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Transcript Exhibit(s)

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(Part 6 of 9)

EXHIBIT

APS-45

Admitted

REBUTTAL TESTIMONY OF JOHN R. DENMAN

On Behalf of Arizona Public Service Company

Docket No. E-01345A-05-0816

September 15, 2006

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REBUTTAL TESTIMONY OF JOHN R. DENMAN ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY (Docket No. E-01345A-05-0816)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND POSITION WITH APS.

A. My name is John R. Denman. I am the Vice President of Fossil Generation for Arizona Public Service Company ("APS" or "Company").

Q. WHAT IS YOUR PROFESSIONAL BACKGROUND?

A. I have worked for APS for more than 40 years in various positions relating to fossil generation. I have been the Vice President for Fossil Generation since 1997. From 1986 to 1997, I was the Director of Fossil Generation, with the same basic responsibilities I have as Vice President of Fossil Generation. Prior to 1986, I held various positions within fossil generation, including Plant Manager for the Four Corners Power Plant.

Q. DID YOU FILE DIRECT TESTIMONY IN THIS PROCEEDING?

A. No.

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

A. I am responding to the testimony by John Antonuk regarding the examination and evaluation of the Company's procurement and management of fuel and energy conducted by the Arizona Corporation Commission's ("Commission") Utilities Division Staff. I will focus on issues and recommendations relating to coal procurement and plant operations. APS witnesses Don Brandt and Tom Carlson will address issues and recommendations relating to gas commodity procurement, gas transportation, and hedging.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. No.

II. <u>SUMMARY</u>

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A. APS was pleased that Mr. Antonuk has confirmed that the Company appropriately handles fuel and energy procurement and effectively operates its fossil generating facilities, and that the recommendations are intended to improve already-appropriate systems and operations. We considered all of Mr. Antonuk's recommendations in those areas and agree with most of them. In several cases, such as with the process for handling coal weights, we already had addressed or were addressing the recommendations at the time of the audit. In other cases, such as the inventory target at the Cholla Power Plant and the coal contract management process, we agree that the suggested changes will improve our systems, and we will implement those recommendations. Finally, with respect to some of the recommendations, we believe we already had in place the suggested changes but that perhaps we did not adequately explain the Company's process during the audit process.

III. <u>FUEL CONTRACT MANAGEMENT AND ADMINISTRATION</u>

Q. MR. ANTONUK OFFERS VARIOUS RECOMMENDATIONS REGARDING FUEL AND ENERGY PROCUREMENT AND MANAGEMENT. DID YOU REVIEW THOSE RECOMMENDATIONS?

A. Yes, and I agree with Mr. Antonuk's overall conclusion that the Company handled these areas "in a manner that produced appropriate costs during the April through December 2005 period," the period covered by the fuel audit.

Q. DO YOU AGREE WITH MR. ANTONUK'S RECOMMENDATIONS REGARDING FUEL CONTRACT MANAGEMENT AND ADMINISTRATION?

A. In general, yes. Mr. Antonuk offers a few recommendations regarding the Company's fuel contract management processes that in general APS finds to be appropriate. In fact, the Company already was implementing several of those recommendations when Mr. Antonuk's firm, Liberty Consulting, conducted its assessment. The following paragraphs summarize the status and response to the contract management recommendations relating to the Company's coal acquisitions. Mr. Carlson will respond to those recommendations relating to the acquisition of the Company's gas supply.

- <u>Develop a complete set of procedures related to the management and administration of coal contracts</u>: The APS Fuel Procurement Department will review its procedures for fuel contract management and administration and, as appropriate, incorporate additional detail to reflect the processes used.

- <u>Streamline the procedures for handling of information on coal weights</u>: APS agrees that the manual process used for handling coal weight information for the coal sample analysis should be reevaluated for possible automation. Mr. Antonuk's recommendation that APS improve the automation of the data entry of weight information from the coal belt scales at the Four Corners and Cholla Power Plants appears to have merit. APS will evaluate the cost of automating these activities and implement those changes are found to result in a positive cost benefit.

- Revise the inventory target for Regular Coal at the Cholla Power Plant from 25 days of supply to 35 days of supply: As Mr. Antonuk testifies, the Cholla Power Plant practice has been to carry a coal inventory in excess of the lower inventory target. Mr. Antonuk concluded that the Plant's *practice* was appropriate and that the *target* should be revised to reflect that practice. APS Fuel Procurement will work with Cholla Power Plant management to review the inventory target and adjust it to reflect the appropriate inventory practice.

- Conduct a comprehensive analysis of gas purchasing and management under El Paso Natural Gas's revised rate structure, and report to the Commission: Mr. Antonuk clarified in discussions with APS that the Company has taken appropriate steps to date to address pipeline transportation cost concerns. To that end, APS takes a comprehensive approach to investigating alternatives for increasing the Company's options relating to gas transportation. With respect to infrastructure needs, APS has worked with both Kinder Morgan and TransWestern Pipeline to encourage the construction of a new pipeline to serve Arizona. In addition, as Mr. Carlson discusses in his testimony, APS continues to examine options relating to natural gas storage and liquefied natural gas ("LNG").

  Mr. Antonuk's recommendation, therefore, focuses on encouraging the Company to continue that proactive approach in addressing these issues in light of continuing developments relating to the El Paso Natural Gas rates. As Mr. Antonuk discusses in his testimony, it will be important for APS to continue to evaluate options relating to natural gas transport. APS will conduct the recommended "analysis of gas purchasing and management under [El Paso's] revised rate structure" and will submit a confidential report to the Commission summarizing its analysis within one year of the decision in this docket.

IV. PLANT OPERATIONS

Q. MR. ANTONUK ALSO OFFERS SEVERAL RECOMMENDATIONS RELATING TO APS PLANT OPERATIONS. DO YOU HAVE ANY RESPONSES TO THOSE RECOMMENDATIONS?

A. Yes, I do. Although I agree with some of Mr. Antonuk's recommendations, I believe that other recommendations may have been based on an inaccurate or incomplete understanding of the processes APS currently uses to evaluate plant operations.

Q. LET'S START WITH MR. ANTONUK'S RECOMMENDATION THAT APS "FOCUS ON OPTIMIZING THE PERFORMANCE" OF THE REDHAWK AND WEST PHOENIX CC5 UNITS AS THEY TRANSITION INTO APS. DO YOU HAVE ANY RESPONSE TO MR. ANTONUK'S RECOMMENDATIONS?

A. Yes. First, however, I would like to reiterate that Mr. Antonuk found that APS "has appropriately recognized the shift in the market paradigm brought about" by the movement of the Redhawk and West Phoenix CC5 units into APS. As Mr. Antonuk noted, those units have experienced "representative outage frequency and duration."

APS continuously focuses on optimizing the performance of all of its fossil generating units, including Redhawk and West Phoenix CC5. Because of that focus, the transition of these gas-fired units into an intermediate dispatch operation has gone very well overall. As with any generating unit that initially is designed for base-load operation and then changed to intermediate duty, certain systems and equipment have required re-engineering for the new duties.

With respect to Redhawk, many of the start-up and unit operational issues already have been resolved. For example, several steam by-pass valves have been replaced and relocated, additional generator endturn blocking has been added, and larger start-up drains have been added. Because of these efforts, among others, Redhawk is operating at a combined equivalent availability factor ("EAF") of 96.5% for 2006 year-to-date.

At West Phoenix CC5, APS also has addressed operational and start-up issues. Many of the by-pass and feedwater regulating valves have been replaced, and the remaining are scheduled to be replaced during planned future outages. The rotor air cooler system has been redesigned and heater retubing is scheduled for October 2006. Like other units throughout the industry with the same turbine design, West Phoenix CC5 has experienced some problems with the low pressure steam turbine last stage blades ("L-O Blades"). These L-O Blades are the largest turbine blades in each unit. In addition to requiring frequent unit outages for blade inspection, the unit must be operated in a manner that results in higher unit heat rate. We anticipate installing a newly designed blade in the first quarter of 2008. Because of these efforts, among others, West Phoenix CC5's year-to-date EAF is 91.6%.

Q. **MR. ANTONUK ALSO RECOMMENDS THAT APS "PREPARE AND EXECUTE AN ACTION PLAN THAT WILL IMPROVE ECONOMIC EVALUATIONS RELATED TO MINIMIZATION OF OUTAGE TIME." DO YOU AGREE WITH THAT RECOMMENDATION?**

A. We believe APS already has such a process in place. APS schedules required planned outages using a production cost model, which produces the least cost replacement power for the system. All scheduled outages at APS base-load and intermediate units are planned using a critical path planning tool to minimize outage time. The Company schedules planned outages to obtain the shortest duration to minimize replacement power cost. Planned outages for peaking units are scheduled during off-peak times to ensure that scheduled work is performed at the least cost.

Forced outages on the intermediate and peaking units are worked based on value to the system, replacement power cost at the time of the outage, and forecasted near term anticipated dispatch of the unit. We perform an assessment of each unit to determine options for extending the time between required outages. For example, we may install upgraded materials or change equipment design to reduce wear. With respect to outage duration, we work to reduce outage time by making sure appropriate resources (such as labor, tools, parts, contract support) are available so the outage is as short as possible.

Q. ALTHOUGH MR. ANTONUK'S RECOMMENDATION IS BROADLY STATED, THE ASSOCIATED CONCLUSION IN THE AUDIT REPORT FOCUSES ON APS'S REFLECTION OF NET REPLACEMENT POWER COSTS IN ITS ECONOMIC EVALUATIONS. DO YOU HAVE ANY COMMENT ON THAT ISSUE?

A. I absolutely agree with Mr. Antonuk that net replacement power cost should be considered in economic evaluations relating to spare parts and inventory and, in fact, APS considers those costs already. At the Company's intermediate gas plants, capital spare parts are justified and purchased for inventory based on an economic evaluation using differential fuel cost and projected loss of generation. Major spare parts are evaluated for consideration to stock (i.e., kept as inventory) based on expected lead time to purchase, expected refurbish time for the maintenance spare, and the expected time between planned maintenance.

With respect to replacement combustion hardware, for example, one set of spare combustion hardware costs well over $8 million dollars, and the Company has determined that one set of spares for the Redhawk units and a second set of spares for West Phoenix is reasonable and appropriate. In addition, the Company's Long Term Service Agreements ("LTSAs") guarantee that APS will be provided with needed combustion parts beyond our in-house inventory levels without any delay in scheduled or forced outage time.

The Company purchases routine inventory spares based on frequency of need, risk of failure, and criticality to plant operations. We have evaluated all systems as both base-load and intermediate load units with the objective of identifying spare parts and spare equipment needs. Where it is cost effective to do so, spare parts and equipment have been purchased.

Q. HOW DO YOU RESPOND TO MR. ANTONUK'S RECOMMENDATION THAT APS EVALUATE THE REPLACEMENT OF BOILER SECTIONS AT FOUR CORNERS POWER PLANT UNIT #5 AND NAVAJO GENERATING STATION UNITS #2 AND #3?

A. Boiler tube leaks on coal fired generating units usually constitute the major contributor to lost generation for these types and vintage of units. Many factors influence boiler tube leaks, including boiler design, fuel quality, and age of the different boiler components, among others. Because APS (for Four Corners) and SRP (for Navajo Generating Station) continuously review and research new applications of boiler maintenance procedures and the use of up-graded materials to anticipate and reduce boiler tube leaks, APS believes that Mr.. Antonuk's recommendation already is being met.

APS and SRP each have an integrated boiler tube leak reduction program that includes inspection and testing to anticipate leaks in addition to procedures to determine the root cause of leaks, ensure that repairs are performed properly, require the development of short and long-term corrective action plans, and monitor implementation of corrective action plans to assure timely completion. Based on our comprehensive boiler tube leak reduction program, planned boiler components replacement is performed at each planned outage. All major component replacements are based on an estimated remaining life assessment and economic evaluation of component failure.

Q. MR. ANTONUK ALSO RECOMMENDS THAT APS CONDUCT A REVIEW OF OPERATOR AND MAINTENANCE ERRORS TO DETERMINE WHY SUCH ERRORS APPEAR TO OCCUR MORE FREQUENTLY AT FOUR CORNERS UNIT #3 AND NAVAJO UNIT #3. HOW DO YOU RESPOND?

A. *It is important* to first clarify that operator and maintenance errors at all APS base-load coal plants and at the Navajo Generating Station, operated by Salt River Project ("SRP"), already are investigated for root causes. With respect to the plants that APS operates, I receive daily reports on plant operation and review monthly plant performance issues with plant management. In addition, I require each coal plant to provide me a quarterly report on all lost generation. That report also sets out the plant's corrective action plans to address any issues identified.

We regularly conduct operational assessments at each of the base-load and intermediate load plants that APS operates to assure that operators are knowledgeable and are following good operational practices. Appropriate corrective action is identified based on investigation findings when a human performance error occurs. Corrective actions can include training, changes in procedures, additional procedures, and/or employee coaching.

With respect to the Navajo Generating Station, SRP provides daily status and monthly lost generation reports to me, the APS Manager of Technical Services and the APS Manager of Generation Engineering, both of whom report to me. APS representatives also attend quarterly Engineering & Operating ("E&O") Committee meetings where SRP provides detailed information about Navajo's operations, including lost generation events, to all plant owners. SRP also identifies corrective actions that it has taken or plans to take to address issues and problems identified.

There were seven human performance errors reported at Four Corners Unit 3 in 2005 - one maintenance and six operations. Of the six operations errors, five were related to one event. In February 2006, the Company identified the actual root cause—a faulty check valve. The Company decided not to correct the 2005 data to reflect that these five reported errors were *not* in fact operator errors.

There were six human performance errors reported at Navajo Unit 3 in 2005. All were related to unit start up and operator experience. Consistent with the plant's root cause policy, each of these events was investigated and appropriate action taken to help insure that human performance errors are kept to the lowest possible level. Procedures, employee training, employee coaching, and operations audits are used to keep human performance errors to the lowest level possible.

In short, we do not agree that there is any unusual pattern of operator errors at these two units requiring the suggested special evaluation. The current practice of root cause analysis of outages with follow up corrective actions, if needed, is sufficient.

Q. DO YOU AGREE WITH MR. ANTONUK'S RECOMMENDATION THAT APS "IMPLEMENT FOR WEST PHOENIX #5 THE REQUIREMENT FOR ROOT CAUSE ANALYSIS WHEN GENERATION IS LOST"?

A. I agree with Mr. Antonuk's endorsement of root cause analysis, but West Phoenix CC5 *already* is required to comply, and does comply, with the same requirement for root cause analysis that applies to the rest of the Company's fossil generating units. In addition, as I indicated above, I meet with the Plant Manager of each fossil plant monthly to discuss lost generation events. I require the plants to develop specific Action Plans to address root cause corrective actions and review them regularly with plant management to assure implementation.

V. CONCLUSION

Q. DO YOU HAVE ANY CONCLUDING COMMENTS?

A. I appreciate Mr. Antonuk's overall conclusion that APS's fuel procurement and plant operations are effective and appropriate, as we have worked hard to have an effective operation. Any operation can be improved, however, and as I indicated above, the Company already has in place or is implementing a number of the recommendations made by Mr. Antonuk. We will continue to implement those processes. In addition, we will update our analysis of options relating to gas transportation and provide the Commission with a confidential report on that analysis within one year after the decision in this proceeding.

Q. DOES THAT CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

DIRECT TESTIMONY OF PATRICK DINKEL

On Behalf of Arizona Public Service Company

Docket No. E-01345A-05-0816

January 31, 2006

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

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND POSITION WITH APS.

A. My name is Patrick Dinkel. I am the Director of Corporate Planning and Resource Acquisition for Arizona Public Service Company ("APS" or "Company"). I led the APS team responsible for conducting the 2003 APS Request for Proposals—Power Supply Resource Proposal for the Procurement of Generating Capacity (the "2003 RFP"), evaluating the resulting proposals, negotiating the Asset Purchase Agreement with PPL Sundance Energy, LLC ("PPL Sundance"), and closing the transaction that resulted in APS owning the Sundance Generating Station and associated assets ("Sundance Assets"). I also conducted the two 2005 RFPs called for by Decision No. 67744 (April 7, 2005) – one seeking at least 100 MW of renewables and a second all-source procurement for at least 1000 MW.

Q. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. I received a Bachelors of Science degree from Marymount College and a Masters of Business Administration from Northern Arizona University. I joined APS in 1986. Before becoming Director of Corporate Planning and Resource Acquisitions in 2004, I was the Manager of Corporate Planning, and the Manager of Business Unit Analysis and Reporting. Before that, I held various positions within APS and Pinnacle West Capital Corporation ("Pinnacle West"), primarily within the financial planning and budgeting areas.

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

A. APS is seeking to include the Sundance Assets in its rate base. My testimony explains the validity of the procurement process and the value of the Sundance Assets for serving APS customers. APS witness Ms. Laura Rockenberger will discuss the operating income pro forma for the Sundance Assets.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes, I have. I testified in support of APS' request to acquire the Sundance Assets in Docket No. E-01345A-04-0407 ("Sundance Acquisition Docket"). My testimony in that docket addressed the 2003 RFP and the evaluation process that resulted in the selection of the PPL Sundance proposal. In addition, I addressed APS' proposed financing of the acquisition and provided details relating to the Accounting Order that APS was requesting. Because it is relevant to the issues in this rate case application, a copy of my pre-filed direct testimony in the Sundance Acquisition Docket is attached as Attachment PD- 1.

Q. WHAT WAS THE OUTCOME OF THE SUNDANCE ACQUISITION DOCKET?

A. In Decision No. 67504, (January 20, 2005), the Commission affirmed APS' ability, subject to applicable regulatory requirements, to buy new generation assets for native load.[1] The Commission declined to approve the acquisition prior to its consideration in a ratemaking proceeding, or to make a determination as to whether the assets were "used and useful." The Commission did determine that the Sundance Assets acquisition satisfied the evidentiary and legal standards

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[1] Subsequent to the decision in the Sundance Acquisition Docket, the Commission issued Decision No. 67744 (April 7, 2005), which imposed certain restrictions on APS' ability to self-build or acquire new generation.

necessary to be accorded full cost recovery under traditional cost of service principles in a future rate proceeding. The Commission also found that the financing authorizations granted in Decision Nos. 54230 and 55017 were in full force and effect and could be used for the acquisition of the Sundance Assets. A specific modification to the Sundance Certificate of Environmental Compliance was approved as requested. In addition, the Commission held that subject to specified conditions, including the approval of the proposed Power Supply Adjustor (PSA) in the then pending APS rate case, APS was authorized to defer certain costs of owning, operating, and maintaining the Sundance Assets.

Q. DID APS RECEIVE THE REQUIRED APPROVAL FROM FERC FOR ITS ACQUISITION OF THE SUNDANCE ASSETS?

A. Yes. That approval was received by Letter Order on May 6, 2005. I have attached a copy of FERC's Order as Attachment PD-2. The sale and purchase transaction closed on May 13, 2005.

Q. PLEASE SUMMARIZE YOUR TESTIMONY IN THIS RATE CASE DOCKET.

A. My testimony will demonstrate that:

- APS' long range forecasts in 2002 and 2003 showed that the Company would need a significant amount of additional generation resources to meet its continued load growth.
- The Company's ultimate decision to purchase the Sundance Assets was based on a fair and appropriate Request for Proposal ("RFP") process. The acquisition of the Sundance Assets was analyzed with sound economic principles and determined to be a cost effective means of acquiring critical long-term peaking capacity for our customers. We also

analyzed the performance of the units and found that they were well suited for our customers' needs.

II. SUNDANCE ASSETS

Q. PLEASE DESCRIBE THE SUNDANCE ASSETS.

A. The Sundance Generating Station is a 450-megawatt ("MW"), natural gas-fired, simple cycle, peaking electric generating facility located in Pinal County, approximately five miles southwest of Coolidge, Arizona. The plant began commercial operation in July 2002. APS acquired the Sundance Assets from PPL Sundance, which constructed the facility and managed it as a merchant power plant prior to the sale. Sundance consists of ten 45 MW General Electric LM6000-PC combustion turbines arranged in pairs, along with five generation step-up transformers. The plant uses well-known technology with a solid operational and environmental track record.

Q. WHY DID APS ISSUE AN RFP IN DECEMBER 2003?

A. APS routinely prepares forecasts of its projected load requirements and compares them to its available resources, including owned generation and any long-term purchased power contracts it may have in place. In 2002 and 2003, the Company was forecasting continued load growth that, when compared to the Company's existing resources, signaled a need for a significant amount of additional generation resources. The APS Summer Supply & Demand Balance Assessment showed that APS would have a resource shortfall by the summer of 2007 of more than 1400 MW. This assessment included the 1700 MW of Arizona assets owned by Pinnacle West Energy Corporation ("PWEC"), which APS proposed to have included in its rate base in its then-pending rate case. APS issued the 2003 RFP in December 2003 to explore options for meeting the resource shortfall and to take advantage of any potentially favorable market purchase alternatives.

Q. WHAT FACTORS DID APS CONSIDER IN ISSUING THE RFP?

A. Timing was a major consideration. APS saw the potential for favorable prices in the near-term given the wholesale market at the time and reports that some of the resources in the area may be for sale. APS felt that it was important to determine quickly whether the Company could procure long-term resources for its customers from the competitive wholesale market at a reasonable price. The timing of a new long-term resource acquisition was another consideration.

Q. PLEASE DESCRIBE THE RFP ISSUED BY APS.

A. The 2003 RFP identified APS' projected capacity shortfall of 1447 MW in 2007, with growth of approximately 300 MW per year. APS expressed a willingness to consider either long-term purchase power agreements or asset ownership. The 2003 RFP specifically sought proposals that would deliver a power supply to APS commencing in the summer of 2007.

Q. WHAT WAS THE PROCESS THE COMPANY USED TO EVALUATE WHETHER THE SUNDANCE ASSETS WERE THE BEST GENERATION OPTION FOR APS CUSTOMERS?

A. A team of experienced employees from various APS departments, as well as legal counsel and outside experts, reviewed the proposals submitted in response to the 2003 RFP and reported their conclusions. The defined objective was to identify any issue that warranted consideration or that could have a material impact on a transaction.

The Company evaluated the economics of those proposals that were in contention for further consideration by computing and comparing the installed cost of each asset sale proposal, the levelized busbar cost of each bid, and the system revenue requirement impact of each bid.

The installed cost, including any interest capitalized during construction, is usually the investment included in a utility's rate base. APS calculated the installed cost of each asset sale proposal to provide a snapshot of how each alternative would impact customers. This analysis provided an indication of the fixed costs associated with each option. Additional discussion of the installed cost analysis is included in Attachment PD-1.

The busbar cost is the revenue required to cover the costs of owning and operating the plant (including fuel and cost of capital) or of purchasing power under a PPA, divided by the anticipated MWh output at the plant's "bus" or the MWh purchase. A "levelized" busbar cost is the busbar cost over the period evaluated (*e.g.*, 30 years) stated in constant dollars. In completing the busbar analysis, APS incorporated information submitted with each proposal along with equipment manufacturer data and standard financial and capacity factor assumptions. Further detail on the busbar cost economic analysis is included in Attachment PD-1.

The system revenue requirement cost study we employed calculated the present value cost for each alternative of providing power to customers, including the cost of fuel, purchased power and ownership. APS evaluated the Sundance Generating Station against alternative new-build simple cycle cases and purchases from the wholesale market. The revenue requirement results were consistent with the busbar results, showing that the acquisition of the Sundance Generating Station produced present value saving of $79 million to $154 million compared to the other available alternatives. Additional discussion of this analysis is included in Attachment PD-1.

Set out below is a table summarizing select information relating to Sundance and other selected options.

Simple Cycle Technology Comparison			
	Sundance LM6000	New LM6000	New 7EA
Installed Cost ($/kW)	475	762	695
Summer Output (MW)	40	40	76
Heat Rate (Btu/kWh)	9,855	9,855	12,125
Quick Start (<10 Min.)	Y	Y	N
Busbar Cost ($ per MWh)	151	177	182

Q. WHY DID APS SELECT THE PPL SUNDANCE PROPOSAL?

A. APS elected to pursue the PPL Sundance proposal because the Company's analysis demonstrated that purchasing the Sundance Assets was the least cost means for APS to acquire critical long-term peaking capacity. Also, because the units can ramp up quickly, they provide cost-effective reserves for APS' system reliability. The generation can start up in less than ten minutes from a warm or cold standby condition. Sundance was the only constructed or permitted simple-cycle plant that was available in the Arizona market, and it was acquired for peaking capacity at a discounted price that will benefit APS customers far into the future.

Q. WHAT WERE STAFF'S COMMENTS IN THE SUNDANCE ACQUISITION DOCKET REGARDING THE SUITABILITY OF APS' ACQUISITION OF THE SUNDANCE ASSETS?

A. Staff made several particularly relevant observations during the four month period that the filing was under evaluation.[2] First, Staff agreed that there were "positive aspects" to APS' acquisition of the Sundance facility, including "increased reliability," "[i]ncreased operational flexibility" and that "the plant would be acquired through a fair and open RFP."[3] Second, Staff noted that the Sundance Plant was "well situated to support the peaking needs of Arizona customers in Phoenix and Tucson areas."[4] Third, Staff recognized that the "Sundance units' quick start capability and grid location would provide APS with additional options in responding to system disturbances . . . and would provide flexibility in meeting system reserve requirements."[5] Fourth, Staff pointed out that "[i]n the normal course of business, [Sundance] will displace older less efficient units [such as Ocotillo, West Phoenix, Saguaro and Yucca combustion turbines] in the dispatch priority.[6] Finally, Staff noted:

> According to the APS busbar cost, the PPL Sundance purchase is a lower cost alternative to new construction of comparable plants. The cost comparison does not reflect some additional advantages. For instance, PPL Sundance is operational, has been reliable, and has an acquisition cost set forth in the asset purchase agreement that cannot be exceeded. In contrast, construction of a new plant can have

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[2] Testimony of Matthew Rowell, Docket No. E-01345A-04-0407, Hearing Transcript at 356.

[3] Testimony of Matthew Rowell, Docket No. E-01345A-04-0407, Hearing Transcript at 364-65.

[4] Direct Testimony of William Gehlen, Docket No. E-01345A-04-0407, at 5.

[5] Direct Testimony of William Gehlen, Docket No. E-01345A-04-0407, at 5-6; *see also*, Testimony of Matthew Rowell, Docket No. E-01345A-04-0407, Hearing Transcript at 365-66.

[6] Direct Testimony of William Gehlen, Docket No. E-01345A-04-0407, at 6; *see also* Testimony of Matthew Rowell, Docket No. E-01345A-04-0407, Hearing Transcript at 381-83.

cost overruns that far exceed the original anticipated cost to build.[7]

Q. DID STAFF ANALYZE THE RFP SOLICITATION AND BID EVALUATION IN THE SUNDANCE ACQUISITION DOCKET?

A. Yes. In direct pre-filed testimony, Staff described its review of the RFP process and bid evaluation. Based on its review, Staff opined that APS displayed a willingness to individually evaluate a wide range of bids, as most of the proposals did not conform to the RFP.[8]

Q. DID STAFF EXPRESS AN OPINION REGARDING THE ECONOMICS OF THE SUNDANCE PLANT ACQUISITION?

A. Yes, as evidenced from the quote above, Staff found that according to the APS economic analysis, including the busbar cost, the Sundance Assets purchase was a lower cost alternative as compared to new construction of comparable plants.

Q. WHEN APS PROPOSED TO ACQUIRE THE SUNDANCE ASSETS, DID APS BELIEVE THE FACILITY WOULD PROVIDE IMMEDIATE BENEFITS TO THE COMPANY AND ITS CUSTOMERS?

A. Yes. APS had been using a portion of the Sundance Assets pursuant to a long-term agreement and shorter-term market purchases to serve APS customers' needs since July 2003. Projections indicated that the Company would need the full capacity of the units in the future. The acquisition of the Sundance Assets provided APS with 325 MW of critical additional capacity during the summer peak season in 2005, as it will in 2006. The full output from the plant will be utilized to serve APS customers beginning in the summer of 2007 after a

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[7] Direct Testimony of William Gehlen, Docket No. E-01345A-04-0407, at 7.

[8] Direct Testimony of William Gehlen, Docket No. E-01345A-04-0407, at 4.

previously existing agreement between PPL and Tucson Electric Power Company expires.

Q. ASIDE FROM THE NEED FOR THE SUNDANCE ASSETS IN DELIVERING ENERGY DURING PERIODS OF PEAK LOAD, WERE THERE OTHER FACTORS THAT LED APS TO BELIEVE THAT THE FACILITY WOULD BE BENEFICIAL TO APS AND ITS CUSTOMERS?

A. Yes. The additional benefits for APS and its customers in acquiring the Sundance Assets included increased operational flexibility from owning ten quick-start 45 MW units and the availability of the units to help APS more efficiently manage its reserves. With typical unit start times of six minutes from a hot or cold stand-by condition and a very short ramping time to full-rated output, these units provide valuable non-spinning reserves to APS. Although the largest benefit is from added operational flexibility, the reserve value allows APS to more efficiently manage its total reserves requirement needed to support reliable operations. Furthermore, the Sundance Plant benefits APS and its customers by decreasing the exposure to fluctuating wholesale power prices, insufficient supply or supplier default.

Q. GIVEN THE NEEDS ASSESSMENT AND THE ANALYSIS DISCUSSED ABOVE, IN YOUR OPINION, WAS THE DECISION TO ACQUIRE SUNDANCE APPROPRIATE?

A. Yes. All of the economic analyses showed that the acquisition of the Sundance Assets at the offered price was the best available peaking resource alternative for meeting our customers' needs. Our operational analysis indicated that the plant was an outstanding technology and an exceptional match for our customers' projected peaking power needs. The Company's due diligence reviews verified that the Sundance Assets were in good working order, and ensured that all agreements were reviewed and no unexpected liabilities came with the plant.

Q. IS THERE A NEED FOR THE SUNDANCE PLANT'S CAPACITY AND IS IT BEING USED TO MEET THAT NEED?

A. Yes. The above-referenced needs assessment demonstrated that APS clearly has a functional need for the Sundance capacity. In fact, APS still remains short on capacity even after the Sundance Assets acquisition. In addition, as I discussed above, the Sundance Assets provide APS with operational flexibility and enhances the reliability of the APS generation portfolio.

Q. WHAT WAS THE PURCHASE PRICE APS PAID FOR THE SUNDANCE ASSETS?

A. The purchase price was $189.5 million, excluding a post-closing adjustment for the value of the plant inventory. This closing price is the same as the negotiated price for a closing on March 31 and the price used in completing the above analysis.

III. <u>CONCLUSION</u>

Q. DO YOU HAVE ANY CONCLUDING COMMENTS?

A. APS' acquisition of the Sundance Assets was the product of a fair and open procurement process and was based on sound economic principles. APS had a clearly defined need for the peaking plant based upon its previous resource plans and in fact is already using the Sundance Assets to meet the reliability and energy needs of its customers.

Q. DOES THAT CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Attachment PD-1

DIRECT TESTIMONY OF PATRICK DINKEL
On Behalf of Arizona Public Service Company

Docket No. E-01345A-04-_____

Docket No. L-00000W-00-0107

June 1, 2004

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DIRECT TESTIMONY OF PATRICK DINKEL
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-04_____, et al.)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND POSITION WITH APS.

A. My name is Patrick Dinkel. I am the Manager of Corporate Planning for Arizona Public Service Company ("APS" or "Company"). I led the APS team responsible for conducting the APS Request for Proposals—Power Supply Resource Proposal for the Procurement of Generating Capacity ("RFP"), evaluating the resulting proposals, and negotiating the Asset Purchase Agreement with PPL Sundance Energy, LLC ("PPL Sundance").

Q. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. I received a Bachelors of Science degree from Marymount College and a Masters of Business Administration from Northern Arizona University. I joined APS in 1986. Before becoming Manager of Corporate Planning, I was the Manager of Business Unit Analysis and Reporting, with responsibility for corporate budgeting. Before that, I held various positions within APS and Pinnacle West Capital Corporation ("Pinnacle West"), primarily within the financial planning area.

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

A. I will discuss the RFP and the evaluation process that resulted in the selection of the PPL Sundance proposal. I also will address APS' proposed financing of the acquisition and provide the details on the Accounting Order that APS is requesting.

Q. PLEASE SUMMARIZE YOUR TESTIMONY

A. APS' Long Range Forecasts consistently show that APS is facing a growing need for additional generation resources. Based on these forecasts, the current state of the wholesale market, and the apparent willingness of some parties to sell assets, APS elected to conduct a RFP for long-term resources. The Company conducted a review of all of the proposals submitted in response to the RFP and eliminated a number of responses from further consideration. The Company conducted a more detailed review of those remaining proposals most likely to be able to meet APS' needs. Ultimately, APS selected the PPL Sundance proposal and negotiated an agreement to purchase the Sundance Generating Station.

The acquisition of the Sundance Generating Station will efficiently and cost-effectively address some of APS' future capacity needs. Sundance was the only peaking plant bid in the RFP and is the only recently-completed merchant peaking plant in Arizona. Given that APS customer demand requires peaking resources and that there are no additional merchant peaking facilities currently permitted or planned for construction in Arizona, the Sundance Generating Station fits well into APS' generation portfolio. Other advantages of the facility are its operational flexibility and quick-start capabilities that allow it to provide essential reliability support for APS customers. APS has concluded that acquiring the Sundance Generating Station is the least cost alternative through an analysis of available options, including building new peaking units and buying power from the wholesale market.

To finance the acquisition, APS contemplates issuing additional short-term and/or long-term debt under the Company's current debt limits approved by the

Arizona Corporation Commission ("Commission"). This assumes that the Commission finds the Sundance Generating Station to be a prudent addition to the Company's generation portfolio serving APS customers.

APS is purchasing the Sundance Generating Station for less than its book value. Due to regulatory accounting requirements in the FERC Uniform System of Accounts ("USOA"), APS will record a "negative acquisition adjustment" equal to the difference between the purchase price and the net book value of the plant as of closing. APS will amortize the negative acquisition adjustment over the remaining life of the facility.

APS is requesting an Accounting Order authorizing APS to defer for future recovery capital and operating costs associated with the acquisition, along with a debt return on the deferred balance. The amount of the deferral will be offset by any savings to the Company resulting from the acquisition. A deferral order will allow APS to acquire the Sundance Generating Station at a price that will bring significant long-term value to customers without the Company incurring unnecessary and significant financial harm prior to the Sundance Generating Station being reflected in APS rates.

II. <u>RFP PROCESS</u>

Q. WHY DID APS ISSUE AN RFP IN DECEMBER 2003?

A. APS regularly prepares forecasts of its projected load requirements and compares them to its available resources, including owned generation and long-term purchased power contracts. APS has a near-term resource shortfall that it meets in the short-term wholesale market. The Company is forecasting continued growth, which requires a significant amount of additional resources.

The APS Summer Supply & Demand Balance Assessment ("Summer Supply & Demand Balance"), which was included as Attachment 1 to the RFP, shows that APS will have a resource shortfall in the summer of 2007 of more than 1400 MW, even assuming the inclusion of Pinnacle West Energy Corporation's ("PWEC") 1700 MW of Arizona assets as APS is requesting in its pending rate case. The RFP, with all attachments, is provided as Schedule PD-1 to this testimony. A revised Summer Supply & Demand Balance, showing that the Company will have a shortfall of more than 3100 MW in 2007 without the inclusion of the PWEC Arizona assets, was prepared and provided to bidders in January 2004. That revised Summer Supply & Demand Balance and an amended RFP schedule are attached to my testimony as Schedule PD-2.

Q. **WHAT OTHER FACTORS DID APS CONSIDER IN ISSUING THE RFP?**

A. Timing was a major consideration. APS saw the potential for favorable prices in the near term given the current stage of the cyclic capacity market and reports that some of the resources in the area may be up for sale. APS felt that it was important to determine quickly whether the Company could procure long-term resources for its customers at a reasonable price. The timing of a new long-term resource acquisition was another consideration. APS targeted 2007 in the RFP because the Company could likely purchase short-term resources in the open market for the next few years through the Secondary Procurement Protocol. By 2007, the Company's significant capacity shortfall requires an asset purchase, new construction or long-term purchases to procure much of the resources needed for necessary reliability and price stability. In addition, APS' internal wholesale electric price forecast predicted that, by 2007, the present oversupply of generation would tighten, leading to increased prices for such resources.

Q. PLEASE PROVIDE A GENERAL DESCRIPTION OF THE RFP SCHEDULE.

A. APS first announced its plans to conduct the RFP on November 19, 2003 and formally issued it on December 3, 2003. The RFP was widely distributed to generators and marketers conducting business in the Company's service territory. On December 15, 2003, APS held a bidders' conference attended by nine interested generators and energy marketers. At that bidders' conference, APS provided an overview of the RFP, gave a presentation on transmission capacity, and responded to questions. Bidders submitted RFP responses by January 21, 2004. In mid February, 2004, APS notified those bidders who were short-listed, including PPL Sundance. After significant additional analysis, negotiations and due diligence, APS entered into the Asset Purchase Agreement with PPL Sundance on June 1, 2004.

Q. PLEASE DESCRIBE THE RFP ISSUED BY APS.

A. APS requested proposals for generation to meet APS' rapidly growing retail load, with the minimum size of any single generating unit bid being 35 MW and the maximum size being approximately 550 MW. These limits did not exclude any constructed or permitted merchant facility in Arizona. The RFP specifically sought proposals that would deliver a power supply to APS commencing in the summer of 2007 for reasons previously mentioned. Although the RFP expressed a preference for the purchase of generating assets already constructed or permitted, APS also indicated that it would consider reasonably-priced proposals for long-term unit-specific purchase power agreements ("PPAs"). For any proposal for a long-term unit-specific PPA, APS sought full dispatch rights for the applicable unit. If a proposal involved the sale of a unit that was currently operating or would be operating prior to June 1, 2007, APS expressed a preference for acquiring the unit at the conclusion of negotiations and then entering into a Sale Back Arrangement with the bidder for the output of that generating unit through May 31, 2007. In contrast to asset sales, the solicited PPAs were, by their terms, for deliveries on and after June 1, 2007, and thus no proposed Sale Back Arrangement was necessary.

Q. WHAT OTHER PROVISIONS WERE INCLUDED IN THE RFP?

A. To mitigate risk to APS and its customers, and consistent with other asset acquisitions, the proposed Asset Purchase Agreement included in the RFP provided that any acquisition of a generating unit would be conditioned upon approval by any and all regulatory authorities with jurisdiction over the transaction. Additional requirements are set forth in the RFP attached as Schedule PD-1.

Q. HOW DID APS ARRIVE AT THE TERMS OF ITS RFP?

A. Several principles drove the RFP requirements. It was important to conduct a timely and efficient RFP that attracted the largest number of bidders. Thus, the Company tried to make the RFP as inclusive as possible. APS left the RFP open to any fuel type, any location (as long as it could reach APS' customers), permitted and existing plants, renewable generation, asset purchases and PPAs. Timing was important because there were a number of plants in the region that appeared to be in a state of flux from an ownership perspective. APS understood that owners of those plants would be reluctant to leave their plants in limbo if the Company took too long to evaluate their proposals.

Q. PLEASE EXPLAIN IN MORE DETAIL THE RESULTS OF THE RFP PROCESS.

A. APS received 13 different proposals from nine entities in response to the RFP, for a total of approximately 6800 MW. All of the bidders were merchant generators or power marketers. The proposals included existing generating units, generation under construction, planned projects holding some (but not all) of the necessary permits, proposed but undeveloped projects, and sales from unidentified assets. All of the asset-backed proposals involved natural gas-fired generating units, none of which were utility-owned or within the Phoenix load pocket. In addition, all of those proposals required APS and its customers to bear the fuel price risk in one manner or another. The "APS Summary of Responses Received to its Power Supply Resource Request for Proposals Dated December 3, 2003" (attached as Schedule PD-3) was filed with the Commission on January 27, 2004 and provides additional information about the RFP results.

Q. PLEASE DISCUSS APS' PRELIMINARY EVALUATION OF THE BIDS RECEIVED?

A. APS performed a preliminary analysis of all of the proposals it received in response to the RFP to identify a short-list of proposals warranting additional consideration. APS reviewed each proposal for credibility and value in relation to generation operations, gas transportation, transmission availability, power marketing, environmental compliance, credit, and overall resource mix, as well as compliance with the minimum bid requirements. Although most of the proposals presented one or more issues related to the minimum bid requirements, APS did not reject any proposal because of those issues. Several proposals, however, provided insufficient information or non-firm pricing thereby making consideration of those proposals more difficult and reducing the probability of selection.

A team of experienced employees from various APS departments as well as legal counsel reviewed the proposals and reported their conclusions. The objective was to identify any issue that warranted further evaluation or that could have a material impact on a transaction.

The Company evaluated the economics of proposals that were in contention for further consideration by computing the levelized busbar cost of each such bid. The busbar cost is the revenue required to cover the costs of owning and operating the plant (including fuel and cost of capital) divided by the anticipated MWh output at the plant's "bus." A "levelized" busbar cost is the busbar cost over the period evaluated (e.g., 30 years) stated in constant dollars. In completing the busbar analysis, APS incorporated information submitted with each proposal along with equipment manufacturer data and standard financial and capacity factor assumptions.

As a result of its preliminary analysis, APS narrowed the proposals received in response to the RFP down to three. Most of those proposals that were not selected for short-listing were eliminated on the basis of price; however, development risk for projects not yet under construction, credit risk of lower credit counterparties, and price uncertainty also were significant factors. Next, APS entered into discussions with the bidders of the three remaining proposals, eventually narrowing its focus to the PPL Sundance proposal.

Q. WHY DID APS SELECT THE PPL SUNDANCE PROPOSAL?

A. APS accepted the PPL Sundance proposal because purchasing the Sundance Generating Station is the least cost means of APS acquiring critical long-term peaking capacity. Because the units can ramp up quickly, they are able to provide cost-effective reserves and improve APS' system reliability.

Q. PLEASE DESCRIBE GENERALLY THE PPL SUNDANCE FACILITY AND PROPOSAL.

A. The Sundance Generating Station is a nominally rated 450 MW facility located approximately 55 miles southeast of Phoenix in Pinal County. It was placed in service in July 2002 and consists of ten 45 MW General Electric LM 6000PC combustion turbines. Such units typically are used to meet peaking capacity needs because of their ability to start up in less than 10 minutes from a warm or cold standby condition compared to five to seven hours for a typical combined cycle unit. As described in more detail in the testimony filed by PPL, the facility is natural gas fired, uses Central Arizona Project excess water as its primary water supply, and interconnects to the Western Area Power Administration ("WAPA") transmission grid at WAPA's Coolidge substation.

PPL Sundance initially submitted a proposal to sell the entire Sundance facility to APS for $185 million as of December 31, 2004. Its proposal did not include a Sale Back Arrangement. The proposal also required APS to assume certain existing contracts associated with the facility. The final agreed-upon price of $189.5 million reflects an adjustment for PPL Sundance's added carrying costs for a March 2005 closing.

Q. WHAT ARE THE EXISTING CONTRACTS ASSOCIATED WITH THE PLANT?

A. As a result of Tucson Electric Power's ("TEP") Track B process, PPL Sundance entered into a tolling agreement with TEP for 75 MW of capacity year-round through the end of 2006. The proposal required APS to assume that contract with its acquisition of the PPL Sundance facility. In addition, there were several transmission contracts with WAPA and gas transportation contracts with El Paso Natural Gas included in the proposal.

Q. WHAT FOLLOWED THE PRELIMINARY SELECTION OF PPL SUNDANCE'S BID IN THE RFP?

A. After narrowing its focus to the PPL Sundance proposal, APS began a multi-track process that included due diligence, a more detailed economic analysis and comprehensive negotiations. The due diligence on the facility sought to identify any material issues related to the construction, operation, ownership, performance or environmental condition of the plant. A team of experts reviewed contracts, permits, schedules and reports, and conducted on-site inspections to review plant construction, operations, operating and maintenance history, regulatory issues, real estate and land use, environmental compliance, fuels transportation issues, and transmission capabilities, among other topics. This due diligence effort did not identify any issues that warranted rejecting the bid. The economic analysis, which showed that the PPL Sundance proposal was the most attractive option available, is discussed in more detail in Section IV of this testimony.

APS and PPL discussed the PPL Sundance bid and APS' interest over the following weeks. APS incorporated into its discussions the results of its due diligence and economic analysis. PPL Sundance repeatedly indicated that its offer assumed a sale of the plant for cash in 2005, not 2007, and in fact, made no offer for a 2007 sale. PPL Sundance was unwilling to both absorb the short-term impact of the Sale Back Arrangement in 2005-2006 and give APS the long-term benefit of the Sundance Generating Station from 2007 forward. In the end, APS determined that the final agreement was an attractive purchase and the best option available to customers.

