel.
2. Natural gas commodity costs, categorized by short-term purchases (one month or less) and longer term purchases, including price per them, total cost, supply basin, and volume by contract.

E. APS will also provide:

1. Monthly projections for the next 12-month period showing estimated (Over)/under-collected amounts.
2. A summary of unplanned outage costs by resource type.
3. A summary of the net margins on the sale of emission allowances.
4. The data necessary to arrive at the System and Off-System Book Fuel and Purchased Power cost reflected in the non-confidential filing.
5. The data necessary to arrive at the Native Load Energy Sales MWh reflected in the non-confidential filing.

Work papers and other documents that contain proprietary or confidential information will be provided to the Commission Staff under an appropriate confidentiality agreement. APS will keep fuel and purchased power invoices and contracts available for Commission review. The Commission has the right to review the prudence of fuel and power purchases and any calculations associated with the PSA at any time. Any costs flowed through the PSA are subject to refund, if those costs are found to be imprudently incurred.

## *9. Allowable Costs*

### a. Accounts

The allowable PSA costs include fuel and purchased power costs incurred to provide service to retail customers. And, the prudent direct costs of contracts used for hedging system fuel and purchased power will be recovered under the PSA. Additionally, the net margins on the sale of emission allowances will also be refunded or recovered through the PSA. Lastly, allowable chemical costs will be refunded or recovered through the PSA. The allowable cost components include the following Federal Energy Regulatory Commission ("FERC") accounts:

- 501 Fuel (Steam)
- 518 Fuel (Nuclear) less ISFSI regulatory amortization
- 547 Fuel (Other Production)
- 555 Purchased Power
- 565 Wheeling (Transmission of Electricity by Others)
- 411 O&M (Margins on the Sale of Emission Allowances)
- xxx O&M (Allowable Chemical Costs)

Additionally, broker fees recorded in FERC account 557 are allowable up to the limit set in Decision No. ~~71448~~xxxxx.

These accounts are subject to change if the Federal Energy Regulatory Commission alters its accounting requirements or definitions.

### b. Directly Assignable Power Supply Costs Excluded

Decision No. 66567 provides APS the ability to recover reasonable and prudent costs associated with customers who have left APS standard offer service, including special contract rates, for a competitive generation supplier and then return to standard offer service. For administrative purposes, customers who were direct access customers since origination of service and request standard offer service would be considered to be returning customers. A direct assignment or special adjustment may be applied that recognizes the cost differential between the power purchases needed to accommodate the returning customer and the power supply cost component of the otherwise applicable standard offer service rate. This process is described in the Returning Customer Direct Access Charge rate schedule and associated Plan for Administration filed with the Commission.

In addition, if APS purchases power under specific terms on behalf of a standard offer special contract customer, the costs of that power may be directly assigned. In both cases, where specific power supply costs are identified and directly assigned to a large returning customer or standard offer special contract customer or group of customers, these costs will be excluded from the Adjustor Rate calculations. Schedule E-36 and AG-1 customers are directly assigned power supply costs based on the APS system incremental cost at the time the customer is consuming power from the APS system so their power supply costs are excluded from the PSA.

# Power Supply Adjustment
# Plan of Administration

## *Table of Contents*

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## *1. General Description*

This document describes the plan for administering the Power Supply Adjustment mechanism ("PSA") approved for Arizona Public Service Company ("APS") by the Commission on June 28, 2007 in Decision No. 69663 and amended by the Commission on December 30, 2009 in Decision No. 71448 and as further amended by the Commission on [insert date] in Decision No. xxxxx. 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 ($0.032415 per kWh) authorized in Decision No. xxxxx, from [insert date]. It also provides for refund or recovery of the net margins from sales of emission allowances, to the extent the actual sales margins deviate from the base rate amount of ($0.000001) per kWh[1]. Lastly, it provides for the refund or recovery of Allowable Chemical costs, to the extent that actual Allowable Chemical costs deviate from the base rate amount of $0.000442 per kWh[2].

The PSA described in this Plan of Administration ("POA") uses a forward-looking estimate of fuel and purchased power costs, net margins on the sales of emission allowances, and environmental chemical costs ("PSA Costs") to set a rate that is then reconciled to actual costs experienced.

This PSA includes a limit of $0.004 per kilowatt-hour (kWh) on the amount the PSA rate may change in any one year. This PSA also provides a mechanism for mid-year rate adjustment in the event that conditions change sufficiently to cause extraordinarily high balances to accrue under application of this PSA.