III. APS' NEED FOR PPL SUNDANCE FACILITY

Q. WHEN APS ACQUIRES THE SUNDANCE GENERATING STATION, WILL THAT GENERATION BE USED BY APS?

A. Yes. APS has been using the Sundance Generating Station to serve APS customers and will need the units in the future. Acquiring the Sundance Generating Station provides APS with 400 MW of additional capacity during the summer peak season. Sundance is expected to produce 400 MW during the summer rather than its rated capacity of 450 MW due to the fact that the peak capacity for combustion turbines drops as the ambient air temperature rises. PPL Sundance fills only a fraction of the Company's anticipated future resource needs, even if all of the PWEC Arizona generation is included in the Company's rate base following the pending rate case. With the Sundance purchase, the capacity shortfall in 2005, 2006, and 2007 is 456 MW, 785 MW, and 1047 MW, respectively. The shortfall in 2007 and beyond could grow if Salt River Project chooses to terminate all or part of its existing long-term purchased power contract with APS.

Q. ASIDE FROM THE NEED FOR THE SUNDANCE GENERATING STATION IN SERVING APS PEAK LOAD, ARE THERE ADDITIONAL BENEFITS SUCH THAT THE FACILITY WOULD BE "USEFUL" IF ACQUIRED BY APS AND DEDICATED TO SERVING APS CUSTOMERS?

A. As Mr. Wheeler mentions in his testimony, the benefits for APS and customers of acquiring the PPL Sundance facility include increased operational flexibility from owning ten quick-start 45 MW units and the availability of the units to help APS more efficiently manage its reserves. There is significant value in APS owning the Sundance Generating Station and being able to quickly dispatch the facility instead of having to use day-ahead scheduling required under the PPA.

IV. ECONOMIC EVALUATION OF PROPOSED ACQUISITION

Q. WHAT ECONOMIC ANALYSIS DID APS UNDERTAKE TO EVALUATE THE PROPOSED ACQUISITION?

A. APS evaluated the economics of the PPL Sundance proposal from several perspectives. First, APS looked at the depreciated acquisition cost plus estimated deferrals and compared that to the available alternatives. Second, APS compared the busbar costs of various alternatives. Finally, APS calculated the present value revenue requirement of the system generation cost for each of the alternatives, including an alternative of purchasing the power from the wholesale market.

Q. PLEASE DISCUSS THE ALTERNATIVES YOU CONSIDERED.

A. The table below summarizes the alternative peaking generation technologies that could be used to construct simple cycle combustion turbines in 2007 along with several key characteristics associated with each technology. The PPL Sundance facility (which consists of LM6000 turbines) is the lowest-cost alternative and is estimated to cost approximately 60% of a facility constructed with new LM6000 turbines. The PPL Sundance facilities also provide the better fuel efficiency (through a lower heat rate) and shorter start times of the two technologies.

Simple Cycle Technology Comparison

	Sundance LM6000	**New LM6000**	**New 7EA**
Installed Cost ($/kW)	475	762	695
Summer Output (MW)	40	40	76
Heat Rate (Btu/kWh)	9,855	9,855	12,125
Quick Start (<10 Min.)	Y	Y	N

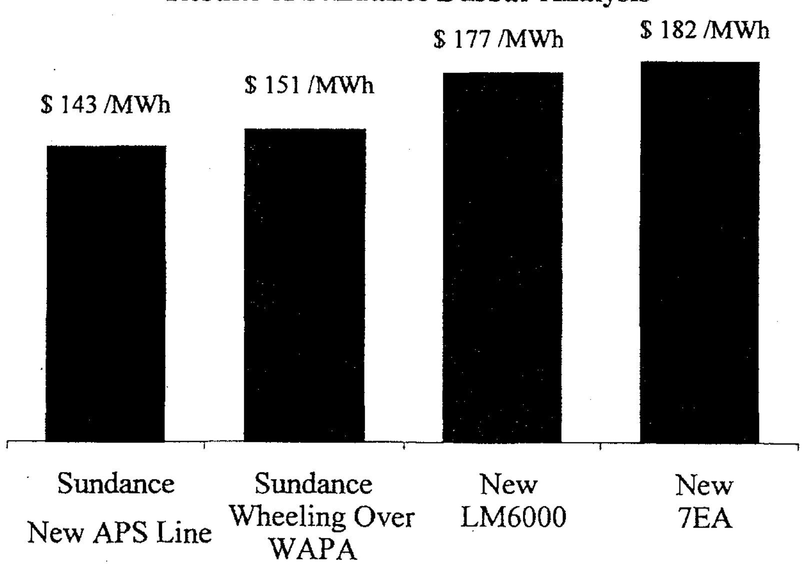
The installed cost is usually the investment included in a utility's rate base. APS calculated this amount to provide a snapshot of how each alternative would impact customers. Although not intended to be a comprehensive comparison, it does provide an indication of the fixed costs associated with each option. The installed cost is provided in 2007 dollars, and the Sundance Generating Station installed cost <u>includes</u> the estimated impacts associated with the requested Accounting Order.

Q. PLEASE DISCUSS THE BUSBAR COST STUDIES.

A. As mentioned previously, the busbar cost equals the revenue required to pay for the costs to own and operate a plant (including fuel and cost of capital) divided by the anticipated MWh output from that plant. The busbar cost study performed by APS compared the levelized busbar cost of acquiring the Sundance

Generating Station against the levelized busbar cost of building new simple cycle plants. For purposes of the busbar cost study, a consistent capacity factor for these options was assumed for all alternatives. The study period began in 2007 and covered the life of the units. In analyzing the PPL Sundance proposal, APS developed two alternative transmission options which are reflected in the graph below: 1) assuming rollover of the existing transmission contracts with WAPA; and 2) assuming a new transmission line is added from the Sundance Generating Station to APS' Santa Rosa substation. The results, as summarized in the graph below, indicated that acquiring the Sundance Generating Station under either transmission option is superior to the new-build alternatives even without consideration of any permitting or construction risk typically associated with new build alternatives.

Results of Sundance Busbar Analysis



Q. PLEASE DISCUSS THE SYSTEM REVENUE REQUIREMENT COST STUDY

A. The system revenue requirement cost study calculated the present value cost for each alternative of providing power to customers, including the cost of fuel, purchased power and ownership. The analysis is based on a system dispatch simulation utilizing the GE-MAPS system dispatch model and supporting calculations. APS evaluated the Sundance Generating Station against alternative new-build simple cycle cases and purchases from the wholesale market. The system revenue requirement analysis captured the particular technology characteristics of each alternative and ensured that the projected customer load would be met at the least cost to customers. The study period began January 1, 2007 and covered the life of the units. The revenue requirement results were consistent with the busbar results, showing that the acquisition of the Sundance Generating Station produced a present value saving of $119 million to $194 million compared to other available alternatives. The analysis assumed APS constructed a new transmission line to connect Sundance to APS' transmission grid. If APS were to purchase WAPA transmission for the life of the Sundance plant the present value savings from acquiring Sundance would be $79 million to $154 million. Both of these ranges of present value savings include the impact of the requested deferral order. This result is consistent with the facts that the PPL Sundance proposal had the lowest up-front investment cost (expressed as $/KW) and the best fuel efficiency (expressed as Btu/KWh) as shown above in the table Results of Sundance Busbar Analysis.

Q. WHY DID YOU START ALL OF THE STUDIES IN 2007?

A. The year 2007 serves as a reasonable date to begin comparison of resource alternatives. First, given that simple cycle units take two years or more to build, a new unit could not be completed much sooner than 2007. Second, APS is not asking the Commission to include the cost of the acquisition in customer rates until after its next general rate case. Thus, analyzing the costs starting in 2007 provides a reasonable estimation of the impact on customers.

Q. WHAT ABOUT THE IMPACTS TO APS AND CUSTOMERS PRIOR TO 2007?

A. Assuming the Commission issues the Accounting Order and deferral authorization requested, APS believes that the PPL Sundance purchase will not have a material impact on the Company's financial status prior to its inclusion in rates. The Accounting Order, however, is essential to minimize the near-term financial impact associated with the purchase. Customers will see no economic impact from the acquisition assuming that the near-term fuel and purchased power savings are excluded from the Power Supply Adjustment ("PSA") mechanism requested by APS in its general rate case, as discussed later.

Q. APS IS CURRENTLY BUYING POWER FROM SUNDANCE UNDER A TRACK B CONTRACT. WHAT WILL HAPPEN WITH THAT CONTRACT WHEN APS PURCHASES THE PLANT?

A. APS entered into a tolling agreement with PPL Sundance in 2003 as part of the Company's Track B procurement process. Under that agreement, APS purchased 150 MW of capacity from PPL Sundance for the summer months of June through September in 2003, 2004, and 2005. At closing, there will be four months of 150 MW remaining under the contract. APS and PPL Sundance have agreed to terminate the Track B contract upon closing. Customers will get the value of the 150 MW of Sundance capacity consistent with the contract, and the savings from the avoided contract capacity payment will be used to offset the cost deferral.

V. PROPOSED FINANCING AND ACCOUNTING TREATMENT

Q. HOW DOES APS INTEND TO FINANCE THE TRANSACTION?

A. APS anticipates issuing a combination of long- and/or short-term debt depending on the market conditions prevailing at the time of the financing.

Q. HOW WILL THE ACQUISITION BE TREATED FROM A REGULATORY ACCOUNTING STANDPOINT?

A. The regulatory accounting associated with the acquisition is subject to the USOA, which applies to APS pursuant to A.A.C. R14-2-212(G)(2). The USOA requires that APS record the PPL Sundance Generating Station at its depreciated book value at the time of the acquisition. Under the USOA, the difference between book value and the amount paid by APS is recorded as an "acquisition adjustment." In this case, a negative acquisition adjustment will be recorded because the purchase price is less than the book value of the plant. For purposes of calculating APS' rate base, the negative acquisition adjustment reduces the book value of the plant to the amount APS paid for the asset. APS will amortize the negative acquisition adjustment over the plant's remaining service life.

Q. PLEASE DISCUSS THE DEFERRAL ORDER THAT APS IS REQUESTING.

A. APS is requesting that an Accounting Order authorize the Company to defer for future recovery the capital and operating costs associated with the acquisition, net of any savings produced by the acquisition. APS is requesting that the Commission authorize a return on the deferred amount at the cost of debt determined in APS' pending rate case. The specific language that the Company believes necessary in the Accounting Order to authorize this deferral is set forth in Schedule PD-4. Also, APS requests that the period for which APS is authorized to defer costs be limited to five years from the date of a final order in this case.

Q. WHY IS A DEFERRAL ORDER NECESSARY FOR THIS ACQUISITION?

A. The favorable price that PPL Sundance proposed for the Sundance Generating Station required APS to acquire the facilities in 2005. Given that APS is already using this resource and it brings immediate operational and reliability benefits to our customers, APS believes that acquiring the facility today is appropriate and in the best interests of customers. However, because the costs associated with this new investment are not yet reflected in APS' rates, the adverse financial impact to APS that results from acquiring the Sundance Generating Station without immediately including it in rates should be mitigated. A deferral order is a standard and well-accepted regulatory tool for exactly these circumstances.

Q. HAS THE COMMISSION PREVIOUSLY ISSUED DEFERRAL ORDERS TO APS WHEN NEW GENERATION RESOURCES WERE ACQUIRED?

A. Yes. The Commission authorized deferral of capital and operating costs associated with both Palo Verde Unit 2 and Unit 3. In Decision No. 55325 (December 5, 1986), the Commission stated:

> In a perfect regulatory world, there would be little time between the introduction of large increments of plant into service and the setting of rates which took that plant into consideration. We do not live in such a world, and rate cases cannot, for any number of reasons (including those attributable to the utility), be exactly timed so as to prevent significant mismatches between revenue and expenses.

Decision No. 55325 at 5. Shortly afterwards, in Decision No. 55931 (April 1, 1988), the Commission summarized the policy reasons supporting such deferrals:

> According to the Commission, the problem posed by the commercial operation of Palo Verde 2 was the time between the introduction of large increments of plant into service and the setting of rates which takes that plant into consideration.

Decision No. 55931 at 36. In connection with Palo Verde Unit 3, the Commission recognized that, "Issuance of an accounting order will properly synchronize cost recording with cost recovery." Decision No. 55939 (April 6, 1988) at 4-5.

In addition to these decisions, I would also note that deferral orders continue to be issued by other regulatory commissions in cases involving utilities acquiring new generation. For example, the Michigan Public Service Commission recently approved the acquisition of a $120 million peaking facility by Wisconsin Public Service Corporation and authorized a deferral of costs associated with the acquisition in a February 20, 2003 decision in Docket No. U-13621.

Q. **IN THE DEFERRAL ORDER THAT APS IS REQUESTING, HOW WILL SAVINGS ASSOCIATED WITH THE ACQUISITION BE USED TO OFFSET THE AMOUNT OF DEFERRALS?**

A. The savings from the cancellation of the Track B contract (e.g., the avoided capacity payments that would otherwise be due) will reduce the 2005 deferral amount at the time the contract is cancelled. Other savings, such as reduced fuel or purchased power costs, associated with the acquisition of the Sundance Generating Station would also reduce the amount of the deferrals associated with capital and operating costs each year. To avoid double-counting such savings, all fuel cost savings, purchased power cost savings, and additional off-system sales margins will be excluded from any calculation under the PSA that APS is requesting in its pending rate case.

Q. HAS THE COMPANY ESTIMATED THE AMOUNT OF THE DEFERRAL?

A. APS estimates that the pretax deferral will be approximately $10 million to $15 million per year. This deferral estimate assumes that fuel and purchased power savings as well as avoided Track B capacity payments are used to reduce the impact of the costs of ownership as previously mentioned. The estimate is also dependent upon the market price of gas and electricity which will affect the level of off-setting savings.

Q. WHEN WOULD APS SEEK RECOVERY OF THE DEFERRED BALANCE?

A. When APS files its next rate case, it would include the deferral in its application. APS is not proposing a specific amortization period for the regulatory asset associated with the deferral. The Commission could select a reasonable amortization period for the deferred balance at the time it establishes rates that include the new facility.

VI. CONCLUSION

Q. DO YOU HAVE ANY CONCLUDING COMMENTS?

A. Through the RFP, APS has identified an acquisition of an asset that will fit well into APS' existing generation portfolio and bring value to customers. Because of the circumstances surrounding the acquisition, however, an accounting order is required to facilitate the transaction. Because the Company sees significant value to its customers in completing this transaction, the Company is requesting the Commission's finding that the acquisition is prudent and its approval of the requested Accounting Order.

Q. DOES THAT CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

1521574

UNITED STATES OF AMERICA 111 FERC ¶62,146
FEDERAL ENERGY REGULATORY COMMISSION

PPL Sundance Energy, LLC Docket No. EC05-20-000
PPL EnergyPlus, LLC
Arizona Public Service Company

ORDER AUTHORIZING DISPOSITION AND ACQUISITION OF JURISDICTIONAL FACILITIES

(Issued May 6, 2005)

On November 22, 2004, PPL Sundance Energy, LLC (PPL Sundance), PPL EnergyPlus, LLC (PPL EnergyPlus) and Arizona Public Service Company (APS) filed an application under section 203 of the Federal Power Act[1] requesting Commission authorization for a disposition and acquisition of jurisdictional facilities related to PPL Sundance's proposed sale of its Sundance Generating Station (Facility) to APS.[2] The jurisdictional facilities involved in the proposed transaction include transmission interconnection facilities and a power sales contract.

PPL Sundance, an indirect, wholly-owned subsidiary of PPL Corporation (PPL), owns and operates the Facility, consisting of ten combustion turbines with a total capacity of 450 megawatts (MWs) and associated interconnection facilities that deliver power from the Facility to the Western Area Power Administration transmission grid. PPL Sundance is authorized to make sales of energy and ancillary services at market-based rates. PPL EnergyPlus, a PPL power marketing affiliate, purchases the entire output of the Facility and supplies APS with 150 MWs of power from the Facility during summer months under a contract that will expire at the end of Summer, 2005. PPL EnergyPlus also provides 75 MWs of power to Tucson Electric Power Company (TEP).

APS, a public utility, is a wholly-owned subsidiary of Pinnacle West Capital Corporation (Pinnacle West), an exempt investor-owned public utility holding company. APS owns and operates generation and transmission facilities, and engages in the wholesale sale and transmission of electricity. APS also provides electric service at retail in its service territory, including the Phoenix metropolitan area and throughout the state of Arizona. APS' Pinnacle West affiliate, Pinnacle West Energy Corporation owns directly and through a subsidiary about 2000 MWs of generating capacity comprised of various generating facilities in Arizona and Nevada.

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[1] 16 U.S.C. § 824b (2000).

[2] Applicants amended their application on February 11, 2005, March 29, 2005 and April 22, 2005.

Under the Asset Purchase Agreement by and between PPL Sundance Energy, LLC as Seller and Arizona Public Service Company as Purchaser, dated as of June 1, 2004, PPL Sundance proposes to sell to APS a 100 percent ownership interest in the Facility and associated jurisdictional assets. As part of the transaction, PPL EnergyPlus will transfer to APS the contract to provide TEP with 75 MWs of capacity. APS will also acquire PPL Sundance's transmission rights on the WAPA system for delivering APS' share of the Facility's energy to serve APS' load, and the Facility will be a network resource for APS. In addition, APS will acquire PPL Sundance's other contracts associated with the Facility's operation, including agreements with El Paso Natural Gas Company for gas transportation service. The contracts under which PPL Sundance sells all of the output of the Facility to PPL EnergyPlus and PPL EnergyPlus sells 150 MWs of power to APS will be terminated upon consummation of the transaction.

Upon consummation of the transaction, APS proposes to implement a market monitoring plan (APS' Plan) that will provide for an independent expert to monitor APS' generation dispatch and the operation of its transmission system and to identify and report to the Commission any potentially anti-competitive conduct. Applicants state that this plan will be consistent with the plan recently approved by the Commission in Docket No. EC04-92-000, involving the indirect indisposition of jurisdictional facilities associated with the acquisition of UniSource Energy Corporation by Saguaro Utility Group I and affiliated entities.[3] APS' market monitoring plan will continue in effect until the Commission approves a regional market monitoring entity with a Commission-approved market monitoring plan or for five years, whichever is earlier.

Applicants assert that the proposed transaction will not adversely affect competition, rates or regulation. Based on an analysis of the effect of APS' acquisition of the Facility on concentration and of other factors affecting the competitive situation, they contend that the proposed transaction does not present horizontal market power concerns in any relevant market. They also assert that the transaction does not raise vertical market issues. Applicants note that APS has an open access transmission tariff on file with the Commission and is a participant in wesTTrans, an OASIS for many western transmission providers. They also state that APS commits to implement, upon consummation of the transaction, a market monitoring plan, as described above, that will encompass generation dispatch and operation of APS' transmission system. Authorization of the transaction is granted herein based in part on this commitment.

Applicants also assert that the transaction will not adversely affect rates. They note that most of APS' wholesale energy transactions occur pursuant to agreements negotiated under market-based provisions of its power tariff and or the Western Systems Power Pool Agreement. Although other wholesale power agreements contain a fuel adjustment clause for pricing energy, Applicants state that customers under these

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[3] *UniSource Energy Corporation, et al.*, 109 FERC ¶ 61,047 (2004).

agreements are protected from adverse rate impacts due to "hold harmless" provisions previously adopted by APS.

Applicants further contend that the transaction will not adversely affect Commission or state regulation. They note that the transaction will not result in the creation of a new, registered public utility holding company. Applicants state that APS and PPL EnergyPlus will continue to be subject to the Commission's regulation with respect to wholesale sales of energy and that APS' retail operations will continue to be subject to the jurisdiction of the Arizona Corporation Commission.

This filing was noticed on November 24, 2004, February 18, 2005, April 1, 2005 and April 25, 2005, with comments, protests or interventions due on or before May 5, 2005. Panda Gila River, L.P. (Panda) filed a timely motion to intervene and comments. On April 8, 2005, Panda filed a notice of withdrawal of its comments. Notices of intervention and unopposed timely filed motions to intervene are granted pursuant to the operation of Rule 214 of the Commission's Rules of Practice and Procedure (18 C.F.R. § 385.214). Any opposed or untimely filed motion to intervene is governed by the provisions of Rule 214.

After consideration, it is concluded that the proposed transaction is consistent with the public interest and is authorized, subject to the following conditions:

(1) The proposed transaction is authorized upon the terms and conditions and for the purposes set forth in the application;

(2) The foregoing authorization is without prejudice to the authority of the Commission or any other regulatory body with respect to rates, service, accounts, valuation, estimates, or determinations of cost, or any other matter whatsoever now pending or which may become before the Commission;

(3) Nothing in this order shall be construed to imply acquiescence in any estimate or determination of cost or any valuation of property claimed or asserted;

(4) The Commission retains authority under sections 203(b) and 309 of the FPA to issue supplemental orders as appropriate;

(5) Applicants shall make appropriate filings under section 205 of the FPA, as necessary, to implement the transaction; and

(6) Applicants shall notify the Commission within 10 days of the date that the disposition of jurisdictional facilities has occurred.

This action is taken pursuant to the authority delegated to the Director, Division of Tariffs and Market Development – West, under 18 C.F.R. § 375.307. This order constitutes final agency action. Requests for rehearing by the Commission may be filed within 30 days of the date of issuance of this order, pursuant to 18 C.F.R. § 385.713

Jamie L. Simler
Director
Division of Tariffs and Market Development - West

EXHIBIT
APS-47
Admitted

REBUTTAL TESTIMONY OF PATRICK DINKEL

On Behalf of Arizona Public Service Company

Docket No. E-01345A-05-0816

September 15, 2006

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REBUTTAL TESTIMONY OF PATRICK DINKEL ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY (Docket No. E-01345A-05-0816)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Patrick Dinkel, 400 North Fifth Street, Phoenix, Arizona 85004.

Q. DID YOU PROVIDE DIRECT TESTIMONY IN THIS DOCKET?

A. Yes. I filed Direct Testimony in this docket on November 4, 2005 ("Initial Filing"), and also provided updated testimony on January 31, 2006 ("January Filing").

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to respond to the testimony of Mr. David Berry of Western Resource Advocates and his position regarding the use of renewable energy as a hedge against high natural gas prices. In addition, I will be responding to the concerns raised by Ms. Amanda Ormond of Interwest Energy Alliance regarding wind integration costs. Finally, I will discuss APS' position related to the testimony of Staff and several Intervenors and their increased interest in Demand Response programs.

II. SUMMARY OF TESTIMONY

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY IN THIS RATE CASE DOCKET.

A. My testimony will address the use of renewables as a hedge. Specifically, APS agrees that renewable energy should be a bigger percentage of APS' generation portfolio and that renewable energy will offset the need for generation from conventional resources. However, to date, APS is paying a premium for renewable energy, and that premium must be given consideration. My testimony will also include a discussion of APS' pending Wind Integration Cost Study and the concerns raised by Interwest Energy Alliance. Finally, I will discuss APS' interest in exploring additional Demand Response offerings to provide effective supply side options for meeting our system needs.

III. RENEWABLES AS A HEDGE

Q. IN MR. BERRY'S TESTIMONY, HE INDICATES THAT APS SHOULD USE AN INCREASED AMOUNT OF RENEWABLE ENERGY AS A HEDGE AGAINST HIGH NATURAL GAS PRICES. DO YOU AGREE WITH HIS CONCLUSION?

A. I agree with his proposition that renewable energy should make up a larger percentage of APS' generation portfolio. APS has supported the increasing renewable energy requirements proposed in the draft Renewable Energy Standard ("RES").

Q. DO YOU BELIVE THAT THE RENEWABLE ENERGY PROCURED BY APS IS AN EFFECTIVE HEDGE AGAINST NATURAL GAS?

A. While renewable energy will offset some of the need for generation from natural gas, this displacement comes at a higher cost than natural gas, based on current prices. In general, there is a cost premium for any "hedge", and careful consideration of the cost is required. So, while renewable generation may be "effective" as a hedge due to its displacement of future gas needs, the critical questions are whether they are a *cost effective* hedge and whether the added costs are acceptable from the perspective of APS customers. Natural gas hedges can be secured at a relatively small cost over prevailing market prices, yet renewable energy is currently only available at a more expensive premium to the cost of conventional, gas-fired energy resources. Mr. Berry provides data that indicates that renewable energy can be procured at a small premium to, or possibly even below, the cost of conventional resources. There have been some very recent projects in certain states where that has been true, but unfortunately APS has not been in that situation. APS has been acquiring resources in the market and is paying a significant premium compared to the cost of conventional energy resources utilizing natural gas.

Q. WHY IS APS NOT ACQUIRING RENEWABLE PROJECTS AT THE RELATIVELY LOW PRICES MR. BERRY IS CITING?

A. A number of factors affect the price of renewable generation, such as federal and state incentives, the price of equipment, and the quality of the natural resource (e.g., wind, geothermal steam, or biomass material). Arizona renewable resources are limited and can be lower quality than renewable energy resources available in some states. APS' choices are to procure out-of-state renewable resources in direct competition with other utilities, or to acquire the limited in-state resources at a higher cost.

Q. DOES THIS MEAN RENEWABLES ARE NOT AN EFFECTIVE ECONOMIC HEDGE AGAINST NATURAL GAS?

A. Not necessarily. It just means that the economics are not as obvious or compelling for APS as they may be for other utilities, and that global statements on the topic may prove inaccurate in the specific case of APS. Project specific analysis is required to adequately measure the economic value of each renewable project.

Q. DOES THE TYPE OF RENEWABLE TECHNOLOGY AFFECT ITS VALUE AS A HEDGE?

A. Yes. Renewable energy that displaces energy produced by natural gas generation will cause a reduction in gas volume purchases and thus will reduce the total exposure to natural gas price volatility. But, as Mr. Berry correctly points out in his testimony, wind energy is an intermittent source of power, which means that the timing of when the energy is being produced is uncertain from hour to hour, day to day and variable over the course of the year. Moreover, the wind energy resources that might be most available to the Company generally are less available during the peak summer demand period when gas generation is most needed. This uncertainty means it may be difficult to schedule the gas purchases needed to counterbalance the renewable resource intermittency, possibly resulting in increased costs.

Q. MR. BERRY INDICATES THAT AN ADVANTAGE OF USING RENEWABLE ENERGY IS THAT RENEWABLE ENERGY PRICES ARE FIXED. DO YOU SEE THIS AS A BENEFIT?

A. Yes, it is a benefit. Renewable energy is generally either at a fixed price or a price with known escalators, which in either case removes price uncertainty from a certain percentage of APS' energy portfolio. However, it generally comes at a premium when compared to the expected price of energy from conventional resources. Our renewable purchases made under settlement agreement in Decision No. 67744 locked in a cost of renewable energy that was up to 125% above APS avoided cost. We can't ignore the premium we are paying for the benefit of a fixed price.

IV. WIND INTEGRATION COST STUDY

Q. MS. ORMOND RAISES CONCERNS ABOUT APS' METHODOLOGY FOR CALCULATING WIND INTEGRATION COSTS. DOES APS SHARE MS. ORMOND'S CONCERNS?

A. We believe it is in everyone's best interest that we continue to study the impact of the integration of renewable resources into our portfolio. For this reason, APS is in the final stages of discussion with Northern Arizona University for the coordination of a Wind Integration Cost Study.

Q. DESCRIBE THE APS WIND INTEGRATION COST STUDY.

A. The wind integration cost study is being designed to answer the question of what are the system impacts and costs associated with effectively integrating potential wind projects into APS' system. It will address the nuances of APS' system, and the known characteristics of probable wind projects that may be made available to APS. This study should establish a basis to start from, and as we gain experience with actual renewable resources we will have the ability to better predict and evaluate the costs and impacts of integrating specific renewable resource technologies into the system, particularly those which demonstrate intermittency like wind and solar. NAU will conduct the analysis with the direct involvement of industry experts, with the scope, technical process and results overseen by a Technical Advisory Committee. In addition, a Stakeholder Advisory Committee is being formed to provide review from a variety of stakeholders including other utilities and renewable energy advocates. A time frame is currently being evaluated, but APS expects the integration cost study to be complete in approximately 6 to 8 months.

Q. WHY IS A WIND INTEGRATION COST STUDY NECESSARY?

A. Our most recent experience is that APS has had limited availability to detailed wind data. Our recent experience is that very few bidders could provide detailed wind data, so getting multiple years of data on numerous projects, as one would require for an effective cost study, has been difficult if not impossible. To date, wind data is still very difficult to acquire because developers have limited site specific data and carefully guard what data they have. Industry knowledge is also limited and is to date, system and project specific. APS' system and Arizona's wind resources are unique and widely publicized studies based upon others' projects and systems are not directly transferable to Arizona projects on APS' system. The wind in Texas isn't the same as the wind in Arizona. Also, APS relies heavily upon natural gas fired power plants for system regulation whereas other utilities may be able to provide regulation out of lower cost hydroelectric or coal-fired facilities. A Wind Integration Cost Study would incorporate input from industry professionals and establish a more credible method to determine the expected wind resource integration costs. In addition, APS will be gaining specific knowledge on wind integration costs once our two wind projects begin operation in early 2007.

V. <u>DEMAND RESPONSE</u>

Q. SEVERAL INTERVENORS EXPRESSED AN INTEREST IN DEMAND RESPONSE. DOES APS SUPPORT DEMAND RESPONSE?

A. Yes. APS is interested in Demand Response ("DR") and believes it may be able to provide effective supply-side options for meeting system needs, in addition to introducing greater elasticity in energy demand and use. To be effective, DR programs must adequately address reliability requirements and provide economics that are favorable compared to other supply-side options.

Q. DO YOU AGREE WITH STAFF AND RUCO THAT DEMAND RESPONSE OFFERINGS NEED TO BE EXPLORED?

A. Yes. There are a variety of demand response programs which differ in their implementation cost, benefits, infrastructure needs and complexity of administration. Price response in particular is very complex and requires a through assessment of infrastructure costs, customer acceptance and pricing mechanisms. One only needs to look to the myriad of demand response initiatives in California to realize large number of potential approaches. For that reason, a thorough study is necessary to determine which types of Demand Response programs would be likely to produce the most cost effective benefits for the APS system and our customers. We will need to analyze the types of technologies (measures) to be considered, measure-by-measure benefit to cost, potential MW impacts, types of customers who would participate and their specific loads, likely customer responses and behavior, what it would take to get customers to participate, and the costs of infrastructure/equipment for such a program. The results of this analysis should be reviewed and commented on by interested parties, including the Arizona Corporation Commission ("ACC"), Residential Utility Consumer Group ("RUCO"), and industry participants. Staff has proposed that APS perform a feasibility study for demand response programs and a cost/benefit analysis within eight (8) months of the Decision and submit one or more demand response programs for ACC approval after the study is completed. Although APS is not opposed to conducting such a study, eight months is not a sufficient amount of time to complete a thorough study and develop appropriate demand response programs.

Q. RUCO HAS SUGGESTED THAT A TASK FORCE BE FORMED TO EXPLORE OPPORTUNITIES FOR LOAD SHAVING AND LOAD SHIFTING THROUGH DEMAND RESPONSE PROGRAMS. DO YOU AGREE?

A. The first course of action should be to conduct a study to determine which types of Demand Response programs are most beneficial to the APS system and our customers. APS is not opposed to a task force but believes the most effective and expeditious way to manage this first phase is for APS to conduct the study with open communication with interested parties. After the assessment is complete, the specifics of which programs are selected, the costs of the programs, and how certain programs are procured and managed can be discussed with interested parties and filed with the Commission for approval.

Q. IS THERE A FUNDING MECHANISM FOR COSTS THAT WOULD BE INCURRED TO STUDY AND DEVELOP DEMAND RESPONSE PROGRAMS?

A. Since Demand Response is included in Decision No. 67744 along with Demand Side Management programs, the DSM adjustor mechanism provides for such funding and, for now, is the appropriate mechanism. Demand Response programs funded through the DSM adjustor mechanism would be filed with the Commission for approval prior to implementation in a manner similar to the DSM programs.

VI. <u>CONCLUSION</u>

Q. AND DOES THIS CONCLUDE YOUR PREFILED REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. Yes.

EXHIBIT
APS-48
admitted

DIRECT TESTIMONY OF CHRIS N. FROGGATT

On Behalf of Arizona Public Service Company

Docket No. E-01345A-05-0816

January 31, 2006

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TESTIMONY OF CHRIS N. FROGGATT
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-05- 0816)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

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

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

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

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

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

II. SUMMARY OF TESTIMONY

Q. PLEASE PROVIDE A SUMMARY OF YOUR TESTIMONY.

A. My testimony addresses historical accounting data and pro forma adjustments that are required by various Standard Filing Requirement ("SFR") Schedules of the Arizona Corporation Commission ("Commission") to support the Company's rate case filing. I will discuss information from the Test Year (twelve months ended September 30, 2005) and prior years relating to the Summary Schedules, SFR Schedules A-2 and A-3, and income statements relating to the Test Year and prior years, as set forth in SFR Schedule C-1. Of the pro formas set forth in SFR Schedule C-2, I will be sponsoring the following:

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

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

III. HISTORICAL AND TEST YEAR ACCOUNTING DATA

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

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

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

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

A. Summary Schedules

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

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

Q. PLEASE DISCUSS SFR SCHEDULE A-3.

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

B. Test Year Income Statements

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

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

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

Q. ARE YOU SPONSORING ANY OTHER RELATED SFR SCHEDULES?

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

Q. PLEASE DESCRIBE SFR SCHEDULE C-3.

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

C. Capital Structure and Cost of Capital

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

A. SFR Schedule D-1 is the summary of the Company's historical and projected cost of capital. I am sponsoring the Test Year data in this schedule. Mr. Brandt will discuss the Company's proposed capital structure and the pro forma adjustments to the cost of capital. SFR Schedule D-2 presents supporting detail for the long-term debt that is summarized on SFR Schedule D-1. SFR Schedule D-3, which addresses preferred stock, is included in the Company's schedules for completeness, but it is not applicable because APS had no outstanding preferred stock at the end of September 2005 and in fact, has had none for many years. SFR Schedule D-4 addresses the Company's cost of common equity.

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

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

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

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

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

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

D. Financial Statements

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

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

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

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

Q. PLEASE DISCUSS SFR SCHEDULE E-4.

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

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

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

Q. PLEASE DISCUSS SFR SCHEDULE E-8.

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

Q. PLEASE DISCUSS SFR SCHEDULE E-9.

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

E. Projections and Forecasts

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

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

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

IV. <u>PRO FORMA ADJUSTMENTS</u>

A. Test Year

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

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

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

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

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

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

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

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

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

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

1) Accounting, *i.e.*, adjustments that remove expenses or revenues properly recorded during the Test Year but associated with prior periods;

2) Annualizations, *i.e.*, adjustments typically made in a rate case to annualize the full effect of events taking place during the Test Year; and

3) Known and measurable changes, *i.e.*, adjustments to expenses or revenues that took place or will take place after the end of the Test Year, and which are of such significance that they should be recognized for ratemaking purposes.

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

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

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

B. Pro Forma Adjustments To Operating Income

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

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

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

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

(i) Regulatory Assessments and Franchise Fees

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

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

(ii) Base Rates Component for EPS

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

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

(iii) Demand Side Management

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

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

(iv) Interest On Customer Deposits

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

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

(v) Amortization of Regulatory Assets

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

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

(vi) PWEC Loan

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

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

(vii) Out of Period Income Tax Adjustments

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

A. This pro forma adjustment removes income tax true-up items impacting income tax expense that were recorded during the Test Year period, but relate to a period earlier than the Test Year period. In addition, it adds income tax true-up items that relate to the Test Year period. Finally, it removes income tax expense recorded during the Test Year period related to non-recurring income tax items. This pro forma decreases income tax expense by $1,287,000. The Test Year income tax expense still includes credits and other items related to the Test Year. *See* Attachment CNF 1-7.

(viii) Generation Production Income Tax Deduction

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

A. On October 11, 2004, President Bush signed into law the American Jobs Creation Act ("Act"). The Act created Internal Revenue Code Section 199 ("Section 199"), which provides a new income tax deduction related to income attributable to qualified production activities. On October 20, 2005, the Internal Revenue Service ("IRS") issued proposed regulations addressing Section 199. Electricity production is considered a qualified production activity for purposes of this Act; however transmission and distribution services are not. The proposed regulations provide that a joint owner who owns less than 50% of a generating facility will not be attributed the qualified production activity associated with such generation facility. This deduction applies to years beginning in 2005. For 2005, the deduction is equal to the lesser of three percent of the qualified production activities income ("QPAI") or the consolidated taxable income. The deduction increases to six percent in 2007 and increases again to nine percent in 2010. QPAI is equal to gross receipts, less the cost of production and other related direct and allocable indirect costs. In calculating this pro forma, gross receipts were determined by using the 12 months ended September 30, 2005 Test Year functionalized revenue requirement, excluding the impact of this deduction, for electricity production. The related direct and allocable indirect costs (except for interest expense) were determined by using the 12 months ended September 30, 2005 functionalized operating expenses for electric production. Functionalized interest expense for electric production was determined by multiplying electric production for the Test Year rate base by the weighted interest rate component of the cost of capital. Next, adjustments were made to reflect items treated differently for GAAP and income tax purposes. Finally, a reduction was made to remove the QPAI generated by jointly-owned generating facilities in which APS owns 50% or less. This reduction was determined by first deriving the ratio of net book value of plant for the jointly-owned facilities divided by net book value for all generating facilities. This ratio was multiplied by the total generation QPAI, which was then subtracted from total generation QPAI to arrive at QPAI attributable to APS. QPAI for electric production activities associated with generating facilities wholly owned by APS for the 12 months ended September 30, 2005 Test Year is approximately $79 million. The deduction percentage in 2007, which is the year the new rates will become effective, is six percent. Therefore the deduction is approximately $4.8 million, which translates into a reduction in income tax expense of $1,862,000. The Proposed Regulations may be modified prior to becoming final regulations and the final regulations may change the amount of this deduction. This calculation is set forth in Attachment CNF 1-8.

(ix) Income Tax / Interest Synchronization

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

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

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Appendix A
Statement of Qualifications
Chris N. Froggatt

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

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

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

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

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

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

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

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

PRO FORMA ADJUSTMENT: **BASE RATE COMPONENT FOR EPS**

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

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

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

PRO FORMA ADJUSTMENT: **DEMAND SIDE MANAGEMENT**

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

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

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

PRO FORMA ADJUSTMENT: **INTEREST ON CUSTOMER DEPOSITS**

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

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

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

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

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

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

PRO FORMA ADJUSTMENT: **PWEC LOAN**

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

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

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

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

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

Attachment CNF 1-8

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

PRO FORMA ADJUSTMENT: **GENERATION PRODUCTION INCOME TAX DEDUCTION**

Adjustment to Test Year operations to reflect the tax benefit associated with the domestic manufacturing income tax deduction.

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

Attachment CNF 1-9

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

PRO FORMA ADJUSTMENT:

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

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

EXHIBIT
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REBUTTAL TESTIMONY OF CHRIS N. FROGGATT

On Behalf of Arizona Public Service Company

Docket No. E-01345A-05-0816

September 15, 2006

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REBUTTAL TESTIMONY OF CHRIS N. FROGGATT

ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY

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

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND POSITION WITH APS.

A. My name is Chris N. Froggatt, and I am Vice President and Controller for Arizona Public Service Company ("APS" or "Company").

Q. DID YOU FILE DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes. I filed Direct Testimony in this docket on November 4, 2005 ("Initial Filing"), and also provided updated testimony on January 31, 2006 ("January Filing").

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

A. The purpose of my Rebuttal Testimony is to address several adjustments to operating income proposed by Staff and RUCO witnesses. I will also address two proposed rate base adjustments. I will indicate where we are in agreement with those recommendations, and will discuss those that I do not believe are appropriate or accurate. In addition, I will present the Company's revised income statement, which incorporates the adjustments the Company has accepted as discussed herein.

II. SUMMARY OF REBUTTAL TESTIMONY

Q. PLEASE PROVIDE A SUMMARY OF YOUR REBUTTAL TESTIMONY.

A. Staff and intervenors in this case have proposed both rate base and operating income adjustments to the Company's original request. In some cases, proposals are for reasonable revisions due to legislative changes, updated information that was not available at the time the Company filed its original request, or corrections for errors uncovered during the discovery process. Other adjustments that have been proposed are clearly inappropriate or inaccurate, and I discuss why these adjustments should either be revised or not accepted at all. Specifically, I discuss the following proposed operating income adjustments with which I agree:

- Staff and RUCO's Unregulated Marketing and Trading adjustment
- Staff's Income Tax adjustment

In addition, I agree with Staff and RUCO's rate base adjustment related to long term disability deferrals (SFAS 112).

The following proposed operating income adjustments are those with which I agree in principle, but portions of the calculations require corrections, which I discuss:

- RUCO's Interest on Customer Deposits adjustment
- Staff's Generation Production Deduction adjustment
- Staff and RUCO's Income Tax/Interest Synchronization adjustment
- RUCO's Out-of-Period Tax Consulting Fee adjustment

However, I do not agree with Staff's Investment Tax Credit rate base adjustment.

Additional Staff and intervenor operating income pro forma recommendations are addressed by APS witnesses Laura L. Rockenberger, Peter M. Ewen, and David J. Rumolo in their Rebuttal Testimony. Ms. Rockenberger will also address the remainder of the proposed adjustments to rate base.

Additionally, the Company's Adjustments to Schedule C-1, the revised income statement which incorporates all adjustments accepted or corrected by the Company, is attached to my testimony as Attachment CNF-1RB. I sponsor the Total Company calculations that are presented on page 1. Attachment CNF-2RB is the Company's Adjustments to Schedule C-2, which individually presents each adjustment, including those adjustments that other Company witnesses are discussing. Of these adjustments, I am sponsoring the Total Company column for those which I have listed above and discuss in my Rebuttal Testimony.

All jurisdictional allocations shown on the attached Adjustments to Schedule C-1 and C-2 have been calculated using the same factors that were used in APS' January 31, 2006 filing, and were addressed by Mr. Rumolo in his Direct Testimony.

The overall change in the Company's rate request, which includes these revisions, is addressed by APS witness Steven M. Wheeler in his Rebuttal Testimony.

III. STAFF AND INTERVENOR RECOMMENDED ADJUSTMENTS

A. Unregulated APS Marketing & Trading Activity

Q. DO YOU AGREE WITH AN ADJUSTMENT TO REMOVE UNREGULATED APS MARKETING AND TRADING ACTIVITY AS IS RECOMMENDED BY BOTH STAFF AND RUCO?

A. Yes, I do. During the discovery process, the Company became aware that it had inadvertently failed to exclude revenue and expenses associated with APS' unregulated marketing and trading activities. These activities relate to transactions that are not used to serve APS native load, and therefore should have been excluded in the Company's test year calculations. This adjustment is proposed in

Staff Schedules C-4 and C-5, sponsored by Staff witness Dittmer, and in the Direct Testimony of RUCO witness Diaz Cortez on page 24. This additional adjustment increases test year pre-tax operating income by $15.1 million, and is shown on Attachment CNF-3RB.

B. Federal and State Income Tax

Q. DID STAFF PROPOSE A REVISION TO THE FEDERAL AND STATE INCOME TAX PRO FORMA ADJUSTMENT?

A. Yes. As part of the discovery process, Staff and the Company agreed upon a "top down" cost-of-service income tax expense calculation. This calculation uses 2006 levels of various tax credits and other permanent tax items to estimate on-going income tax expense. This calculation is shown on Staff Schedule C-20, sponsored by Mr. Dittmer, and reduces test year income tax expense by $4.8 million. I agree with Staff's proposal and this adjustment is set forth on Attachment CNF-4RB.

C. Rate Base Offset for Long Term Disability (SFAS 112)

Q. DOES THE COMPANY AGREE WITH THE RECOMMENDATION OF STAFF AND RUCO TO ADJUST RATE BASE FOR LONG TERM DISABILITY DEFERRED CREDITS (SFAS 112)?

A. Yes. Mr. Dittmer presents Staff's proposed rate base adjustment on Staff Schedule B-1, and Ms. Diaz Cortez discusses RUCO's proposed adjustment on pages 7 and 8 of her Direct Testimony. Deferred credits related to expenses for employees on long-term disability were incorrectly excluded from rate base. The expenses are included in the test year and the related credit should likewise be included as a rate base offset. The calculation is shown on Attachment CNF-5RB and results in a rate base reduction of $3.9 million.

D. Interest on Customer Deposits

Q. WHAT IS THE OPERATING INCOME ADJUSTMENT PROPOSED BY RUCO WITNESS RIGSBY REGARDING INTEREST ON CUSTOMER DEPOSITS?

A. On RUCO Schedule WAR-1, Mr. Rigsby calculates an adjustment for interest on customer deposits of $2.5 million, which results in an increase of $976,000 over the Company's original proposal. RUCO recommends using the most recent interest rate (as determined in the Company's Service Schedule 1, Terms and Conditions for Standard Offer and Direct Access, paragraph 2.7.4) available prior to the filing deadline for direct testimony. In this case, the most recent rate is the 2006 rate of 4.38 percent, in contrast to the 2005 rate of 2.79 percent used by the Company in its January Filing.

Q. DO YOU AGREE WITH THIS ADJUSTMENT?

A. I agree with the principle of adjusting this interest rate to the most recently available rate. However, it appears that RUCO inadvertently utilized the March 31, 2006 deposit balance rather than the test year balance at September 30, 2005. Using the September 30, 2005 balance multiplied by the revised rate results in a total interest expense of $2.4 million. This revised calculation is shown on Attachment CNF-6RB and results in a pre-tax operating income decrease of $871,000 from the Company's January Filing calculation.

E. Generation Production Deduction

Q. DO YOU AGREE WITH STAFF'S ADJUSTMENT TO THE COMPANY'S ORIGINAL GENERATION PRODUCTION INCOME TAX DEDUCTION CALCULATION?

A. I agree in principle with the changes to the Generation Production Deduction calculation as discussed by Staff witness Dittmer on pages 126 through 128 of his

Direct Testimony. Staff presents a series of appropriate revisions to the Company's original calculation, based on the final Treasury Regulations pursuant to the American Jobs Creation Act, which were not available when the Company filed its direct testimony on this issue.

Q. DO YOU DISAGREE WITH A PORTION OF STAFF'S ADJUSTMENT?

A. Yes, I do. Staff calculates its deduction adjustment using its proposed weighted cost of common equity. As discussed by APS witness Donald Brandt in his Rebuttal Testimony, the Company does not agree with Staff's recommended weighted cost. Therefore, I have recalculated the deduction adjustment using Staff's proposed changes, but with the Company's recommended capital structure. This revised calculation results in a reduction in income tax of approximately $3.1 million, an additional $1.2 million reduction from the calculation included in the Company's January Filing pro forma adjustments. The Company's recalculated Generation Production Deduction is shown on Attachment CNF-7RB. Ultimately, this adjustment should reflect the cost of capital used by the Commission to establish rates in its final order.

F. Income Tax/Interest Synchronization

Q. PLEASE DESCRIBE THE PURPOSE OF AN INCOME TAX/INTEREST SYNCHRONIZATION PRO FORMA ADJUSTMENT.

A. The purpose of this adjustment is to align the cost of long-term debt and the capital structure, which was utilized as a part of the calculation of the Company's rate request, with the effect of pro forma adjustments made to the test year rate base. Therefore, when a rate base pro forma adjustment is revised (which would reflect a change in future capital requirements, possibly requiring a different cost or level of debt acquisition), this synchronization pro forma must be revised as well to reflect any change in the Company's cost or level of debt related to that revision. Resultant income tax changes due to increases or decreases in debt are then included in operating income.

Q. DID STAFF AND RUCO PROPOSE CHANGES IN THE COMPANY'S ORIGINAL SYNCHRONIZATION PRO FORMA?

A. Yes. Staff's recommendation is proposed by Mr. Dittmer and presented on Schedule C-19. RUCO's adjustment is sponsored by Mr. Rigsby and is shown on Schedule WAR-3.

Q. DO YOU AGREE WITH THEIR ADJUSTMENTS?

A. I agree that it is appropriate to revise the synchronization adjustment as revisions to rate base and/or cost or level of debt are proposed. However, because the Company does not agree with all of the Staff and RUCO rate base adjustments, or changes to the Company's weighted cost of debt, I do not agree with their specific synchronization calculations.

Q. WHAT IS THE COMPANY'S PROPOSED ADJUSTMENT?

A. The Company's proposed synchronization adjustment calculation is presented on Attachment CNF-8RB. The calculation reflects rate base adjustments accepted or recalculated by the Company and results in a synchronization adjustment decrease of $263,000 in interest expense.

G. Out-of-Period Tax Consulting Fees

Q. ARE YOU IN AGREEMENT WITH RUCO'S PROPOSED ADJUSTMENT FOR OUT-OF-PERIOD TAX CONSULTING FEES?

A. Yes, I am. These consulting fees were incurred to prepare a claim made by APS to the IRS for certain Investment Tax Credits ("ITCs") that was ultimately successful. This expense was incurred prior to the beginning of the test year, is not an on-going expense, and is appropriate to exclude from operating expense.

The adjustment proposed by RUCO does not include an additional expense of $1.5 million recorded in the test year. This additional expense, although recorded during the test year, is non-recurring and should also be removed from operating expense. This revision increases RUCO's adjustment from a $1.2 million reduction to operating expense (as discussed in Ms. Diaz Cortez's Direct Testimony at page 21) to a $2.8 million operating expense reduction, as shown on Attachment CNF-9RB.

Q. DID STAFF ADDRESS THIS SAME OUT-OF-PERIOD CONSULTING FEE?

A. Yes, Mr. Dittmer addresses this fee in Staff's Schedule C-12. Staff includes both portions of the fee in its calculation, but proposes that the expense reduction be split on a 50/50 basis between ratepayers and the Company as part of a larger proposal involving the ITCs themselves as a rate base reduction. I do not agree with the overall Staff proposal regarding these ITCs and the corresponding consulting fees. I believe both the fees and the tax credits are appropriately removed from regulated cost of service in their entirety.

Q. WHY DO YOU BELIEVE BOTH THE FEES AND THE TAX CREDITS ARE APPROPRIATELY REMOVED FROM REGULATED COST OF SERVICE AND RATE BASE?

A First, as I discuss above in full agreement with Staff and RUCO, both the fees and the related tax credits are non-recurring and clearly unrelated to the test year.

Second, as part of the 1994 settlement (Docket No. U-1345-94-120, Decision No. 58644), the Company was authorized to accelerate below the line amortization of all deferred ITC's in order to fully amortize those credits over a five year period beginning in 1995. Staff's proposed adjustment is not consistent with this treatment.

Lastly, I will address the rate base portion of Staff's proposal below.

H. Investment Tax Credit Rate Base Reduction

Q. PLEASE DISCUSS STAFF'S RATE BASE PROPOSAL REGARDING ITCs.

A. These ITCs are income tax credits, originally issued by the IRS in 1962 specifically for reinvestment purposes, which were realized by APS as a result of our recent claim requesting additional credits for a specific transition period after repeal of the ITCs in 1986 (as allowed by law). In Schedule B-3, Staff has proposed a 50/50 sharing of the ITCs.

Q. DO YOU AGREE WITH THIS PROPOSAL?

A. No. It is clear, based on discussions with outside legal counsel, that Staff's proposed treatment would constitute an IRS normalization violation.

Q. WHY DOES THIS TREATMENT CONSTITUTE A NORMALIZATION VIOLATION?

A. Of the additional ITCs allowed as a result of this claim, the majority (62%) relates to nuclear fuel. Under the ITCs regulations, a Company rate base offset (as proposed by Staff) requires a corresponding below-the-line amortization of the ITCs over time. The amortization period can vary, but in no event can it exceed the remaining useful life of the related asset. This fuel, being fully spent years ago, has no remaining useful life. Therefore, under no circumstances can the related ITCs be treated as a rate base offset and amortized 15 years after the fact. This clearly constitutes a normalization violation.

In fact, there have been several recent (2005 - 2006) IRS rulings on this subject, in response to utilities that have sought to continue the amortization of existing ITCs balances despite the fact that the facilities to which the ITCs was related were transferred or sold. The IRS has consistently issued adverse rulings premised on the fact that the related facilities had no remaining useful life.

Q. THAT COVERS ONLY A PORTION OF THE ITC. WHAT ABOUT THE REMAINING PORTION?

A. The remainder of the additional ITCs (38%) relates to facilities that may have a remaining useful life. However, APS is in the unique situation of receiving the ITC 15 to 20 years into the useful life of the related assets (as our claim related to the tax years 1986-1990). It is likely that tax authorities would determine that any rate base offset allowed would be limited to what would have been the unamortized 2006 balance from the time the assets were placed in service. If the balance is required to be calculated in this manner, Staff's proposed treatment for this remaining portion would be a normalization violation as well. Determination of the treatment of these ITC's would have to be requested from the IRS in the form of a Private Letter Ruling.

Q. DO PENALTIES EXIST FOR NORMALIZATION VIOLATIONS?

A. Yes. Tax law regarding normalization violations for ITC's specifies that a violation results in a full disallowance of the entire ITC originally allowed for those years within the statue of limitations. The Company's statute of limitations remains open back to the 1980's. This would be a significant liability for APS and, ultimately, its customers.

Therefore, for all these reasons discussed above, I do not support Staff's ITC proposal.

IV. CONCLUSION

Q. WHAT IS THE IMPACT OF ADDITIONAL ADJUSTMENTS ON THE COMPANY'S TEST YEAR OPERATING INCOME?

A. All Staff and intervenor recommended adjustments that the Company agrees with or has revised, including those addressed by other Company witnesses, are shown on Attachment CNF-2RB. These adjustments result in an Adjusted Total Company net income of $(51,137,000) for the test year ending September 30, 2005, as shown on Attachment CNF-1RB, page 1. This is an increase of $4,032,000 over the January Filing of Adjusted Total Company test year net income.

As I mentioned earlier, the overall change to the Company's rate request, which includes this adjusted test year net income, is presented and discussed by Mr. Wheeler in his Rebuttal Testimony.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

1885728.1

ARIZONA PUBLIC SERVICE COMPANY
Total Company
Adjusted Test Year Income Statement
Test Year 12 Months Ended 09/30/2005

(Dollars in Thousands)

		Total Company		
Line No.	Description	SFR Schedule C-1 as Filed on 1/31/06	Rebuttal Adjustments to C-1	Rebuttal Adjusted C-1
		(a)	(b)	(c)
1	Electric Operating Revenues	$ 3,509,720	$ (836,652)	$ 2,673,068
2	Purchased power and fuel costs	2,174,283	(810,949)	1,363,334
3	Operating revenues less purchased power and fuel costs	1,335,437	(25,703)	1,309,734
4	Other operating expenses:			
5	Operation and maintenance	684,209	(20,565)	663,644
6	Depreciation and amortization	344,690	(262)	344,428
7	Income taxes	9,952	(7,200)	2,752
8	Other taxes	141,839	(1,708)	140,131
9	Total	1,180,690	(29,735)	1,150,955
10	Operating income	154,747	4,032	158,779
11	Other income (deductions):			
12	Income taxes	56,698		56,698
13	Allowance for equity funds used during construction	10,433		10,433
14	Regulatory disallowance	(143,217)		(143,217)
15	Other income	26,019		26,019
16	Other expense	(15,176)		(15,176)
17	Total	(65,243)	-	(65,243)
18	Income before income deductions	89,504	4,032	93,536
19	Interest deductions:			
20	Interest on long-term debt	141,301	-	141,301
21	Interest on short-term debt	6,285		6,285
22	Debt discount, premium and expense	4,344		4,344
23	AFUDC - debt	(7,257)		(7,257)
24	Total	144,673	-	144,673
25	Net Income	$ (55,169)	$ 4,032	$ (51,137)

ARIZONA PUBLIC SERVICE COMPANY
ACC Jurisdiction
Adjusted Test Year Income Statement
Test Year 12 Months Ended 9/30/2005

(Dollars in Thousands)

Line No.	Description	ACC Jurisdiction SFR Schedule C-1 as Filed on 1/31/06 (a)	Rebuttal Adjustments to C-1 (b)	Rebuttal Adjusted C-1 (c)
1	Electric operating revenues	$ 3,440,590	$ (823,174)	$ 2,617,416
2	Purchased power and fuel costs	2,129,741	(797,409)	1,332,332
3	Operating revenues less purchased power and fuel costs	1,310,849	(25,765)	1,285,084
4	Other operating expenses:			
5	Operation and maintenance	766,212	(20,209)	746,003
6	Depreciation and amortization	306,988	(259)	306,729
7	Income taxes	395	(7,116)	(6,721)
8	Payroll and Other taxes	121,350	(1,688)	119,662
9	Total	1,194,945	(29,272)	1,165,673
10	Operating income	$ 115,904	$ 3,507	$ 119,411

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Twelve Months Ended 9/30/2005
(Thousands of Dollars)

		(1) SFR Sch. C-2 Total as filed on Jan. 31, 2006 Income Statement Adjustments		(2) REBUTTAL Tax Consulting Fees		(3) REBUTTAL Unregulated APS Marketing and Trading Activity	
Line No.	Description	Total Co. (A)	ACC (B)	Total Co. (C)	ACC (D)	Total Co. (E)	ACC (F)
1.	Electric Operating Revenues	$ 138,174	$ 137,135	$ -	$ -	$ (849,248)	$ (835,567)
2.	Purchased Power and Fuel Costs	351,718	350,695	-	-	(855,618)	(841,847)
3.	Oper Rev Less Purch Pwr & Fuel Costs	(213,544)	(213,560)	-	-	6,370	6,280
	Other Operating Expenses:						
4.	Operations Excluding Fuel Expense	65,716	63,234	(2,778)	(2,746)	(6,618)	(6,511)
5.	Maintenance	17,131	16,756	-	-	-	-
6.	Subtotal	82,847	79,990	(2,778)	(2,746)	(6,618)	(6,511)
7.	Depreciation and Amortization	25,806	23,504	-	-	-	-
8.	Amortization of Gain	(77)	(71)	-	-	-	-
9.	Administrative and General	27,400	24,958	-	-	(2,161)	(2,126)
10.	Other Taxes	16,867	16,719	-	-	-	-
11.	Total	152,843	145,100	(2,778)	(2,746)	(8,779)	(8,637)
12.	Operating Income Before Income Tax	(366,387)	(358,660)	2,778	2,746	15,149	14,917
13.	Interest Expense	(5,669)	(4,470)	-	-	-	-
14.	Taxable Income	(360,718)	(354,190)	2,778	2,746	15,149	14,917
15.	Current Income Tax Rate - 39.05%	(144,010)	(140,396)	1,085	1,072	5,916	5,825
16.	Operating Income (line 12 - line 15)	$ (222,377)	$ (218,264)	$ 1,693	$ 1,674	$ 9,233	$ 9,092
	WITNESS:			FROGGATT		FROGGATT	

(1) Total Income Statement Adjustments from APS' Direct Testimony filed on Jan. 31, 2006. Please see SFR Schedule C-2, page 11, Columns (KKK) and (LLL).

(2) Additional adjustment to operating expense to remove out-of-period and non-recurring tax consultant fees.

(3) Additional operating income pro forma to remove APS unregulated marketing and trading activities from operating expense.

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Twelve Months Ended 9/30/2005
(Thousands of Dollars)

Line No.	Description		(4) REBUTTAL Generation Production Deduction Total Co. (G)	ACC (H)	(5) REBUTTAL Interest on Customer Deposits Total Co. (I)	ACC (J)	(6) REBUTTAL Income Tax/Interest Synchronization Total Co. (K)	ACC (L)
1.	Electric Operating Revenues		$ -	$ -	$ -	$ -	$ -	$ -
2.	Purchased Power and Fuel Costs		-	-	-	-	-	-
3.	Oper Rev Less Purch Pwr & Fuel Costs		-	-	-	-	-	-
	Other Operating Expenses:							
4.	Operations Excluding Fuel Expense		-	-	871	871	-	-
5.	Maintenance		-	-	-	-	-	-
6.	Subtotal		-	-	871	871	-	-
7.	Depreciation and Amortization		-	-	-	-	-	-
8.	Amortization of Gain		-	-	-	-	-	-
9.	Administrative and General		-	-	-	-	-	-
10.	Other Taxes		-	-	-	-	-	-
11.	Total		-	-	871	871	-	-
12.	Operating Income Before Income Tax		-	-	(871)	(871)	-	-
13.	Interest Expense		-	-	-	-	(263)	(240)
14.	Taxable Income		-	-	(871)	(871)	263	240
15.	Current Income Tax Rate -	39.05%	(1,227)	(1,213)	(340)	(340)	103	94
16.	Operating Income (line 12 - line 15)		$ 1,227	$ 1,213	$ (531)	$ (531)	$ (103)	$ (94)

WITNESS: FROGGATT FROGGATT FROGGATT

(4) Adjustment to the Company's original pro forma to reflect the final Treasury Regulations pursuant to the American Jobs Creation Act.

(5) Adjustment to the Company's original pro forma to reflect the use of the 1/2/06 Treasury Interest rate and the deposit balance at 9/30/05.

(6) Additional adjustment to reflect interest expense related to certain proposed changes in rate base reflected in the Company's rebuttal testimony.

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Twelve Months Ended 9/30/2005
(Thousands of Dollars)

Line No.	Description		(7) REBUTTAL Federal and State Income Tax Total Co. (M)	ACC (N)	(8) REBUTTAL Administrative and General Total Co. (O)	ACC (P)	(9) REBUTTAL Property Taxes Total Co. (Q)	ACC (R)
1.	Electric Operating Revenues		$ -	$ -	$ -	$ -	$ -	$ -
2.	Purchased Power and Fuel Costs		-	-	-	-	-	-
3.	Oper Rev Less Purch Pwr & Fuel Costs		-	-	-	-	-	-
	Other Operating Expenses:							
4.	Operations Excluding Fuel Expense		-	-	-	-	-	-
5.	Maintenance		-	-	-	-	-	-
6.	Subtotal		-	-	-	-	-	-
7.	Depreciation and Amortization		-	-	-	-	-	-
8.	Amortization of Gain		-	-	-	-	-	-
9.	Administrative and General		-	-	(8,520)	(8,422)	-	-
10.	Other Taxes		-	-	-	-	(1,708)	(1,688)
11.	Total		-	-	(8,520)	(8,422)	(1,708)	(1,688)
12.	Operating Income Before Income Tax		-	-	8,520	8,422	1,708	1,688
13.	Interest Expense		-	-	-	-	-	-
14.	Taxable Income		-	-	8,520	8,422	1,708	1,688
15.	Current Income Tax Rate -	39.05%	(4,838)	(4,588)	3,327	3,289	667	659
16.	Operating Income (line 12 - line 15)		$ 4,838	$ 4,588	$ 5,193	$ 5,133	$ 1,041	$ 1,029
	WITNESS:		FROGGATT		ROCKENBERGER		ROCKENBERGER	

(7) Additional adjustment to the Company's original cost-of-service income tax expense to reflect a top-down tax calculation including permanent tax items.

(8) Remove out-of-period and other legal costs from administrative and general expense.

(9) Adjustment to Test Year operations to remove the 2007 phase-in cost increase for new generation plant.

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Twelve Months Ended 9/30/2005
(Thousands of Dollars)

Line No.	Description		(10) REBUTTAL Advertising Total Co. (S)	(10) REBUTTAL Advertising ACC (T)	(11) REBUTTAL Bark Beetle Total Co. (U)	(11) REBUTTAL Bark Beetle ACC (V)	(12) REBUTTAL Pension Total Co. (W)	(12) REBUTTAL Pension ACC (X)
1.	Electric Operating Revenues		$ -	$ -	$ -	$ -	$ -	$ -
2.	Purchased Power and Fuel Costs		-	-	-	-	-	-
3.	Oper Rev Less Purch Pwr & Fuel Costs		-	-	-	-	-	-
	Other Operating Expenses:							
4.	Operations Excluding Fuel Expense		(171)	(167)	110	110	2,249	2,119
5.	Maintenance		-	-	-	-	-	-
6.	Subtotal		(171)	(167)	110	110	2,249	2,119
7.	Depreciation and Amortization		-	-	-	-	-	-
8.	Amortization of Gain		-	-	-	-	-	-
9.	Administrative and General		(337)	(312)	-	-	-	-
10.	Other Taxes		-	-	-	-	-	-
11.	Total		(508)	(479)	110	110	2,249	2,119
12.	Operating Income Before Income Tax		508	479	(110)	(110)	(2,249)	(2,119)
13.	Interest Expense		-	-	-	-	-	-
14.	Taxable Income		508	479	(110)	(110)	(2,249)	(2,119)
15.	Current Income Tax Rate -	39.05%	198	187	(43)	(43)	(878)	(827)
16.	Operating Income (line 12 - line 15)		$ 310	$ 292	$ (67)	$ (67)	$ (1,371)	$ (1,292)
	WITNESS:		ROCKENBERGER		ROCKENBERGER		ROCKENBERGER	

(10) Adjustment to Test Year operations to exclude advertising expenses related to Company branding.

(11) Update Test Year expense to reflect revised bark beetle remediation costs.

(12) Adjustment to Test Year operations to reflect actual 2006 pension expense.

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Twelve Months Ended 9/30/2005
(Thousands of Dollars)

Line No.	Description		(13) REBUTTAL Post Retirement Medical Benefits		(14) REBUTTAL Spent Fuel Storage		(15) REBUTTAL Palo Verde Unit 1 Steam Generators Replacement Depreciation	
			Total Co. (Y)	ACC (Z)	Total Co. (AA)	ACC (BB)	Total Co. (CC)	ACC (DD)
1.	Electric Operating Revenues		$ -	$ -	$ -	$ -	$ -	$ -
2.	Purchased Power and Fuel Costs		-	-	(264)	(260)	-	-
3.	Oper Rev Less Purch Pwr & Fuel Costs		-	-	264	260	-	-
	Other Operating Expenses:							
4.	Operations Excluding Fuel Expense		(3,191)	(3,006)	-	-	-	-
5.	Maintenance		-	-	-	-	-	-
6.	Subtotal		(3,191)	(3,006)	-	-	-	-
7.	Depreciation and Amortization		-	-	-	-	(262)	(259)
8.	Amortization of Gain		-	-	-	-	-	-
9.	Administrative and General		-	-	-	-	-	-
10.	Other Taxes		-	-	-	-	-	-
11.	Total		(3,191)	(3,006)	-	-	(262)	(259)
12.	Operating Income Before Income Tax		3,191	3,006	264	260	262	259
13.	Interest Expense		-	-	-	-	-	-
14.	Taxable Income		3,191	3,006	264	260	262	259
15.	Current Income Tax Rate -	39.05%	1,246	1,174	103	102	102	101
16.	Operating Income (line 12 - line 15)		$ 1,945	$ 1,832	$ 161	$ 158	$ 160	$ 158
	WITNESS:		ROCKENBERGER		ROCKENBERGER		ROCKENBERGER	

(13) Adjustment to Test Year operations to reflect actual 2006 post retirement medical expenses.

(14) Adjustment to Test Year operations for current period spent nuclear fuel storage costs.

(15) Remove Test Year depreciation expense related to the old low pressure turbine rotors that were retired.

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Twelve Months Ended 9/30/2005
(Thousands of Dollars)

Line No.	Description		(16) REBUTTAL Base Fuel and Purchased Power Including Off-System Sales		(17) REBUTTAL Schedule 1	
			Total Co. (EE)	ACC (FF)	Total Co. (GG)	ACC (HH)
1.	Electric Operating Revenues		$ 12,596	$ 12,393	$ -	$ -
2.	Purchased Power and Fuel Costs		44,933	44,698	-	-
3.	Oper Rev Less Purch Pwr & Fuel Costs		(32,337)	(32,305)	-	-
	Other Operating Expenses:					
4.	Operations Excluding Fuel Expense		-	-	(19)	(19)
5.	Maintenance		-	-	-	-
6.	Subtotal		-	-	(19)	(19)
7.	Depreciation and Amortization		-	-	-	-
8.	Amortization of Gain		-	-	-	-
9.	Administrative and General		-	-	-	-
10.	Other Taxes		-	-	-	-
11.	Total		-	-	(19)	(19)
12.	Operating Income Before Income Tax		(32,337)	(32,305)	19	19
13.	Interest Expense		-	-	-	-
14.	Taxable Income		(32,337)	(32,305)	19	19
15.	Current Income Tax Rate -	39.05%	(12,628)	(12,615)	7	7
16.	Operating Income (line 12 - line 15)		$ (19,709)	$ (19,690)	$ 12	$ 12

WITNESS: EWEN RUMOLO

(16) Adjustment to the Company's original pro forma to include 2007 base fuel and purchased power expense and off-system revenues in cents/kWh at adjusted test year usage levels.

(17) Adjustment to the Company's original pro forma for Schedule 1 charges.

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Twelve Months Ended 9/30/2005
(Thousands of Dollars)

Line No.	Description	(18) REBUTTAL Total Rebuttal Pro Forma Income Statement Adjustments		(19) REBUTTAL Total Rebuttal Total Income Statement Adj.	
		Total Co. (II)	ACC (JJ)	Total Co. (KK)	ACC (LL)
1.	Electric Operating Revenues	$ (836,652)	$ (823,174)	$ (698,478)	$ (686,039)
2.	Purchased Power and Fuel Costs	(810,949)	(797,409)	(459,231)	(446,714)
3.	Oper Rev Less Purch Pwr & Fuel Costs	(25,703)	(25,765)	(239,247)	(239,325)
	Other Operating Expenses:				
4.	Operations Excluding Fuel Expense	(9,547)	(9,349)	56,169	53,885
5.	Maintenance	-	-	17,131	16,756
6.	Subtotal	(9,547)	(9,349)	73,300	70,641
7.	Depreciation and Amortization	(262)	(259)	25,544	23,245
8.	Amortization of Gain	-	-	(77)	(71)
9.	Administrative and General	(11,018)	(10,860)	16,382	14,098
10.	Other Taxes	(1,708)	(1,688)	15,159	15,031
11.	Total	(22,535)	(22,156)	130,308	122,944
12.	Operating Income Before Income Tax	(3,168)	(3,609)	(369,555)	(362,269)
13.	Interest Expense	(263)	(240)	(5,932)	(4,710)
14.	Taxable Income	(2,905)	(3,369)	(363,623)	(357,559)
15.	Current Income Tax Rate - 39.05%	(7,200)	(7,116)	(151,210)	(147,512)
16.	Operating Income (line 12 - line 15)	$ 4,032	$ 3,507	$ (218,345)	$ (214,757)

WITNESS:

ARIZONA PUBLIC SERVICE COMPANY
ADJUSTMENTS TO THE COMPANY'S ORIGINALLY FILED OPERATING INCOME
Total Company
(Thousands of Dollars)

ADJUSTMENT: **APS UNREGULATED MARKETING AND TRADING ACTIVITY**
Additional operating income pro forma to remove APS unregulated marketing and trading activities from operating expense.

Line No.	Description	Amount
1.	**REVENUES:**	(849,248)
2.	**EXPENSES:**	
3.	Purchased Power and Fuel Expense	(855,618)
4.	**Operating Revenue Less Purchased Power and Fuel Expense**	6,370
5.	Other Operating Expenses	
6.	Operations Excluding Fuel Expense	(6,618)
7.	Administrative and General	$ (2,161)
8.	Total Other Operating Expense	(8,779)
9.	Total Pro Forma Adjustment	15,149
10.	**OPERATING INCOME (before income tax)**	**15,149**
11.	Income Tax at 39.05%	5,916
12.	**OPERATING INCOME AFTER TAX**	**$ 9,233**

ARIZONA PUBLIC SERVICE COMPANY
ADJUSTMENTS TO THE COMPANY'S ORIGINALLY FILED OPERATING INCOME
Total Company
(Thousands of Dollars)

ADJUSTMENT: **FEDERAL AND STATE INCOME TAX**
Additional adjustment to the Company's original cost-of-service income tax expense to reflect a top-down tax calculation including permanent tax items.

Line No.	Description	Amount
1.	OPERATING INCOME (before income tax)	
2.	Income Tax	(4,838)
3.	**OPERATING INCOME**	**4,838**

ARIZONA PUBLIC SERVICE COMPANY
ADJUSTMENTS TO THE COMPANY'S ORIGINALLY FILED RATE BASE
Total Company
(Thousands of Dollars)

ADJUSTMENT: **RATE BASE OFFSET FOR LONG TERM DISABILITY (SFAS 112)**
Additional adjustment to the Company's rate base to include deferred credits related to expenses for employees on long-term disability.

Line No.	Description	Amount
1.	Gross Utility Plant in Service	$ -
2.	Less: Accumulated Depreciation and Amortization	$ -
3.	Net Utility Plant in Service	$ -
4.	Less: Total Deductions	$ 3,886
5.	Total Additions	$ -
6.	**TOTAL RATE BASE**	**$ (3,886)**

ARIZONA PUBLIC SERVICE COMPANY
ADJUSTMENTS TO THE COMPANY'S ORIGINALLY FILED OPERATING INCOME
Total Company
(Thousands of Dollars)

ADJUSTMENT: **INTEREST ON CUSTOMER DEPOSITS**
Adjustment to the Company's original pro forma to reflect the use of the 1/2/06 Treasury Interest rate and the deposit balance at 9/30/05.

Line No.	Description		Amount
1.	**EXPENSES:**		
2.	Other Operating Expenses		
3.	Operations Excluding Fuel Expense		
4.	Balance of Customer Deposits at 9/30/05	$ 54,800	
5.	One year Treasury Constant Maturities Interest Rate as of 1/2/06	4.38%	
6.	Total Pro Forma Adjustment to Expenses		2,400
7.	OPERATING INCOME (before income tax)		(2,400)
8.	Company's original Interest on Customer Deposits pro forma	(1,529)	
9.	**ADJUSTMENT TO COMPANY'S ORIGINAL PRO FORMA**		**(871)**
10.	Income Tax at 39.05%		(340)
11.	**ADDITIONAL ADJUSTMENT TO OPERATING INCOME AFTER TAX**		**$ (531)**

ARIZONA PUBLIC SERVICE COMPANY
ADJUSTMENTS TO THE COMPANY'S ORIGINALLY FILED OPERATING INCOME
Total Company
(Thousands of Dollars)

ADJUSTMENT: **GENERATION PRODUCTION DEDUCTION**
Adjustment to the Company's original pro forma to reflect the final Treasury Regulations pursuant to the American Jobs Creation Act.

Line No.	Description		Amount
1.	OPERATING INCOME (before income tax)		$ -
2.	Income Tax		(3,089)
3.	Company's original Generation Production Deduction pro forma	(1,862)	
4.	**ADJUSTMENT TO COMPANY'S ORIGINAL PRO FORMA**		(1,227)
5.	**ADDITIONAL ADJUSTMENT TO OPERATING INCOME AFTER TAX**		$ 1,227

ARIZONA PUBLIC SERVICE COMPANY
ADJUSTMENTS TO THE COMPANY'S ORIGINALLY FILED OPERATING INCOME
Total Company
(Thousands of Dollars)

ADJUSTMENT: **INCOME TAX/INTEREST SYNCHRONIZATION**
Additional adjustment to reflect interest expense related to certain proposed changes in rate base reflected in the Company's rebuttal testimony.

Line No.	Description	Amount
1.	**OPERATING INCOME (before income tax)**	$ -
2.	Interest Expense	(263)
	TAXABLE INCOME	**263**
5.	Income Tax at 39.05%	103
6.	**OPERATING INCOME AFTER TAX**	**$ (103)**

ARIZONA PUBLIC SERVICE COMPANY
ADJUSTMENTS TO THE COMPANY'S ORIGINALLY FILED OPERATING INCOME
Total Company
(Thousands of Dollars)

ADJUSTMENT: **TAX CONSULTING FEES**
Additional adjustment to operating expense to remove out-of-period and non-recurring tax consultant fees.

Line No.	Description	Amount
1.	**EXPENSES:**	
2.	Other Operating Expenses	
3.	Operations Excluding Fuel Expense	(2,778)
4.	Total Pro Forma Adjustment to Expenses	(2,778)
5.	**OPERATING INCOME (before income tax)**	2,778
6.	Income Tax at 39.05%	1,085
7.	**ADDITIONAL ADJUSTMENT TO OPERATING INCOME AFTER TAX**	$ 1,693

EXHIBIT

tabbies

APS-50

admitted

REJOINDER TESTIMONY OF CHRIS N. FROGGATT

On Behalf of Arizona Public Service Company

Docket No. E-01345A-05-0816
Docket No. E-01345A-05-0826
Docket No. E-01345A-05-0827

October 4, 2006

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REJOINDER TESTIMONY OF CHRIS N. FROGGATT ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY (Docket No. E-01345A-05-0816) (Docket No. E-01345A-05-0826) (Docket No. E01345A-05-0827)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, ADDRESS AND OCCUPATION.

A. My name is Chris N. Froggatt, and I am Vice President and Controller for Arizona Public Service Company ("APS" or "Company"). My business address is 400 North Fifth Street, Phoenix, Arizona, 85004.

Q. DID YOU PREVIOUSLY FILE DIRECT AND REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REJOINDER TESTIMONY?

A. I have reviewed the Surrebuttal Testimony of Staff witness Dittmer and am responding to his latest proposal for the treatment of certain Investment Tax Credits ("ITCs").

Q. DOES YOUR SILENCE REGARDING ANY OF THE ISSUES DISCUSSED BY OTHER PARTIES INDICATE AN ACCEPTANCE OF THOSE POISTIONS BY THE COMPANY?

A. No, it does not. For those issues, the Company maintains its position discussed in previous testimony.

II. SUMMARY OF REJOINDER TESTIMONY

Q. PLEASE SUMMARIZE YOUR REJOINDER TESTIMONY.

A. In surrebuttal testimony, Staff proposes a modification to its original rate base treatment of ITCs (as proposed in Staff Direct Testimony) in order to address the fact that implementation of Staff's initial proposal would constitute an IRS normalization violation. While the modified proposal does address that one concern, I continue to believe that Staff's treatment of these ITCs is inappropriate and inconsistent with prior Commission directives, and that these credits should be eliminated from rate base in their entirety.

III. STAFF'S MODIFIED ITC RATE BASE PROPOSAL

Q. PLEASE SUMMARIZE STAFF'S TREATMENT OF THESE CREDITS.

A. In Direct Testimony, Staff proposed a 50/50 ratepayer/shareholder sharing of the "net" savings realized from the Company's recent ITC claim. In my Rebuttal Testimony, I discussed how this proposal would violate the normalization provisions of the Internal Revenue Code. Material ramifications of such a violation would include the forfeiture of tens of millions of dollars in previously claimed ITCs. In Surrebuttal Testimony, Staff modified their rate base proposal in an attempt to avoid any violation. Staff now proposes that 100% of the *unamortized* ITC balance related to plant *not fully depreciated* be reflected as a rate base offset.

Q. DO YOU AGREE THAT THE MODIFIED PROPOSAL AVOIDS AN IRS NORMALIZATION VIOLATION?

A. Yes, I believe Staff's latest proposal would not result in an IRS violation. However, I do not support or agree with Staff's modified proposal.

Q. WHY DO YOU CONTINUE TO DISAGREE WITH THE PROPOSAL?

A. First of all, this proposed treatment is still wholly inconsistent with Decision No. 58644, wherein the Company was authorized to accelerate amortization of **all** deferred ITCs over a five year period beginning in 1995. The Company's ITC claim in question related to the years *1986 through 1990*. Had these credits been issued on original income tax returns, they would have been fully amortized by the year 2000 – some 6 years ago.

Q. WHAT ARE YOUR OTHER CONCERNS?

A. As I discussed in my Rebuttal Testimony, both the costs to obtain these tax credits and the tax credits themselves are **non-recurring** and clearly **unrelated** to the test year. For this reason alone, Staff's modified proposal should be rejected. The Company **is** in full agreement with excluding the cost of obtaining these ITCs from test year operating expense.

IV. <u>CONCLUSION</u>

Q. DOES THIS CONCLUDE YOUR REJOINDER TESTIMONY?

A. Yes, it does.

REBUTTAL TESTIMONY OF MARK K. GORDON

On Behalf of Arizona Public Service Company

Docket No. E-01345A-05-0816

September 15, 2006

EXHIBIT
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REBUTTAL TESTIMONY OF MARK K. GORDON ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY

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

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Mark K. Gordon. My business address is One Embarcadero Center, Suite 1400, San Francisco, California 94111.

Q. HAVE YOU PROVIDED PREVIOUS TESTIMONY IN THIS PROCEEDING?

A. No, I have not.

Q. PLEASE DESCRIBE THE NATURE AND PURPOSE OF YOUR REBUTTAL TESTIMONY.

A. I was asked to analyze APS' incentive compensation programs, evaluate the goals and effectiveness of the programs, and respond to the suggestions by certain Staff and Intervenor witnesses that some of the costs of these programs should be disallowed by the Commission in calculating APS' recoverable costs.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A. My educational background includes a Bachelors degree in Psychology and a Masters in Business Administration from the University of California at Berkeley.

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

A. I am a principal with Hewitt Associates LLC and a senior consultant in our Talent and Organization Consulting practice.

Q. PLEASE DESCRIBE THE NATURE OF THE BUSINESS OF HEWITT ASSOCIATES.

A. Hewitt Associates LLC ("Hewitt") is a global human resources management and administration consulting firm. Since 1940, Hewitt has provided well over 10,000 organizations with a broad range of consulting and administrative services related to total compensation and other human resource needs. Hewitt consults with many mid- and large-sized organizations, including over half of the *FORTUNE*® 500 companies. In addition, our proprietary Total Compensation Measurement™ (TCM™) DataBase represents the total compensation (including base salary, annual- and long-term incentives, supplemental benefits and perquisites) practices of over half of the *FORTUNE* 500 companies and a substantial representation of the electric and gas utility sector.

Q. PLEASE DESCRIBE YOUR OWN PROFESSIONAL QUALIFICATIONS.

A. I work with a broad range of public and private general industry corporations including utility and energy service businesses in the West Region. I have twenty years of management consulting experience with Hewitt, specializing in executive and broad-based compensation program strategy, design, and implementation. My testimony is based on my own professional experience; the collective compensation consulting experience of Hewitt Associates; our extensive library of published, private, and proprietary compensation surveys; and our understanding of the Arizona Public Service Company's ("APS") incentive plans.

Q. HOW DOES THE EXPERIENCE YOU HAVE DESCRIBED ABOVE RELATE TO YOUR TESTIMONY IN THIS PROCEEDING?

A. My educational background in psychology and business emphasized the study of motivation theory and organizational behavior management. This perspective is very helpful in assessing the effectiveness of incentive design from both an objective and qualitative point of view. Over the past twenty years, I have been personally involved in the design and review of hundreds of officer, management and broad based employee incentive plans covering annual and multi-year performance periods for clients in a variety of industries, including regulated gas and electric utilities. This experience, in the context of consulting on "total compensation" strategy and evaluation of competitive market practice provides a strong foundation for me to comment on the structure, potential value and effectiveness of APS' Variable Incentive Plan. In addition to my client activity, I have years of experience working annually with a variety of published and private survey sources which help me stay current on competitive market practices and trends in compensation management.

II. PURPOSE AND SUMMARY OF TESTIMONY

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

A. I was asked to comment on the purpose, prevalence, cost, and effectiveness of variable pay incentive programs in corporate America, including the utility industry and respond to the suggestions by certain Staff and Intervenor witnesses that some of the costs of these programs should be disallowed by the Commission in calculating APS' recoverable costs. In addition, I was asked to evaluate the nature and effectiveness of APS' incentive compensation program based on a variety of objective data and interviews with selected APS employees representing various organization levels who are participants in the program. My testimony addresses the benefits these types of incentive programs provide for key constituents (including customers, employees, and shareholders); the motivational value of incentive programs in encouraging employees to achieve key operational, customer service, and cost containment goals; and the need to be market competitive to attract and retain a stable, talented workforce. My testimony also addresses my evaluation of the effectiveness of APS' incentive compensation program in achieving its stated goals and objectives.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS REGARDING THE APS COMPENSATION PROGRAMS.

A. Based on my review of APS' annual variable incentive plans, and the long-term incentive plan, I conclude that these plans are designed consistently with competitive market practices, and their targeted compensation value is either below or consistent with competitive market practices. This indicates to me that cash compensation has been conservatively managed at APS.

I believe these plans are integral in providing a reasonable, competitive "total" compensation program at all levels of the organization. The elimination of any of these programs would significantly impair APS' ability to attract and retain employees critical to its successful ongoing operation. In fact, it could lead to higher turnover rates which would likely result in reductions in productivity, increase recruiting and training costs as well as damage employee morale and erode the Company's value system of high performance, accountability and pay for performance. Given my years of experience and knowledge of competitive practices, I view these compensation and benefit programs as a normal and reasonable "cost of doing business" and therefore the costs of these programs should not be disallowed by the Commission in calculating APS' recoverable costs.

In addition, the variable incentive plan has demonstrated effectiveness at aligning employees with its business objectives and reinforcing a high performance culture. The design and administration of the variable pay programs, including the goals and objectives, appear to correlate well with performance results that have significantly benefited customers over the past 10 years. APS' commitment to goal setting at all levels of the organization and ongoing communication serve to motivate employees and create a clear focus on accountability and pay for performance.

Given the current demographics of APS' workforce, including the high percentage of employees who are currently or soon will be eligible to retire, and the projected decrease in talented candidates entering the workforce, APS' ability to maintain stability with its current workforce and effectively compete for new talent will be critical to its future performance. Providing a competitive total compensation opportunity is fundamental to APS' ability to attract and retain high performing employees and in the best interests of customers.

III. NATURE OF WORK PERFORMED

Q. PLEASE EXPLAIN WHAT YOU DID AND WHAT YOU REVIEWED AS PART OF YOUR WORK ON THIS MATTER.

A. When I agreed to testify for APS, I asked for and was furnished with the following information by APS management to better understand the APS compensation program including incentive plan designs, award structures, performance results and payout history as of 2005:

- APS Variable Incentive Plans (PNW Chairman and CEO, Officer, Senior Management, Management, and Employee)
- Ten years of history (1996-2005) of APS performance metrics, goals and incentive results

- Industry performance benchmarking results on a variety of operating, customer and safety criteria
- Description of the APS Performance Share plan and Pinnacle West Capital Corporation 2002 Long Term Incentive Plan document

I also requested and was provided with the most recent (October 2005) results of an annual independent consultant market assessment of APS executive compensation levels compared to a Board approved peer group of other utilities with similar operating characteristics and general industry companies. I supplemented my analysis with additional benchmark information from Hewitt's proprietary executive compensation database, including detailed plan design and administrative specifications for incentives and target award opportunities at a selected group of approximately 20 electric and gas utilities.

In addition to reviewing the above documentation, I interviewed selected APS non-officer employees at various organization levels to gather anecdotal experience and perceptions related to the understanding and motivational value of the annual Variable Incentive Plan. I also had access to management for clarification of any program designs or administrative activities, as needed.

I was also recently provided with a copy of the direct testimonies of Mr. James R. Dittmer on behalf of the Utilities Division Staff (dated August 18, 2006) and Ms. Marylee Diaz Cortez, CPA on behalf of the Residential Utility Consumer office.

My testimony reflects the independent evaluation of this background information, my understanding of market practices and my extensive experience working with clients on these types of programs.

IV. OVERVIEW OF VARIABLE PAY INCENTIVE PROGRAMS

Q. PLEASE PROVIDE AN OVERVIEW OF WHAT YOU CALL VARIABLE PAY INCENTIVE PROGRAMS.

A. Corporate America, including the utility industry, has undergone significant changes and restructuring over the past two decades. Evolving business strategies, deregulation, global competition, workforce demographics, and the competitive labor market are key factors driving companies to create flexible organization structures and human resource systems necessary for ongoing business success. One of the more subtle but sweeping changes in human resource strategy over this time period has been the widespread implementation of variable incentive compensation programs at virtually all organization levels as an integral element of the total compensation and performance management systems. These programs and systems, once reserved for senior management, increasingly have been extended to cover all employees in some form.

I'd like to make an important distinction between a "bonus" program and "incentive" program. A bonus program is often viewed as a discretionary "add-on" to base pay, with the award size subjectively determined at the end of the year. Whereas, an annual incentive program is an integral part of annual cash compensation where a portion of the employee pay is put at risk and establishes an expectation for the participant at the beginning of the year that if certain performance results are achieved, a predictable award will be earned based on objective criteria and the actual award earned is variable based on actual results relative to the pre-set goals. This type of system provides a more clear connection between variable pay and performance.

A properly designed incentive program with a competitive award structure has become a critical part of employee retention strategies as well as for attracting new talent and motivating desired performance. In many organizations, it also plays a strategic role in aligning pay with performance results and engaging employees to take more ownership in business success. A company without an incentive compensation program today is clearly at a competitive and operational disadvantage.