[1] *($0.000001) per kWh is the result of the following: (2010 net gains from sales of $SO_2$ allowances of $21,178)/(2010 test year native load sales of 28,075,248 MWh)/1000.*
[2] *$0.000442 per kWh is the result of the following: (2010 Allowable Chemical costs of $12,400,620)/(2010 test year sales of 28,075,248 MWh)/1000.*

## *2. PSA Components*

The PSA Rate will consist of three components designed to provide for the recovery of actual, prudently incurred PSA Costs. Those components are:

1. The Forward Component, which recovers or refunds differences between expected PSA Year (each February 1 through January 31 period shall constitute a PSA Year) PSA Costs and those embedded in base rates.
2. The Historical Component, which tracks the differences between the PSA Year's actual fuel and purchased power costs and those recovered through the combination of base rates and the Forward Component, and which provides for their recovery during the next PSA Year.
3. The Transition Component, which provides for:
    a. The opportunity to seek a mid-year change in the PSA rate in cases where variances between the anticipated recovery of fuel and purchased power costs for the PSA Year under the combination of base rates and the Forward Component become so large as to warrant recovery, should the Commission deem such an adjustment to be appropriate.
    b. The tracking of balances resulting from the application of the Transition Components, in order to provide a basis for the refund or recovery of any such balances.

Except for circumstances when the Commission approves new base rates, a PSA Year begins on February 1 and ends on the ensuing January 31. In the event that new base rates become effective on a date other than February 1, the Commission may, at its discretion, adjust any or all of the PSA components to reflect the new base rates.

On or before September 30 of each year, APS will submit a PSA Rate filing, which shall include a calculation of the three components of the proposed PSA Rate. This filing shall be accompanied by such supporting information as Staff determines to be required. APS will supplement this filing with Historical Component and Transition Component filings on or before December 31 in order to replace estimated balances with actual balances, as explained below.

### a. Forward Component Description

The Forward Component is intended to refund or recover the difference between: (1) PSA Costs embedded in base rates and (2) the forecast PSA Costs over a PSA Year that begins on February 1 and ends on the ensuing January 31. APS will submit, on or before September 30 of each year, a forecast for the upcoming calendar year (January 1-December 31) of its PSA Costs. It will also submit a forecast of kWh sales for the same calendar year, and divide the forecast costs by the forecast sales to produce the cents/kWh unit rate required to collect those costs over those sales. The result of subtracting the Base PSA Costs from this unit rate shall be the Forward Component.

APS shall maintain and report monthly the balances in a Forward Component Tracking Account, which will record APS' over/under-recovery of its actual PSA Costs as compared to the Base PSA Costs recovered in revenue. The balance calculated as a result of these steps is then reduced

by the current month's collection of Forward Component revenue. This account will operate on a PSA Year basis (i.e.; February to January), and its balances will be used to administer this PSA's Historical Component, which is described immediately below.

**b. Historical Component Description**

The Historical Component in any current PSA Year is intended to refund or recover the balances accumulated in the Forward Component Tracking Account (described above) and Historical Component Tracking Account (described below) during the immediately preceding PSA Year. The sum of the projected Forward Component Tracking Account balance on January 31 of the following calendar year and the projected Historical Component Tracking Account balance on January 31 of the following calendar year is divided by the forecast kWh sales used to set the Forward Component for the coming PSA Year. That result comprises the proposed Historical Component for the coming PSA year.

APS shall maintain and report monthly the balances in a Historical Component Tracking Account, which will reflect monthly collections under the Historical Component and the amounts approved for use in calculating the Historical Component.

Each annual September 30 APS filing will include an accumulation of Forward Component Tracking Account balances and Historical Component Tracking Account balances for the preceding February through August and an estimate of the balances for September through January (the remaining five months of the current PSA Year). The APS filing shall use these balances to calculate a preliminary Historical Component for the coming PSA Year[3]. On or before December 31, APS will submit a supplemental filing that recalculates the preliminary Historical Component. This recalculation shall replace estimated monthly balances with those actual monthly balances that have become available since the September 30 filing.

The September 30 filing's use of estimated balances for September through January (with supporting workpapers) is required to allow the PSA review process to begin in a way that will support its completion and a Commission decision, if necessary, prior to February 1. The December 31 updating will allow for the use of the most current balance information available prior to the time when a Commission decision, if necessary, is expected. In addition to the December 31 update filing, APS monthly filings (for the months of September through December) of Forward Component Tracking Account balance information and Historical Component Tracking Account balance information will include a recalculation (replacing estimated balances with actual balances as they become known) of the projected Historical Component unit rate required for the next PSA Year.[4]

The Historical Component Tracking Account will measure the changes each month in the Historical Component balance used to establish the current Historical Component as a result of collections under the Historical Component in effect. It will subtract each month's Historical

[3] For example, the September 30, 2008 filing would include actual balances for February through August of 2008 and estimated balances for September 2008 through January 2009.

[4] This updating to replace estimated with actual information will allow for the Commission to use the latest available balance information in determining what Historical Component is appropriate to establish for the coming PSA Year.

Component collections from the Historical Component balance. The Historical Component Account will also include Applicable Interest on any balances. APS shall file the amounts and supporting calculations and workpapers for this account each month.

**c. Transition Component Description**

The Transition Component will be used as the method for incorporating any future, approved mid-year changes to the PSA rate. APS, Staff, or the Commission on its own motion retain the ability to request at any time a change in the PSA rate through an adjustment to the Transition Component to address a significant imbalance between anticipated collections and costs for the PSA Year under the Forward Component element of this PSA. After the review of such request, the Commission may provide for the refund or collection of such balance (through a change to the Transition Component Balance) over such period as the Commission determines appropriate through a unit rate ($/kWh) imposed as part of the Transition Component.

A Transition Component Tracking Account will measure the changes each month in the Transition Component balance. APS, Staff, or the Commission on its own motion may request that the balance in any Transition Component Tracking Account at the end of the period set for recovery be included in the establishment of the Transition Component for the coming PSA Year.

The Transition Component Account will also include Applicable Interest as determined by the Commission. APS shall file the amounts and supporting calculations and workpapers for this account each month.

As it must do for the Historical Component filing, APS shall file on or before September 30 of each year an accumulation of Transition Component Tracking Account balances for the preceding February through August and an estimate of the balances for September through January (the remaining five months of the prior PSA Year). Those balances will form the basis for setting the preliminary Transition Component for the coming PSA Year. On or before December 31, APS will submit a supplemental filing to update the Transition Component calculation in the same manner as required for the Historical Component.

## *3. Calculation of the PSA Rate*

The PSA rate is the sum of the three components; *i.e.,* Forward Component, Historical Component, and Transition Component. The PSA rate shall be applied to customer bills. Unless the Commission has otherwise acted on a new PSA rate by February 1, the proposed PSA rate (as amended by the updated December 31 filing) shall go into effect. However, the PSA rate may not change from the prior year's PSA rate by more than plus or minus $0.004 per kWh without an offsetting change in the Base Cost of Fuel and Purchased Power. The PSA rate shall be applicable to APS' retail electric rate schedules (with the exception of E-36, Direct Access service and any other rate that is exempt from the PSA) and is adjusted annually. The PSA Rate shall be applied to the customer's bill as a monthly kWh charge that is the same for all customer classes.

The PSA rate shall be reset on February 1 of each year, and shall be effective with the first February billing cycle unless suspended by the Commission. It is not prorated.

## *4. Filing and Procedural Deadlines*

### a. September 30 Filing

APS shall file the PSA rate with all Component calculations for the PSA year beginning on the next February 1, including all supporting data, with the Commission on or before September 30 of each year. That calculation shall use a forecast of kWh sales and of PSA Costs for the coming calendar year, with all inputs and assumptions being the most current available for the Forward Component. The filing will also include the Historical Component calculation for the year beginning on the next February 1, with all supporting data. That calculation shall use the same forecast of sales used for the Forward Component calculation. The Transition Component filing shall also include a proposed method for addressing the over or under recovery of any Transition Component balances that result from changes in the sales forecasts or recovery periods set or any additions to or subtractions from Transition Component balances reviewed or approved by the Commission since the last February 1 resetting of the new PSA.[5]

### b. December 31 Filing

APS shall by December 31 update the September 30 filing. This update shall replace estimated Forward Component Tracking Account balances, the Historical Component Tracking Account balances, and the Transition Component Tracking Account balances with actual balances and with more current estimates for those months (December and January) for which actual data are not available. Unless the Commission has otherwise acted on the APS calculation by February 1, the PSA rate proposed by APS shall go into effect with the first February billing cycle.[6]

### c. Additional Filings

APS shall also file with the Commission any additional information that the Staff determines it requires to verify the component calculations, account balances, and any other matter pertinent to the PSA.