Q. WHAT IS THE PURPOSE OF SUCH VARIABLE PAY INCENTIVE PROGRAMS?

A. The philosophy and strategic reasons behind the introduction of variable incentive plans include to:

- Link pay with business performance and personal contribution to results.
- Motivate participants to achieve higher levels of performance.
- Communicate and focus on critical success measures.
- Reinforce desired business behaviors, as well as results.
- Reinforce an employee ownership culture.

In other words, incentive plans serve many purposes. Principally, however, they are intended to improve business results by focusing employees on critical goals, motivating them to direct their behaviors and rewarding them for performance achievement, all while maintaining a reasonable compensation level.

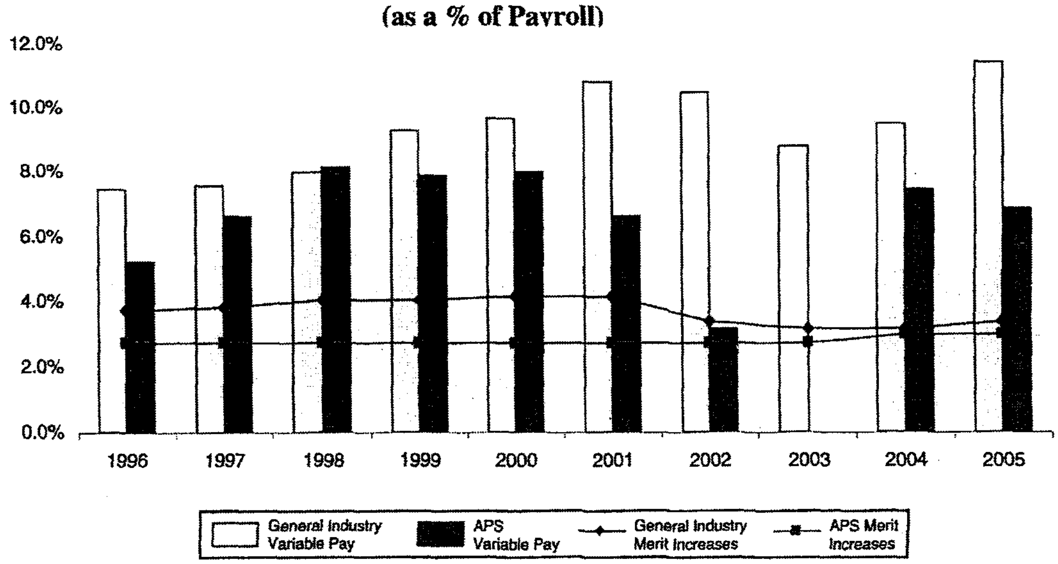
Moreover, incentive plans are undertaken because the benefits (or performance outcomes) associated with payments generally outweigh the program costs. The key benefits of incentive plans include motivating performance which achieves desired results, making total compensation cost variable depending on company performance, delivering a total compensation program that is attractive to existing and potential employees and aligning and focusing attention on key behaviors or specific goals.

Q. HOW PREVALENT ARE SUCH INCENTIVE COMPENSATION PROGRAMS IN CORPORATE AMERICA TODAY, WHAT ARE THE TYPICAL COSTS OF THESE PROGRAMS, AND HOW DOES APS COMPARE?

A. A recent Hewitt survey (*2005 Salary Increase Survey*) shows that the prevalence of U.S. companies with at least one broad-based variable compensation plan has increased from 60% in 1994 to over 75% in 2005. Company spending on variable pay for salaried exempt employees (as a percent of payroll) below the officer level over this period increased from 6.4% to 11.4%. Over the same time period (1994-2005), average annual merit base salary increases have declined from approximately 4.0% of payroll to 3.6%.

The following table summarizes the ten year historical spending trend in employee variable pay and annual merit increases for salaried exempt employees among general industry companies compared with APS:

General Industry vs. APS Spending on Broad-Based Cash Compensation for Salaried Exempt Employees (as a % of Payroll)



As shown in the table, APS' spending on variable pay has been considerably below industry averages in all years except 1998 and base salary increases have likewise been below industry averages in all years. This indicates to me that cash compensation has been conservatively managed at APS for a number of years.

Q. DOES THE NATURE OF THE UTILITY INDUSTRY, AS DIFFERENTIATED FROM CORPORATE AMERICA GENERALLY, MAKE INCENTIVE COMPENSATION PROGRAMS LESS IMPORTANT OR LESS BENEFICIAL?

A. Absolutely not. In fact, incentive compensation plans have taken on increasing importance in helping utilities provide a competitive "total compensation" package that allows them to compete with general industry companies to attract and retain a competent, stable workforce that in turn provides efficiencies and costs savings for the company and its customers and shareholders. As job mobility across industries and heightened competition for leadership and top talent has increased in recent years, workforce stability and the retention of key leadership throughout the employee ranks provide several benefits to a utility company and its customers, including:

- Minimizing costs associated with high turnover including recruiting, training, and decreased productivity associated with filling vacant positions.
- Continuity of the executive, management, and professional teams to develop and implement effective business strategies.
- More consistent and efficient customer service, with resultant cost savings and other customer benefits.

In the regulated public utility industry, companies must meet the needs of multiple stakeholders including customers, shareholders, and the communities in which they operate. Incentive compensation programs, if properly designed and implemented, provide benefits to all of those constituents.

V. THE DESIGN OF APS' INCENTIVE COMPENSATION PROGRAM

Q. DOES THE BASIC DESIGN OF APS' INCENTIVE COMPENSATION PROGRAM COMPORT WITH THE GENERAL OBJECTIVES AND PURPOSES OF SUCH INCENTIVE PROGRAMS?

A. Yes. APS' annual program as of 2005 is called the Variable Incentive Plan and has five distinct organization levels of participation—PNW Chair/CEO, Officer (includes APS President, EVP and VP), Senior Management, Management and Broad-Based Employees. These plans combine a focus on Company performance and Business Unit results defined as Critical Success Indicators ("CSIs") and provide a monetary incentive when these goals are accomplished. At APS, the current plan is funded when Company earnings exceed a threshold level of performance. Having a corporate performance threshold based on earnings is consistent with a large majority (88%) of similar gas and electric utilities reported in the Hewitt database. The amount of the funded pool that is earned is based on the achievement of Company Earnings and Business Unit CSIs. CSIs are key business goals covering areas including operational efficiency, safety, environment, and customer satisfaction. The incentive program has been in place at APS for over ten years and is an integral part of the overall business and human resource strategy to align employees with the Company's mission, strategy, and value system and enhance awareness of key business objectives.

A unique dimension to the employee alignment strategy of the APS incentive program is the inclusion of IBEW members, which represent almost one-third of the workforce, and at the participation level of other frontline employees. The participation of represented groups is not common in the utility industry, and I believe it has been particularly effective at APS in directing their behavior and reinforcing the importance of key operating goals and objectives throughout the organization across all employee groups.

Factors that have been identified through research and reported in general industry surveys as enhancing incentive plan effectiveness include:

- Setting realistic goals/targets.
- Effectively communicating plans.
- Using appropriate measures.
- Ensuring a clear understanding of plan objectives.
- Correlating accomplishments with rewards.

In addition, motivation theory suggests that the effectiveness of an incentive plan is driven by the employees' perception of the ability to impact performance results, the probability of achieving pre-set goals, and the meaningfulness of rewards. APS' Variable Incentive Plan is designed consistent with these underlying "effectiveness" factors.

Finally, APS' variable incentive compensation helps to manage the Company's ongoing cost structure of total pay because incentive awards must be "re-earned" every year.

Q. COULD YOU PLEASE EXPLAIN IN MORE DETAIL HOW APS' INCENTIVE COMPENSATION PROGRAM OPERATES TO ACHIEVE THE GOAL AND OBJECTIVES OF THE PROGRAM?

A. APS has used its annual Variable Incentive Plan to focus employee behavior and provide a meaningful opportunity to impact and share in the Company's operating results. APS provides a threshold, midpoint and maximum award opportunity (as a percent of base pay) to its employees consistent with those reported among other utility and general industry companies. A midpoint, or "target" award is the amount which an employee will receive if the actual results generally equal those budgeted. Actual payments are based on the results achieved and are below target if the overall performance is less than planned or above target if performance exceeds plan goals.

APS's incentive awards are determined based on a combination of financial and operating performance results. The APS incentive payment is based on the Company meeting a threshold earnings goal and, at the Business Units, the level of achievement of CSIs. If the threshold earnings goal is not met, no payout is made. After the threshold earnings goal is met, the incentive award is generally determined 50% based on Company earnings and 50% based on CSIs through the EVP level. This performance/award structure effectively balances participants' focus on customers and shareholders. For Frontline employees, an additional award "kicker" of up to 2% of pay is awarded based on customer satisfaction scores. In 2005, no Officer awards were granted. The 2005 incentive payout was approximately $30 million (of which a significant part was paid by non-APS generation plant participants). Non-officer management awards represented 35% of the pool and Frontline employee (including IBEW) awards represented 65% of the total incentive pool. Awards at these organization levels reflected Corporate earnings performance and the achievement of Business Unit CSIs (as described above). The performance/award structure effectively balances the focus on performance for customers and shareholders, with an increasing emphasis on incentives tied to customer performance metrics below the Officer level, providing a more meaningful focus on pay for performance for the Frontline employees.

Q. HOW DO THE 2005 TARGETS AND ACTUAL INCENTIVES OF THE APS PROGRAM COMPARE TO THOSE OF OTHER COMPANIES THAT HAVE INCENTIVE COMPENSATION PROGRAMS?

A. APS's target award structure, in general, appears to be reasonably positioned and in some cases lower than median when compared with the opportunity at comparable utilities and general industry companies. A target award (generally expressed as a percentage of base pay) is the expected award level assuming all performance goals are met at "plan" or "budgeted" levels. The following table compares APS's 2005 target awards to the typical market range of target annual business incentive awards at the Officer level (Chair/CEO/President, EVP, VP) Salaried Exempt—Management, Salaried Exempt/Non-Exempt—Frontline, and Union Hourly—Frontline levels [1].

[1] Results from Hewitt's 2005 Total Compensation Measurement™ DataBase survey of industrial and service organizations and 2005 Competitive Compensation Analysis of executive and officer positions at APS.

Employee Group	2005 Utility Industry Target (%) Average	Median	75th %ile	2005 General Industry Target (%) Average	Median	75th %ile	APS Target (% of base pay)
Chair/CEO	-	85%	100%	-	104%	-	125%
President	-	80%	85%	-	99%	-	75%
EVP	-	50%	60%	-	60%	70%	50%
VP	-	40%	45%	-	45%	50%	35%
Salaried Exempt—Management	11.3	10.0	13.1	11.1	10.0	15.0	7.5%
Salaried Exempt/Non-Exempt—Frontline	7.6	5.5	10.5	5.6	5.0	7.0	3%+1%
Union Hourly—Frontline	3.8	2.9	5.0	3.8	3.5	5.0	3%+1%

As summarized above, the PNW Chair/CEO target is somewhat above average but as pointed out later total target direct pay is below the market median. All other organization levels appear to have target award opportunities that are at or below the market median. While the Senior Management level is not shown in the table due to the lack of a direct general market comparison, based on my experience, I believe that APS' target of 15% for this participant level would also be at or below the market median. The large majority of incentive plan structures provide for a potential range of actual awards from 0 to two times the target award (e.g., if the management target is 7.5% of pay, the maximum award for significantly exceeding budgeted goals is 15% of pay). APS' award range opportunity is consistent with this market practice.

The following table compares APS' actual 2005 incentive awards (as a % of base pay) and 5-year average actual awards to the 2005 market actuals for the same participant levels:

Employee Group	2005 Utility Industry Actual (%) Average	Median	75th %ile	2005 General Industry Actual (%) Average	Median	75th %ile	APS Actual (% of base pay) 2005	2001–2005 Average
Chair/CEO		103%	148%		104%	178%	0%	65.1%
President	-	-	-	-	-	-	0%	42.4%
EVP	-	61%	120%	-	66%	119%	0%	21.0%
VP	-	43%	78%	-	47%	92%	0%	15.8%
Salaried Exempt—Management	12.3	10.0	16.8	11.4	10.0	15.0	12.6%	8.0%
Salaried Exempt/Non-Exempt—Frontline	8.1	6.5	9.9	5.9	5.0	7.8	5.00%	3.8%
Union Hourly—Frontline	3.7	2.3	5.0	4.0	4.0	5.0	5.00%	3.2%

As summarized above, the actual 2005 and 5-year average annual awards (expressed as a percentage of base pay) under the APS plan show a dramatic shortfall for the executive and officer levels, 2005 Management awards were near the market average and Frontline awards were below the median for salaried non-exempt employees and at the 75th percentile for IBEW participants. Five year average awards were below market averages at all levels. Overall, these award levels continue the trend of APS' conservative management of cash compensation relative to the market.

VI. <u>THE BENEFIT TO CUSTOMERS</u>

Q. HOW DOES APS' INCENTIVE COMPENSATION PROGRAM BENEFIT CUSTOMERS?

A. APS' incentive program directly benefits customers in a number of ways. In general, as part of a total compensation program that helps to attract, motivate and retain key employees, it is a key factor in driving a high performance culture. By retaining high-performing employees, customers benefit not only from the heightened experience of these valued employees but also by minimizing turnover costs arising from recruiting, "downtime" and retraining. In addition, variable incentive compensation helps to manage payroll expenses because incentive awards must be "re-earned" every year.

APS' incentive program goals emphasize a balanced performance focus on customers, shareholders, and the communities in which it operates. As mentioned above, management and broad-based employee participants have specific goals contributing to operational efficiency, improved productivity, safety, environment, customer service, and cost control. All of these goals contribute to two common results: reducing costs, which can then be passed along to customers in the form of reduced rates or which can free up funds for other investments to benefit customers, and higher levels of customer service.

APS' performance goals are specific, meaningful, achievable, relevant and time sensitive. The measures directly benefit customers by focusing on controlling costs, providing good customer service, and promoting safety. Goals are established at the Corporate level, but also at the operating Business Unit (e.g., Fossil, Delivery, Shared Services) level to provide employee "line-of-sight" with measures that they impact day-to-day. Goals are communicated to participants to help them understand why objectives are important and how accomplishment of "local" goals contributes to achievement of higher-level Company goals. For example, APS' Delivery Unit CSIs include Safety goals measuring weeks without a preventable recordable injury, Customer Satisfaction as measured by survey results, Business Performance Trends, System Average Interruption Frequency Index ("SAIFI") performance and Environmental Incidents. These measures clearly have a strong correlation with customers.

VII. THE EFFECTIVENESS OF THE APS PROGRAM

Q. WHAT DETERMINATIONS ABOUT THE ACTUAL EFFECTIVENESS OF THE APS INCENTIVE COMPENSATION PROGRAM HAVE YOU MADE?

A. I reviewed data prepared by APS comparing its performance against industry performance on a variety of operating metrics. My conclusion is that, over the past ten years, APS has a demonstrated performance record of cost containment, system operating reliability and safety as summarized in:

- **Attachment MKG-1** summarizes the Non-Generation O&M per Customer APS v. Similar Sized and Regional Utilities 1995-2005 which shows that APS has outperformed other regional and similarly sized utilities in every year since 1995
- **Attachment MKG-2** summarizes the Edison Electric Institute's 2004 Reliability Report based on System Average Interruption Frequency Index (SAIFI) and System Average Interruption Duration Index (SAIDI) from 1996 to 2004 which shows that APS has improved SAIFI by 38% and SAIDI by 44% while the National Average SAIFI has gotten worse by 9% and the National Average SAIDI has gotten worse by 109% during the same period.
- **Attachment MKG-3** summarizes how APS has consistently ranked among the top utilities according to the Edison Electric Institute Safety Survey for the lowest total recordable injury incidence rate from 1996-2005
- **Attachment MKG-4** summarizes the JD Powers Studies of Residential and Business Customers which show that APS has ranked among the top

third of utilities in each of the last five years, including the top ten in three of those years on customer satisfaction.

As described previously, these operating, safety and customer service metrics are Critical Success Indicators in the annual Variable Incentive Plan. Based on my review of plan documents and discussions with employees and officers, I believe the incentive process has significantly contributed to APS' impressive and consistent results on these criteria.

I also conducted interviews with selected plan participants below the officer level to gain insight into the motivational value and understanding of the incentive plan purpose and mechanics. The interviews suggest that the annual variable incentive plan has been effective in enhancing employee awareness of critical operating activities and, particularly at the Management level and above, influencing behavior. The plan is well communicated and understood and is viewed as an important part of the total compensation program at all organization levels. Generally, the employees I spoke with believe that the structure of the incentive program and award determinations is reasonable. The interview results are further evidence that the APS incentive programs have been effective and continue to meet the program purpose and objectives.

VIII. IMPORTANCE OF THE STOCK COMPONENT OF APS'S PROGRAM

Q. TO WHAT EXTENT IS THE STOCK COMPENSATION COMPONENT OF THE APS INCENTIVE COMPENSATION PROGRAM AN IMPORTANT ELEMENT OF THE PROGRAM?

A. Long-term incentives have been the fastest growing component of executive and officer compensation over the past fifteen years. Today, long-term incentive awards account for more than one-third of officer direct pay and are integral to a company's ability to attract and retain management personnel. Based on the most recent competitive analysis of APS' executive compensation program, 93% of its utility peer companies provide long term incentives to executives and officers in the form of stock-based awards (e.g., stock options, restricted stock, and performance shares) and/or cash awards.

In 2002, the PWCC board adopted, and shareholders approved the 2002 Long Term Incentive Plan, which provided for the granting of stock options, performance shares and stock ownership awards. In Mr. Dittmer's testimony, he says that the stated purpose of the Plan is to promote the success and enhance the value of PWCC by linking the participants' personal interests to those of shareholders. However, the complete description of the stated objectives of the Plan, as disclosed in the PWCC proxy statement relating to the May 22, 2002 Annual Meeting of Shareholders, is as follows: "The Plan is designed to attract, motivate and retain selected employees of the Company. These objectives are accomplished by making long-term incentive awards under the Plan, thereby providing Participants with a proprietary interest in the growth and performance of the Company."

My understanding is that APS' long-term incentive plan for its officers has awarded limited performance shares and stock ownership awards, but it has not granted stock options since 2003.

Under the performance share plan, participants are granted a "target" number of shares, with a grant value that was determined to be below the market median in the independent consultant study for the PNW Chairman/CEO, APS President/CEO and EVP level and at the market median for other officers.

Awards are earned based on the Company's compound annual growth rate in Earnings Per Share over a three-year performance period relative to the S&P Electric Utilities Super Composite EPS growth rate over the same period. Minimum, target and superior achievement goals are set at the beginning of the performance period and final award levels may range from 0 to 2 times the "target" grant size. However, for the three-year performance period ended December 31, 2005, there were no payouts under the performance shares.

Half of the APS peer companies reported granting performance shares to its executive officers and more than three-quarters (79%) reported some form of multi-year performance plan. Typical performance periods cover three or four years and EPS is a commonly used metric for determining award size among other utilities and general industry companies.

In addition to serving as a key component of a competitive total compensation opportunity, enabling APS to attract and retain key leadership talent, the long-term incentive plan also benefits APS customers by:

- Minimizing costs associated with high turnover at the executive level, including recruiting, productivity reductions and continuity of leadership
- Minimizing the need for additional base pay or other fixed benefits to provide competitive compensation levels
- Providing focus and accountability for the executive and management team to develop and implement effective business strategies that span multiple year periods. Using Earnings Per Share as the long-term performance goal focuses on cost management and productivity gains which directly translate into ongoing savings for customers. It serves as

the broadest measure of all the functions of utility cost performance, both within and between years.

- Long-term financial health provides Company stability and allows the Company to continue to invest in the business operations, grow its asset base and continue to improve operating efficiencies through economy of scale and upgrades in technology and infrastructure which directly benefit customers through maintaining a low cost generation and delivery structure.

Q. DOES APS HAVE A SPECIFIC EXECUTIVE RETENTION INCENTIVE?

A. No, and because the Company stopped granting stock options after 2003 and its performance shares have a grant value below the market median for senior officers, I believe the Company should address this issue. After discussions with management, I understand that the Company is now considering retention measures that would better position the Company to offer a competitive overall compensation package. I also understand that such action would not adversely affect APS' rates or financial ratios.

IX. RESPONSE TO RUCO'S PROPOSED 20% DISALLOWANCE

Q. RUCO HAS PROPOSED TO DISALLOW 20% OF ALL INCENTIVE COMPENSATION FROM APS'S RECOVERABLE COSTS ON THE THEORY THAT APS SHOULD SHARE THE COST OF ELECTRICITY PRICE HIKES. DO YOU AGREE WITH THIS SUGGESTION?

A. No, I do not agree. While I understand the principle being suggested, it would be inappropriate to exclude any portion of incentive compensation as this is part of the normal "cost of doing business". As previously stated, incentive compensation is an integral part of a competitive total pay program necessary to attract and retain employees. The variable incentive program has also been critical in reinforcing APS' achievement of Critical Success Indices and its pay for performance culture. The 2005 executive compensation market study showed that total direct pay levels for the PNW Chairman/CEO, APS CEO/President and EVP levels were below the market median and VP levels were at the competitive market median. This study reflected cash incentive awards paid in 2005 for 2004 performance. Given that no executive and officer cash awards were paid in 2006 for 2005 performance, I expect that all levels will be well below market median in the 2006 study. Had the 5-year average incentive awards been reflected in the study, the conclusion would still have been that APS executives' total direct pay has been below the market median. I believe that it is in the best interest of customers that APS continue to provide a competitive variable incentive compensation opportunity to drive pay for performance. Even Mr. Dittmer acknowledged in staff testimony (page 110 line 20), that the cash incentives in place today are primarily tied to performance measures that directly benefit APS consumers.

X. <u>CONCLUSION</u>

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS.

A. Given the current demographics of APS' workforce, including the high percentage of employees who are currently or soon will be eligible to retire, and the projected decrease in talented candidates entering the workforce, APS' ability to maintain stability and effectively compete for new talent will be critical to its future performance. Providing a competitive total compensation opportunity is fundamental to APS' ability to attract and retain high performing employees.

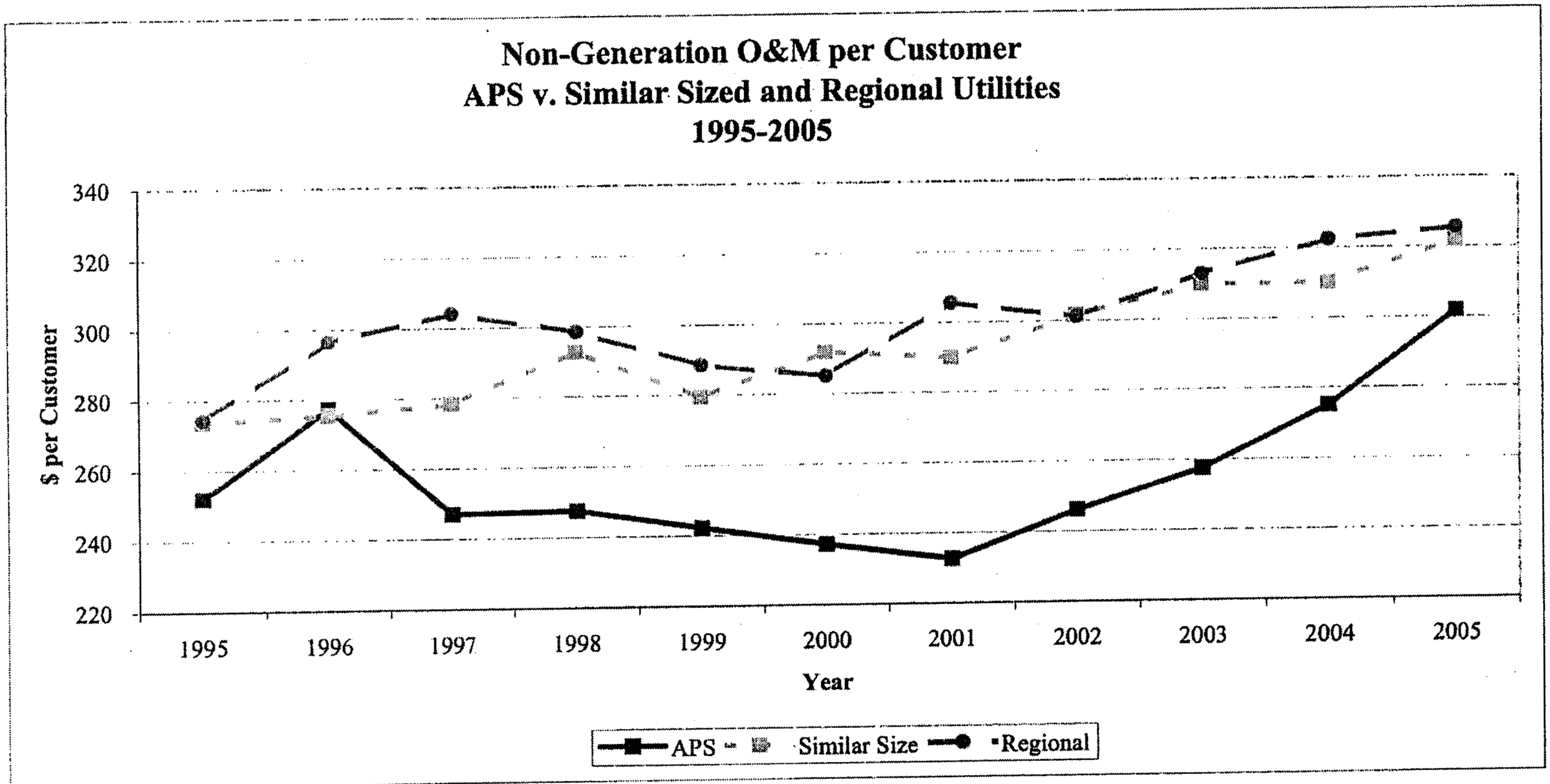
APS' use of an annual variable incentive compensation program and a long term performance plan is consistent with competitive market practices in terms of design, and the targeted compensation value is either below or consistent with competitive market practices.

The results of the most recent (2005) competitive market study for officers and executives demonstrated that the total direct (base pay, annual- and long-term incentives) compensation package for the PNW Chairman/CEO, APS President/CEO and EVP levels are below the market median and the VP level, generally, is competitive with the market median only when annual incentives are paid. Since annual incentive awards were not paid to executives and officers for 2005 performance, and no performance shares were awarded, the competitive position significantly drops below the market median for all levels. The elimination of any of these programs would significantly impair APS' ability to attract and retain employees critical to its successful ongoing operation. In fact, it could lead to higher turnover rates which would likely result in reductions in productivity rates, increased recruiting and training costs as well as damage employee morale and erode the Company's value system of high performance, accountability and pay for performance.

In addition, the annual incentive plan has demonstrated effectiveness at aligning employees with key business objectives and reinforcing a high performance culture. The design and administration of the variable pay programs, including the goals and objectives, appear to correlate well with performance results that have significantly benefited customers over the past 10 years. APS' commitment to goal setting at all levels of the organization and ongoing communication serve to motivate employees, enhance awareness and create a clear focus on accountability and pay for performance. In sum, APS' incentive compensation programs are integral to its ability to attract and retain its employees, align employee behavior with company goals and motivate employee performance, all of which are critical to the success of a high-performing and efficient energy generation and distribution company in today's competitive business environment.

Q. DOES THIS CONCLUDE YOUR WRITTEN REBUTTAL TESTIMONY?

A. Yes.



	Sample	Years											1995-2005 Change	
		1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	Nominal	CPI Adjusted
Non-Gen O&M per Customer	APS	252	277	247	248	242	237	233	246	258	275	302	19.7%	-6.6%
	Similar Size	274	276	278	293	280	292	290	302	310	310	322	17.6%	-8.2%
	Regional	274	297	304	299	289	285	306	301	313	322	326	18.6%	-7.4%

Summary of EEI Annual Reliability Reports **Attachment MKG-2**

EEI National Average

Year	SAIFI	SAIDI	Number of Companies
1996	1.35	181.80	46
1997	1.24	170.40	44
1998	1.62	248.40	41
1999	1.45	230.40	62
2000	1.53	252.60	58
2001	1.48	208.20	47
2002	1.53	330.00	64
2003	1.59	364.90	68
2004	1.47	380.54	75

APS Average

	SAIFI	SAIDI
1996	1.91	170.40
1997	1.69	132.60
1998	1.51	112.20
1999	1.43	96.60
2000	1.56	127.20
2001	1.64	125.40
2002	1.11	106.80
2003	1.40	111.60
2004	1.18	95.40

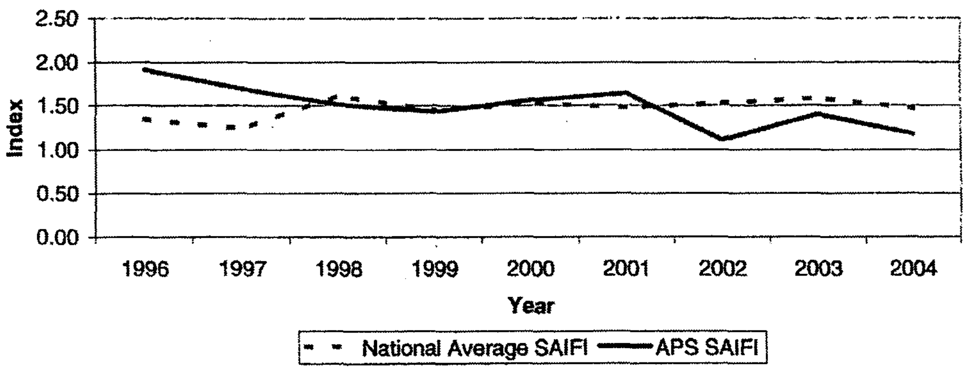
APS change from 1996:

SAIFI Improvement	38%
SAIDI Improvement	44%

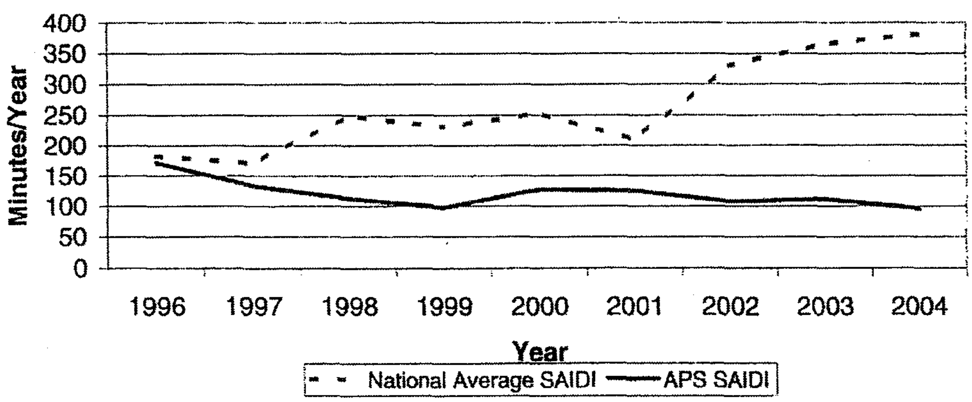
EEI change from 1996:

SAIFI Change	-9%
SAIDI Change	-109%

SAIFI Comparison



SAIDI Comparision



Source: Annual EEI Reliability reports

Attachment MKG-3

Arizona Public Service Company

Edison Electric Institute Safety Survey (Group Number 2)

Total Recordable Incidence Rate

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
1 Worse	8.37	6.08	8.45	5.29	8.36	10.25	8.17	7.63	5.98	5.95
2	6.10	5.83	4.65	4.75	6.71	5.26	6.65	5.41	5.68	5.67
3	5.63	5.48	4.62	3.29	5.54	4.68	5.50	5.26	5.16	4.37
4	5.62	4.31	4.30	3.27	5.52	4.59	5.17	4.99	4.50	3.61
5	5.28	3.61	3.12	3.12	5.49	4.22	4.98	3.92	4.26	3.47
6	5.11	3.21	2.83	2.53	5.15	3.2	4.70	2.88	4.08	2.55
7	5.11	2.23	2.25	2.18	2.53	2.09	3.53	2.71	3.58	2.44
8	3.52	2.18	1.98	1.98	2.29	1.79	2.92	2.70	2.52	2.28
9	3.45	1.56	1.86	1.91	2.15	1.70	2.49	2.18	2.42	2.21
10	3.32	0.97	1.68	1.77	1.55	1.63	2.42	1.84	1.89	1.53
11	3.12	0.77	1.55	1.17	1.18		1.81		1.53	0.81
12	2.71									
13	2.41									
14	1.90									
15 Better	1.47									
APS	1.90	2.18	1.68	1.77	2.29	1.79	1.81	2.18	1.53	2.28
Rank	#2	#4	#2	#2	#4	#3	#1	#2	#1	#4
Percentile	93	73	91	91	73	80	100	90	100	73

Industry data source:
Edison Electric Institute Group Number 2 (4,000 to 6,999 Employees).

APS Electric Utility Residential Customer Satisfaction

1999-2006[1]

Year	*Customer Satisfaction Index* Industry	APS	Ranking
1999	97	96	51st among 78 utilties
2000	98	102	43rd among 75 utilities
2001	98	98	50th among 70 utilities
2002	100	104	22nd among 74 utilities
2003	101	110	7th among 77 utilities
2004	98	107	9th among 78 utilities
2005	99	111	6th among 78 utilities
2006	94	100	24th among 78 utilities[2]

Notes:

[1] Information prior to 1999 is not available as that is the first year JD Power conducted the study.

[2] In 2006 APS was ranked in the top quadrant among Investor Owned Utilities (IOUs) nationwide and second among the West Region IOUs.

Source:

JD Power Study of Residential Customers, 1999-2006.

APS Electric Utility Business Customer Satisfaction

2004-2006[1]

Customer Satisfaction Index

Year	Industry	APS	Ranking
2004	100	104	12th among 52 utilities
2005	103	105	13th among 53 utilities
2006	104	108	9th among 52 utilities[2]

Notes:

[1]Comparable information prior to 2004 is not available.

[2]In both 2005 and 2006 APS was the top ranking IOU in the West Region

Source:

JD Power Study of Business Customers, 2004-2006.

Staff PSA Proposal in APS Rate Case Compared to TEP ECAC Proposal[1]

	Staff Proposal	TEP ECAC Proposal
Base Fuel Cost	Traditional TY cost-of-service approach	Traditional TY cost-of-service approach
Prospective Adjustor (or "ECAC") Basis	Established from difference between base fuel cost and projected average fuel cost	Forward market price phased in over four years for sales growth above test year
Forecast Method	All known fuel cost changes rolled in, averaged over all kWh sales	Palo Verde forward price for year of delivery weighted by 25% in each of 4 years preceding delivery
Escalation in Embedded Fuel Costs Covered?	Yes	No
Hedged Positions Reflected in Adjustor?	Yes	Not directly
Included Off-System Sales Margins in Adjustor	Yes	No
Dispatch Issues Reflected in Adjustor (e.g., year-to-year changes in maintenance schedules)?	Yes	No
True-Ups for Forecast Deviations?	Cost deviations (higher or lower) are deferred, recovered the following year – possibly	True-ups for • incremental sales differences and • actual MGC price vs. forward price used to price last 25% of incremental sales
Deferral Accounting Required?	Yes	Unclear
Amortization Period for True-Ups/Deferrals	Up to Commission discretion	Unspecified

[1] This document summarizes APS's understanding and interpretation of the respective proposals by ACC Staff in APS' Rate Case and TEP with regard to establishing a fuel recovery mechanism.

EXHIBIT
tabbies
APS-52
Admitted

REJOINDER A-1
Submitted 10/30/06

ARIZONA PUBLIC SERVICE COMPANY - **REJOINDER POSITION**
Computation of Increase in Gross Revenue Requirements
ACC Jurisdictional
Adjusted Test Year Ended 09/30/2005
(Dollars in Thousands)

		Electric - APS Rejoinder			
Line No.	Description	Original Cost	RCND	Fair Value	Line No.
1	**Adjusted Rate Base**[1/]	**4,456,937**	**7,765,052**	**6,110,995**	**1**
2	Adjusted Operating Income[2/]	129,539	129,539	129,539	2
3	Current Rate of Return	2.91%	1.67%	2.12%	3
4	Required Operating Income	389,091	389,091	389,091	4
5	**Required Rate of Return**[3/]	**8.73%**	**5.01%**	**6.37%**	**5**
6	Operating Income Deficiency	259,552	259,552	259,552	6
7	Gross Revenue Conversion Factor[4/]	1.6407	1.6407	1.6407	7
8	Adjusted Increase in Base Revenue Requirements	425,847	425,847	425,847	8
9	Environmental Improvement Charge[5/]	4,542	4,542	4,542	9
10	Environmental Portfolio Standard[6/]	4,250	4,250	4,250	10
11	**Total Increase in Revenue Requirement**[7/]	**434,639**	**434,639**	**434,639**	**11**
12	Total Sales to Ultimate Retail Customers	2,127,322	2,127,322	2,127,322	12
13	**Percentage Rate Increase**	**20.43%**	**20.43%**	**20.43%**	**13**

1/ Rebuttal Testimony of APS Witness Rockenberger, Attachment LLR-3-1RB, page 1.
2/ APS Exhibit 53, page 2 of 3 (Schedule C-1, as adjusted in Rebuttal Testimony of APS Witness Froggatt, Attachment CNF-1RB, page 2, with rejoinder adjustments).
3/ SFR Schedule D-1 page 1 of 2, filed 1/31/06.
4/ SFR Schedule C-3, filed 1/31/06.
5/ Rebuttal Workpapers of APS Witness DeLizio, GAD_WP4RB, page 1.
6/ Rebuttal Testimony of APS Witness DeLizio, page 6.
7/ As discussed in Rejoinder Testimony of APS Witness Wheeler, page 2. This is a reduction in revenue requirement of $16.6 million from the rebuttal revenue requirement shown in the Rebuttal Testimony of APS Witness Wheeler, Attachment SMW-1RB.

EXHIBIT
tabbies
APS-53
Admitted

REJOINDER C-1

ARIZONA PUBLIC SERVICE COMPANY
Total Company
Adjusted Test Year Income Statement - Rejoinder
Test Year 12 Months Ended 09/30/2005
(Dollars in Thousands)

		ACC Jurisdiction		
Line No.	Description	Rebuttal Adjusted Schedule C-1 as Filed on 9/15/06 1/	Rejoinder Adjustment to Schedule C-1	Rejoinder Adjusted Schedule C-1
		(d)	(e)	(f)
1	Electric Operating Revenues	$ 2,617,416	$ (72,396)	$ 2,545,020
2	Purchased power and fuel costs	1,332,332	(89,013)	1,243,319
3	Operating revenues less purchased power and fuel costs	1,285,084	16,617 2/	1,301,701
4	Other operating expenses:			
5	Operation and maintenance	746,003	-	746,003
6	Depreciation and amortization	306,729	-	306,729
7	Income taxes	(6,721)	6,489	(232)
8	Other taxes	119,662	-	119,662
9	Total	1,165,673	6,489	1,172,162
10	Operating income	119,411	10,128	129,539
11	Other income (deductions):			
12	Income taxes			
13	Allowance for equity funds used during construction			
14	Regulatory disallowance			
15	Other income			
16	Other expense			
17	Total			
18	Income before income deductions			
19	Interest deductions:			
20	Interest on long-term debt			
21	Interest on short-term debt			
22	Debt discount, premium and expense			
23	AFUDC - debt			
24	Total			
25	Net Income	$ 119,411	$ 10,128	$ 129,539

1/ Rebuttal Testimony of APS Witness Froggatt, Attachment CNF-1RB, page 2 of 2, col (c).
2/ Rejoinder Testimony of Peter Ewen, page 2, line 7.

Comparison of FFO to Debt from May 2, 2006 ACC Open Meeting on Emergency Asking to FFO to Debt from APS Rebuttal Testimony

Projected 12/31/06 FFO to debt as provided at May 2, 2006 ACC Open Meeting assuming 7mil adjustor effective May 1, and no step 2 surcharge recovery in 2006	18.2%
Current 12/31/06 estimate utilizing same methodology as in place as of May 2, 2006 estimate	17.9%
Calculation methodology changes mandated by S&P subsequent to May 2, 2006:	
Change from average debt to year-end debt	-0.9%
Change in method for operating leases	0.5%
Change in discount rate on PPA's from 10% to embedded cost of debt (5.9% at 12/31/05)	-0.4%
Change in treatment of Palo Verde decommissioning contributions	0.5%
Total	-0.3%
Current 12/31/06 estimate (DEB_WP1RB)	17.6%

EXHIBIT
tabbies
APS-54
admitted

UNISOURCE ENERGY CORPORATION AND PINNACLE WEST CAPITAL CORPORATION

EXHIBIT
tabbies
APS-55
admitted

PENSION FUND DATA

$ Millions

	2001	2002	2003	2004	2005	2006	
Plan Assets at Year-End							
Unisource Energy Corporation	$120	$106	$124	$136	$149		
Pinnacle West Capital Corporation	$765	$721	$887	$982	$1,065		
Projected Benefit Obligation Liabiltiy (PBO)							
Unisource Energy Corporation	$117	$133	$162	$188	$208		
Pinnacle West Capital Corporation	$885	$1,059	$1,249	$1,372	$1,493		
Underfunded PBO $							
Unisource Energy Corporation	-$3	$27	$38	$52	$59		
Pinnacle West Capital Corporation	$120	$338	$362	$390	$428		
Underfunded PBO %							
Unisource Energy Corporation	-2.6%	20.3%	23.5%	27.7%	28.4%		
Pinnacle West Capital Corporation	13.6%	31.9%	29.0%	28.4%	28.7%		
Plan Contributions							**2001-2006 Total**
Unisource Energy Corporation	$2	$6	$3	$6	$7	$9	$33
Pinnacle West Capital Corporation	$44.2	$26.6	$46.0	$35.0	$52.7	$46.5	$251.0
Plan Contributions as % of Year-End Plan Assets							**Average**
Unisource Energy Corporation	1.7%	5.7%	2.4%	4.4%	4.7%		3.8%
Pinnacle West Capital Corporation	5.8%	3.7%	5.2%	3.6%	4.9%		4.6%
Return on Plan Assets							
Unisource Energy Corporation[1]	-9.5%	-11.7%	18.9%	9.7%	8.8%		
Pinnacle West Capital Corporation	-2.7%	-4.4%	23.3%	12.3%	7.7%		
S&P 500 Index	-11.9%	-22.1%	28.7%	10.9%	4.9%		

1 Percentages derived from data available in Form 10-K; Return on assets/Beginning Value of Assets
2 All Unisource information is from publicly available sources.

EXHIBIT
APS-56
admitted

DIRECT TESTIMONY OF LAURA L. ROCKENBERGER

On Behalf of Arizona Public Service Company

Docket No. E-01345A-05-0816

January 31, 2006

Table of Contents

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

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Laura L. Rockenberger. My business address is 400 North Fifth Street, Phoenix, Arizona, 85004.

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

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

Q. WHAT SCHEDULES ARE YOU SPONSORING?

A. I am sponsoring the following Standard Filing Requirement ("SFR") Schedules: the historical and test year information contained in SFR Schedule A-4, related to Construction Expenditures and Gross Utility Plant in Service; the SFR Schedules B Rate Base information; certain operating income pro forma adjustments in SFR Schedule C-2; the historical and test year information contained in SFR Schedule E-5, Detail of Utility Plant; and the test year information contained in SFR Schedule F-3 related to construction requirements. The B schedules show the elements of APS' rate base at original cost and reconstructed cost new ("RCN") at September 30, 2005, as well as the pro forma adjustments to rate base.

Q. WAS YOUR PRE-FILED TESTIMONY PREPARED BY YOU OR UNDER YOUR DIRECTION?

A. Yes.

II. SUMMARY OF TESTIMONY

Q. PLEASE PROVIDE A SUMMARY OF YOUR TESTIMONY.

A. In large part, the pro forma adjustments to the test year rate base represent the implementation of Arizona Corporation Commission ("Commission" or "ACC") Decision No. 67744, issued April 7, 2005. Included in this Decision was Commission approval to transfer certain Pinnacle West Energy Corporation ("PWEC") units, specifically Redhawk Units 1 and 2, West Phoenix Units 4 and 5 and Saguaro Unit 3 ("PWEC Units") to APS. This subsequently occurred on July 29, 2005. In addition, in Decision No. 67504, issued January 20, 2005, the Commission authorized the purchase of the PPL Sundance Energy, LLC generating units ("Sundance Units") and approved an accounting order for the deferral of costs. The Sundance Units were subsequently acquired by APS on May 13, 2005. There are no Sundance Unit cost deferrals included in this filing because the criteria for cost deferrals, as allowed pursuant to Decision No. 67504, has not been met. The majority of the pro formas that I am sponsoring in this proceeding simply implement these Commission Decisions.

In response to a request from Commission Staff, APS has selected a fiscal year, the 12 months ending September 30, 2005, as a test period ("Test Year"). As such, the PWEC Units and the Sundance Units were included in the rate base at September 30, 2005. The Test Year was then adjusted to make it more representative of normal operations at the time new rates in this docket are approved by the Commission, which is assumed to be January 1, 2007.

My testimony addresses a number of accounting-related topics to support the Company's rate case application. I identify and explain adjustments to rate base and certain operating income adjustments. The rate base pro forma adjustments include the following adjustments: West Phoenix Unit 4 Regulatory Disallowance, Independent Spent Fuel Storage Installation ("ISFSI" or "Spent Fuel Storage") costs, Palo Verde Unit 1 steam generators ("PV Unit 1 Steam Generators") replacement costs, and deferred bark beetle remediation costs. For these items, there are corresponding operating income pro forma adjustments. In addition, there are operating income pro forma adjustments for the PWEC Units, the Sundance Units, nuclear plant decommissioning expense, coal reclamation costs, depreciation and amortization, property taxes, payroll, underfunded pension liability, advertising, and certain other miscellaneous adjustments in the SFR Schedule C-2 pro formas. The operating income pro formas also include an income tax calculation at the current statutory combined state and federal income tax rates. The SFR Schedule C-2 pro formas for the West Phoenix Unit 4 Regulatory Disallowance, Spent Fuel Storage, PV Unit 1 Steam Generators and bark beetle remediation include a calculation for the synchronization of interest expense used in the calculation of state and federal income tax expense. Mr. Chris Froggatt provides details regarding the income tax adjustment and interest synchronization adjustment in his testimony. I also provide direct testimony on an overall allowance for working capital and Reconstructed Cost New Less Depreciation ("RCND"), which is shown on SFR Schedule B-4. And finally, I sponsor SFR Schedule E-5 and actual Test Year information contained in SFR Schedule F-3.

Q. **HOW IS YOUR TESTIMONY ORGANIZED?**

A. I will first discuss the items that have a pro forma adjustment to Original Cost Rate

Base, as set out in Attachments LLR-1-1 through LLR-1-5, and the corresponding pro forma adjustments to operating income. I will then discuss the remaining operating income pro forma adjustments. These pro forma adjustments, as set out in Attachments LLR-2-1 through LLR-2-17 and LLR-3, reflect total Company amounts prior to any jurisdictional allocation. Next I will present the results of the Company's Allowance for Working Capital (Attachment LLR-4), followed by the most recent RCN Study (Attachments LLR-5-1 and LLR-5-2) and SFR Schedule E-5, Detail of Utility Plant.

III. PRO FORMA ADJUSTMENTS AFFECTING BOTH RATE BASE & OPERATING INCOME

Q. WHAT ARE PRO FORMA ADJUSTMENTS?

A. Because the Commission requires a historical test year, it is necessary to adjust recorded revenues and expenses for known and measurable changes in rates or charges. The use of pro forma test year revenues and expenses more accurately reflects the level of revenues and expenses in the future, when the new rates will be in effect. Pro forma adjustments include normalizations, annualizations and known and measurable changes that affect actual rate base, revenues, and expenses in the test year.

Q. WHAT ARE "NORMALIZATIONS"?

A. Normalizations are adjustments that modify test year data to reflect a typical test year. These are generally accounting adjustments that remove expenses or revenues properly recorded during the Test Year, but are associated with prior periods.

Q. WHAT ARE "ANNUALIZATIONS"?

A. Annualizations are adjustments that compensate for timing differences, such as adjusting the number of customers at the end of the test year, along with the sales revenues and expenses to reflect the revenues associated with those customers and the costs of serving that number of customers at the end of the test year.

Q. WHAT IS A "KNOWN AND MEASURABLE" ADJUSTMENT?

A. Known and measurable adjustments reflect the Company's expected financial conditions when the new rates are expected to be in effect. An adjustment is considered to be "known" when, given all the circumstances, its probability of occurrence is significantly greater than the chance it will not occur. An adjustment is "measurable" if it can be quantified in a meaningful fashion, such that the recognition of at least part of its effect on Test Year results will make the Test Year "more representative" than if the adjustment were omitted altogether.

A. PWEC Units - West Phoenix Unit 4 Regulatory Disallowance

Q. DID YOU RECORD THE REGULATORY DISALLOWANCE FOR THE PWEC UNITS IN ACCORDANCE WITH DECISION NO. 67744?

A. Yes. In Decision No. 67744, the Commission authorized a jurisdictional $700,000,000 original cost rate base ("OCRB") for the PWEC Units at December 31, 2004. Because the PWEC Units did not transfer to APS until July 29, 2005, the $700,000,000 OCRB was reduced by additional accumulated depreciation and related deferred taxes for the period of January 1, 2005 through July 29, 2005. Thus, the regulatory disallowance for the PWEC Units at July 29, 2005 reduced the net plant by $155,036,000. *See* Attachment LLR-1-1.

Q. ARE THERE DIFFERENCES BETWEEN THE REGULATORY ACCOUNTING FOR THE DISALLOWANCE AND THE ACCOUNTING UNDER GENERALLY ACCEPTED ACCOUNTING PRINCIPLES ("GAAP")?

A. Yes. Under GAAP, the portion of the regulatory disallowance related to West

Phoenix Unit 4 could not be recorded in the GAAP financial statements because the unit was not considered "recently completed".

Q. PLEASE DISCUSS THE ACCOUNTING GUIDANCE THAT WOULD NOT ALLOW THE WEST PHOENIX UNIT 4 REGULATORY DISALLOWANCE TO BE REFECTED IN YOUR GAAP FINAL STATEMENTS.

A. Statement of Financial Accounting Standards ("SFAS") No. 90, "Regulated Enterprises – Accounting for Abandonments and Disallowances of Plant Costs" was the authoritative accounting guidance we relied on in determining the amount of the loss that should be recorded for GAAP purposes. In accordance with the SFAS 90, when it becomes probable that part of the cost of a recently completed plant will be disallowed for rate-making purposes and a reasonable estimate of the amount of the disallowance can be made, the estimated amount of the probable disallowance shall be deducted from the reported cost of the plant and recognized as a loss.

SFAS 90 does not define "recently completed". Based on discussions with Deloitte, our external auditors, we concluded that a plant that was completed within twelve months of a rate filing is considered recently completed for purposes of SFAS 90. The in-service date for West Phoenix Unit 4 was June of 2001. Our rate filing requesting that West Phoenix Unit 4 be included in rates was made in June of 2003, two years after the in-service date. Thus, the plant was not considered recently completed and the disallowance could not be recorded for GAAP accounting purposes.

Q. PLEASE EXPLAIN THE RATE BASE PRO FORMA ADJUSTMENT FOR WEST PHOENIX UNIT 4 REGULATORY DISALLOWANCE.

A. Because the disallowance was not recorded for GAAP purposes, a pro forma adjustment is needed to reduce the rate base by the disallowed amount. Accordingly, the rate base reduction for the West Phoenix Unit 4 regulatory disallowance at September 30, 2005 is $11,155,000. *See* Attachment LLR-1-2.

Q. IS THERE A CORRESPONDING OPERATING INCOME ADJUSTMENT FOR THE DEPRECIATION EXPENSE RELATED TO THE WEST PHOENIX UNIT 4 REGULATORY DISALLOWANCE?

A. Yes. The operating income pro forma reflects an annual reduction in depreciation expense of $230,000. *See* Attachment LLR-2-1.

B. INDEPENDENT SPENT FUEL STORAGE INSTALLATION

Q. WHY IS THERE A NEED FOR INDEPENDENT SPENT FUEL STORAGE INSTALLATION?

A. An Independent Spent Fuel Storage Installation is a dry storage facility for the temporary disposal of spent nuclear fuel. The fuel pools where the spent nuclear fuel from the Palo Verde Nuclear Generation Station ("Palo Verde") is currently stored have reached the maximum allowed capacity. Because the U.S. Department of Energy has delayed siting and constructing permanent spent nuclear fuel storage facilities, the continued operation of Palo Verde requires an alternative interim storage solution for spent nuclear fuel. The costs associated with Spent Fuel Storage are the costs of interim storage for spent nuclear fuel at Palo Verde.

Q. IS APS ASKING FOR CONTINUING RECOVERY OF SPENT FUEL STORAGE COSTS IN THIS RATE CASE FILING?

A. Yes. The Company has included pro forma adjustments for Spent Fuel Storage in a manner consistent with APS' last rate application. Specifically, APS is requesting recovery of its share of the ongoing costs associated with Spent Fuel Storage and an amortized portion of deferred amounts, as discussed below.

Q. WHAT IS THE BASIS FOR THE RECOVERY OF SPENT FUEL STORAGE COSTS?

A. Commission rule, A.A.C. R14-2-1608, provides for the recovery of interim spent nuclear fuel storage costs through a Systems Benefit Charge. The Commission first approved the recovery of system benefits costs for APS in Decision No. 61973, issued October 6, 1999, which adopted a settlement agreement that addressed electric restructuring.

Q. WHAT CHANGES RELATED TO SPENT FUEL STORAGE OCCURRED AS A RESULT OF DECISION NO. 67744?

A. On April 1, 2005 (the effective date of Decision No. 67744), APS commenced recovery for the amortization of prior deferred costs and the current accrual for Spent Fuel Storage costs associated with the current fuel burn. A portion of those costs represent post-shutdown Spent Fuel Storage costs that are being funded into the Palo Verde nuclear decommissioning trusts, which I discuss later in my testimony.

Q. HOW ARE THE COSTS ESTIMATED?

A. The cost estimates for Spent Fuel Storage are updated every three years and were most recently updated again by TLG Services, Inc. for 2004.

Q. PLEASE EXPLAIN THE SPENT FUEL STORAGE PRO FORMA RATE BASE ADJUSTMENT.

A. The net rate base reduction of $5,869,000 results from funds collected in regulated rates and reserved for the cost of current on-going and future activities in the decommissioning period to transfer spent nuclear fuel to the dry storage facility. *See* Attachment LLR-1-3.

Q. IS SPENT FUEL STORAGE EXPENSE INCLUDED IN NUCLEAR FUEL EXPENSE IN THE TEST YEAR?

A. Yes. Since the Test Year (ended September 30, 2005) occurred after the effective date of Decision No. 67744 (April 1, 2005), there are six months of Spent Fuel Storage expenses included in the unadjusted Test Year expenses. Thus the Spent Fuel Storage expense needs to be annualized in an operating income pro forma adjustment.

Q. PLEASE EXPLAIN THE CORRESPONDING OPERATING INCOME PRO FORMA ADJUSTMENT FOR SPENT FUEL STORAGE.

A. The total Test Year annualized nuclear fuel expense is $14,759,000. Of this amount, $3,667,000 represents ongoing Spent Fuel Storage expense, which is included in the Base Fuel and Purchase Power Expense pro forma, and is addressed in Mr. Ewen's testimony. The pro forma adjustment of $11,092,000 reflects the annual amortization of previously deferred amounts. This is shown on Attachment LLR-2-2.

Q. HOW DOES THE COMPANY PROPOSE TO ADDRESS THE AMORTIZATION OF PREVIOUSLY DEFERRED SPENT FUEL STORAGE EXPENSE?

A. The Spent Fuel Storage annualized expense for amounts previously deferred is $11,092,000, which is comprised of pre-shutdown costs of $9,976,000 and post-shutdown costs of $1,116,000. Consistent with Decision No. 67744, the Company proposes to amortize the costs associated with pre-shutdown activities over a five-year period. For Units 1 and 3, the post-shutdown costs are amortized over the license period, and for Unit 2, over the term of the sale/leaseback agreement (through December 31, 2015). This is also consistent with our last rate proceeding. The Company is requesting that the Commission's Decision in this docket specifically provide for the amortization of the Spent Fuel Storage expense regulatory asset included in Attachment LLR-2-2.

Q. OF THESE PROPOSED AMOUNTS TO BE RECOVERED IN RATES, WHAT PORTION REPRESENTS POST-SHUTDOWN OPERATIONS TO BE FUNDED IN THE DECOMMISSIONING TRUSTS?

A. APS is requesting annual funding into the decommissioning trusts for the amounts approved in Decision No. 67744. Included in these amounts is $752,000, which represents post-shut down costs included in the ongoing accrual, and $792,000, which represents the amortization of previously deferred post-shut down amounts. *See* Attachment LLR-3. The amount that APS is requesting does not reflect the post-shutdown component of Spent Fuel Storage cost estimated in the 2004 study. The Company is deferring the difference for future recovery in subsequent rate proceedings.

Q. DO POST-SHUTDOWN SPENT FUEL COSTS QUALIFY FOR FAVORABLE TAX TREATMENT?

A. APS has filed a private letter ruling requesting Internal Revenue Service ("IRS") approval to use the qualified decommissioning funds for spent fuel costs. If such approval is granted, APS plans to use the qualified decommissioning funds for post-shutdown spent fuel costs to their fullest extent, as allowed under the federal income tax rules.

C. PALO VERDE UNIT 1 STEAM GENERATORS

Q. WHY HAS APS MADE AN ADJUSTMENT FOR THE REPLACEMENT OF PALO VERDE UNIT 1 ("PV UNIT 1") STEAM GENERATORS?

A. Like other nuclear generating stations throughout the nation, heat and corrosion have caused damage to the tubes in the Palo Verde ("PV") steam generators. The PV owners, including APS, have determined it is both necessary and economically desirable to replace PV steam generators and related equipment in each unit to prevent a decrease in the unit's output and to maintain its reliability. The Unit 2 steam generators and related equipment were replaced in 2003, as addressed in Decision No. 67744. The Unit 1 steam generators and related equipment were replaced in 2005 and are included in this rate case. Unit 3 steam generators and related equipment are expected to be replaced in 2007, and recovery of the related costs will be requested in a subsequent rate proceeding.

Q. **WHAT RELATED COMPONENTS WERE REPLACED DURING THE PROJECT FOR PV UNIT 1?**

A. In addition to the two PV Unit 1 Steam Generators, three low-pressure turbine rotors, core protection calculators and pressurized heaters were replaced, which improves the future reliability and efficiency of PV Unit 1, as well as increases its output by approximately 22 megawatts. The 22 megawatt improvement was included in the simulation used to determine the Company's proposed fuel and purchased power expense and off-system margin, as sponsored by Mr. Ewen. Therefore, the PV Unit 1 Steam Generators rate base pro forma adjustment reflects the "matching principle," as well as fairness principles, which dictate that the investment required to generate the additional 22 megawatts, which are included in the fuel simulation, should also be included in rate base.

Q. **WHEN WAS THE PV UNIT 1 STEAM GENERATORS REPLACEMENT PROJECT COMPLETED?**

A. The PV Unit 1 Steam Generators replacement project was completed in December 2005, a full year before new rates from this case are likely to be in effect.

Q. **WHAT IS THE BASIS FOR DETERMINING THE PV UNIT 1 STEAM GENERATORS RATE BASE ADJUSTMENT?**

A. The $82,896,000 increase in rate base was calculated using the new Steam

Generators' estimated cost, as of December 31, 2005, when the Steam Generators were placed in service. *See* Attachment LLR-1-4.

Q. PLEASE EXPLAIN THE CORRESPONDING OPERATING INCOME ADJUSTMENT FOR THE PV UNIT 1 STEAM GENERATORS REPLACEMENT PROJECT.

A. Depreciation expense needs to be adjusted to include one full year of depreciation on the new PV Unit 1 Steam Generators and exclude the actual Test Year depreciation expense on the old PV Unit 1 Steam Generators. Because the fuel and purchased power operating income pro forma already reflects the impact of the PV Unit 1 Steam Generators replacement, there are no other test period results affected by this adjustment. This adjustment increases expenses for the Test Year by $2,047,000. *See* Attachment LLR-2-3.

D. BARK BEETLE REMEDIATION

Q. WHY WERE PRO FORMA ADJUSTMENTS FOR BARK BEETLE REMEDIATION NECESSARY?

A. Decision No. 67744 allows for the deferral of bark beetle remediation costs over and above the normal vegetation control expense. This "bucket of costs" can then be deferred, amortized and included in rates. A rate base pro forma is necessary to add the deferred bark beetle remediation costs to rate base. A corresponding operating income pro forma adjustment removes the actual bark beetle remediation costs from the Test Year and includes an annual amortization of the deferred costs.

Q. PLEASE EXPLAIN THE RATE BASE PRO FORMA ADJUSTMENT FOR BARK BEETLE REMEDIATION COSTS.

A. APS began deferring these dollars in 2005 and has estimated a total deferral of distribution-related bark beetle remediation costs of $11,288,000 by January 1, 2007, when rates are expected to be in place to recover these costs. This pro forma adds $6,115,000 to rate base. *See* Attachment LLR-1-5. Mr. Stephen Bishoff discusses bark beetle remediation activities related to these costs in his testimony.

Q. PLEASE EXPLAIN THE CORRESPONDING OPERATING INCOME ADJUSTMENT FOR BARK BEETLE REMEDIATION.

A. As stated above, the Company expects to spend approximately $11,288,000 on distribution-related bark beetle remediation from January 1, 2005, to January 1, 2007, when it is anticipated that rates from this filing will be in place to recover these costs. APS is proposing a three-year amortization of these expenses, which is $3,763,000 in annual amortization expense. The $1,438,000 pro forma adjustment increases Test Year expenses and represents the difference between the proposed $3,763,000 annual amortization and the $2,325,000 actual expense included in the Test Year. *See* Attachment LLR-2-4.

Q. WHAT IS THE ANTICIPATED ONGOING BARK BEETLE REMEDIATION EXPENSE?

A. It is unknown whether the bark beetle remediation efforts will be completed by December 31, 2006, or if the actual costs will exceed the estimated costs as of that date. If the actual amounts exceed the estimated amounts included in this filing, and/or extend beyond 2006, such amounts will be deferred for recovery in a subsequent rate case.

IV. <u>TOTAL RATE BASE ADJUSTMENTS</u>

Q. PLEASE SUMMARIZE THE ADJUSTED TEST YEAR ORIGINAL RATE BASE PROPOSED BY APS.

A. At September 30, 2005, APS is proposing a total Company OCRB adjustment of $71,987,000 to increase the OCRB to $5,327,833,000. The jurisdictional allocation of the OCRB is $4,466,697,000, which is sponsored by Mr. David Rumolo. These adjustments are summarized in SFR Schedule B-2.

V. ADDITIONAL PRO FORMA ADJUSTMENTS TO OPERATING INCOME

A. PWEC UNITS

Q. WHY WERE PRO FORMA ADJUSTMENTS NECESSARY FOR THE PWEC UNITS?

A. The Commission authorized the transfer of the PWEC Units to APS in Decision No. 67744, and the Federal Energy Regulatory Commission ("FERC") approved the transfer on June 15, 2005. The PWEC Units then transferred to APS on July 29, 2005. Because the PWEC Units transferred to APS during the Test Year, the PWEC units are already included in the Test Year rate base; however, an operating income pro forma adjustment is necessary to annualize the PWEC Units operating expenses.

Q. WHAT IS THE OPERATING INCOME PRO FORMA ADJUSTMENT FOR THE PWEC UNITS?

A. The pro forma adjustment to operating income is for $53,644,000, which annualizes the revenue and operating expenses for the PWEC Units. *See* Attachment LLR-2-5.

Q. PLEASE EXPLAIN THE REDUCTION IN THE "OPERATING REVENUE LESS FUEL AND PURCHASE POWER EXPENSES" COMPONENT OF THE OPERATING INCOME PRO FORMA ADJUSTMENT FOR THE PWEC UNITS.

A. As discussed in Mr. Peter Ewen's testimony, the reduction of $1,125,000 is associated with auxiliary power purchased by PWEC from APS that is no longer applicable because the PWEC Units are now owned by APS.

Q. HOW WAS THE ROUTINE OPERATIONS AND MAINTENANCE EXPENSE COMPONENT OF THE OPERATING INCOME PRO FORMA ADJUSTMENT FOR THE PWEC UNITS CALCULATED?

A. Annualized routine operations and maintenance expense of $26,204,000 reflects the actual 2004 expenditures for the PWEC Units, adjusted for the expected increase in average projected operating megawatt hours for 2006 through 2011. The $22,363,000 pro forma adjustment reflects the $26,204,000 annualized operations and maintenance expense reduced by $3,841,000, which represents two months of actual costs in the Test Year.

Q. **IS THERE AN OVERHAUL MAINTENANCE EXPENSE COMPONENT OF THE OPERATING INCOME PRO FORMA ADJUSTMENT FOR THE PWEC UNITS?**

A. Because the PWEC Units have recently been placed in-service, the Company has no historical cost basis for calculating overhaul costs. As discussed in Mr. Ewen's testimony, the normalized overhaul maintenance expense of $10,000,000 was estimated using a projected 12-year average, restated in 2004 dollars. The $9,741,000 pro forma adjustment reflects the $10,000,000 normalized cost reduced by $259,000, which represents two months of actual costs in the Test Year.

Q. **PLEASE EXPLAIN THE ADMINISTRATIVE AND GENERAL ("A&G") EXPENSE COMPONENT OF THE OPERATING INCOME PRO FORMA ADJUSTMENT FOR THE PWEC UNITS.**

A. The operating income pro forma for PWEC A&G expenses represents the portion of 2004 actual A&G expenses charged to the PWEC that will now be charged to APS in compliance with the Company's Affiliate Accounting policies. Thus, the ongoing A&G costs associated with the PWEC Units transferred to APS when the assets transferred. The $20,415,000 pro forma adjustment thus reflects ten months of A&G expense based on historical PWEC actual costs that were not included in the Test Year.

Q. **IS THERE A DEPRECIATION AND AMORTIZATION EXPENSE COMPONENT OF THE OPERATING INCOME PRO FORMA ADJUSTMENT FOR THE PWEC UNITS?**

A. Yes. The annualized depreciation and amortization expense and related pro forma adjustment for the PWEC Units is included in the APS Depreciation and Amortization pro forma, which I discuss later in my testimony. *See* Attachments LLR-2-9 and LLR-2-10.

Q. IS THERE A PROPERTY TAX COMPONENT OF THE OPERATING INCOME PRO FORMA ADJUSTMENT FOR THE PWEC UNITS?

A. Yes, the annualized property tax expense and related pro forma adjustment is included in the APS Property Taxes pro forma, which I discuss later in my testimony. *See* Attachments LLR-2-12 and LLR-2-13.

B. SUNDANCE UNITS

Q. ARE THE SUNDANCE UNITS INCLUDED IN THIS FILING?

A. Yes. In January 2005, the Commission authorized APS to purchase the Sundance Units (Decision No. 67504). They were subsequently acquired on May 13, 2005 for $189,500,000 and are included in the rate base. SFR Schedule C-2 includes a pro forma adjustment to operating income, which is necessary to annualize the Test Year expense.

Q. PLEASE EXPLAIN THE CORRESPONDING OPERATING INCOME PRO FORMA ADJUSTMENT FOR THE SUNDANCE UNITS.

A. As shown in SFR Schedule C-2, the operating income pro forma adjustment of $4,860,000 includes non-fuel operations and maintenance expenses of the Sundance Units. *See* Attachment LLR-2-6.

Q. HOW WAS THE ROUTINE OPERATIONS AND MAINTENANCE ("O&M") COMPONENT OF THE OPERATING INCOME PRO FORMA ADJUSTMENT FOR THE SUNDANCE UNITS DETERMINED?

A. The annualized O&M expense of $6,410,000 includes $3,660,000, which reflects one full year of routine O&M expense and $2,750,000 of overhaul maintenance costs. The routine O&M expense was estimated based on the projected information provided by PP&L Sundance Energy, LLC, as adjusted for the expected level of Company operation, as discussed in Mr. Ewen's testimony. The $4,860,000 pro forma adjustment reflects the difference between the $6,410,000 annualized costs and the Test Year actual costs of $1,550,000, which is about five months of actual costs.

Q. IS THERE A DEPRECIATION AND AMORTIZATION EXPENSE COMPONENT OF THE OPERATING INCOME PRO FORMA ADJUSTMENT FOR THE SUNDANCE UNITS DETERMINED?

A. Yes. The annualized depreciation and amortization expense and related operating income pro forma adjustment are included in the APS Depreciation and Amortization pro forma, which I discuss later in my testimony. *See* Attachments LLR-2- 9 and LLR-2-10.

Q. IS THERE ALSO A PROPERTY TAX COMPONENT OF THE OPERATING INCOME PRO FORMA ADJUSTMENT FOR THE SUNDANCE UNITS?

A. Yes. These amounts are included in the APS Property Taxes pro forma, which I discuss later in my testimony. *See* Attachments LLR-2-12 and LLR-2-13.

Q. DID THE COMPANY DEFER ANY COSTS RELATED TO THE SUNDANCE UNITS AS AUTHORIZED IN DECISION NO. 67504?

A. No. APS did not defer costs under the accounting order authorized in Decision No. 67504. This Decision allowed for the deferral of cost, net of savings, of owning, operating and maintaining the Sundance Units that were not recovered in the unbundled generation rates. The Sundance Units did not meet this threshold, as defined in the Commission's Decision.

C. NUCLEAR PLANT DECOMMISSIONING

Q. PLEASE EXPLAIN THE NUCLEAR DECOMMISSIONING EXPENSE.

A. Like all nuclear power plants, Palo Verde eventually will need to be decommissioned, an expensive and time consuming process. Regulatory agencies throughout the country, including this Commission, have required that the cost of the eventual decommissioning be recovered from utility customers during the operating life of the facility.

Q. WHAT IS MEANT BY A "QUALIFIED" DECOMMISSIONING FUND?

A. A qualified decommissioning fund is a segregated reserve fund dedicated exclusively to the payment of nuclear decommissioning costs and management costs and tax liability of the fund. Beneficial owners of the qualified decommissioning trust are allowed a deduction for cash payments to these funds. There is a preferential tax rate (of 20%) on realized gains associated with the assets held by the qualified decommissioning fund. Currently, the amounts collected from customers that relate to decommissioning of Palo Verde are being deposited into a "qualified" decommissioning fund. The Nuclear Regulatory Commission and most state regulators, including this Commission, prefer the external funding into qualified decommissioning funds for two reasons: (1) the increased security of the funding for its intended purpose; and (2) the income tax benefits afforded qualified decommissioning funds. The latter translates into lower annual decommissioning expense for our customers.

Q. PLEASE EXPLAIN THE NEED FOR A PRO FORMA ADJUSTMENT FOR THE NUCLEAR DECOMMISSIONING EXPENSE.

A. In Decision No. 67744, the Commission approved an annual decommissioning funding amount of $19,211,000, beginning April 1, 2005. *See* Attachment LLR-3.

A pro-forma adjustment of $3,883,000 is required to annualize the qualified funding levels to $19,211,000 as approved in Decision No. 67744. *See* Attachment LLR-2-7. The Company is requesting that the Commission's Decision in this docket specifically provide for approval of the $19,211,000 annual level of decommissioning funding. Attachment LLR-3 should be attached to any Commission Decision accepting these amounts.

D. FOUR CORNERS COAL RECLAMATION

Q. WHAT IS COAL RECLAMATION?

A. Coal reclamation is the process of returning the site of a coal mine to its original state. Coal reclamation is regulated by the Office of Surface Mining ("OSM"), an agency within the U.S. Department of Interior. The OSM has established standards and procedures for approving permits and inspecting active coal mining and reclamation operations. OSM requires the mine be brought back to its "Approximate Original Contour" ("AOC").

Q. WHY DOES APS HAVE TO PAY FOR COAL RECLAMATION?

A. APS is under contract with BHP Billiton until June 30, 2016, to receive coal for the Four Corners Power Plant. Pursuant to this contract, APS must pay for its share of final reclamation costs as a component of the price of coal.

Q. WHY IS THERE A NEED FOR A COAL RECLAMATION PRO FORMA ADJUSTMENT?

A. The estimate for final reclamation costs is generally revised every five years. The total costs are based on a study performed by Marston as of September 2004. The study reflects an onsite visit to the mine and a review of the AOC. The estimate is developed in two parts: ongoing reclamation while the mine is in operation and final reclamation at the end of the life cycle of the mining pit. The Company has reduced the 2004 Marston study overhead costs to be more consistent with the OSM guidelines regarding overhead costs related to reclamation activities and has added royalties and revenue taxes to the study costs. A pro forma adjustment of $1,305,000 is included in SFR Schedule C-2 to reflect the annual expense based upon the 2004 Marston study. *See* Attachment LLR-2-8.

Q. HAS THE COMMISSION PREVIOUSLY AUTHORIZED THE INCLUSION OF COAL RECLAMATION COSTS IN REGULATED RATES?

A. Yes, in Decision No. 59601, the Commission approved the recovery of previously deferred coal reclamation costs. The Company is requesting a similar recovery in this case for the increase in coal reclamation cost estimates.

Q. WHY IS COAL RECLAMATION EXCLUDED FROM THE FUEL AND PURCHASE POWER PRO FORMA?

A. Coal reclamation is excluded from the Fuel and Purchase Power pro forma in order to exclude those costs that are not related to the current fuel burn from the Power Supply Adjustor calculation.

E. DEPRECIATION AND AMORTIZATION

Q. WHAT ADJUSTMENTS HAS THE COMPANY MADE TO DEPRECIATION AND AMORTIZATION EXPENSE?

A. Consistent with Decision No. 67744, as of April 1, 2005, APS implemented the depreciation rates ordered by the Commission. For this filing, Dr. Ronald White performed depreciation studies as of December 31, 2004, which included the APS assets and the PWEC Units. Dr. White's technical update of the depreciation rates that were authorized in Decision No. 67744 generally reflects the passage of time from December 31, 2002 through December 31, 2004. Please refer to Dr. White's testimony for further discussion of this point.

Based upon results of the technical update to the depreciation study, depreciation and amortization expense increases from $321,526,000 in the Test Year to $344,581,000. This pro forma adjustment increases annual expense by $23,055,000. *See* Attachments LLR-2-9 and LLR-2-10.

Q. WERE THE PWEC UNITS INCLUDED IN THE DEPRECIATION STUDIES PREPARED BY DR. WHITE?

A. Yes. The annualized depreciation expense was calculated based on the original cost of the PWEC Units at September 30, 2005, as reduced by the regulatory disallowance recorded under GAAP, and extended plant lives that were required by Decision No. 67744.

Q. WERE THE SUNDANCE UNITS INCLUDED IN THE DEPRECIATION STUDIES PREPARED BY DR. WHITE?

A. No. Since the Sundance Units were acquired after December 31, 2004 (the date of Dr. White's studies), these units were not included in the APS study. This annualized depreciation expense is based on the annual depreciation rates authorized in Decision No. 67744 for Saguaro Unit 3 combustion turbine generators, which are the APS units most nearly similar to the Sundance Units.

Q. DO THE DEPRECIATION RATES PROVIDE FOR A NET SALVAGE ALLOWANCE?

A. Yes. Consistent with the Commission's rules and depreciation rates approved in Decision No. 67744, APS provides for a net salvage allowance in the depreciation rates. As such, the Statement of Financial Accounting Standards 143: Asset Retirement Obligations has not been implemented for ratemaking purposes, which was also provided for in Decision No. 67744.

Q. PLEASE EXPLAIN THE OPERATING REVENUE INCLUDED ON THE DEPRECIATION AND AMORTIZATION PRO FORMA.

A. The depreciation study prepared by Dr. White does not include an allocation for Company depreciation to APS Energy Services ("Energy Services") or to Pinnacle West Capital Corporation ("PWCC") Marketing and Trading ("PWCC M&T"), which is in accordance with the Commission's Code of Conduct and the Company's Affiliate Accounting policies. Therefore, the pro forma includes an operating revenue adjustment of $480,000, which reflects the amounts received from other affiliates for their allocation of shared services depreciation expense. *See* Attachment LLR-2-9.

Q. PLEASE EXPLAIN THE AMORTIZATION OF GAIN INCLUDED ON THE DEPRECIATION AND AMORTIZATION PRO FORMA.

A. The $77,000 shown on Attachment LLR-2-9 is the operating income pro forma adjustment necessary to annualize the $155,000 gain amortization, which represents the annual amortization expense of the total $775,000 gain associated with the previously authorized sale of the Glen Canyon 230 kV line to PacifiCorp, pursuant to Decision No. 64306. A five year amortization of the gain is consistent with the treatment of this item in the Company's last rate case.

Q. IS THE COMPANY PROPOSING ANY CHANGES TO ITS EXISTING AMORTIZATION RATES?

A. No, APS is not requesting any change to the amortization rates authorized in Decision No. 67744. These rates are set out on Attachment LLR-2-11.

Q. IS THE COMPANY PROPOSING ANY NEW AMORTIZATION RATES?

A. Yes, the Company is requesting approval for two new rates to provide for the amortization of leased vehicles that are purchased by the Company at the end of the lease term. The Company is requesting a 50% amortization rate for vehicles with a

Gross Vehicle Weight ("GVW") under 26,000 pounds, and a 20% amortization rate for vehicles with a GVW greater than 26,000 pounds. The rates reflect what we believe will be the estimated lives for such vehicles. *See* Attachment LLR-2-11.

F. PROPERTY TAXES

Q. HAS APS PROPOSED AN ADJUSTMENT TO THE TEST YEAR AD VALOREM (PROPERTY) TAXES?

A. Yes, the pro forma adjustment is an increase in operating expense of $16,867,000. This adjustment includes amounts to annualize the PWEC Units property taxes, one full year of property taxes for the Sundance Units, estimated taxes for the full Maricopa Community College Bond, and an automatic 2007 increase in property taxes that will result when the PWEC Units have passed the "phase-in" period provided by A.R.S. § 42-14156, after which, the units will have to apply the Arizona Department of Revenue's ("ADOR") scheduled depreciated value in the same manner as all of APS' existing generation units. *See* Attachments LLR-2-12 and LLR-2-13.

Q. HOW WERE PROPERTY TAXES CALCULATED?

A. The property taxes reflect actual plant values received from the ADOR as of December 31, 2004. The 2005 tax year APS composite tax rate, which includes the PWEC Units, was calculated based on tax rates provided by the County Treasurer in each of the counties where APS has property. In addition to the APS composite tax rate, the actual 2005 tax rate for the Sundance Units was used. Finally, this pro forma adjustment takes into account the reduction in assessment ratio provided by House Bill 2779, which was passed during the 2005 legislative session.

G. PAYROLL

Q. DID APS ANNUALIZE TEST YEAR PAYROLL?

A. Yes. Attachment LLR-2-14 shows an increase to Test Year expenses of $9,239,000. This pro forma adjustment annualizes the Test Year payroll, benefits, and payroll tax expense to December 2005 employee levels, and includes December 2005 wage levels for performance review employees, April 2006 wage levels for union employees and no cash incentives for officers. This methodology for performance review employees and union employees is consistent with payroll annualization adjustments authorized by the Commission in prior APS cases. Officer salaries are included at 2004 levels. The net effect of these adjustments is an increase to Test Year operating expenses as a result of higher costs associated with a rising average salary and increased employee levels.

Q. DOES THIS TOTAL PAYROLL ADJUSTMENT ONLY AFFECT O&M?

A. Yes, this adjustment excludes those costs that are capitalized. This O&M adjustment was estimated by calculating the percentage of APS O&M payroll to total payroll during the Test Year. The resulting O&M payroll and payroll taxes were allocated to fuel, operations (excluding fuel), and maintenance based on the Test Year payroll amounts booked to each of these activities.

H. UNDERFUNDED PENSION LIABILITY

Q. PLEASE EXPLAIN THE PRO FORMA ADJUSTMENT FOR ACCELERATED RECOVERY OF THE UNDERFUNDED PENSION LIABILITY.

A. This adjustment is intended to accelerate the recovery of our underfunded pension liability over a five-year period beginning in 2007. This would be accomplished by increasing pension expense and establishing a regulatory liability. Amounts collected under this adjustment would be contributed to the pension plan. Since the recovery is accelerated, the Company is proposing a ten year amortization of this regulatory liability, beginning in 2012. This would have the impact of reducing future pension expense during the amortization period.

Q. HOW WAS THE PRO FORMA ADJUSTMENT FOR ACCELERATED RECOVERY OF THE UNDERFUNDED PENSION LIABILITY DETERMINED?

A. PWCC sponsors a pension plan for all its employees, including employees of APS. As of December 31, 2004, the date of the most recent actuarial study, the projected benefit obligation ("PBO") of the pension plan was approximately $1,371 million. The fair value of the plan's assets was approximately $982 million. The difference of approximately $389 million represents the underfunded position of the pension plan. APS' share of the plan represents approximately 92% or approximately $358 million (Pinnacle West and the other subsidiaries make up the other 8%). At December 31, 2004, the portion attributable to APS ratepayers represents approximately 61% or $218 million of the underfunded pension liability. The remaining 39% relates to APS employees that support jointly owned facilities. Because we are proposing accelerated recovery over five years, the annual increase to pension expense proposed in this adjustment is approximately $44 million. *See* Attachment LLR-2-15. Again, since this is an accelerated recovery, we propose amortizing the regulatory liability and reducing pension expense over 10 years (beginning in 2012) in the amount of approximately $22 million.

I. ADVERTISING

Q. WHAT IS THE PURPOSE OF THE ADVERTISING PRO FORMA?

A. This pro forma adjustment reduces Test Year expenditures by $6,140,000 for all those advertising expenses that are related to branding or promotion. This approach is consistent with Staff's recommendation in the Company's prior rate case. *See*

Attachment LLR-2-16.

J. MISCELLANEOUS ADJUSTMENTS

Q. PLEASE EXPLAIN THE MISCELLANEOUS ADJUSTMENTS.

A. This pro forma adjustment eliminates non-recurring or out of period expenses or credits from the Test Year. The net increase to operating expense for these adjustments is $ 3,876,000. Individually, they are as follows:

Financial Data Warehouse Costs	$ (892,000)
Four Corners Severance Reserve True-Up	$ 1,748,000
FERC Audit Reserve	$ 2,000,000
APS Corporate Offices Rent Expense	$ 3,237,000
Bill Estimation Refund	$(2,217,000)

See Attachment LLR-2-17.

Q. PLEASE EXPLAIN THE MISCELLANEOUS PRO FORMA ADJUSTMENTS.

A. **Financial Data Warehouse:** APS terminated this project because it was determined it would not meet the Company's business needs. The adjustment removes the write-off of the prior year costs.

Four Corners Severance Reserve True-Up: A prior period reserve, which was associated with Four Corners' participant disputes, was settled in 2004.

FERC Audit Reserve: This adjustment eliminates an audit reserve reversal for a transmission audit issue that was successfully resolved without a finding against the Company.

APS Corporate Offices Rent Expense: This adjustment reflects the portion of the CHQ Rent true-up for calendar year 2004 that is outside the Test Year period.

Bill Estimation Refund: Adjustment to reverse the revenue impact of the Bill Estimation accrual, pursuant to Decision No. 68112.

VI. ALLOWANCE FOR WORKING CAPITAL

Q. WHAT IS THE ALLOWANCE FOR WORKING CAPITAL SHOWN ON SFR SCHEDULE B-1?

A. The allowance for working capital shown on SFR Schedule B-l is $168,146,000. *See* Attachment LLR-4.

Q. PLEASE EXPLAIN SFR SCHEDULE B-5.

A. This SFR Schedule outlines the allowance for working capital to be included in the Company's rate base. Working capital represents the amount of cash, materials and supplies, fuel inventories, and prepayments needed to meet current expenses and contingencies that might ordinarily develop. Working capital is an investment just like other capital requirements, such as power plants and transmission and distribution infrastructure; thus it is part of APS' rate base. I am testifying to all of the data in SFR Schedule B-5, with the exception of the Working Capital calculation (line 1 of page 1), which Mr. Fred Balluff will address. My testimony presents the calculation of the allowance for working capital, which includes a cash working capital component determined using the lead/lag study methodology required by Decision No. 55931.

Q. WHAT IS THE ALLOWANCE FOR WORKING CAPITAL?

A. Based on APS Test Year balances, the calculation of a reasonable allowance for working capital results in an addition to rate base of $168,146,000. This includes $191,768,000 of materials, supplies and fuel inventories, and $5,517,000 of prepaid amounts. This amount is reduced by the net cash working capital of $29,139,000 that is provided by operations.

Q. HOW WAS THE CASH WORKING CAPITAL CALCULATED?

A. The net cash working capital is calculated by performing a "lead/lag" study. See Mr. Balluff's testimony for further discussion of this study and its results. The lead lag study days, which were calculated from the study of the calendar year 2004, were applied to the Test Year income statement.

VII. REPRODUCTION COST NEW STUDY

Q. WHAT IS MEANT BY THE TERMS "RCN" AND "RCND" AS USED IN YOUR TESTIMONY?

A. A.A.C. R14-2-103(A) (3) (n) defines "Reconstructed Cost New Less Depreciation" or "RCND" as:

> An amount consisting of the depreciated reconstruction cost new of property (exclusive of contributions and/or advances in aid of construction) at the end of the test year, used and useful, plus a proper allowance for working capital and including all applicable pro forma adjustments. Contributions and advances in aid of construction, if recorded in the accounts of the public service corporation, shall be increased to a reconstruction new basis.

Thus, Reproduction Cost New ("RCN") refers to the estimated costs that would be incurred if the utility properties of APS that were devoted to public service as of September 30, 2005 were to be reproduced or reconstructed as new properties using current cost levels. RCND is a net amount that results after deducting accumulated depreciation and amortization (both of which are also restated in current dollars) from the RCN amount.

Q. WHAT IS SHOWN ON SFR SCHEDULE B-4?

A. SFR Schedule B-4 presents the RCN and RCND amounts of APS' utility properties. These amounts were determined using an RCN Study performed by the Company. *See* Attachment LLR-5-2.

Q. WOULD YOU BRIEFLY DESCRIBE THE PROCEDURES YOU FOLLOWED IN CONDUCTING THE RCN STUDY?

A. Consistent with A.A.C. R14-2-103, the RCN study that supports SFR Schedule B-4 was conducted by taking depreciable plant at original cost by FERC account,[1] by vintage year, and adding back Contributions in Aid of Construction ("CIAC") at original cost. Electric and gas utilities are required by the Uniform System of Accounts to subtract CIAC from original cost plant-in-service, rather than record it as a separate liability account, as is done by water and sewer utilities. This amount was multiplied by the Handy-Whitman Index factor, based on vintage year, to arrive at RCN before CIAC adjustment. CIAC was also multiplied by the appropriate Handy-Whitman Index. The adjusted CIAC (which is a negative number) was added to the RCN determined before the CIAC adjustment, to arrive at the final RCN number shown in column (a) of SFR Schedule B-4.

Q. WOULD YOU EXPLAIN IN MORE DETAIL THE CONSIDERATION THAT YOU GAVE TO CIAC IN DETERMINING RCN?

A. Yes. CIAC is generally cash paid to APS by third parties for construction of facilities that will be owned by APS. Sometimes, it may also include property donated to the Company to provide service. Line extensions are the most common source of CIAC. As with original cost plant, CIAC is indexed using the Handy-

[1] The Commission has adopted the FERC Uniform System of Accounts ("USOA") in A.A.C. R14-2-212(G).

Whitman Index, as required by A.A.C R14-2-103, to arrive at RCN. A summary of CIAC is provided in column (b) of Attachment LLR-5-1.

Q. WHAT IS THE HANDY-WHITMAN INDEX?

A. The Handy-Whitman Index is recognized by the utility industry as an equivalent to a Consumers Price Index for electric utility property. It compares the current cost of constructing electric utility property with past construction costs, and presents the comparison in the form of a cost index. For example, assume that transmission towers and fixtures were purchased by APS in 1985 at an original cost of $400,000. To determine RCN, the original cost would be multiplied by the appropriate Handy-Whitman index factor for towers and fixtures. In this case, the index factor is determined by dividing the current year index of 388 for 2004 by the vintage year index of 245 for 1985, or 388/245, which equals 1.58. The index factor of 1.58 multiplied by the original cost of $400,000 equals the current reproduction cost or RCN of $632,000.

Q. WERE ALL ASSETS INDEXED AS YOU JUST DESCRIBED?

A. No, land and land rights, intangibles, capitalized leases, and leasehold improvements are included in RCN at their original cost levels only, consistent with previous treatment of these assets by the Commission.

Q. PLEASE DEFINE INTANGIBLES AND DESCRIBE THE AMOUNT OF INTANGIBLES THAT ARE INCLUDED IN RCN AS SHOWN ON SFR SCHEDULE B-4?