### d. Review Process

The Commission Staff and interested parties shall have an opportunity to review the September 30 and December 31 forecast, balances, and supporting data on which the calculations of the three PSA components have been based. Any objections to the September 30 calculations shall be filed within 45 days of the APS filing. Any objections to the December 31 calculations shall be filed within 15 days of the APS filing.

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[5] This method assumes that the Commission defers the recovery of any approved Transition Component Balance changes until the next February 1 PSA resetting. The Commission may also, as part of the approval of any such Transition Component Balance change, make a PSA change effective on dates and across periods as it determines to be appropriate when it approves such a Transition Component Balance change.

[6] No reference in this plan to effectiveness in the absence of Commission action shall be interpreted as precluding the normal application of the balance reconciliation provisions generally established for the PSA.

## *5. Verification and Audit*

The amounts charged through the PSA shall be subject to periodic audit to assure their completeness and accuracy and to assure that all fuel and purchased power costs were incurred reasonably and prudently. The Commission may, after notice and opportunity for hearing, make such adjustments to existing balances or to already recovered amounts as it finds necessary to correct any accounting or calculation errors or to address any costs found to be unreasonable or imprudent. Such adjustments, with appropriate interest, shall be recovered or refunded through the Transition Component.

## *6. Definitions*

Allowable Chemical Costs - Costs associated with reagent (lime), sulfur and ammonia used in the production of electricity.

Applicable Interest - Based 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.

Base Cost of Allowable Chemicals - An amount generally expressed as a rate per kWh, which reflects the cost of Allowable Chemicals embedded in base rates as approved by the Commission in APS' most recent rate case. The Base Cost for Allowable Chemicals is set at $0.000442 per kWh effective on [insert date].

Base Cost of Fuel and Purchased Power - An amount generally expressed as a rate per kWh, which reflects the fuel and purchased power cost embedded in the base rates as approved by the Commission in APS' most recent rate case. The Base Cost of Fuel and Purchased Power recovered in base revenue is the approved rate per kWh times the applicable sales volumes. Decision No. xxxxx set the base cost at $0.032415 per kWh effective on [insert date].

Base Net Margins on the Sale of Emission Allowances - An amount generally expressed as a rate per kWh, which reflects the net margins on sales of $SO_2$ emission allowances embedded in the base rates as approved by the Commission in APS' most recent rate case. The Base Net Margins on the Sale of Emission Allowances is set at ($0.000001) per kWh effective on [insert date].

Base PSA Costs - An amount generally expressed as a rate per kWh, which reflects the fuel and purchased power cost, net margins from the sales of emission allowances, and allowable chemical costs embedded in the base rates as approved by the Commission in APS' most recent rate case. The Base PSA Costs recovered in base revenue is the approved rate per kWh times the applicable sales volumes.

PSA Costs - The combination of System Book Fuel and Purchased Power Costs net of the System Book Off-System Sales Revenues plus the Net Margins on the Sales of Emission Allowances and Allowable Chemical Costs.

Forward Component - An amount generally expressed as a rate per kWh charge that is updated annually on February 1 of each year and effective with the first billing cycle in February. The

Forward Component for the PSA Year will adjust for the difference between the forecast PSA Costs generally expressed as a rate per kWh less the Base PSA Costs generally expressed as a rate per kWh embedded in APS' base rates. The result of this calculation will equal the Forward Component, generally expressed as a rate per kWh.

Forward Component Tracking Account - An account that records on a monthly basis APS' over/under-recovery of its actual PSA Costs as compared to the actual Base PSA Costs recovered in revenue and Forward Component revenue; plus Applicable Interest. The balance of this account as of the end of each PSA Year is, subject to periodic audit, reflected in the next Historical Component calculation. APS files the balances and supporting details underlying this Account with the Commission on a monthly basis.

Historical Component - An amount generally expressed as a rate per kWh charge that is updated annually on February 1 of each year and effective with the first billing cycle in February unless suspended by the Commission. The purpose of this charge is to provide for a true-up mechanism to reconcile any over or under-recovered amounts from the preceding PSA Year tracking account balances to be refunded/collected from customers in the coming year's PSA rate.