A. Intangibles are assets that provide future economic benefit but have no physical substance. Examples include patents and computer software. APS' intangible plant is included in column (a), line 4 of SFR Schedule B-4 at its original cost of $285,337,000 on September 30, 2005.

Q. BASED ON YOUR STUDY, WHAT IS THE RCN OF APS' UTILITY PROPERTY DEVOTED TO SERVICE TO THE PUBLIC AS OF THE END OF THE TEST YEAR?

A. Total RCN for APS' utility property is $17,767,330,000 including the $285,337,000 of intangible plant discussed above. This total amount is shown in column (c) of Attachment LLR-5-1, and in column (a) of SFR Schedule B-4.

Q. WOULD YOU EXPLAIN HOW RCND WAS CALCULATED AS SHOWN ON SFR SCHEDULE B-4?

A. Yes. RCN by FERC account (or Plant account) number is shown in column (a) of SFR Schedule B-4. To arrive at RCND, RCN is multiplied by a "condition percent," also known as a net book value percent, which is shown in column (b). RCND is shown in column (c). The condition percent used to convert RCN to RCND is calculated by first taking the original cost less accumulated depreciation (in other words, the net book value) for all depreciable plant by FERC account. This is divided by the original cost for each FERC account to arrive at condition percent. Thus, the condition percent is the percentage that results when one compares original cost less accumulated depreciation and the original cost of plant in service.

For example, using the same hypothetical that I used earlier, assume again that transmission towers and fixtures have an original cost of $400,000, and assume accumulated depreciation of $250,000. The original cost less accumulated depreciation would be $150,000, which is $400,000 minus $250,000. Also, assume the towers and fixtures were purchased in 1985 and have a RCN value of $632,000. Using these assumptions, the condition percent is calculated by dividing original cost less accumulated depreciation by original cost, or $150,000/$400,000, resulting in 37.5%. Multiplying RCN by the condition percent yields RCND. In this hypothetical, $632,000 x 37.5% = $237,000.

Q. WOULD YOU PLEASE EXPLAIN SFR SCHEDULE B-4A?

A. SFR Schedule B-4A shows the computation of adjusted jurisdictional RCND rate base as of September 30, 2005. Column (a) presents data for Total RCND rate base. Mr. Rumolo has provided the jurisdictional allocations of the Electric RCND rate base between "ACC" and "Other," which is presented in columns (b) and (c) respectively.

Q. HOW DID YOU ARRIVE AT THE AMOUNTS SHOWN ON LINES 9 THROUGH 23 OF SFR SCHEDULE B-4A?

A. The amounts shown on lines 9 through 23 of SFR Schedule B-4A for other rate base elements were obtained from SFR Schedule B-1, column (a), which is sponsored by Mr. Froggatt. As in past presentations and consistent with past Commission practice, the RCND of these rate base elements are stated at their original cost levels.

Q. WOULD YOU PLEASE EXPLAIN LINES 25 AND 26 OF SFR SCHEDULE B-4A?

A. The amounts shown on line 25 represent the RCND rate base on September 30, 2005. However, the end of test year data needs to be adjusted to more closely reflect the value of certain items of property when the proposed rates become effective. Therefore, it was necessary to reflect the pro forma rate base adjustments in the RCND rate base. The RCND amounts of the pro forma adjustments are shown in detail on SFR Schedule B-3; the total is shown on line 26 of SFR Schedule B-4A.

Q. WHAT IS THE TOTAL ADJUSTED RCND RATE BASE?

A. The total Company RCND rate base, as adjusted, is approximately $9.2 billion. This is shown in SFR Schedule B-4A, column (a), line 28.

Q. PLEASE EXPLAIN HOW YOU COMPUTED COLUMNS (B) THROUGH (E) ON SFR SCHEDULE B-4A TO REFLECT THE JURISDICTIONAL ALLOCATION?

A. The jurisdictional allocation of the RCND rate base elements between state retail service (the Commission) and other jurisdictions (primarily FERC) was made by applying the original cost jurisdiction relationships derived from SFR Schedule G-7, which is sponsored by Mr. Rumolo. The relationships of the allocations shown on line 2, excluding the Southern California Edison ("SCE") 500 kV columns, were used to allocate between jurisdictions on line 8. Total RCN excludes the SCE 500 kV amounts. The data shown in column (d) for the SCE 500 kV line represents known or directly computed information. The jurisdictional allocations of lines 9 through 23, because they are stated at original cost, were obtained directly from SFR Schedule G-7.

Q. WOULD YOU PLEASE SUMMARIZE THE JURISDICTIONAL ALLOCATION OF THE RCND RATE BASE AS OF DECEMBER 31, 2004 AFTER MAKING THE PRO FORMA ADJUSTMENTS?

A. The total Commission-jurisdictional RCND rate base after adjustments is approximately $7.8 billion (SFR Schedule B-4A, column (b), line 28). After pro forma adjustments, the Total All Other RCND rate base is approximately $1.4 billion (SFR Schedule B-4A, column (c)). The sum of columns (b) and (c) equals the Total RCND rate base shown in column (a).

VIII. DETAIL OF UTILITY PLANT

Q. PLEASE DISCUSS SFR SCHEDULE E-5.

A. SFR Schedule E-5 is the detailed statement of utility plant that makes up the Company's rate base, broken down by account number under the Uniform System of Accounts. The first page of SFR Schedule E-5 is a summary, which includes balances for gross plant in service, accumulated depreciation, nuclear fuel, work in progress, and plant held for future use. The remainder of the schedule presents supporting detail by account.

IX. CONSTRUCTION REQUIREMENTS

Q. PLEASE DISCUSS SFR SCHEDULE F-3.

A. SFR Schedule F-3 shows the projected annual construction requirements, by property classification, for 1 to 3 years subsequent to the Test Year. I am sponsoring the actual Test Year information; Mr. Brandt is sponsoring the rest of the information on SFR Schedule F-3.

X. COMMISSION ACTION REQUESTED

Q. PLEASE SUMMARIZE THE SPECIFIC COMMISSION ACTION THAT THE COMPANY IS REQUESTING REGARDING THE DECOMMISSIONING AND SPENT FUEL STORAGE EXPENSES DISCUSSED IN YOUR TESTIMONY.

A. The Company is requesting that the Commission's Decision in this docket specifically provide for approval of the annual level of decommissioning funding and Spent Fuel Storage costs, as set forth on Attachment LLR-3, as well as the amortization of the Spent Fuel Cost regulatory asset included in Attachment LLR-2-2. Attachment LLR-3 should be attached to any Commission Decision accepting these amounts.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Appendix A
Statement of Qualifications
Laura L. Rockenberger

Laura L. Rockenberger is the Manager of Operations Accounting in the Shared Services Finance organization for Arizona Public Service Company ("APS"). In this position, Ms. Rockenberger has responsibility for Generation and Energy Delivery Operations & Maintenance and Fuel accounting; Asset Accounting; Accounting Services Administration, including payroll and accounts payable; and Accounting Systems. These accounting services are provided as needed to support the Pinnacle West Capital Corporation entities.

Ms. Rockenberger graduated cum laude from Miami University in 1982 with a Bachelor of Science Degree in Business with an emphasis in Accounting and is a member of Beta Gamma Sigma. Ms. Rockenberger also has a Bachelor of Arts with an emphasis in Music, graduating cum laude from the University of South Carolina, and is a member of Phi Beta Kappa. Ms. Rockenberger has been a Certified Public Accountant in Arizona since 1985 and is a member of the Arizona Society of Certified Public Accountants and the American Institute of Certified Public Accountants. Ms. Rockenberger has been elected to the Board of Directors for the Society of Depreciation Professionals effective January 1, 2006.

Ms. Rockenberger was employed in public accounting by Price Waterhouse from 1982 to 1984. She joined APS in 1985 as an Internal Auditor and held positions at the Palo Verde Nuclear Generating Station and Pinnacle West Capital Corporation. In 1987 Ms. Rockenberger joined SunCor Development Company ("SunCor"), a real estate subsidiary of Pinnacle West Capital Corporation. At SunCor, she held positions as the Director of Finance and Controller. In 1998 she joined APS as the Manager of Operations Accounting, her current position.

Attachment LLR-1-1

PWEC UNITS
REGULATORY AND GAAP DISALLOWANCE CALCULATION AT JULY 31, 2005
(000's)

	Rate Base Calculation	Total Company 12/31/2004	Total Company 7/31/2005	FERC Jurisdictional 7/31/2005	ACC Jurisdictional 7/31/2005	Regulatory Disallowance as a % of Plant	ACC Jurisdictional Regulatory Disallowance	ACC Jurisdictional 7/31/2005 after Regulatory Disallowance	GAAP 7/31/2005 Disallowance
	Redhawk 1	273,238	273,238	474	272,764	17.3426%	(47,304)	225,460	(47,304)
	Redhawk 2	273,123	273,123	474	272,649	17.3426%	(47,284)	225,365	(47,284)
	Redhawk Trans	49,000	49,000	22,883	26,117	17.3426%	(4,529)	21,588	(4,529)
	WP 4	**79,760**	**79,760**	**138**	**79,622**	**17.3426%**	**(13,809)**	**65,813**	-
	WP 5	309,464	309,464	537	308,927	17.3426%	(53,576)	255,351	(53,576)
	Saguaro	36,645	36,645	64	36,581	17.3426%	(6,344)	30,237	(6,344)
	Gross Plant	1,021,230	1,021,230	24,570	996,660		(172,846)	823,814	(159,037)
	Redhawk 1	26,508	31,066	54	31,012	17.3426%	(5,378)	25,634	(5,378)
	Redhawk 2	26,503	31,056	54	31,002	17.3426%	(5,377)	25,625	(5,377)
	Redhawk Trans	3,915	4,416	2,062	2,354	17.3426%	(408)	1,946	(408)
	WP 4	**10,462**	**11,493**	**20**	**11,473**	**17.3426%**	**(1,990)**	**9,483**	-
	WP 5	17,795	23,063	40	23,023	17.3426%	(3,993)	19,030	(3,993)
	Saguaro	3,236	3,837	7	3,830	17.3426%	(664)	3,166	(664)
Less	**Accum Depr**	88,419	104,931	2,237	102,694		(17,810)	84,884	(15,820)
	Redhawk 1	246,730	242,172	420	241,752	17.3426%	(41,926)	199,826	(41,926)
	Redhawk 2	246,620	242,067	420	241,647	17.3426%	(41,907)	199,740	(41,907)
	Redhawk Trans	*45,085*	*44,584*	*20,821*	*23,763*	*17.3426%*	*(4,121)*	19,642	(4,121)
	WP 4	**69,298**	**68,267**	**118**	**68,149**	**17.3426%**	**(11,819)**	**56,330**	-
	WP 5	291,669	286,401	497	285,904	17.3426%	(49,583)	236,321	(49,583)
	Saguaro	33,409	32,808	57	32,751	17.3426%	(5,680)	27,071	(5,680)
	Net Plant	932,811	916,299	22,333	893,966		(155,036)	738,930	(143,217)
	Redhawk 1	8,775	9,702	17	9,685	17.3426%	(1,680)	8,005	
	Redhawk 2	8,780	9,707	17	9,690	17.3426%	(1,680)	8,010	
	Redhawk Trans	2,560	2,831	1,322	1,509	17.3426%	(262)	1,247	
	WP 4	3,380	3,737	7	3,730	17.3426%	(647)	3,083	
	WP 5	35,809	39,592	68	39,524	17.3426%	(6,854)	32,670	
	Saguaro	5,347	5,912	10	5,902	17.3426%	(1,024)	4,878	
Less	**Accum Def Inc Taxes**	64,651	71,482	1,442	70,040		(12,147)	57,893	-
	Redhawk 1	237,955	232,470	403	232,067		(40,246)	191,821	
	Redhawk 2	237,840	232,360	403	231,957		(40,227)	191,730	
	Redhawk Trans	42,525	41,753	19,499	22,254		(3,859)	18,395	
	WP 4	65,918	64,530	112	64,418		(11,172)	53,246	
	WP 5	255,860	246,809	428	246,381		(42,729)	203,652	
	Saguaro	28,062	26,896	47	26,849		(4,656)	22,193	
	Rate Base	868,160	844,817	20,891	823,926		(142,889)	**681,037**	-

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Original Cost Rate Base as Shown on Schedule B-2
Total Company
(Thousands of Dollars)

PRO FORMA ADJUSTMENT: PWEC UNITS

Adjustment to reduce Test Year rate base for the regulatory disallowance for West Phoenix Unit 4 as required in Decision No. 67744.

Line No.	Description	Total Company Amount
1.	Gross Utility Plant in Service	$ (13,833)
2.	Less: Accumulated Depreciation and Amortization	$ (2,032)
3.	Net Utility Plant in Service	$ (11,801)
4.	Less: Total Deductions	$ (646)
5.	Total Additions	$ -
6.	Total Rate Base	$ (11,155)

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Original Cost Rate Base as Shown on Schedule B-2
Total Company
(Thousands of Dollars)

PRO FORMA ADJUSTMENT: SPENT FUEL STORAGE

Adjustment to Test Year rate base to include System Benefit related Spent Fuel Storage costs consistent with Decision No. 67744.

Line No.	Description		Amount
1.	Gross Utility Plant in Service	$	-
2.	Less: Accumulated Depreciation and Amortization	$	-
3.	Net Utility Plant in Service	$	-
4.	Less: Total Deductions	$	(3,761)
5.	Total Additions	$	(9,630)
6.	Total Rate Base	$	(5,869)

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Original Cost Rate Base as Shown on Schedule B-2
Total Company
(Thousands of Dollars)

PRO FORMA ADJUSTMENT: PALO VERDE UNIT 1 STEAM GENERATORS

Adjustment to Test Year rate base to include the replacement of the Palo Verde Unit 1 Steam Generators in 2005.

Line No.	Description		Amount
1.	Gross Utility Plant in Service	$	88,813
2.	Less: Accumulated Depreciation and Amortization	$	47
3.	Net Utility Plant in Service	$	88,766
4.	Less: Total Deductions	$	5,870
5.	Total Additions	$	-
6.	Total Rate Base	$	82,896

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Original Cost Rate Base as Shown on Schedule B-2
Total Company
(Thousands of Dollars)

PRO FORMA ADJUSTMENT: BARK BEETLE REGULATORY ASSET

Adjustment to Test Year rate base to include the bark beetle remediation regulatory asset.

Line No.	Description	Amount
1.	Gross Utility Plant in Service	$ -
2.	Less: Accumulated Depreciation and Amortization	$ -
3.	Net Utility Plant in Service	$ -
4.	Less: Total Deductions	$ -
5.	Total Additions	$ 6,115
6.	Total Rate Base	$ 6,115

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

PRO FORMA ADJUSTMENT: **West Phoenix 4 Regulatory Disallowance**

Adjustment to Test Year operations to reflect depreciation of the regulatory disallowance of West Phoenix Unit 4 over the remaining life of the plant.

Line No.	Description	Amount
1.	***REVENUES:***	
2.	Operating Revenue	$ -
3.	Fuel and Purchased Power Expense	-
4.	Operating Revenues less Fuel and Purchased Power Expenses	$ -
5.	**EXPENSES:**	
6.	Other Operating Expense	
7.	Operations Excluding Fuel Expense	-
8.	Maintenance	-
9.	Subtotal	-
10.	Depreciation and Amortization	(230)
11.	Amortization of Gain	-
12.	Administrative and General	-
13.	*Other Taxes*	-
14.	Total	(230)
15.	**OPERATING INCOME (before income tax)**	**$ 230**
16.	*Interest Expense*	(275)
17.	**Taxable Income**	**$ 505**
18.	Income Tax at 39.05%	197
19.	**OPERATING INCOME AFTER TAX**	**$ 33**

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

PRO FORMA ADJUSTMENT: ***SPENT FUEL STORAGE***

Adjustment to Test Year operations to amortize deferred Spent Fuel Storage expenses consistent with Decision No. 67744.

Line No.	Description		Amount
1.	**EXPENSES:**		
2.	Fuel Expenses	$	11,092
3.	Other Operating Expenses		
4.	Operations Excluding Fuel Expenses		
5.	Maintenance		
6.	Total Pro Forma Adjustment to Expenses	$	11,092
7.	**OPERATING INCOME (before income tax)**	**$**	**(11,092)**
8.	Interest Expense		(144)
9.	**Taxable Income**	**$**	**(10,948)**
10.	Income Tax at 39.05%		(4,275)
11.	**OPERATING INCOME AFTER TAX**	**$**	**(6,817)**

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

PRO FORMA ADJUSTMENT: PALO VERDE UNIT 1 STEAM GENERATORS REPLACEMENT DEPRECIATION

Adjustment to Test Year depreciation related to the replacement of the Palo Verde Unit 1 steam generators.

Line No.	Description		Amount
1.	**EXPENSES:**		
2.	Other Operating Expenses		
3.	Depreciation and Amortization	$	2,047
4.	Total Pro Forma Adjustment to Expenses	$	2,047
5.	**OPERATING INCOME (before income tax)**	**$**	**(2,047)**
6.	Interest Expense		2,041
7.	**Taxable Income**	**$**	**(4,088)**
8.	Income Tax at 39.05%		(1,596)
9.	**OPERATING INCOME AFTER TAX**	**$**	**(451)**

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

PRO FORMA ADJUSTMENT: Bark Beetle

Adjustment to Test Year operations to exclude expenses related to bark beetle remediation over and above normal 2002 operational expense as required by Decision No. 67744 and to amortize 2005 - 2006 estimated costs over a three year period.

Line No.	Description	Amount
1.	**EXPENSES:**	
2.	Other Operating Expenses	
3.	Operations Excluding Fuel Expenses	$ 1,438
4.	Total Pro Forma Adjustment to Expenses	$ 1,438
5.	**OPERATING INCOME (before income tax)**	**$ (1,438)**
6.	Interest Expense	151
7.	**Taxable Income**	**$ (1,589)**
8.	Income Tax at 39.05%	(621)
9.	**OPERATING INCOME AFTER TAX**	**$ (817)**

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

PRO FORMA ADJUSTMENT: **PWEC Units**

Adjustment to Test Year operations to annualize operating costs for the PWEC Units, which transferred to APS at 7/29/05, as authorized by Decision No. 67744. The PWEC Units include West Phoenix Combined Cycles No. 4 and No. 5, Redhawk Combined Cycles No.1 and No. 2, and Saguaro Combustion Turbine No. 3. Includes revenue adjustment related to plant auxiliary power.

Line No.	Description		Amount
1.	**REVENUES:**		
2.	Operating Revenue	$	(1,791)
3.	Fuel and Purchased Power Expense		(666)
4.	Operating Revenues less Fuel and Purchased Power Expenses	$	(1,125)
5.	**EXPENSES:**		
6.	Other Operating Expense		
7.	Operations Excluding Fuel Expense		22,363
8.	Maintenance		9,741
9.	Subtotal		32,104
10.	Depreciation and Amortization		-
11.	Amortization of Gain		-
12.	Administrative and General		20,415
13.	Other Taxes		-
14.	Total		52,519
15.	**OPERATING INCOME (before income tax)**	**$**	**(53,644)**
16.	Interest Expense		-
17.	**Taxable Income**	**$**	**(53,644)**
18..	Income Tax at 39.05%		(20,948)
19.	**OPERATING INCOME AFTER TAX**	**$**	**(32,696)**

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

PRO FORMA ADJUSTMENT: SUNDANCE UNITS

Adjustment to Test Year operations to include a projected year of O&M for the Sundance Units as authorized by Decision No. 67504.

Line No.	Description	Amount
1.	**REVENUES:**	
2.	Operating Revenue	$ -
3.	Fuel and Purchased Power Expense	-
4.	Operating Revenues less Fuel and Purchased Power Expenses	$ -
5.	**EXPENSES:**	
6.	Other Operating Expense	
7.	Operations Excluding Fuel Expense	2,110
8.	Maintenance	2,750
9.	Subtotal	4,860
10.	Depreciation and Amortization	-
11.	Amortization of Gain	-
12.	Administrative and General	-
13.	Other Taxes	-
14.	Total	4,860
15.	**OPERATING INCOME (before income tax)**	**$ (4,860)**
16.	Interest Expense	-
17.	**Taxable Income**	**$ (4,860)**
18.	Income Tax at 39.05%	(1,898)
19.	**OPERATING INCOME AFTER TAX**	**$ (2,962)**

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

PRO FORMA ADJUSTMENT: NUCLEAR DECOMMISSIONING EXPENSE

Adjustment to Test Year operations to increase contributions to the nuclear decommissioning trust funds to the amount *authorized by Decision No. 67744.*

Line No.	Description		Amount
1.	**EXPENSES:**		
2.	Other Operating Expenses		
3.	Depreciation and Amortization	$	3,883
4.	Total Pro Forma Adjustment to Expenses	$	3,883
5.	**OPERATING INCOME (before income tax)**	**$**	**(3,883)**
6.	Income Tax at 39.05%		(1,516)
7.	**OPERATING INCOME AFTER TAX**	**$**	**(2,367)**

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

PRO FORMA ADJUSTMENT: FOUR CORNERS COAL RECLAMATION

Adjustment to Test Year operations to reflect the annual final coal reclamation expense for the Four Corners Power Plant.

Line No.	Description		Amount
1.	**EXPENSES:**		
2.	Fuel Expenses	$	1,305
3.	Other Operating Expenses		
4.	Operations Excluding Fuel Expenses		
5.	Maintenance		
6.	Total Pro Forma Adjustment to Expenses	$	1,305
7.	**OPERATING INCOME (before income tax)**	**$**	**(1,305)**
8.	Interest Expense		
9.	**Taxable Income**	**$**	**(1,305)**
10.	Income Tax at 39.05%		(510)
11.	**OPERATING INCOME AFTER TAX**	**$**	**(795)**

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

PRO FORMA ADJUSTMENT: ANNUALIZE DEPRECIATION AND AMORTIZATION

Adjustment to Test Year operations to include depreciation and amortization expense based on the technical update to the depreciation rates authorized in Decision No. 67744; operating revenue related to depreciation and amortization billed to APSES; and amortization of gain authorized in Decision No, 64306.

Line No.	Description		Amount
1.	**REVENUES:**		
2.	Operating Revenue	$	480
3.	Fuel and Purchased Power Expense		-
4.	Operating Revenues less Fuel and Purchased Power Expenses	$	480
5.	**EXPENSES:**		
6.	Other Operating Expense		
7.	Operations Excluding Fuel Expense		-
8.	Maintenance		-
9.	Subtotal		-
10.	Depreciation and Amortization		23,055
11.	Amortization of Gain		(77)
12.	Administrative and General		-
13.	Other Taxes		-
14.	Total		22,978
15.	**OPERATING INCOME (before income tax)**	**$**	**(22,498)**
16.	Interest Expense		-
17.	**Taxable Income**	**$**	**(22,498)**
18.	Income Tax at 39.05%		(8,785)
19.	**OPERATING INCOME AFTER TAX**	**$**	**(13,713)**

ARIZONA PUBLIC SERVICE COMPANY
Depreciation and Amortization Expense.
Analysis for Rate Case Test Year 9/30/05

Line No	DEPRECIATION/AMORTIZATION		Original Cost as of Sept 30, 2005	Proposed Expense Rate Case	Actual Expense for TME 9/30/05	Proforma Adjustments (B - C)
			A	B	C	D
	Production					
1	Steam		1,408,146,703	53,458,148	43,970,164	9,487,984
2	Nuclear		2,442,093,756	70,594,467	77,569,136	(6,974,669)
3	Nuclear - Decommissioning (a)		0	15,327,864	15,327,864	0
4	Hydro		0	0	1,008,972	(1,008,972)
5	Hydro Decommissioning		0	0	1,556,713	(1,556,713)
6	Other Production (Gas, Oil & Solar) (W Phx, Yucca, Ocotillo)		210,429,541	6,178,589	7,110,031	(931,442)
	Total APS Production Depreciation		4,060,669,999	145,559,069	146,542,880	(983,811)
7	Other Production (PWEC Units)		808,262,684	21,856,238	3,912,868	17,943,369
8	Other Production (Sundance)		273,489,133	5,258,765	2,040,208	3,218,557
	Total PWEC Units & Sundance Production Depreciation		1,081,751,817	27,115,003	5,953,076	21,161,926
9	Total Production	[Total Lines 1 - 8]	5,142,421,816	172,674,071	152,495,956	20,178,115
	Transmission					
10	Transmission - SCE and Limited Term Land Rights		65,756,449	1,175,864	1,419,006	(243,142)
11	Transmission Depreciation - ACC		44,199,297	495,786	471,342	24,444
12	Transmission Depreciation - FERC		1,107,261,158	23,926,588	22,941,241	985,347
13	Transmission Depreciation - Sundance		4,481,838	74,847	8,814	66,032
14	Transmission Depreciation - PWEC Units		38,629,154	667,089	117,605	549,484
15	Total Transmission	[Total Lines 10-14]	1,260,327,898	26,340,174	24,958,009	1,382,165
	Distribution					
16	Distribution Depreciation		3,531,491,685	87,424,209	97,064,283	(9,640,074)
17	Distribution - Limited Term Land Rights and Leased Property		2,258,798	131,607	167,551	(35,943)
18	Total Distribution	[Total Lines 16-17]	3,533,750,483	87,555,816	97,231,833	(9,676,017)
	General & Intangible & Land					
	Total General (Studied)					
19	General (Studied)		338,363,809	19,459,245	18,329,278	1,129,967
20	General - Sundance		3,437,728	46,388	7,731	38,657
21	General & Intangible (Not Studied)		540,599,777	38,505,181	28,502,759	10,002,422
22	Total General & Intangible		882,401,314	58,010,814	46,839,768	11,171,046
23	**Total Depreciation & Amortization**		10,818,901,511	344,580,875	321,525,566	23,055,309

NOTE: (a) - Proposed rates (column B) does not include the $3.878 million increase in decommissioning which is included in a separate Proforma in decommissioning funding.

ARIZONA PUBLIC SERVICE
Amortization Rate Summary
Related to Electric Plant at December 31, 2004

Account	Amortization Group	Amortization Rate
Rates from Decision No. 67744		
INTANGIBLES		
FERC 301	Organization	0.00%
FERC 302	Franchise and Consents	4.00%
FERC 303L	PV Unit 2 Sale & Leaseback-Software	Over Life of lease
FERC 303	Misc Intangible-Contributed Plant	10.00%
FERC 303	Misc Intangible -Mexico Tie	20.00%
FERC 3031	Computer Software-5year life	20.00%
FERC 3032	Computer Software-10year life- Projects greater than $10 million	10.00%
PRODUCTION		
FERC 321-325	PV Unit 2 & Common-Sale & Leaseback	Over Life of lease
LAND RIGHTS		
FERC 3303	Limited Term Land Rights-Hydro Plants	Over Remaining Life of Plant
FERC 3503	Limited Term Land Rights-Transmission Lines	Over Life of Land Right
FERC 3503	Limited Term Land Rights-SCE	Over Life of Land Right
FERC 3603	Limited Term Land Rights-Distribution Lines	Over Life of Land Right
DISTRIBUTION PLANT		
FERC 361-368-371	Distribution Plant Leased Property	Over Life of Each Lease
GENERAL PLANT		
FERC 390	Buildings- Leasehold Improvements	Over Life of Each Lease
FERC 391	Capital Lease-Computer Equipment	Over Life of Each Lease
FERC 392	Capital Lease-Transportation Vehicles	Over Life of Each Lease
FERC 392	Transportation Vehicles	Depreciated by Vehicle Class(1)
FERC 396	Power Operated Equipment	Depreciated by Vehicle Class(1)
FERC 397	PV Common Sale & Lease Back	Over Life of Lease
New Amortization Rates		
FERC 392.1	Vehicles Purchased Off Lease Less Than 26,000 GVW	50.00%
FERC 392.2	Vehicles Purchased Off Lease Greater Than 26,000 GVW	20.00%

(1) The depreciation study did not include accounts 392 or 396, therefore no changes are being proposed in this study.
See attached schedule for rate by vehicle class.

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

PRO FORMA ADJUSTMENT: ANNUALIZE PROPERTY TAXES

Adjustment to Test Year operations to annualize property taxes calculated using December 31, 2004 plant balances.

Line No.	Description		Amount
1.	**EXPENSES:**		
2.	Other Operating Expenses		
3.	Other Taxes	$	16,867
4.	Total Pro Forma Adjustment to Expenses	$	16,867
5.	**OPERATING INCOME (before income tax)**	**$**	**(16,867)**
6.	Income Tax at 39.05%		(6,587)
7.	**OPERATING INCOME AFTER TAX**	**$**	**(10,280)**

ARIZONA PUBLIC SERVICE COMPANY
TWELVE MONTHS ENDED 9/30/05 PROPERTY TAX PRO FORMA

	PRO FORMAS						
		APS		PWEC UNITS		SUNDANCE UNITS	TOTAL
	Ref.		Ref.		Ref.		
Twelve Months Ended 9/30/05 Accrued O&M Property Taxes	A20	121,736,987	A20	1,666,666		0	123,403,653
Less:							
New Mexico	A20	*(9,450,000)*		*0*		0	(9,450,000)
Nevada	A20	(40,971)		0		0	(40,971)
California	A20	(26,687)		0		0	(26,687)
A&G Allocation	A20	84,000		0		0	84,000
Navajo County Refund (2003)	A40	1,281		0		0	1,281
CIAC Reserve (2003)	A40	(496,875)		0		0	(496,875)
O&M Property Taxes For Twelve Months Ended 9/30/05		111,807,734		1,666,666		0	113,474,401
2006 Estimated O&M Property Taxes	A50	110,784,101	A50	13,072,585		0	123,856,686
Add:							
Maricopa Community College Bond (2006)	A55	617,997	A55	17,177		0	635,173
Sundance Units Estimated Property Tax for 2006:		0		0	A80	4,141,256	4,141,256
Phase-In Adjustment for PWEC Units: *Increase from 2005 to 2007*		0	A90	1,708,338		0	1,708,338
Normalized Pro Forma O&M Property Taxes		111,402,098		14,798,100		4,141,256	130,341,454
Total Pro Forma O&M Adjustment		(405,636)		13,131,433		4,141,256	16,867,053

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

PRO FORMA ADJUSTMENT: ANNUALIZE PAYROLL

Adjustment to Test Year operations to reflect the annualization of payroll, payroll tax, and benefit expenses to December 2005 employee levels, December 2005 wage levels for performance review employees, and April 2006 wage levels for union employees. Adjustment to Test Year to remove officer incentive expense.

Line No.	Description		Amount
1.	**EXPENSES:**		
2.	Fuel Expenses	$ -	
3.	Other Operating Expenses		
4.	Operations Excluding Fuel Expenses	5,326	
5.	Maintenance	3,913	
6.	Total Pro Forma Adjustment to Expenses		$ 9,239
7.	**OPERATING INCOME (before income tax)**		**$ (9,239)**
8.	Income Tax at 39.05%		(3,608)
9.	**OPERATING INCOME AFTER TAX**		**$ (5,631)**

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

PRO FORMA ADJUSTMENT: UNDERFUNDED PENSION LIABILITY

Adjustment to Test Year operations to increase pension expense to accelerate the recovery of the Company's underfunded pension liability.

Line No.	Description		Amount
1.	**EXPENSES:**		
2.	Other Operating Expenses		
3.	Operations Excluding Fuel Expenses	$	43,695
4.	Total Pro Forma Adjustment to Expenses	$	43,695
5.	**OPERATING INCOME (before income tax)**	**$**	**(43,695)**
6.	Income Tax at 39.05%		(17,063)
7.	**OPERATING INCOME AFTER TAX**	**$**	**(26,632)**

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

PRO FORMA ADJUSTMENT: ADVERTISING

Adjustment to Test Year operations to exclude advertising expenses related to Company branding.

Line No.	Description		Amount
1.	**EXPENSES:**		
2.	Other Operating Expenses		
3.	Operations Excluding Fuel Expenses	$	(6,140)
4.	Total Pro Forma Adjustment to Expenses	$	(6,140)
5.	**OPERATING INCOME (before income tax)**	**$**	**6,140**
6.	Income Tax at 39.05%		2,398
7.	**OPERATING INCOME AFTER TAX**	**$**	**3,742**

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

PRO FORMA ADJUSTMENT: MISCELLANEOUS ADJUSTMENTS

Adjustment to Test Year operations to eliminate non-recurring and out-of-period expenses.

Line No.	Description		Amount
1.	**REVENUES:**		
2.	Operating Revenue	$	2,217
3.	Fuel and Purchased Power Expense		-
4.	Operating Revenues less Fuel and Purchased Power Expenses	$	2,217
5.	**EXPENSES:**		
6.	Other Operating Expense		
7.	Operations Excluding Fuel Expense		6,093
8.	Maintenance		-
9.	Total		6,093
10.	**OPERATING INCOME (before income tax)**	**$**	**(3,876)**
11.	Interest Expense		-
12.	**Taxable Income**	**$**	**(3,876)**
13.	Income Tax at 39.05%		(1,514)
14.	**OPERATING INCOME AFTER TAX**	**$**	**(2,362)**

ARIZONA PUBLIC SERVICE COMPANY
SCHEDULE OF AMOUNTS TO BE DEPOSITED IN THE
DECOMMISSIONING TRUSTS INCLUDED IN COST OF SERVICE
PALO VERDE TOTAL
(Thousands of Dollars)
(APS Share)

LINE	YEAR	POST SHUTDOWN ON-GOING ISFSI ANNUAL CONTRIBUTION REQUIRED	POST SHUTDOWN ISFSI REGULATORY ASSET AMORTIZATION ANNUAL CONTRIBUTION REQUIRED	DECOMMISSIONING ANNUAL CONTRIBUTION REQUIRED	TOTAL ANNUAL CONTRIBUTION REQUIRED	ACC JURISDICTIONAL AMOUNT /1/
1	2004	$ 376	$ 396	$ 15,328	$ 16,100	$ 15,865
2	2005	752	792	19,211	20,755	20,452
3	2006	752	792	19,211	20,755	20,452
4	2007	752	792	19,211	20,755	20,452
5	2008	752	792	19,211	20,755	20,452
6	2009	1,816	792	19,211	21,819	21,500
7	2010	4,481	792	19,211	24,484	24,127
8	2011	4,481	792	19,211	24,484	24,127
9	2012	4,481	792	19,211	24,484	24,127
10	2013	4,481	792	19,211	24,484	24,127
11	2014	4,481	792	19,211	24,484	24,127
12	2015	4,481	792	19,211	24,484	24,127
13	2016	1,920	404	11,139	13,463	13,266
14	2017	1,920	404	11,139	13,463	13,266
15	2018	1,920	404	11,139	13,463	13,266
16	2019	1,920	404	11,139	13,463	13,266
17	2020	1,920	404	11,139	13,463	13,266
18	2021	1,920	404	11,139	13,463	13,266
19	2022	1,920	404	11,139	13,463	13,266
20	2023	1,920	404	11,139	13,463	13,266
21	2024	1,920	404	11,139	13,463	13,266
22	2025	960	190	6,017	7,167	7,062
23	2026	1,004	238	6,017	7,259	7,153
		$ 51,330	$ 13,172	$ 338,934	$ 403,436	$ 397,546

/1/ ACC Jurisdictional share is approximately 98.54%.

ARIZONA PUBLIC SERVICE COMPANY
SCHEDULE OF AMOUNTS TO BE DEPOSITED IN THE
DECOMMISSIONING TRUSTS INCLUDED IN COST OF SERVICE
PALO VERDE UNIT 1
(Thousands of Dollars)
(APS Share)

LINE	YEAR	POST SHUTDOWN ON-GOING ISFSI ANNUAL CONTRIBUTION REQUIRED	POST SHUTDOWN ISFSI REGULATORY ASSET AMORTIZATION ANNUAL CONTRIBUTION REQUIRED	DECOMMISSIONING ANNUAL CONTRIBUTION REQUIRED	TOTAL ANNUAL CONTRIBUTION REQUIRED	ACC JURISDICTIONAL AMOUNT /1/
1	2004	$ 125	$ 107	$ 4,077	$ 4,309	$ 4,246
2	2005	251	214	5,122	5,587	5,505
3	2006	251	214	5,122	5,587	5,505
4	2007	251	214	5,122	5,587	5,505
5	2008	251	214	5,122	5,587	5,505
6	2009	605	214	5,122	5,941	5,854
7	2010	960	214	5,122	6,296	6,204
8	2011	960	214	5,122	6,296	6,204
9	2012	960	214	5,122	6,296	6,204
10	2013	960	214	5,122	6,296	6,204
11	2014	960	214	5,122	6,296	6,204
12	2015	960	214	5,122	6,296	6,204
13	2016	960	214	5,122	6,296	6,204
14	2017	960	214	5,122	6,296	6,204
15	2018	960	214	5,122	6,296	6,204
16	2019	960	214	5,122	6,296	6,204
17	2020	960	214	5,122	6,296	6,204
18	2021	960	214	5,122	6,296	6,204
19	2022	960	214	5,122	6,296	6,204
20	2023	960	214	5,122	6,296	6,204
21	2024	960	214	5,122	6,296	6,204
22	2025					
23	2026					
		$ 16,134	$ 4,387	$ 106,517	$ 127,038	$ 125,183

/1/ ACC Jurisdictional share is approximately 98.54%.

ARIZONA PUBLIC SERVICE COMPANY
SCHEDULE OF AMOUNTS TO BE DEPOSITED IN THE
DECOMMISSIONING TRUSTS INCLUDED IN COST OF SERVICE
PALO VERDE UNIT 2
(Thousands of Dollars)
(APS Share)

LINE	YEAR	POST SHUTDOWN ON-GOING ISFSI ANNUAL CONTRIBUTION REQUIRED	POST SHUTDOWN ISFSI REGULATORY ASSET AMORTIZATION ANNUAL CONTRIBUTION REQUIRED	DECOMMISSIONING ANNUAL CONTRIBUTION REQUIRED	TOTAL ANNUAL CONTRIBUTION REQUIRED	ACC JURISDICTIONAL AMOUNT /1/
1	2004	$ 126	$ 194	$ 6,153	$ 6,473	$ 6,378
2	2005	250	388	8,072	8,710	8,583
3	2006	250	388	8,072	8,710	8,583
4	2007	250	388	8,072	8,710	8,583
5	2008	250	388	8,072	8,710	8,583
6	2009	606	388	8,072	9,066	8,934
7	2010	2,561	388	8,072	11,021	10,860
8	2011	2,561	388	8,072	11,021	10,860
9	2012	2,561	388	8,072	11,021	10,860
10	2013	2,561	388	8,072	11,021	10,860
11	2014	2,561	388	8,072	11,021	10,860
12	2015	2,561	388	8,072	11,021	10,860
13	2016					
14	2017					
15	2018					
16	2019					
17	2020					
18	2021					
19	2022					
20	2023					
21	2024					
22	2025					
23	2026					
		$ 17,098	$ 4,462	$ 94,945	$ 116,505	$ 114,804

/1/ ACC Jurisdictional share is approximately 98.54%.

ARIZONA PUBLIC SERVICE COMPANY
SCHEDULE OF AMOUNTS TO BE DEPOSITED IN THE
DECOMMISSIONING TRUSTS INCLUDED IN COST OF SERVICE
PALO VERDE UNIT 3
(Thousands of Dollars)
(APS Share)

LINE	YEAR	POST SHUTDOWN ON-GOING ISFSI ANNUAL CONTRIBUTION REQUIRED	POST SHUTDOWN ISFSI REGULATORY ASSET AMORTIZATION ANNUAL CONTRIBUTION REQUIRED	DECOMMISSIONING ANNUAL CONTRIBUTION REQUIRED	TOTAL ANNUAL CONTRIBUTION REQUIRED	ACC JURISDICTIONAL AMOUNT /1/
1	2004	$ 125	$ 95	$ 5,098	$ 5,318	$ 5,240
2	2005	251	190	6,017	6,458	6,364
3	2006	251	190	6,017	6,458	6,364
4	2007	251	190	6,017	6,458	6,364
5	2008	251	190	6,017	6,458	6,364
6	2009	605	190	6,017	6,812	6,713
7	2010	960	190	6,017	7,167	7,062
8	2011	960	190	6,017	7,167	7,062
9	2012	960	190	6,017	7,167	7,062
10	2013	960	190	6,017	7,167	7,062
11	2014	960	190	6,017	7,167	7,062
12	2015	960	190	6,017	7,167	7,062
13	2016	960	190	6,017	7,167	7,062
14	2017	960	190	6,017	7,167	7,062
15	2018	960	190	6,017	7,167	7,062
16	2019	960	190	6,017	7,167	7,062
17	2020	960	190	6,017	7,167	7,062
18	2021	960	190	6,017	7,167	7,062
19	2022	960	190	6,017	7,167	7,062
20	2023	960	190	6,017	7,167	7,062
21	2024	960	190	6,017	7,167	7,062
22	2025	960	190	6,017	7,167	7,062
23	2026	1,004	238	6,017	7,259	7,153
		$ 18,098	$ 4,323	$ 137,472	$ 159,893	$ 157,559

/1/ ACC Jurisdictional share is approximately 98.54%.

ARIZONA PUBLIC SERVICE COMPANY
COMPUTATION OF ALLOWANCE FOR WORKING CAPITAL
TWELVE MONTHS ENDED SEPTEMBER 30, 2005

LINE	DESCRIPTION		AMOUNT	
1	WORKING CAPITAL - OPERATIONS	$	(29,139)	
2	MATERIALS & SUPPLIES[1]		106,427	a
3	FUEL - COAL AND OIL		25,452	b
4	FUEL - NUCLEAR, NET		59,889	c
5	PREPAYMENTS		5,517	
6	ALLOWANCE FOR WORKING CAPITAL	$	168,146	
		a+b+c=	191,768	

Note [1]: APS Materials and Supplies include FERC 154 & 156

Attachment LLR-5-1

ARIZONA PUBLIC SERVICE COMPANY

RCN by Major Plant Accounts

With Contribution In Aid of Construction Identified by Function

Test year September 30, 2005

(Thousands of Dollars)

Line No.	Description	Gross Amount (a)	Contributions In Aid Of Construction (b)	Net Amount (c)
1.	Intangible Plant	$ 285,337	$ -	$ 285,337
2.	Production Plant	9,052,491	(88,770)	$ 8,963,721
3.	Transmission Plant	2,922,088	(244,751)	$ 2,677,337
4.	Distribution Plant	5,361,101	(179,408)	$ 5,181,693
5.	General Plant	668,325	(9,083)	$ 659,242
6.	Utility Plant In Service	$ 18,289,342	$ (522,012)	$ 17,767,330

ARIZONA PUBLIC SERVICE COMPANY
RCND BY MAJOR PLANT ACCOUNTS
TEST YEAR ENDING 9-30-2005
(Thousands of Dollars)

SCHEDULE B-4

Line No.	Function	PLANT ACCOUNT	DESCRIPTION	RCN	CONDITION PERCENT Percent	RCND
				(a)	(b)	(c)
1.	INTANGIBLES	301	Organization	$74	100.00%	$74
2.		302	Franchises and consents	2,964	78.61%	2,330
3.		303	Miscellaneous intangible plant	282,299	37.61%	106,168
4.			SUBTOTAL	$285,337		$108,572
5.	PRODUCTION	310	Land and Land Rights	3,308	100.00%	3,308
6.		310	Limit Term Land Rights	64	35.12%	22
7.		311	Structures and improvements	256,142	46.36%	118,748
8.		312	Boiler plant equipment	1,996,765	41.76%	833,910
9.		314	Turbogenerator units	609,483	46.23%	281,756
10.		315	Accessory electric equipment	431,039	38.33%	165,236
11.		316	Miscellaneous power plant equip.	114,110	57.52%	65,638
12.		320	Land and land rights	3,502	100.00%	3,502
13.		321	Structures and improvements	1,032,084	52.35%	540,328
14.		322	Reactor plant equipment	1,645,347	52.13%	857,675
15.		323	Turbogenerator units	572,968	52.21%	299,120
16.		324	Accessory electric equipment	574,278	48.88%	280,703
17.		325	Misc power plant equip	221,602	50.96%	112,923
18.		330	Limit Term Land Rights	0	0.00%	0
19.		331	Structures and improvements	0	0.00%	0
20.		332	Reservoirs, dams, and waterways	0	0.00%	0
21.		333	Water wheels, turbines and generators	0	0.00%	0
22.		334	Accessory electric equipment	0	0.00%	0
23.		335	Miscellaneous power plant equip.	0	0.00%	0
24.		336	Roads, railroads and bridges	0	0.00%	0
25.		340	Land and land rights	3,158	100.00%	3,158
26.		341	Structures and improvements	58,435	77.07%	45,033
27.		342	Fuel holders, products, and accessories	57,147	63.19%	36,110
28.		343	Prime movers	680,365	75.46%	513,379
29.		344	Generators	545,368	82.98%	452,526
30.		345	Accessory electric equipment	145,429	71.11%	103,414
31.		346	Miscellaneous power plant equip.	13,127	47.14%	6,188
32.			SUBTOTAL	$8,963,721		$4,722,677
33.	TRANSMISSION	350	Land and land rights	44,721	100.00%	44,721
34.		350	Limit Term Land Rights	18,288	49.82%	9,111
35.		352	Structures and improvements	54,233	52.24%	28,332
36.		353	Station equipment	1,063,880	72.82%	774,735
37.		354	Towers and fixtures	313,974	30.32%	95,194
38.		355	Poles and fixtures	390,956	72.09%	281,828
39.		356	Overhead conductors and devices	714,447	53.84%	384,657
40.		357	Underground conduit	29,887	70.32%	21,017
41.		358	Underground conductors and devices	46,951	53.51%	25,124
42.			SUBTOTAL	$2,677,337		$1,664,719
43.	DISTRIBUTION	360	Land and land rights	32,572	100.00%	32,572
44.		360	Limit Term Land Rights	1,823	73.30%	1,336
45.		361	Structures and improvements	55,723	59.39%	33,091
46.		362	Station equipment	435,463	74.96%	326,404
47.		364	Poles, towers, and fixtures	619,812	75.81%	469,876
48.		365	Overhead conductors and devices	442,054	86.72%	383,334
49.		366	Underground conduit	698,391	91.47%	638,841
50.		367	Underground conductors and devices	1,347,195	66.75%	899,221
51.		368	Line transformers	742,797	51.88%	385,391
52.		369	Services	401,744	59.01%	237,085
53.		370	Meters	233,878	69.96%	163,611
54.		371	Installations on customers' premises	60,020	84.06%	50,453
55.		373	Street lighting and signal systems	110,221	60.77%	66,977
56.			SUBTOTAL	$5,181,693		$3,688,192
1.	GENERAL	389	Land and land rights	10,640	100.00%	10,640
2.		390	Structures and improvements	209,593	65.90%	138,112
3.		391	Office furniture and equipment	126,667	41.16%	52,137
4.		391	*Capitalized Lease-Computer Equipment*	8,776	14.74%	1,294
5.		392	Transportation equipment	34,806	2.37%	825
6.		392	Capitalized Lease-Transportation Equip.	12,518	58.03%	7,265
7.		393	Stores equipment	5,821	-5.42%	-315
8.		394	Tools, shop and garage equipment	21,543	68.84%	14,831
9.		395	Laboratory equipment	3,255	49.95%	1,626
10.		396	Power operated equipment	32,427	28.15%	9,127
11.		397	Communication equipment	184,924	52.16%	96,455
12.		398	Miscellaneous equipment	8,272	91.45%	7,565
13.			SUBTOTAL	$659,242		$339,562
14.		TOTAL PLANT		$17,767,330		$10,523,722

Supporting Schedules
RCND Study

ReCap Schedules
(a) B-3

REBUTTAL TESTIMONY OF LAURA L. ROCKENBERGER

On Behalf of Arizona Public Service Company

Docket No. E-01345A-05-816

September 15, 2006

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REBUTTAL TESTIMONY OF LAURA L. ROCKENBERGER
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-05-816)

I. INTRODUCTION

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

A. My name is Laura L. Rockenberger. My business address is 400 North Fifth Street, Phoenix, Arizona, 85004. I am the Manager of Operations Accounting for Arizona Public Service Company ("APS" or "Company").

Q. DID YOU FILE DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes. I filed direct testimony in this docket on November 4, 2005 ("Initial Filing"), and also provided updated testimony on January 31, 2006 ("January Filing").

II. SUMMARY OF REBUTTAL TESTIMONY

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

Most importantly, my Rebuttal Testimony addresses the critical need of the Company to maintain an appropriate level of cash working capital and refutes both the Staff and Residential Consumer Utility Office ("RUCO") recommended reductions in cash working capital that will further handicap the Company's ability to have cash available to operate and maintain its electric system on a daily basis. The Company opposes Staff recommendations that cash working capital be reduced by $59,600,000 by removing "non-cash items" and including interest expense in the Cash Working Capital calculation. RUCO also recommends that depreciation expense, as a "non-cash item," be excluded from and interest expense be included in the cash working capital calculation. Certain income statement expenses have been casually referred to as "non-cash" items; but, the stark reality is that these items provide cash resources that the Company desperately needs to maintain operations while funding expansive growth in its service territory. The fundamental regulatory concept that we must remain focused on is that the current period depreciation expense, and other non-cash expenses, reduce rate base before the cash is collected from the customers. Because there is a gap in time from the rate base reduction (when the Company stops earning a return on the assets which are "consumed" in operations and allocated to expense) and the cash collection from the customers, it makes sense to bridge that "gap" in time by including those expenses in the cash working capital calculation. APS witness Balluff will provide further elaboration on the technical merits of including these non-cash items and excluding interest expense in the cash working capital calculation. Finally, the Company does not oppose $5,019,000 in cash working capital reductions recommended by Staff which are based on adjustments to the cash working capital calculation.

My Rebuttal Testimony also discusses the rate base and operating income adjustments advocated by Staff, RUCO and Arizonans for Electric Choice and Competition ("AECC"). These adjustments fall into these categories: recommendations we do not oppose; those we can support in part; and, those we completely oppose. These adjustments are summarized below. All the rate case and operating income adjustments summarized are stated as total company numbers. The jurisdictional portion of the adjustments are summarized in Attachments LLR-3-1RB through LLR-3-3RB.

Adjustments to Both Rate Base and Operating Income

A. Palo Verde Unit 1 Steam Generators

The Company does not oppose RUCO's recommendation to record the $36,684,000 retirement of the old steam generators and low pressure turbines which has no impact on rate base. Accordingly, the Company does not oppose the related $262,000 adjustment to reduce operating income for depreciation expense related to a portion of the old low pressure turbine equipment retired, but does oppose the recommended $404,000 adjustment for depreciation on the old steam generators which was included in the Company's calculation.

B. Bark Beetle Remediation

The Company has deferred bark beetle remediation costs in compliance with Decision No. 67744, and opposes both (1) Staff recommendations to remove 2005 expenses from January 1, 2005 through March 31, 2005, and (2) RUCO's recommendation to remove projected costs from the end of the Test Year through December 31, 2006. These recommendations would decrease the allowable deferred bark beetle remediation costs and related annual amortization expense. The Company is not opposed to certain adjustments to include the impacts of deferred income taxes in rate base and correct the original pro forma for the actual costs at September 30, 2005. The Company is also proposing to update the projected costs through December 31, 2006. This will increase the total deferred bark beetle remediation costs by $333,000 to $11,622,000. The net pro forma adjustment will reduce rate base by $1,755,000 and increase amortization expense by $110,000.

Additional Pro Forma Adjustments to Operating Income

A. PWEC Units[1] and Sundance Units

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[1] "PWEC Units" refers to the generation plants that were transferred to APS in the prior rate case, as discussed in my Direct Testimony.

Mr. Ewen discusses the PWEC Units' and Sundance Units O&M in his Rebuttal Testimony.

The Company is opposed to Mr. Higgins' recommended adjustment to reduce the PWEC Units' A&G by $11,618,000 based on the concept that A&G recovery should be limited to historical levels. It should be noted, however, that the Company is not opposed to $5,098,000 in out-of-period adjustments related to PWEC A&G which I address in "J. Other Administrative and General Adjustments".

B. Decommissioning

The Company is opposed to RUCO's recommended $765,000 reduction in operating expenses related to decommissioning. RUCO included the decommissioning costs, but did not take into consideration that funding into the decommissioning trusts also provides for post-shutdown spent nuclear fuel storage costs which was properly recorded as $765,000 in fuel expense and funded into the decommissioning trusts.

C. Spent Nuclear Fuel Storage

The Company is not opposed to Staff's recommendation to reduce operating income by $264,000 for ongoing spent nuclear fuel storage expenses.

D. Depreciation and Amortization

The Company is opposed to RUCO's recommended $6,991,000 reduction in amortization expense, as RUCO provided an historical average rate which understates normalized amortization expense in a period of time when assets balances are increasing significantly and, thus, amortization expense is increasing.

E. Property Taxes

The Company is not opposed to Staff's recommended $1,708,000 reduction in property taxes related to the 2007 phase-in of new generation plant costs. Accordingly, the Company is opposed to RUCO's adjustment to reduce the property taxes by $5,977,000 based on the temporary suspension of the County Education Tax Rate, because RUCO did not take into consideration all known and measurable factors impacting the assessed value which would impact the pro forma adjustment.

F. Payroll

The Company is opposed to both Staff and RUCO recommendations to disallow stock-based incentive compensation and to have an overall 20% reduction in incentive compensation. Mr. Wheeler discusses this further in his Rebuttal Testimony. The Company is also opposed to RUCO's recommendation that Supplemental Excess Benefit Retirement Plan ("SEBRP") expense be disallowed. Mr. Brandt discusses this further in his Rebuttal Testimony.

Staff has proposed an $8,155,000 increase in pension costs and a $2,038,000 increase in post retirement medical costs based on estimated 2006 expenses. The Company agrees that the Test Year expenses should be based on 2006 cost levels and has now received final 2006 actuarial calculations, which increase Test Year pension expense by $2,249,000 and decrease post retirement medical costs by $3,191,000. The Company is proposing adjustments based on these final 2006 actuarial calculations.

G. Underfunded Pension Liability

The Company opposes Staff, RUCO and AECC recommendation to deny the Company's request to accelerate the recovery of its underfunded pension liability over a five-year period beginning in 2007. Mr. Brandt discusses the necessity for the Company to accelerate this funding in his Rebuttal Testimony.

H. Advertising

The Company is not opposed to the $437,000 reduction in advertising costs recommended by Staff, $66,000 of the $566,000 reduction recommended by RUCO, and the $4,625.00 reduction recommended by Mr. Rigsby. The Company is opposed to RUCO's recommendation to remove $400,000 of meals expense from operating expenses as these costs are incurred to provide company lunches for employees that are working during their personal lunch time. The Company is proposing a pro forma adjustment to reduce operating expenses by $508,000.

I. Lobbying

The Company is opposed to adjustments to remove lobbying costs from the Test Year, as Mr. Wheeler discusses in his Rebuttal Testimony.

J. Other Administrative and General Adjustments

The Company is not opposed to Staff and RUCO recommended adjustments to reduce A&G by $8,520,000 for out-of-period costs and legal fees. This amount includes $5,098,000 in PWEC Units out-of-period adjustments.

Liberty Consulting Group Fuel Audit

My Rebuttal Testimony also responds to one recommendation which was addressed by Staff's consultant, Liberty Consulting Group, in its *Final Audit Report: APS Fuel and Purchased Power Procurement and Costs* ("Fuel Audit

Report"), which was issued August 31, 2006. This recommendation addresses an accounting practice for allocating refunds on fuel transportation costs to fuel expense and inventory. The Fuel Audit Report noted that the recommended accounting adjustment is only a short-term timing issue regarding the flow of fuel expense through the Power Supply Adjustor ("PSA").

Finally, my Rebuttal Testimony includes the calculation of estimated Plant-in-Service at December 31, 2006, as discussed in Mr. Wheeler's Rebuttal Testimony. The estimated Plant-in-Service is $11,369,665,000. The increase in Plant-in-Service from the Test Year to December 31, 2006 is estimated to be $572,058,000, which has a related revenue requirement of $13,480,000.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. First, I will discuss the adjustment to the cash working capital ("CWC") included in the Allowance for Working Capital, as set forth in Attachment LLR-1-1RB. Then, I will discuss the items that have a pro forma adjustment to Original Cost Rate Base, as set forth in Attachments LLR-2-1RB through LLR-2-3RB and any corresponding pro forma adjustments to operating income. After the discussion of these items, which adjust the rate base, I will present the Summary of Original Cost and RCND Rate Base Elements, Adjustments to B-2 and Adjustments to B-3 in Attachments LLR-3-1RB through LLR-3-3RB. I will then discuss the remaining operating income pro forma adjustments. These pro forma adjustments, as set forth in Attachments LLR-4-1RB through LLR-4-8RB, reflect total Company amounts prior to any jurisdictional allocation. Then I will discuss one of the recommendations in the Fuel Audit Report that is related to fuel accounting practices. Finally, I will discuss the estimated Plant-in-Service at December 31, 2006 as set forth in Attachment LLR-5-1RB.

III. ALLOWANCE FOR WORKING CAPITAL

Q. HAVE YOU REVIEWED STAFF AND RUCO TESTIMONY AND EXHIBITS RELATING TO WORKING CAPITAL?

A. Yes. Both Staff witness Mr. Dittmer and RUCO witness Ms. Diaz Cortez discuss working capital issues in their testimony. Both make significant adjustments to the Company's lead lag study in the area of cash working capital ("CWC"), as identified in Staff Schedule B-4 and RUCO Schedule MDC-5.

Q. PLEASE IDENTIFY STAFF'S RECOMMENDED ADJUSTMENTS TO CWC.

A. As is shown in Mr. Dittmer's Direct Testimony on page 32, Staff's recommended CWC adjustments are as follows:

APS CWC Recommendation	$(29.3) million
Staff CWC Adjustments:	
Remove Non-Cash Items	(43.7) million
Recognize Interest Expense	(15.9) million
Total Non-Cash and Interest Expense	(59.6) million
Revise Palo Verde Lease Payment Lag	(7.1) million
Adjust Level of Purchased Power Expense	2.6 million
Re-weight Revenue Lag	(0.5) million
Total Other CWC Adjustments	(5.0) million
Total Staff CWC Adjustments:	$(64.6) million
Staff's Recommended CWC:	$(93.9) million

Q. PLEASE IDENTIFY RUCO'S RECOMMENDED ADJUSTMENTS TO CWC.

A. Ms. Diaz Cortez also recommends that depreciation expense be excluded and interest expense be included in the CWC calculation. Although Ms. Diaz Cortez also substituted RUCO's recommended expense levels for the Company in its

CWC calculation, she states in her testimony on page 12 that her entire proposed adjustment "is primarily attributable to the depreciation and interest expense factors and decreases cash working capital by $78.2 million."

Q. DO YOU AGREE WITH THESE RECOMMENDATIONS?

A. I agree with Staff's recommendations for adjustments to Palo Verde lease payment lags, levels of purchased power expense, and to its re-weighting of revenue lags in CWC. However, I strongly disagree with both Staff and RUCO's recommendation to eliminate so called "non-cash" items from CWC. I also strongly disagree with their recommendation to include interest expense in the CWC calculations. APS witness Balluff discusses the appropriateness of inclusion of "non-cash" items, as well as the exclusion of interest expense in the CWC calculations, in his Rebuttal Testimony.

Q. TAKING INTO CONSIDERATION THE RECOMMENDATIONS THAT YOU DO NOT OPPOSE, CAN YOU SUMMARIZE THE COMPANY'S REVISED CASH WORKING CAPITAL REQUEST?

A. Yes. The Company does not oppose the recommended adjustments to the Palo Verde lease payment lags, levels of purchased power expense, and to its re-weighting of revenue lags. These total changes result in a revised cash working capital request of ($34,158,000), which is a reduction of $5,019,000 from the January Filing in SFR Schedule B-5, line 1. *See* Attachment LLR-1-1RB.

Q. PLEASE EXPLAIN WHY CASH WORKING CAPITAL IS A CRITICAL SOURCE OF FUNDS TO THE COMPANY.

A. The Company must operate and maintain its electric system on a daily basis. As Mr. Wheeler discussed in his Direct Testimony, APS is experiencing dramatic growth in its service territory. Mr. Brandt discusses in his Rebuttal Testimony that the Company anticipates spending in excess of an average of $900 million per year, from 2007 through 2009, for capital investments to serve its rapidly growing customer base and maintain high service reliability. Cash working capital is a critical source of funds.

The arbitrary reduction of rate base to the tune of about $44 million, due to a perception by Staff and RUCO that such depreciation expense is not a "cash" item, effectively reduces APS' cash flow during a time in which the Company is experiencing unprecedented growth and must be able to generate sufficient cash to continue construction and provide reliable service to its rapidly increasing customer base.

Q. PLEASE EXPLAIN THE FUNDAMENTAL CONCEPT THAT PROVIDES FOR INCLUDING NON-CASH ITEMS IN THE CASH WORKING CAPITAL CALCULATION.

A. The fundamental regulatory concept that we must remain focused on is that the current period depreciation expense, and other non-cash expenses, reduce rate base before the cash is collected from the customers. Because there is a gap in time from the rate base reduction (when the Company stops earning a return on the assets which are "consumed" in operations and allocated to expense) and the cash collection from the customers, it makes sense to bridge that "gap" in time by including those expenses in the cash working capital calculation.

Q. IS APS' REQUEST TO INCLUDE THESE OTHER REVENUE ITEMS IN THE LEAD LAG STUDY UNPRECEDENTED OR OUT-OF-LINE WITH OTHER COMMISSIONS' TREATMENT OF THESE SAME EXPENSES?

A. No. Mr. Balluff discusses the fact that other state commissions have recognized the appropriateness of reflecting these non-cash items somewhere in a utility's rate base. For APS, it has been eighteen years since these issues were litigated, so it is time for the Commission to revisit the analysis of how cash working capital is determined for rate making purposes.

IV. PRO FORMA ADJUSTMENTS TO BOTH RATE BASE & OPERATING INCOME

A. Palo Verde Unit 1 Steam Generators

Q. RUCO IDENTIFIED THAT THE COMPANY'S RATE BASE PRO FORMA, WHICH REFLECTED THE REPLACEMENT OF STEAM GENERATORS FOR PALO VERDE UNIT 1, FAILED TO INCLUDE A PROVISION FOR THE RETIREMENT OF THE ORIGINAL UNIT 1 STEAM GENERATORS AND PROPOSED A RATE BASE ADJUSTMENT TO REFLECT THAT RETIREMENT. DO YOU AGREE WITH RUCO'S PROPOSED ADJUSTMENT?

A. Yes. As a result, the Company is proposing a rate base pro forma to reflect the retirement of the original steam generators, including the low pressure turbine rotors. The pro forma will decrease plant assets by $36,684,000 and decrease accumulated depreciation by $36,684,000. This pro forma has no effect on rate base, but does have an impact on depreciation expense. *See* Attachment LLR-2-1RB.

Q. PLEASE EXPLAIN THE IMPACT OF THIS PRO FORMA ON DEPRECIATION EXPENSE.

A. The Test Year depreciation expense was adjusted to reflect the increase in the level of plant-in-service resulting from the addition of the replacement steam generators, net of the retirement of the original steam generators. The Company's depreciation expense adjustment was properly calculated for the replacement of the steam generators, but did not include the retirement of the low pressure turbine rotors in the calculation.

Q. RUCO PROPOSED A $666,000 ADJUSTMENT TO REDUCE DEPRECIATION EXPENSE TO REFLECT THE RETIREMENT OF THE ORIGINAL STEAM GENERATORS AND THE ADDITION OF THE REPLACEMENT STEAM GENERATORS, INCLUDING THE LOW PRESSURE TURBINES. DO YOU AGREE WITH RUCO'S ADJUSTMENT?

A. The Company agrees with a portion of the adjustment. The $666,000 adjustment includes reductions in depreciation expense of $404,000 related to the steam generators and $262,000 related to the low pressure turbine rotors. The Company agrees with the $262,000 adjustment for the low pressure turbine rotors proposed by Mr. Rigsby, which is included in Attachment LLR-4-1RB. However, the $404,000 depreciation adjustment for the retirement of the original steam generators was included in the Company's Test Year pro forma adjustment, therefore, Mr. Rigsby's adjustment would double count depreciation expense reduction for the original steam generators. *See* LLR_WP17, page 2 of 12.

B. Bark Beetle Remediation

Q. HAVE YOU REVIEWED STAFF AND RUCO TESTIMONY AND EXHIBITS RELATING TO BARK BEETLE REMEDIATION?

A. Yes. Mr. Dittmer and Mr. Rigsby each addressed bark beetle remediation in their Direct Testimony. They each concluded that Decision No. 67744 provided for the deferral of bark beetle remediation costs and subsequent amortization of such costs; and, furthermore, each accepted the three-year amortization period proposed by the Company. Additionally, Mr. Dittmer and Mr. Rigsby each propose certain pro forma adjustments, which I shall now address.

Q. MR. DITTMER RECOMMENDED THAT THE COSTS DEFERRED FOR THE PERIOD OF JANUARY 1, 2005 THROUGH MARCH 31, 2005 BE REMOVED FROM THE DEFERRED COSTS AND CORRESPONDINGLY, THAT THE ANNUAL AMORTIZATION

EXPENSE BE REDUCED. DO YOU AGREE WITH THIS RECOMMENDATION?

A. No. Mr. Dittmer believes that the effective date to commence deferral of bark beetle remediation costs should be April 1, 2005, the effective date of Decision No. 67744. However, the language of that Decision, which states, "APS is authorized to defer for later recovery the reasonable and prudent direct costs of bark beetle remediation that exceed the test _year_ [emphasis added] levels of tree and bush control", indicates that a full year of cost recovery was intended. Therefore, the Company actually began deferring costs incurred effective January 1, 2005. The Company believes that the August 2004 Settlement intended and Decision No. 67744, effective April 1, 2005, authorized that deferrals would include the entire calendar year in which the deferral became effective. Thus, effective January 1, 2005, the Company began deferring costs to ensure that the allowable deferred costs were properly calculated for 2005.

Q. **MR. DITTMER ALSO RECOMMENDS ADJUSTMENTS TO CORRECT THE COMPANY'S ORIGINAL PRO FORMA ADJUSTMENT. DO YOU AGREE WITH THIS RECOMMENDATION?**

A. The Company agrees that the rate base should include accumulated deferred income taxes associated with APS' pre-tax pro forma rate base adjustment and that the actual bark beetle deferral balance used in the Company's original pro forma adjustment was incorrect. These corrections have been made and the projected cost deferral through December 31, 2006 has been updated and slightly increased. Taking these items into consideration, the Company is proposing a pro forma adjustment to reduce the rate base by $1,755,000. *See* Attachment LLR-2-2RB. This includes an adjustment to reduce the rate base by $2,793,000 for accumulated deferred income taxes related to rate base adjustments, partially offset by a

$1,038,000 rate base increase comprised of a $705,000 addition to rate base to correct the calculation for the actual September 30, 2005, deferred bark beetle remediation costs in the Company's original pro forma in the January filing, as discussed in Mr. Bischoff's testimony, and a $333,000 addition to rate base to increase the projected bark beetle remediation cost deferral through December 31, 2006.

Q. IS THERE A CORRESPONDING OPERATING INCOME PRO FORMA TO ADJUST THE ANNUAL AMORTIZATION EXPENSE?

A. Yes. A pro forma adjustment to increase the operating costs by $110,000 from $1,438,000 to $1,548,000 to reflect the increased bark beetle amortization cost is included as Attachment LLR-4-2RB.

Q. MR. RIGSBY PROPOSES A PRO FORMA ADJUSTMENT TO REMOVE ESTIMATED BARK BEETLE REMEDIATION COSTS INCLUDED IN THE COMPANY'S DEFERRAL CALCULATION. DO YOU AGREE WITH THIS RECOMMENDATION?

A. No. Estimating costs for the period of time from September 30, 2005 (the end of the Test Year) through January 1, 2007 (when rates are expected to be in place), is a reasonable period of time to project the costs for ongoing remediation activities and also meets the standard of known and measurable costs. Our current financial projections, based on actual costs at July 31, 2006, and including transportation costs related to remediation activities, indicate that the Company will have about $11,622,000 in deferred costs at December 31, 2006, about $333,000 more than the amounts estimated in our January Filing. It is appropriate under the matching principal to use estimated costs to ensure that the rates in effect in 2007 provide (at a minimum) for the amortization of the actual costs incurred by year-end 2006. Thus, APS does not accept Mr. Rigsby's proposed adjustments to reduce the rate base for costs incurred subsequent to the Test Year, and the corresponding adjustment to reduce operating expenses for the annual amortization expense.

V. TOTAL RATE BASE ADJUSTMENTS

Q. PLEASE SUMMARIZE THE ADJUSTED TEST YEAR ORIGINAL COST RATE BASE PROPOSED BY APS.

A. For the Test Year ending September 30, 2005, APS is proposing a total Company OCRB adjustment of $10,660,000 to decrease the OCRB from $5,327,833,000 in the January Filing to $5,317,173,000. The jurisdictional allocation of the OCRB is $4,456,937,000, which is sponsored by Mr. David Rumolo. These adjustments are summarized in Adjustments to Schedule B-2, which is included as Attachment LLR-3-2RB.

VI. RECONSTRUCTION COST NEW STUDY

Q. HAVE YOU DEVELOPED REVISED RCND CALCULATIONS FOR VARIOUS RATE BASE ADJUSTMENTS PROPOSED OR ACCEPTED BY THE COMPANY?

A. Yes. In my Direct Testimony, I sponsored the Company's Reconstruction Cost New ("RCN") and Reconstruction Cost New Less Depreciation ("RCND") study. In Attachments LLR-3-1RB through LLR-3-3RB, I present the Original Cost and RCND Rate Base Elements, Adjustments to B-2 and Adjustments to B-3.

Q. IS THE METHODOLOGY BY WHICH YOU CALCULATED THE RCN AND RCND AMOUNTS THE SAME AS PRESENTED IN YOUR DIRECT TESTIMONY?

A. Yes. The calculations of the RCN and RCND amounts follow the same methods that I discussed at pages 28-33 of my Direct Testimony.

VII. ADDITIONAL PRO FORMA ADJUSTMENTS TO OPERATING INCOME

A. PWEC and Sundance Units

Q. MR. HIGGINS AND MR. SCHLISSEL RECOMMENDED REDUCTIONS TO THE PWEC UNITS AND SUNDANCE UNITS O&M COSTS INCLUDED IN OPERATING EXPENSES. WHAT IS THE COMPANY'S RESPONSE TO THESE RECOMMENDATIONS?

A. Mr. Ewen responds to these recommended pro forma adjustments in his Rebuttal Testimony.

Q. MR. HIGGINS (AECC) RECOMMENDED THAT THE PWEC UNITS' ADMINISTRATIVE AND GENERAL ("A&G") COSTS BE LIMITED TO THOSE EXPENSES ATTRIBUTED TO THE PWEC UNITS DURING THE COMPANY'S PRIOR RATE CASE. DO YOU AGREE WITH THIS APPROACH?

A. No, I do not agree with Mr. Higgins' pro forma adjustment to arbitrarily reduce PWEC A&G by $11,618,000 based on the argument that some prior year costs should be a consideration for reduction in costs in this rate case. Decision No. 67744 specifically ordered APS to rate base the units at December 31, 2004, at $700,000,000. The order to rate base the generating units did not include any requirements for or limitations on operating expenses. Additionally, it should be noted that the Company has proposed a reduction in operating expenses of $5,098,000 for PWEC Units A&G out-of-period adjustments, which effectively reduces Mr. Higgins' recommended adjustment of $11,618,000 to $6,520,000. These A&G adjustments are discussed later in my testimony and included as Attachment LLR-4-8RB.

B. Nuclear Plant Decommissioning

Q. RUCO PROPOSED A $765,000 REDUCTION IN OPERATING EXPENSES FOR DECOMMISSIONING. DO YOU AGREE WITH THIS ADJUSTMENT?

A. No. During the Test Year, the Company funded $16,093,000 into the decommissioning trusts. Since the decommissioning trusts are funded for both plant decommissioning costs and post-shutdown spent nuclear fuel storage costs, the Test Year operating expenses include $15,328,000 in depreciation expense for decommissioning funding and $765,000 in fuel expense for post-shutdown spent nuclear fuel storage funding. RUCO's proposed adjustment did not include the $765,000 in nuclear fuel expense for funding the post-shutdown spent nuclear fuel storage costs.

C. Spent Fuel Storage

Q. STAFF HAS PROPOSED AN ADJUSTMENT TO SPENT NUCLEAR FUEL STORAGE EXPENSE. DO YOU AGREE WITH THIS RECOMMENDATION?

A. Yes. A pro forma adjustment of $264,000 is included in SFR Schedule C-2 to reduce the ongoing spent nuclear fuel storage expense. *See* Attachment LLR-4-3RB.

D. Depreciation and Amortization

Q. HAVE ANY OF THE PARTIES' TAKEN THE POSTION THAT THE COMPANY'S DEPRECIATION RATES PROPOSED IN THIS CASE ARE DIFFERENT THAN THOSE AUTHORIZED IN COMMISSION DECISION NO. 67744?

A. No. In fact, Staff witness Smith acknowledged that the depreciation rates proposed by APS were developed in a manner that is consistent to the depreciation rates that the Commission approved in Decision No. 67744 and recommended that those rates be adopted.

Q. HAVE YOU REVIEWED THE TESTIMONY PROVIDED BY RUCO REGARDING AMORTIZATION EXPENSE?

A. Yes. Ms. Diaz Cortez objected to the Company pro forma increasing amortization expense by $10,002,000 without the Company performing a study of the general and intangible assets. Ms. Diaz Cortez proposed an operating expense reduction of $6,991,000 based on her analysis.

Q. WHAT ANALYSIS DID MS. DIAZ CORTEZ PERFORM TO CALCULATE HER ADJUSTMENT TO AMORTIZATION EXPENSE?

A. The composite rate appears to have been calculated by taking amortization expense for the twelve months ended September 30, 2005, and dividing that amount by the original cost plant balance at September 30, 2005. That composite rate multiplied by the increase in the original cost plant balances during the Test Year, increased amortization expense by $3,011,000. The pro forma adjustment proposed by RUCO reduces the increase in amortization expense to that level.

Q. WHAT OBSERVATIONS DID YOU MAKE REGARDING THE METHODOLOGY USED BY MS. DIAZ CORTEZ IN HER PRO FORMA ADJUSTMENT CALCULATION?

A. Her calculation methodology does not have sufficient analysis or detail to properly normalize amortization expense. The method is a high level general estimating process that may be appropriate to use when the assets all have similar estimated useful lives. However, because the Company's intangible assets have a wide range of estimated useful lives, and because each asset is individually amortized, the calculation cannot properly normalize amortization expense.

Q. PLEASE EXPLAIN THE METHODOLOGY USED IN PREPARING THE COMPANY PRO FORMA ADJUSTMENT FOR AMORTIZATION EXPENSE.

A. The pro forma adjustment proposed by the Company used a more precise method to calculate amortization expense. The calculation was based on the actual individual asset costs and lives at September 30, 2005, multiplied by the actual amortization rates for each individual asset. By using the actual assets at September 30, 2005, the calculation would exclude recent retirements and include recent additions for a full year calculation of amortization expense. Fully amortized assets were properly excluded from the calculation. The amortization rates in effect today were approved by the Commission in Decision No. 67744. The pro forma adjustment is the difference between the normalized annual amortization expense and the actual test year amortization expense. This calculation method was consistently used by the Company in the last rate case filing and has not been objected to by any party in that case or by Staff in this case.

Q. **HAVE YOU PERFORMED ANY ADDITIONAL REVIEWS OF AMORTIZATION EXPENSE SINCE THE END OF THE TEST YEAR?**

A. Yes. For the period of time from the end of the Test Year, September 30, 2005 through June 30, 2006, the General and Intangible Assets have increased from \$371 million to \$387 million. At June 30, 2006, the annualized level of amortization expense is \$45.3 million which exceeds the normalized pro forma adjustment proposed by the Company in its January Filing by \$6.6 million.

Q. **IS THE COMPANY REQUESTING ANY CHANGES TO ITS EXISTING AMORTIZATION RATES?**

A. No. As I discussed in my Direct Testimony, APS is not requesting any change to the amortization rates authorized in Decision No. 67744. These rates are set forth on Attachment LLR-2-11.

Q. **IS THE COMPANY REQUESTING ANY NEW AMORTIZATION RATES?**

A. Yes. APS is requesting two new rates which I discussed in my Direct Testimony. No parties have objected to these rates. These rates are also set forth on Attachment LLR-2-11.

E. Property Taxes

Q. DID YOU REVIEW THE STAFF AND RUCO TESTIMONY FOR PROPERTY TAXES?

A. Yes. Mr. Dittmer proposed an adjustment to reduce property taxes by $1,708,000 to eliminate the APS proposed inclusion of the 2007 statutory phase-in of increased property taxes associated with the PWEC Units. Additionally, Mr. Rigsby proposed an adjustment to reduce property taxes by $5,977,000 to reflect the temporary suspension of the County Education Tax Rate provided by H.B. 2876.

Q. CAN APS ACCEPT STAFF'S PROPERTY TAX RECOMMENDATION FOR THE TEST YEAR?

A. Yes. A $1,708,000 pro forma adjustment is included in SFR Schedule C-2 to reduce operating expenses for property taxes. *See* Attachment LLR-4-4RB.

Q. DO YOU AGREE WITH THE ADJUSTMENTS THAT RUCO PROPOSED?

A. No. The adjustment proposed by Mr. Rigsby only took into consideration the impact of the temporary suspension of the County Education Tax Rate for 2006. The suspension of the County Education Tax Rate will reduce property taxes in 2006, 2007 and 2008. There are other significant issues that will also impact property taxes that Mr. Rigsby did not take into consideration. The Arizona Department of Revenue has approved the 2007 assessed value, which is based on APS plant balances at December 31, 2005, and has recently approved the

Company's request to reduce the 2007 assessed value for the PWEC Units regulatory disallowance reflected in Company records that was discussed in my Direct Testimony. The assessed value of the property, and thus the calculation of the impact on the property taxes for the suspension of the County Education Tax Rate, should appropriately consider these known and measurable net increases in the 2007 assessed value. The Company is now opposed to this pro forma adjustment because these net increases in assessed valuation, which are known and measurable, were not factored into the analysis performed by Mr. Rigsby. If all of these factors were considered at the time Mr. Rigsby proposed his adjustment, Mr. Rigsby's adjustment would fall to $2.4 million, rather than $6 million. In addition, the $2.4 million reduction would also encompass Staff's proposed adjustment for the 2007 generation phase-in costs, which we have not opposed. They are not additive.

F. Payroll

Q. BOTH STAFF AND RUCO HAVE PROPOSED CHANGES TO INCENTIVE COMPENSATION. WHAT IS YOUR RESPONSE TO THESE PROPOSED CHANGES?

A. In his Rebuttal Testimony, Mr. Wheeler explains why the Company disagrees with both Staff's proposal to disallow stock-based incentive compensation and RUCO's proposal that the Commission order an overall 20% reduction in incentive pay for all employees.

Q. WHAT IS THE COMPANY'S RESPONSE TO RUCO'S RECOMMENDATION THAT THE SUPPLEMENTAL EXCESS BENEFIT RETIREMENT PLAN ("SEBRP") COSTS BE DISALLOWED?

A. The Company disagrees with RUCO's position on SEBRP. Mr. Brandt explains the Company's position in his Rebuttal Testimony.

Q. HAVE YOU REVIEWED THE STAFF TESTIMONY ON PENSION EXPENSE?

A. Yes. Mr. Dittmer recommended increasing operating expenses by $8,155,000 for pension expense. His analysis was based on the level of estimated pension expense that the Company was recording in 2006, in excess of the pension expense recorded in the Test Year. In his testimony, Mr. Dittmer also noted that this estimate will need to be adjusted to actual costs in 2006 when the actual costs are known.

Q. HAS THE COMPANY RECENTLY RECEIVED ACTUARIAL INFORMATION THAT PROVIDES THE ACTUAL 2006 PENSION EXPENSE?

A. Yes. The Company has received updated actuarial information for 2006, although the final report has not yet been issued. The actuarially calculated number is higher than last year and indicates that the Test Year expense should be increased by $2,249,000. A pro forma adjustment of $2,249,000 is included to increase pension expense based on the updated actuarial information. *See* Attachment LLR-4-5RB.

Q. HAVE YOU REVIEWED THE STAFF TESTIMONY FOR POST RETIREMENT MEDICAL BENEFITS?

A. Yes. Similar to pension expense, Mr. Dittmer recommended an increase in operating expenses of $2,038,000, which is based on the actuarial estimates that the Company is relying on to record 2006 post retirement benefit costs in excess of the level of costs recorded in the Test Year. Mr. Dittmer also noted that his estimate will need to be adjusted to actual costs when the final information is available.

Q. DID THE ACTUARIAL INFORMATION RECENTLY RECEIVED BY THE COMPANY INCLUDE THE ACTUAL 2006 POST RETIREMENT MEDICAL BENEFITS?

A. Yes. The updated actuarial information indicates that the Test Year expense should be decreased by $3,191,000. A pro forma adjustment of $3,191,000 is included to decrease post retirement medical benefits expense based on the updated actuarial information. *See* Attachment LLR-4-6RB.

G. Underfunded Pension Liability

Q. STAFF, RUCO AND AECC HAVE ALL RECOMMENDED THAT THE COMMISSION DENY THE COMPANY'S REQUEST TO ACCELERATE THE RECOVERY OF ITS UNDERFUNDED PENSION LIABILITY OVER A FIVE-YEAR PERIOD BEGINNING IN 2007. WHAT IS THE COMPANY'S RESPONSE TO THESE RECOMMENDATIONS?

A. Mr. Brandt explains why the Company opposes these recommendations in his Rebuttal Testimony.

H. Advertising

Q. STAFF PROPOSED PRO FORMA ADJUSTMENTS FOR ADVERTISING COSTS. PLEASE DISCUSS THESE ADJUSTMENTS.

A. In his testimony, Mr. Dittmer identified marketing and sponsorship costs totaling $437,000, which the Company has agreed to exclude from operating expenses.

Q. RUCO ALSO PROPOSED PRO FORMA ADJUSTMENTS FOR ADVERTISING COSTS. PLEASE DISCUSS THESE ADJUSTMENTS.

A. Ms. Diaz Cortez proposed adjustments totaling $566,000 for sponsorships and other expenses that she deemed were not needed to provide electric service. Mr. Rigsby proposed an adjustment for $4,625.00 to remove promotional advertising that he believes is similar to branding advertising.

Q. **DO YOU AGREE WITH THE ADJUSTMENTS PROPOSED BY MS. DIAZ CORTEZ?**

A. I agree with $66,000 of the proposed $566,000 adjustment. The $100,000 Dodge Theatre expense was included in the operating adjustment for advertising costs that Staff has proposed and the Company has already accepted. Ms. Diaz Cortez has also proposed a $400,000 adjustment to reduce operating expenses for business lunches. Business lunches are provided by the Company when employees are expected to continue to work during their personal lunch break. We believe these are legitimate business expenses that provide the Company the benefit of additional productive non-interrupted, non-paid work time from our employees. For these reasons, the Company does not agree with Ms. Diaz Cortez's recommendation to reduce operating expenses for these lunches.

Q. **WHAT ADVERTISING COSTS PRO FORMA ADJUSTMENT IS THE COMPANY PROPOSING?**

A. The Company is not opposed to Mr. Dittmer's $437,000 adjustment, $66,000 of Ms. Diaz Cortez's adjustment and Mr. Rigsby's $4,625.00 adjustment. An operating income adjustment of $508,000 is proposed to remove these costs from the Test Year Operations. *See* Attachment LLR–4-7RB.

I. Lobbying

Q. **DO YOU AGREE WITH THE STAFF POSITION THAT LOBBYING EXPENSES SHOULD BE RECORDED IN ACCOUNT NO. 426.4?**

A. We agree that lobbying expenses should be recorded in Account No. 426.4. FERC's instructions for Account 426.4 state:

> *This account shall include expenditures for the purpose of influencing public opinion with respect to the election or appointment of public officials, referenda, legislation, or ordinances (either with respect to the*

possible adoption of new referenda, legislation or ordinances or repeal or modification of existing referenda, legislation or ordinances) or approval, modification, or revocation of franchises; or for the purpose of influencing the decisions of public officials, but shall not include such expenditures which are directly related to appearances before regulatory or other governmental bodies in connection with the reporting utility's existing or proposed operations. [Emphasis added.]

Q. DO THE FERC INSTRUCTIONS PROVIDE ANY ADDITIONAL GUIDANCE ON CHARGING PRACTICES FOR ACCOUNT NO. 426.4?

A. The FERC Instruction states that "the classification of expenses as non-operating and their inclusion in these accounts is for accounting purposes. It does not preclude Commission consideration of proof to the contrary for ratemaking or other purposes."

Q. FERC ACKNOWLEDGES THAT LOBBYING COSTS CHARGED TO FERC ACCOUNT 426.4 MAY BE CONSIDERED FOR RATE MAKING PURPOSES. DOES THE COMPANY BELIEVE THAT LOBBYING COSTS INCLUDED IN TEST YEAR OPERATING EXPENSES BENEFIT THE RATEPAYER?

A. Yes. Mr. Wheeler discusses the benefits of lobbying costs to the ratepayers and the appropriate inclusion of lobbying costs in operating expenses for ratemaking purposes in his Rebuttal Testimony.

J. Other Administrative and General Adjustments

Q. STAFF AND RUCO TESTIMONY PROPOSED PRO FORMA ADJUSTMENTS FOR OUT-OF-PERIOD EXPENSES INCLUDED IN THE TEST YEAR. PLEASE DISCUSS THESE ADJUSTMENTS.

A. Staff testimony by Mr. Dittmer identified $8,419,000 in out-of-period adjustments related to depreciation and rent expense. The $8,419,000 includes $5,098,000 in out-of-period adjustments for the PWEC Units. Ms. Diaz Cortez also identified these depreciation and rent out-of-period costs, which are included in the amounts identified by Mr. Dittmer. Additionally, Mr. Dittmer identified $101,000 in legal costs related to the sale of the Silverhawk generating plant, which he recommended be removed from operating expenses. The Company does not oppose these pro forma adjustments totaling $8,520,000, which reduce operating expenses for out-of-period and legal administrative and general expenses. *See* Attachment LLR-4-8RB.

VIII. LIBERTY CONSULTING GROUP FUEL AUDIT

Q. THE STAFF'S FUEL AUDIT REPORT CONTAINS A CONCLUSION AND A RECOMMENDATION REGARDING ACCOUNTING FOR SUPPLEMENTAL FUEL CHARGES AND REFUNDS. PLEASE IDENTIFY THIS CONCLUSION AND RECOMMENDATION.

A. The Fuel Audit Report "Conclusion" section on page 140 states, "A review of APS handling of supplemental fuel charges and refunds have been accounted for in the PSA [Power Supply Adjustor] when applicable; the accounting methods are not consistent for purposes of recording refunds, but the inconsistency has not had a material impact on the PSA". The related "Recommendation" section on page 13 states that APS should, "Closely review and monitor adjustments to fuel costs to assure that supplemental charges and refunds appropriately consider the impact on inventory values and fuel expenses for financial reporting purposes."

Q. WHAT ARE THE ACCOUNTING TRANSACTIONS REFERENCED IN THESE SECTIONS OF THE FUEL AUDIT REPORT?

A. Staff's consultant reviewed three transactions related to railroad transportation charges for coal delivery. These charges included a refund settlement and retroactive rate reductions that were negotiated as part of a long term agreement. The Fuel Audit Report noted that two of the three transactions properly allocated costs to both fuel expense and inventory based on the period of time that the adjustment related to. The third and final adjustment was charged to fuel expense. The Fuel Audit Report asserts that a portion of the adjustment related to the period of September 2005 thru December 2005 should have been allocated to inventory.

Q. DO YOU AGREE?

A. In retrospect, yes. The final settlement was signed on January 10, 2006, and was related to the period of September 2005 through December 2005. When the entry was made for the January 2005 financial statements, the assumption was that the actual inventory turn approximated the targeted inventory turn of 25 days, or would be close enough to reasonably record the entire amount as fuel expense for the month of January. Actually the inventory turn was about 45-60 days and the refund attributed to the month of December would have been more accurately allocated to inventory and not expensed in January. The refund attributed to December would flow through the inventory charged to fuel expense, and, thus, the PSA in February 2006.

Q. HOW DID THIS IMPACT THE PSA?

A. As noted by Staff's consultant, the only impact would be the amount of time it would have taken the costs to flow through the PSA. In this case, the costs would have flowed through the PSA in the following month. The Fuel Audit Report specifically states that this did not materially impact the PSA.

Q. WERE THESE TRANSACTIONS MONITORED AND REVIEWED AT THE TIME THE ENTRIES WERE RECORDED FOR FINANCIAL REPORTING PURPOSES?