Historical Component Tracking Account - An account that records on a monthly basis the account balance to be collected via the Historical Component rate as compared to the actual Historical Component revenues; plus Applicable Interest; the balance of which at the close of the preceding PSA Year is, subject to periodic audit, then reflected in the next Historical Component calculation. APS files the balances and supporting details underlying this Account with the Commission on a monthly basis.

ISFSI - Costs associated with the Independent Spent Fuel Storage Installation that stores spent nuclear fuel.

Mark-to-Market Accounting - Recording the value of qualifying commodity contracts to reflect their current market value relative to their actual cost.

Native Load - Native load includes customer load in the APS control area for which APS has a generation service obligation and PacifiCorp Supplemental Sales.

Net Margins on the Sale of Emission Allowances - Revenues incurred from the sale of emission allowances net of the costs incurred to produce the excess allowances.

PacifiCorp Supplemental Sales - The PacifiCorp Supplemental Sales agreement is a long-term contract from 1990 which requires APS to offer a certain amount of energy to PacifiCorp each year. It is a component of the set of agreements that led to the sale of Cholla Unit 4 to PacifiCorp and the establishment of the seasonal diversity exchange with PacifiCorp.

PSA - The Power Supply Adjustment mechanism approved by the Commission in Decision No. 69663 and amended by the Commission in Decision No. 71448 and further amended by the commission in Decision No. xxxxx, which 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.

PSA Year - A consecutive 12-month period generally beginning each February 1.

Preference Power - Power allocated to APS wholesale customers by federal power agencies such as the Western Area Power Administration.

System Book Fuel and Purchased Power Costs - The costs recorded for the fuel and purchased power used by APS to serve both Native Load and off-system sales, less the costs associated with applicable special contracts, E-36 AG -1 RCDAC-1, ISFSI, and Mark-to-Market Accounting adjustments. Wheeling costs are included; broker fees are included up to the level in the Base Cost of Fuel and Purchased Power authorized in Decision No.xxxxx.

System Book Off-System Sales Revenue - The revenue recorded from sales made to non-Native Load customers, for the purpose of optimizing the APS system, using APS-owned or contracted generation and purchased power, less Mark-to-Market Accounting adjustments.

Traditional Sales-for-Resale - The portion of load from Native Load wholesale customers that is served by APS, excluding the load served with Preference Power.

Transition Component - An amount generally expressed as a rate per kWh charge to be applied when necessary to provide for significant changes between estimated and actual costs under the Forward Component.

Transition Component Tracking Account - An account that records on a monthly basis the account balance to be collected via the Transition Component as compared to the actual Transition Component revenues, plus applicable interest; the balance of which upon Commission consideration may then be reflected in the next Transition Component calculation. APS files the balances and supporting details underlying this Account with the Commission on a monthly basis.

Wheeling Costs (FERC Account 565, Transmission of Electricity by Others) - Amounts payable to others for the transmission of APS' electricity over transmission facilities owned by others.

## *7. Schedules*

Samples of the following schedules are attached to this Plan of Administration

| | |
|---|---|
| Schedule 1 | Power Supply Adjustment (PSA) Rate Calculation |
| Schedule 2 | PSA Forward Component Rate Calculation |
| Schedule 3 | PSA Year Forward Component Tracking Account |
| Schedule 4 | PSA Historical Component Rate Calculation |
| Schedule 5 | Historical Component Tracking Account |
| Schedule 6 | PSA Transition Component Rate Calculation |

Schedule 7 PSA Transition Tracking Account

## *8. Compliance Reports*

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 Corporations 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.

The publicly available reports will include at a minimum:

1. The PSA Rate Calculation (Schedule 1); Forward Component, Historical Component, and Transition Component Calculations (Schedules 2, 4, and 6); Annual Forward Component, Historical Component, and Transition Component Tracking Account Balances (Schedules 3, 5, and 7). Additional information will provide other relative inputs and outputs such as:
    a. Total power and fuel costs.
    b. Margins on the sale of excess emission allowances.
    c. Costs of allowable chemicals.
    d. Customer sales in both MWh and thousands of dollars by customer class.
    e. Number of customers by customer class.
    f. A detailed listing of all items excluded from the PSA calculations.
    g. A detailed listing of any adjustments to the adjustor reports.
    h. Total off-system sales revenues.
    i. System losses in MW and MWh.
    j. Monthly maximum retail demand in MW.

2. Identification of a contact person and phone number from APS for questions.

APS shall provide to Commission Staff monthly reports containing the information listed below. These reports shall be due within 30 days of the end of the reporting period. All of these additional reports will be provided confidentially.

A. Information for each generating unit shall include the following items:
1. Net generation, in MWh per month, and 12 months cumulatively.
2. Average heat rate, both monthly and 12-month average.
3. Equivalent forced-outage rate, both monthly and 12-month average.
4. Outage information for each month including, but not limited to, event type, start date and time, end date and time, and a description.
5. Total fuel costs per month.
6. The fuel cost per kWh per month.

B. Information on power purchases shall include the following items per seller (information on economy interchange purchases may be aggregated):
1. The quantity purchased in MWh.

2. The demand purchased in MW to the extent specified in the contract.
3. The total cost for demand to the extent specified in the contract.
4. The total cost of energy.

C. Information on off-system sales shall include the following items:
1. An itemization of off-system sales margins per buyer.
2. Details on negative off-system sales margins.

D. Fuel purchase information shall include the following items:
1. Natural gas interstate pipeline costs, itemized by pipeline and by individual cost components, such as reservation charge, usage, surcharges and fuel.
2. Natural gas commodity costs, categorized by short-term purchases (one month or less) and longer term purchases, including price per them, total cost, supply basin, and volume by contract.

E. APS will also provide:
1. Monthly projections for the next 12-month period showing estimated (Over)/under-collected amounts.
2. A summary of unplanned outage costs by resource type.
3. A summary of the net margins on the sale of emission allowances.
4. The data necessary to arrive at the System and Off-System Book Fuel and Purchased Power cost reflected in the non-confidential filing.
5. The data necessary to arrive at the Native Load Energy Sales MWh reflected in the non-confidential filing.

Work papers and other documents that contain proprietary or confidential information will be provided to the Commission Staff under an appropriate confidentiality agreement. APS will keep fuel and purchased power invoices and contracts available for Commission review. The Commission has the right to review the prudence of fuel and power purchases and any calculations associated with the PSA at any time. Any costs flowed through the PSA are subject to refund, if those costs are found to be imprudently incurred.

## *9. Allowable Costs*

### a. Accounts

The allowable PSA costs include fuel and purchased power costs incurred to provide service to retail customers. And, the prudent direct costs of contracts used for hedging system fuel and purchased power will be recovered under the PSA. Additionally, the net margins on the sale of emission allowances will also be refunded or recovered through the PSA. Lastly, allowable chemical costs will be refunded or recovered through the PSA. The allowable cost components include the following Federal Energy Regulatory Commission ("FERC") accounts:

- 501 Fuel (Steam)
- 518 Fuel (Nuclear) less ISFSI regulatory amortization
- 547 Fuel (Other Production)
- 555 Purchased Power

- 565 Wheeling (Transmission of Electricity by Others)
- 411 O&M (Margins on the Sale of Emission Allowances)
- xxx O&M (Allowable Chemical Costs)

Additionally, broker fees recorded in FERC account 557 are allowable up to the limit set in Decision No. xxxxx.

These accounts are subject to change if the Federal Energy Regulatory Commission alters its accounting requirements or definitions.

**b. Directly Assignable Power Supply Costs Excluded**

Decision No. 66567 provides APS the ability to recover reasonable and prudent costs associated with customers who have left APS standard offer service, including special contract rates, for a competitive generation supplier and then return to standard offer service. For administrative purposes, customers who were direct access customers since origination of service and request standard offer service would be considered to be returning customers. A direct assignment or special adjustment may be applied that recognizes the cost differential between the power purchases needed to accommodate the returning customer and the power supply cost component of the otherwise applicable standard offer service rate. This process is described in the Returning Customer Direct Access Charge rate schedule and associated Plan for Administration filed with the Commission.

In addition, if APS purchases power under specific terms on behalf of a standard offer special contract customer, the costs of that power may be directly assigned. In both cases, where specific power supply costs are identified and directly assigned to a large returning customer or standard offer special contract customer or group of customers, these costs will be excluded from the Adjustor Rate calculations. Schedule E-36 and AG-1 customers are directly assigned power supply costs based on the APS system incremental cost at the time the customer is consuming power from the APS system so their power supply costs are excluded from the PSA.