A. Yes. This transaction was reviewed and approved at the time it was made.

Consideration was given to recording a portion of the entry to inventory and a judgment call was made at the time not to do so. As noted above, the amounts that should have been allocated to inventory were not material and did properly flow through the PSA account within 30 days.

IX. OFFSETS TO FINANCIAL IMPACTS OF PARTIES' RECOMMENDATIONS

A. Plant-In-Service

Q. HAVE YOU CALCULATED THE VALUE FOR THE ADDITIONAL PLANT-IN-SERVICE DISCUSSED IN MR. WHEELER'S REBUTTAL TESTIMONY?

A. Yes. The additional Plant-in-Service is $572,058,000.

Q. HOW DID YOU CALCULATE THE VALUE OF THE ADDITIONAL PLANT-IN-SERVICE?

A. The additional Plant-in-Service of $572,058,000 consists of both actual transfers to Plant-in-Service subsequent to September 30, 2005, and projected transfers to Plant-in-Service through December 31, 2006. This includes $395,634,000 in actual additions to Plant, net of actual retirements, for the period of October 1, 2005, through July 31, 2006. This also includes $176,424,000 of projected additions to Plant, net of estimated retirements, for the period of August 1, 2006, through December 31, 2006.

Q. HOW DID YOU DETERMINE THE INCREMENTAL RATE OF RETURN THAT APPLIES TO THE ADDITIONAL PLANT-IN-SERVICE?

A The incremental rate of return calculated to be 3.0% which is the difference between the 11.5% requested return on equity and the 8.5% projected return on equity at December 31, 2006.

Q. WHAT IS THE RESULTING REVENUE REQUIREMENT FOR THE ADDITIONAL PLANT-IN-SERVICE?

A. The calculated revenue requirement at an 11.5% return on equity for the additional plant-in-service is $13,480,000. *See* Attachment LLR-5-1RB.

Q. IF YOU UPDATE PLANT THROUGH YEAR-END 2006, DON'T YOU HAVE TO UPDATE OTHER COSTS AND REVENUES?

A. No. The 2006 return on equity of 8.5% already reflects the net impact of these other rate-making elements. By calculating only the incremental revenue requirements for this plant, we have implicitly synchronized the adjustment with related costs and revenues. If anything, this is conservative because, as can be seen by Mr. Brandt's Rebuttal Testimony, the Company's return on equity continues to decline in 2007 and 2008.

X. COMMISSION ACTION REQUESTED

Q. DOES THE COMPANY BELIEVE THAT THE COMMISSION NEEDS TO TAKE ANY FURTHER ACTION REGARDING THE APPROVAL OF DEPRECIATION RATES?

A. For purposes of clarity and transparency, we are requesting that the Commission formally authorize and approve, as it has in prior cases, the depreciation rates developed by Dr. White and included in his Direct Testimony as Attachments REW-1 and REW-2.

Q. IS THE COMPANY REQUESTING THAT THE COMMISSION TAKE ANY FURTHER ACTIONS REGARDING AMORTIZATION RATES?

A. Yes. As I stated in my Direct Testimony, the Company is not requesting any changes to the amortization rates authorized in Decision No. 67744. The Company is requesting that the Commission formally authorize the continued use of the amortization rates that are currently in effect and approve two new amortization rates. The two *new* rates provide for the amortization of leased vehicles that are purchased by the Company at the end of the lease term. The Company is requesting a 50% amortization rate for vehicles with a Gross Vehicle Weight ("GVW") under 26,000 pounds and a 20% amortization rate for vehicles with a GVW greater than 26,000 pounds. The rates reflect what we believe will be the estimated useful lives for such vehicles. No party has objected to these rates. We are requesting that the Commission include Attachment LLR-2-11, the Amortization Rate Summary, as part of its final order.

Q. PLEASE SUMMARIZE THE COMMISSION ACTION THAT THE COMPANY REQUESTED IN YOUR DIRECT TESTIMONY RELATED TO DECOMMISSIONING AND SPENT FUEL STORAGE EXPENSE.

A. In my Direct Testimony, the Company requested that the Commission's Decision in this docket specifically provide for approval of the annual level of decommissioning funding and Spent Fuel Storage costs, as set forth in Attachment LLR-3, as well as the amortization of the Spent Fuel Cost regulatory asset included in Attachment LLR-2-2. Attachment LLR-3 should be attached to any Commission Decision accepting these amounts.

XI. <u>CONCLUSION</u>

Q. DOES THAT CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

ARIZONA PUBLIC SERVICE COMPANY
COMPUTATION OF ALLOWANCE FOR WORKING CAPITAL
Revised Schedule B-5
TEST YEAR ENDED SEPTEMBER 30, 2005

LINE	DESCRIPTION	REVISED REBUTTAL AMOUNT	AS FILED AMOUNT	INC/(DEC)	
1	WORKING CAPITAL - OPERATIONS	(34,157,681)	(29,138,598)	(5,019,083)	
2	MATERIALS & SUPPLIES[1]	106,426,822	106,426,822	0	A
3	FUEL - COAL AND OIL	25,452,192	25,452,192	0	B
4	FUEL - NUCLEAR, NET	59,888,780	59,888,780	0	C
5	PREPAYMENTS	5,517,425	5,517,425	0	
6	ALLOWANCE FOR WORKING CAPITAL	163,127,538	168,146,621	(5,019,083)	

Note [1]: Materials and Supplies include FERC 154 & 156

A + B + C =	191,767,794	191,767,794	0

SUMMARY OF ACCEPTED CHANGES	
REVENUE LAG	(427,493)
PURCHASED POWER	2,691,284
PV LEASE	(7,139,392)
STATE TAX LAG	(143,482)
TOTAL	(5,019,083)

ARIZONA PUBLIC SERVICE COMPANY
CASH WORKING CAPITAL SUMMARY - LEAD LAG STUDY
TWELVE MONTHS ENDED SEPTEMBER 30, 2005

LINE	DESCRIPTION	WORKING CAPITAL REQUIREMENT (SOURCE)
1	CASH REQUIRED FOR (PROVIDED BY) OPERATING EXPENSES	(34,391,952)
2	SPECIAL DEPOSITS AND WORKING FUNDS	234,271
3	NET CASH WORKING CAPITAL REQUIRED FOR (PROVIDED BY) OPERATIONS	(34,157,681)

ARIZONA PUBLIC SERVICE COMPANY
CASH WORKING CAPITAL REQUIRED FOR OPERATING EXPENSES - LEAD LAG STUDY
TWELVE MONTHS ENDED SEPTEMBER 30, 2005
REBUTTAL - REVISED

LINE	DESCRIPTION	AMOUNT	REVENUE LAG DAYS	EXPENSE LAG DAYS	NET LAG DAYS	CWC FACTOR	WORKING CAPITAL REQUIREMENT
		(1)	(2)	(3)	(4)	(5)	(6)
1	FUEL FOR ELECTRIC GENERATION:						
2	COAL	200,856,342	$\boxed{36.85231}$	32.36664	4.48567	0.01229	2,468,524
3	NATURAL GAS	237,557,927	36.85231	44.25857	-7.40626	-0.02029	(4,820,050)
4	FUEL OIL	1,077,082	36.85231	32.34060	4.51171	0.01236	13,313
5	NUCLEAR:						
6	AMORTIZATION	34,445,413	36.85231	0.00000	36.85231	0.10097	3,477,953
7	SPENT FUEL	7,336,099	36.85231	76.35359	-39.50128	-0.10822	(793,913)
8	TOTAL NUCLEAR FUEL	41,781,512					2,684,040
9							
10	TOTAL FUEL	481,272,863					345,827
11							
12	PURCHASED POWER	$\boxed{458,146,296}$	36.85231	38.15020	-1.29789	-0.00356	(1,631,001)
13	TRANSMISSION BY OTHERS	14,391,245	36.85231	33.69389	3.15842	0.00865	124,484
14	TOTAL PURCHASED POWER & TRANSMISSION	472,537,541					(1,506,517)
15							
16	TOTAL FUEL AND PURCHASED POWER	953,810,404					(1,160,690)
17							
18	OTHER OPERATIONS & MAINTENANCE:						
19	PAYROLL	240,714,447	36.85231	15.00192	21.85039	0.05986	14,409,167
20	INCENTIVE	8,653,091	36.85231	214.50000	-177.64769	-0.48671	(4,211,546)
21	PENSION AND OPEB	38,986,000	36.85231	77.71371	-40.86140	-0.11195	(4,364,483)
22	EMPLOYEE BENEFITS	26,995,515	36.85231	20.35895	16.49336	0.04519	1,219,927
23	PAYROLL TAXES	18,118,131	36.85231	21.78589	15.06642	0.04128	747,916
24	MATERIALS & SUPPLIES	53,466,114	36.85231	24.22000	12.63231	0.03461	1,850,462
25	FRANCHISE PAYMENTS	11,986,402	36.85231	52.83966	-15.98735	-0.04380	(525,004)
26	VEHICLE LEASE PAYMENTS	3,169,771	36.85231	7.43789	29.41442	0.08059	255,452
27	RENTS	6,776,038	36.85231	-33.48601	70.33832	0.19271	1,305,810
28	PALO VERDE LEASE	45,900,681	36.85231	$\boxed{103.99426}$	-67.14195	-0.18395	(8,443,430)
29	PALO VERDE S/L GAIN AMORT	(4,575,722)	36.85231	0.00000	36.85231	0.10097	(462,011)
30	INSURANCE	4,639,562	36.85231	0.00000	36.85231	0.10097	468,457
31	OTHER	119,131,971	36.85231	35.39000	1.46231	0.00401	477,719
32	TOTAL	573,962,000					2,728,436
33							
34	DEPRECIATION & AMORTIZATION	321,525,565	36.85231	0.00000	36.85231	0.10097	32,464,436
35	AMORT OF ELECTRIC PLT ACQ ADJ	0	36.85231	0.00000	36.85231	0.10097	0
36	AMORT OF PROP LOSSES & REG STUDY COSTS	(2,564,492)	36.85231	0.00000	36.85231	0.10097	(258,937)
37	TOTAL	318,961,073					32,205,499
38							
39	INCOME TAXES:						
40	CURRENT:						
41	FEDERAL	59,824,326	36.85231	58.95000	-22.09769	-0.06054	(3,621,765)
42	STATE	16,379,288	36.85231	$\boxed{62.05000}$	-25.19769	-0.06903	(1,130,662)
43	DEFERRED	77,758,889	36.85231	0.00000	36.85231	0.10097	7,851,315
44	TOTAL	153,962,503					3,098,888
45							
46	OTHER TAXES:						
47	PROPERTY TAXES	123,403,653	36.85231	211.94223	-175.08992	-0.47970	(59,196,732)
48	SALES TAXES	158,240,555	16.69615	40.21000	-23.51385	-0.06442	(10,193,857)
49	FRANCHISE TAXES	18,920,381	16.69615	52.83966	-36.14352	-0.09902	(1,873,496)
50	TOTAL OTHER TAXES	300,564,589					(71,264,085)
51							
52	TOTAL	2,301,260,569					(34,391,952)

SUMMARY OF ACCEPTED CHANGES	Revenue Lag Change Only	All Other	Total
REVENUE LAG	(427,493)	0	(427,493)
PURCHASED POWER	(354,716)	3,046,000	2,691,284
PV LEASE	(11,935)	(7,127,457)	(7,139,392)
STATE TAX LAG	(4,422)	(139,060)	(143,482)
Total	(798,566)	(4,220,517)	(5,019,083)

Attachment LLR-2-1RB

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Original Cost Rate Base as Shown on Schedule B-2
Total Company
(Thousands of Dollars)

PRO FORMA ADJUSTMENT: PALO VERDE UNIT 1 STEAM GENERATORS
Retire PV Unit 1 Steam Generators and LP Turbine Rotors.

Line No.	Description	Amount
1.	Gross Utility Plant in Service	$ (36,684)
2.	Less: Accumulated Depreciation and Amortization	$ (36,684)
3.	Net Utility Plant in Service	$ -
4.	Less: Total Deductions	$ -
5.	Total Additions	$ -
6.	Total Rate Base	$ -

Attachment LLR-2-2RB

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Original Cost Rate Base as Shown on Schedule B-2
Total Company
(Thousands of Dollars)

PRO FORMA ADJUSTMENT: BARK BEETLE REGULATORY ASSET

Adjust regulatory asset balance for deferred taxes; updated projected costs through December 2006; and correction to original calculation.

Line No.	Description	Amount
1.	Gross Utility Plant in Service	$ -
2.	Less: Accumulated Depreciation and Amortization	$ -
3.	Net Utility Plant in Service	$ -
4.	Less: Total Deductions	$ 2,793
5.	Total Additions	$ 1,038
6.	Total Rate Base	$ (1,755)

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Original Cost Rate Base as Shown on Schedule B-2
Total Company
(Thousands of Dollars)

PRO FORMA ADJUSTMENT: ALLOWANCE FOR WORKING CAPITAL
Net reduction to Cash Working Capital for Palo Verde Lease, Revenue Lag and Purchased Power.

Line No.	Description	Amount
1.	Gross Utility Plant in Service	$ -
2.	Less: Accumulated Depreciation and Amortization	$ -
3.	Net Utility Plant in Service	$ -
4.	Less: Total Deductions	
5.	Total Additions	$ (5,019)
6.	Total Rate Base	$ (5,019)

ARIZONA PUBLIC SERVICE COMPANY
Summary of Original Cost and RCND Rate Base Elements
Total Company and ACC Jurisdictional
Adjusted Test Year Ended 09/30/2005
(Dollars in Thousands)

		Original Cost						RCND						
		Total Company			ACC			Total Company			ACC			
Line No.	Description	SFR B-1 Schedule as Filed on 1/31/06 (a)	Rebuttal Adjustments to B-1 (b)	Rebuttal Adjusted B-1 (c)	SFR B-1 Schedule as Filed on 1/31/06 (d)	Rebuttal Adjustments to B-1 (e)	Rebuttal Adjusted B-1 (f)	SFR B-1 Schedule as Filed on 1/31/06 (g)	Rebuttal Adjustments to B-1 (h)	Rebuttal Adjusted B-1 (i)	SFR B-1 Schedule as Filed on 1/31/06 (j)	Rebuttal Adjustments to B-1 (k)	Rebuttal Adjusted B-1 (l)	Line No.
1	Gross Utility Plant in Service	$10,893,882	$ (36,684)	$ 10,857,198	$9,296,308	$ (36,261)	$9,260,047	$17,842,146	$ (62,939)	$17,779,207	$15,219,192	$ (62,213)	$15,156,979	1
2	Less: Accumulated Depreciation	4,168,540	(36,684)	4,131,856	3,546,560	(36,261)	3,510,299	7,241,636	(62,939)	7,178,697	6,161,346	(62,213)	6,099,133	2
3	Net Utility Plant in Service	6,725,342	-	6,725,342	5,749,748	-	5,749,748	10,600,510	-	10,600,510	9,057,846	-	9,057,846	3
	Deductions:													
4	Deferred Taxes	1,205,461	303	1,205,764	1,084,449	447	1,084,896	1,205,444	303	1,205,747	1,084,432	447	1,084,879	4
5	Investment Tax Credits	-	-	-	-	-	-	-	-	-	-	-	-	5
6	Customer Advances for Construction	59,807	-	59,807	59,807	-	59,807	59,807	-	59,807	59,807	-	59,807	6
7	Customer Deposits	54,860	-	54,860	54,860	-	54,860	54,860	-	54,860	54,860	-	54,860	7
8	Pension Liability	72,920	-	72,920	68,699	-	68,699	72,920	-	72,920	68,699	-	68,699	8
9	Liability for Asset Retirement	263,457	-	263,457	260,419	-	260,419	263,457	-	263,457	260,419	-	260,419	9
10	Other Deferred Credits	111,791	6,376	118,167	109,485	6,007	115,492	111,791	6,376	118,167	109,485	6,007	115,492	10
11	Unamortized Gain-sale of Utility Plant	46,901	-	46,901	46,360	-	46,360	46,901	-	46,901	46,360	-	46,360	11
12	Regulatory Liabilities	168,048	-	168,048	160,744	-	160,744	168,048	-	168,048	160,744	-	160,744	12
13	Total Deductions	1,983,245	6,679	1,989,924	1,824,823	6,454	1,831,277	1,983,228	6,679	1,989,907	1,824,806	6,454	1,831,260	13
	Additions:													
14	Regulatory Assets	84,531	-	84,531	64,020	-	64,020	84,531	-	84,531	64,020	-	64,020	14
15	Miscellaneous Deferred Debits	42,522	1,038	43,560	39,464	1,038	40,502	42,522	1,038	43,560	39,464	1,038	40,502	15
16	Depreciation Fund - Decommissioning	290,537	-	290,537	285,855	-	285,855	290,537	-	290,537	285,855	-	285,855	16
17	Allowance for Working Capital	168,146	(5,019)	163,127	152,433	(4,344)	148,089	168,146	(5,019)	163,127	152,433	(4,344)	148,089	17
18	Total Additions	585,736	(3,981)	581,755	541,772	(3,306)	538,466	585,736	(3,981)	581,755	541,772	(3,306)	538,466	18
19	Total Rate Base	$ 5,327,833	$ (10,660)	$ 5,317,173	$4,466,697	$ (9,760)	$4,456,937	$ 9,203,018	$ (10,660)	$ 9,192,358	$ 7,774,812	$ (9,760)	$ 7,765,052	19

ARIZONA PUBLIC SERVICE COMPANY
Original Cost Rate Base
Adjustments to Schedule B-2 (Pro Forma Adjustments)
(Dollars in Thousands)

Line No.	Description	(1) SFR Sch. B-2 Total as filed on Jan. 31, 2006 Test Year 9/30/2005 Total Co. (A)	ACC (B)	(2) REBUTTAL Long Term Disability (SFAS 112) Total Co. (C)	ACC (D)	(3) REBUTTAL Bark Beetle Regulatory Asset Total Co. (E)	ACC (F)
1.	Gross Utility Plant in Service	$ 10,893,882	$ 9,296,308	$ -	$ -	$ -	$ -
2.	Less: Accumulated Depreciation & Amort.	4,168,540	3,546,560	-	-	-	-
3.	Net Utility Plant in Service	6,725,342	5,749,748	-	-	-	-
4.	Less: Total Deductions	1,983,245	1,824,823	3,886	3,661	2,793	2,793
5.	Total Additions	585,736	541,772	-	-	1,038	1,038
6.	Total Rate Base	$ 5,327,833	$ 4,466,697	$ (3,886)	$ (3,661)	$ (1,755)	$ (1,755)
				FROGGATT		ROCKENBERGER	

(1) Total Rate Base Adjustments from APS' Direct Testimony filed on Jan. 31, 2006. Please see SFR Schedule B-2, page 3, columns (M) and (N).

(2) Additional rate base pro forma to include deferred credits related to expenses for employees on long term disability.

(3) Adjust regulatory asset balance for deferred taxes; updated projected costs through December 2006; and correction to original calculation.

ARIZONA PUBLIC SERVICE COMPANY
Original Cost Rate Base
Adjustments to Schedule B-2 (Pro Forma Adjustments)
(Dollars in Thousands)

Line No.	Description	(4) REBUTTAL Allowance for Working Capital Total Co. (G)	ACC (H)	(5) REBUTTAL Palo Verde Unit 1 Steam Generators Total Co. (I)	ACC (J)	(6) REBUTTAL Total Original Cost Rate Base Pro Forma Adjustments Total Co. (K)	ACC (L)
1.	Gross Utility Plant in Service	$ -	$ -	$ (36,684)	$ (36,261)	$ (36,684)	$ (36,261)
2.	Less: Accumulated Depreciation & Amort.	-	-				
3.	Net Utility Plant in Service	-	-	(36,684)	(36,261)	(36,684)	(36,261)
4.	Less: Total Deductions	-	-	-	-	-	-
5.	Total Additions	-	-	-	-	6,679	6,454
		(5,019)	(4,344)	-	-	(3,981)	(3,306)
6.	Total Rate Base	$ (5,019)	$ (4,344)	$ -	$ -	$ (10,660)	$ (9,760)

ROCKENBERGER ROCKENBERGER

(4) Net reduction to Cash Working Capital for Palo Verde Lease, Revenue Lag and Purchased Power.

(5) Retire Palo Verde Unit 1 Steam Generators and Low Pressure Turbine Rotors.

ARIZONA PUBLIC SERVICE COMPANY
Original Cost Rate Base
Adjustments to Schedule B-2 (Pro Forma Adjustments)
(Dollars in Thousands)

Line No.	Description	(7) REBUTTAL Adjusted for Rebuttal at the end of Test Year 9/30/2005 Total Co. (M)	ACC (N)
1.	Gross Utility Plant in Service	$ 10,857,198	$ 9,260,047
2.	Less: Accumulated Depreciation & Amort.	4,131,856	3,510,299
3.	Net Utility Plant in Service	6,725,342	5,749,748
4.	Less: Total Deductions	1,989,924	1,831,277
5.	Total Additions	581,755	538,466
6.	Total Rate Base	$ 5,317,173	$ 4,456,937

ARIZONA PUBLIC SERVICE COMPANY
RCND Rate Base
Adjustments to Schedule B-3 (Pro Forma Adjustments)
(Dollars in Thousands)

Line No.	Description	(1) SFR Sch. B-3 Total as filed on Jan. 31, 2006 Test Year 9/30/2005 Total Co. (A)	ACC (B)	(2) REBUTTAL Long Term Disability (SFAS 112) Total Co. (C)	ACC (D)	(3) REBUTTAL Bark Beetle Regulatory Asset Total Co. (E)	ACC (F)
1.	Gross Utility Plant in Service (a)	$ 17,842,146	$ 15,219,192	$ -	$ -	$ -	$ -
2.	Less: Accumulated Depreciation & Amort. (a)	7,241,636	6,161,346	-	-	-	-
3.	Net Utility Plant in Service (a)	10,600,510	9,057,846	-	-	-	-
4.	Less: Total Deductions	1,983,228	1,824,806	3,886	3,661	2,793	2,793
5	Total Additions	585,736	541,772	-	-	1,038	1,038
6.	Total Rate Base	$ 9,203,018	$ 7,774,812	$ (3,886)	$ (3,661)	$ (1,755)	$ (1,755)
				FROGGATT		ROCKENBERGER	

(1) Total Rate Base Adjustments from APS' Direct Testimony filed on Jan. 31, 2006. Please see SFR Schedule B-3, page 3, columns (M) and (N).

(2) Additional rate base pro forma to include deferred credits related to expenses for employees on long term disability.

(3) Adjust regulatory asset balance for deferred taxes; updated projected costs through December 2006; and correction to original calculation.

ARIZONA PUBLIC SERVICE COMPANY
RCND Rate Base
Adjustments to Schedule B-3 (Pro Forma Adjustments)
(Dollars in Thousands)

		(4) REBUTTAL Allowance for Working Capital		(5) REBUTTAL Palo Verde Unit 1 Steam Generators		(6) REBUTTAL Total Original Cost Rate Base Pro Forma Adjustments	
Line No.	Description	Total Co. (G)	ACC (H)	Total Co. (I)	ACC (J)	Total Co. (K)	ACC (L)
1.	Gross Utility Plant in Service (a)	$ -	$ -	$ (62,939)	$ (62,213)	$ (62,939)	$ (62,213)
2.	Less: Accumulated Depreciation & Amort. (a)	-	-	(62,939)	(62,213)	(62,939)	(62,213)
3.	Net Utility Plant in Service (a)	-	-	-	-	-	-
4.	Less: Total Deductions	-	-	-	-	6,679	6,454
5.	Total Additions	(5,019)	(4,344)	-	-	(3,981)	(3,306)
6.	Total Rate Base	$ (5,019)	$ (4,344)	$ -	$ -	$ (10,660)	$ (9,760)
		ROCKENBERGER		ROCKENBERGER			

(4) Net reduction to Cash Working Capital for Palo Verde Lease, Revenue Lag and Purchased Power.

(5) Retire Palo Verde Unit 1 Steam Generators and Low Pressure Turbine Rotors.

ARIZONA PUBLIC SERVICE COMPANY
RCND Rate Base
Adjustments to Schedule B-3 (Pro Forma Adjustments)
(Dollars in Thousands)

Line No.	Description	(7) REBUTTAL Adjusted at the end of Test Year 9/30/2005 Total Co. (M)	ACC (N)
1.	Gross Utility Plant in Service (a)	$ 17,779,207	$ 15,156,979
2.	Less: Accumulated Depreciation & Amort. (a)	7,178,697	6,099,133
3.	Net Utility Plant in Service (a)	10,600,510	9,057,846
4.	Less: Total Deductions	1,989,907	1,831,260
5.	Total Additions	581,755	538,466
6.	Total Rate Base	$ 9,192,358	$ 7,765,052

Attachment LLR-4-1RB

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

PRO FORMA ADJUSTMENT: PALO VERDE UNIT 1 STEAM GENERATORS DEPRECIATION

Remove Test Year depreciation expense related to the old low pressure turbine rotors that were retired.

Line No.	Description		Amount
1.	**EXPENSES:**		
2.	Other Operating Expenses		
3.	Depreciation and Amortization	$	(262)
4.	Total Pro Forma Adjustment to Expenses	$	(262)
5.	**OPERATING INCOME (before income tax)**	**$**	**262**
6.	Interest Expense		-
7.	**Taxable Income**	**$**	**262**
8.	Income Tax at 39.05%		102
9.	**OPERATING INCOME AFTER TAX**	**$**	**160**

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

PRO FORMA ADJUSTMENT: BARK BEETLE

Update Test Year expense to reflect revised bark beetle remediation costs.

Line No.	Description	Amount
1.	**EXPENSES:**	
2.	Other Operating Expenses	
3.	Operations Excluding Fuel Expenses	$ 110
4.	Total Pro Forma Adjustment to Expenses	$ 110
5.	**OPERATING INCOME (before income tax)**	**$ (110)**
6.	Income Tax at 39.05%	(43)
7.	**OPERATING INCOME AFTER TAX**	**$ (67)**

Attachment LLR-4-3RB

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

PRO FORMA ADJUSTMENT: SPENT FUEL STORAGE

Adjustment to Test Year operations for current period spent nuclear fuel storage costs.

Line No.	Description	Amount
1.	**EXPENSES:**	
2.	Fuel Expenses	$ (264)
3.	Other Operating Expenses	
4.	Operations Excluding Fuel Expenses	
5.	Maintenance	
6.	Total Pro Forma Adjustment to Expenses	$ (264)
7.	**OPERATING INCOME (before income tax)**	**$ 264**
8.	Interest Expense	
9.	**Taxable Income**	**$ 264**
10.	Income Tax at 39.05%	103
11.	**OPERATING INCOME AFTER TAX**	**$ 161**

Attachment LLR-4-4RB

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

PRO FORMA ADJUSTMENT: PROPERTY TAXES

Adjustment to Test Year operations to remove the 2007 phase-in cost increase for new generation plant.

Line No.	Description	Amount
1.	**EXPENSES:**	
2.	Other Operating Expenses	
3.	Other Taxes	$ (1,708)
4.	Total Pro Forma Adjustment to Expenses	$ (1,708)
5.	**OPERATING INCOME (before income tax)**	**$ 1,708**
6.	Income Tax at 39.05%	667
7.	**OPERATING INCOME AFTER TAX**	**$ 1,041**

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

PRO FORMA ADJUSTMENT: PENSION

Adjustment to Test Year operations to reflect actual 2006 pension expense.

Line No.	Description		Amount
1.	**EXPENSES:**		
2.	Fuel Expenses	$ -	
3.	Other Operating Expenses		
4.	Operations Excluding Fuel Expenses	2,249	
5.	Maintenance		
6.	Total Pro Forma Adjustment to Expenses		$ 2,249
7.	**OPERATING INCOME (before income tax)**		**$ (2,249)**
8.	Income Tax at 39.05%		(878)
9.	**OPERATING INCOME AFTER TAX**		**$ (1,371)**

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

PRO FORMA ADJUSTMENT: POST RETIREMENT MEDICAL BENEFITS

Adjustment to Test Year operations to reflect actual 2006 post retirement medical expenses.

Line No.	Description		Amount
1.	**EXPENSES:**		
2.	Fuel Expenses	$ -	
3.	Other Operating Expenses		
4.	Operations Excluding Fuel Expenses	(3,191)	
5.	Maintenance		
6.	Total Pro Forma Adjustment to Expenses		$ (3,191)
7.	**OPERATING INCOME (before income tax)**		**$ 3,191**
8.	Income Tax at 39.05%		1,246
9.	**OPERATING INCOME AFTER TAX**		**$ 1,945**

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

PRO FORMA ADJUSTMENT: ADVERTISING

Adjustment to Test Year operations to exclude advertising expenses related to Company branding.

Line No.	Description	Amount
1.	**REVENUES:**	
2.	Operating Revenue	$ -
3.	Fuel and Purchased Power Expense	-
4.	Operating Revenues less Fuel and Purchased Power Expenses	$ -
5.	**EXPENSES:**	
6.	Other Operating Expense	
7.	Operations Excluding Fuel Expense	(171)
8.	Maintenance	-
9.	Subtotal	(171)
10.	Depreciation and Amortization	-
11.	Amortization of Gain	-
12.	Administrative and General	(337)
13.	Other Taxes	-
14.	Total	(508)
15.	**OPERATING INCOME (before income tax)**	$ **508**
16.	Interest Expense	-
17.	**Taxable Income**	$ **508**
18.	Income Tax at 39.05%	198
19.	**OPERATING INCOME AFTER TAX**	$ **310**

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

PRO FORMA ADJUSTMENT: **Administrative and General**
Remove out-of-period and other legal costs from administrative and general expense.

Line No.	Description	Amount
1.	**REVENUES:**	
2.	Operating Revenue	$ -
3.	Fuel and Purchased Power Expense	-
4.	Operating Revenues less Fuel and Purchased Power Expenses	$ -
5.	**EXPENSES:**	
6.	Other Operating Expense	
7.	Operations Excluding Fuel Expense	-
8.	Maintenance	-
9.	Subtotal	-
10.	Depreciation and Amortization	-
11.	Amortization of Gain	-
12.	Administrative and General	(8,520)
13.	Other Taxes	-
14.	Total	(8,520)
15.	**OPERATING INCOME (before income tax)**	**$ 8,520**
16.	Interest Expense	-
17.	**Taxable Income**	**$ 8,520**
18.	Income Tax at 39.05%	3,327
19.	**OPERATING INCOME AFTER TAX**	**$ 5,193**

Revenue Requirement for Additional Plant-in-Service

1.	Total Plant in Service 12/31/06 (contains estimated Jul-Dec)	$	11,369,664,724
2.	Total Plant in Service 9/30/05	$	10,797,607,202
3.	Increased Plant in Service	$	572,057,522
4.	Requested ROE		11.5%
5.	Projected 12/31/06 ROE		8.5%
6.	ROE Shortfall		3.0%
7.	Net Increased Plant In Service	$	572,057,522
8.	ROE Shortfall		3.0%
		$	17,161,726
9.	Equity percentage of capitalization structure		54.5%
		$	9,353,140
10.	Revenue Conversion Factor		1.6407
11.	Total Revenue Requirement	$	15,345,698
12.	ACC Jurisdictional Factor		87.84%
13.	**ACC Revenue Requirement**	**$**	**13,479,661**

EXHIBIT
APS-58
Admitted

REJOINDER TESTIMONY OF LAURA L. ROCKENBERGER

On Behalf of Arizona Public Service Company

Docket No. E-01345A-05-0816
Docket No. E-01345A-05-0826
Docket No. E-01345A-05-0827

October 4, 2006

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REJOINDER TESTIMONY OF LAURA L. ROCKENBERGER
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-05-0816)
(Docket No. E-01345A-05-0826)
(Docket No. E-01345A-05-0827)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, ADDRESS AND OCCUPATION.

A. My name is Laura L. Rockenberger. My business address is 400 North Fifth Street, Phoenix, Arizona, 85004. I am the Manager of Operations Accounting for Arizona Public Service Company ("APS" or "Company").

Q. HAVE YOU PREVIOUSLY FILED DIRECT AND REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REJOINDER TESTIMONY?

A. I will respond to the Surrebuttal Testimony of Mary Lee Diaz Cortez regarding decommissioning costs and amortization and the Surrebuttal Testimony of William A. Rigsby regarding property taxes.

Q. DOES YOUR SILENCE REGARDING ANY OF THE OTHER ISSUES DISCUSSED BY MARY LEE DIAZ CORTEZ OR WILLIAM A. RIGSBY INDICATE AN ACCEPTANCE OF THOSE POSITIONS BY THE COMPANY?

A. No. It does not.

Q. DOES YOUR SILENCE REGARDING ANY ISSUES DISCUSSED BY ANY OTHER PARTY INDICATE AN ACCEPTANCE OF THOSE POSITIONS BY THE COMPANY?

A. No. It does not.

II. SUMMARY

Q. WOULD YOU PLEASE SUMMARIZE YOUR REJOINDER TESTIMONY?

A. My testimony provides additional information to demonstrate that the amounts funded into the Decommissioning Trusts are reflected as expenses in the Test Year and provides supplemental information on amortization and property taxes to support the Company's position on these matters.

III. DECOMMISSIONING

Q. DOES THE CASH FUNDING INTO THE DECOMMISSIONING TRUSTS EXCEED THE TEST YEAR EXPENSES, AS STATED IN THE SURREBUTTAL TESTIMONY OF MS. DIAZ CORTEZ?

A. No, it does not. The cash funding corresponds to the Test Year expense.

Q. HAVE YOU PREPARED AN ANALYSIS THAT IDENTIFIES THE TEST YEAR EXPENSES THAT PROVIDE FOR THE FUNDING LEVEL INTO THE DECOMMISSIONING TRUSTS?

A. Yes. Attachment LLR-1-1RJ provides the analysis that demonstrates the total cash funding of $16.1 million consists of $15.3 million in depreciation expense for funding of plant decommissioning activities and $.8 million in fuel expense for funding of post-shutdown spent nuclear fuel costs.

Q. DOES THE DECOMMISSIONING STUDY INCLUDE COSTS FOR BOTH DECOMMISSIONING ACTIVITIES AND POST-SHUTDOWN SPENT NUCLEAR FUEL ACTIVITIES?

A. Yes, the decommissioning study includes costs for both plant decommissioning activities and post-shutdown spent nuclear fuel activities. The funding levels have been approved by the Commission in Decision No. 67744 and the Company has Private Letter Rulings from the Internal Revenue Service for funding the decommissioning trusts based on the costs included in the decommissioning study.

IV. AMORTIZATION

Q. MS. DIAZ CORTEZ STATED THAT THE COMPANY WAS NOT RESPONSIVE TO RUCO DATA REQUEST 11.4 AND, AS SUCH, THE

COMPANY HAS NOT SUBSTANTIATED ITS PROPOSED AMORTIZATION EXPENSE. DID THE COMPANY RESPOND TO RUCO DATA REQUEST 11.4?

A. Yes. The Company provided a response to RUCO Data Request 11.4 ("RUCO 11.4") on July 21, 2006, which included detailed information by asset type within each asset category with the related monthly amortization expense and annualized amounts. Additionally, the amortization rates were included in my Direct Testimony as Attachment LLR-2-11. No further data requests were received from Ms. Diaz Cortez stating that further information was needed related to RUCO 11.4.

Q. HAS THE COMPANY PROVIDED ADDITIONAL INFORMATION FOR RUCO 11.4?

A. Yes. On October 3, 2006, the Company provided supplemental information to RUCO 11.4 to provide further support for the calculations included in the Test Year expense.

V. PROPERTY TAXES

Q. MR. RIGSBY STATED IN HIS TESTIMONY THAT THE COMPANY HAS NOT UPDATED RUCO DATA REQUEST 11.2 ("RUCO 11.2"), AND, AS SUCH THE COMPANY HAS NOT PROVIDED SUFFICENT INFORMATION TO SUBSTANTIATE THE 2007 PROPERTY TAX EXPENSE CALCULATION REFERENCED IN MY REBUTTAL TESTIMONY. HAVE YOU SINCE UPDATED DATA REQUEST 11.2?

A. Yes. RUCO 11.2 has been updated to provide supplemental information to support the 2007 property tax calculations included in my Rebuttal Testimony and related work papers. This information was provided to RUCO on October 3, 2006.

Q. IN HIS SURREBUTTAL TESTIMONY, MR. RIGSBY STATED THAT HE DOES NOT SUPPORT USING 2007 DATA IN THE TEST YEAR. CAN YOU EXPLAIN WHY YOU SUPPORT USING THE 2007 DATA IN CALCULATING THE TEST YEAR EXPENSE?

A. The 2007 property tax expense calculation is based on historical Plant-in-Service general ledger plant balances at December 31, 2005 which are both known and measurable. Assuming that the rates from this proceeding will go into effect in 2007, it seems logical that the Test Year expense should be based on projected 2007 property taxes to ensure the regulated rates provide for our 2007 property tax expense.

VI. CONCLUSION

Q. DOES THAT CONCLUDE YOUR REJOINDER TESTIMONY IN THIS PROCEEDING?

A. Yes.

ARIZONA PUBLIC SERVICE COMPANY
Comparison of Projected Construction Expenditures per Customer to Test Year Plant in Service Investment per Customer

Exhibit Description: This exhibit presents a comparison of the additional plant investment per customer with the test year plant in service per customer. This analysis shows that projected construction expenditures per new customer of 20.6 thousand dollars is significantly greater than the investment per existing customer of 10.9 thousand dollars that is reflected in current retail rates.

	Projected Construction Expenditures [1] 2007 - 2008 (Thousands)	Test Year Plant in Service [2] (Thousands)
Plant Investment [3]		
Production	$ 660,000	$ 5,645,000
Transmission	$ 449,000	$ 1,352,000
Distribution	$ 711,000	$ 3,821,000
Total	$ 1,820,000	$ 10,818,000

	Projected Construction Expenditures Per Customer 2007 - 2008 (Thousands)	Test Year Plant in Service Per Customer (Thousands)
Investment per Customer		
Production	$ 7.5	$ 5.7
Transmission	$ 5.1	$ 1.4
Distribution	$ 8.0	$ 3.8
Total	**$ 20.6** [4]	**$ 10.9** [5]

[1] From APS Exhibit 27.

[2] From APS witness Rumolo DJR_WP1.

[3] General Plant investment was allocated on a proportional basis to Production, Transmission and Distribution.

[4] Based upon projected 2007-2008 new customer growth of 88,418 customers.

[5] Based on 996,687 customers. This is the test year ending Sept. 05 average number of customers from APS S.F.R Schedule H-2.

EXHIBIT
tabbies
APS 59
admitted

APS Exhibit 60 Submitted 11/3/2006

PINNACLE WEST

October 29, 2003

Robert S. Aiken
Vice President
Federal Affairs

The Honorable John McCain
United States Senate
241 Russell Senate Office Building
Washington, DC 20510

Subject: Senate Bill S.139

Dear Senator McCain:

On behalf of Pinnacle West Capital Corporation, I want to thank you for your leadership in addressing the global climate change issue, and specifically in co-sponsoring the "Climate Stewardship Act of 2003." As the bill is coming up for debate in the Senate, I would like to bring three points to your attention.

First, we strongly support the provision in the bill that all sectors of the economy will be covered and not just the electric power generation sector as in the case of other proposed legislation. It is absolutely imperative that this legislation must apply fairly and evenly, without exemption, to all sources of power generation, irrespective of the type of fuel used. It is also critical that just one sector of the economy is not singled out to carry the burden of dealing with climate change. As you know, climate change is a global issue, and climatic impacts of greenhouse gas (GHG) emissions from any country are not limited to that country or even continent.

Second, we are aware that you plan to introduce a "substitute" to S.139 that will eliminate the Phase II Emissions Limit starting in 2016. I strongly agree with that proposal because the second py costly to the United States economy. Furthermore, that approach will enable the United States government to enter into further consultations with other nations toward developing a truly global action plan to stabilize atmospheric concentrations of greenhouse gases. Only a global action plan can realistically deal with GHG-induced global climate change.

Finally, we believe that it is critical that the role of nuclear power in meeting the country's electricity demand is acknowledged in the legislation. Nuclear generation should be provided "allowances" just as any other non-GHG emitting sources of energy because without the nuclear power other fossil fuel-fired plants would have to offset the nuclear-based generation. We are appreciative of your strong support for nuclear power, especially because of Palo Verde Nuclear Plant's critical contribution to meet the electricity demands for the rapidly growing Arizona population.

If you have any questions, please don't hesitate to contact me. Thank you very much again for your leadership on this issue.

Sincerely,

Robert Aiken

Robert S. Aiken

cc: Bill Post
Edward Fox
C.V. Mathai

EXHIBIT
tabbies
APS 60
admitted

Summary of Price Elasticity Estimates

The attached table summarizes the estimates of the price elasticity of retail demand for electricity available to APS from published industry sources or from APS' own analyses or models.

Each of these studies was similar in purpose, which was to estimate the change in electricity consumption due to a change in the price of electricity. However, the studies differed in design between the following categories:

- **Aggregate models** – uses average price and average usage levels aggregated across groups of customers over time to estimate the relationship between price and consumption;
- **Disaggregate models** – uses actual prices and usage levels at the household level over time to estimate the relationship between price and consumption; and
- **Fuel Substitution models** – uses prices of competing fuels, as well as the price of electricity, to estimate the relationship between price and electricity consumption over time.

In general, the elasticity estimates confirm that electricity demand is relatively inelastic. In other words, the absolute value of the coefficient of elasticity is less than 1.0, meaning that a 1% change in price results in something less than a 1% change in electricity consumption.

Additionally, nearly all reported price elasticity estimates have a negative coefficient, meaning that consumption of electricity declines as the price increases and vice-versa. Price and consumption are therefore considered to be inversely related.

The short-run elasticity estimates from the industry studies summarized in the table tend to fall between -0.1 and -0.4. APS' own estimates of price elasticity tend to be slightly lower than many of those reported in the industry, but the industry estimates also span a fairly broad range and the APS estimates are contained within that range.

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EXHIBIT
APS 61
admitted

SUMMARY OF PRICE ELASTICITY ESTIMATES

			Price Elasticity Estimates					
			Short-Run*			Long-Run*		
INDUSTRY STUDIES	# of Studies	Dates Published	Low	High	Average Point Est.	Low	High	Average Point Est.
Residential Customers								
1. Aggregated Models	16	1962-1993	0.57	-0.80	-0.21	-0.81	-1.66	-0.97
2. Fuel Substitution Models	4	1974-1978	-0.18	-0.54	-0.25	-0.72	-2.10	-0.99
3. Disaggregated models	9	1970-1993	0.04	-1.08	-0.39	-0.45	-2.33	-0.99
Commercial Customers	10	1973-1993	0.00	-1.18	-0.33	-0.56	-1.60	-0.93
Industrial Customers	9	1973-1992			-0.14			-0.97

APS ANALYSES / MODELS	Low	High	Average Point Est.
Residential Customers	-0.06	-0.35	-0.19
Commercial Customers	-0.09	-0.20	-0.15

* Short-run elasticity captures behavioral response within 1st year; Long-run elasticity is over multiple years to permit appliance replacement and fuel switching.

ARIZONA PUBLIC SERVICE COMPANY
Bill Impact of CWIP and Attrition Adjustments on Rate Schedule E-12 Residential Customer

	(a)	(b)	(c)	(d)
	170 Basis Point Attrition Adj. and CWIP Adj.		350 Basis Point Attrition Adj. and CWIP Adj.	
	Summer E-12 Rates	Winter E-12 Rates	Summer E-12 Rates	Winter E-12 Rates
1. Customer's Monthly kWh	800	800	800	800
2. Monthly Bill on Current (May 06) Rates [1]	$ 91.50	$ 77.70	$ 91.50	$ 77.70
3. Attrition Adjustment [2]	$ 2.01	$ 2.01	$ 4.14	$ 4.14
4. CWIP Adjustment [3]	$ 0.91	$ 0.91	$ 0.91	$ 0.91

1 Total Monthly Bill on current rates as shown on Appendix A, Column C from APS' October 9, 2006 response to Commission Mayes' October 2, 2006 letter that requested rate impacts at 800 kWh. The Total Monthly Bill amounts shown include the base charges, $.004/kWh PSA Adjustor rate, $.007/kWh PSA Interim Adjustor, $.000554/kWh PSA Surcharge, EPS, CRCC and franchise fees.

2 A 170 basis point Attrition Adj. charge of $.00251/kWh and a 350 basis point Attrition Adj. charge of $.00518/kWh were used for this calculation. These charges were derived based on a $66,449,000 ACC jurisdictional original cost revenue requirement increase for 170 basis points and $137,235,000 for 350 basis points.

3 A CWIP Adj. charge of $.00114/kWh was used for this calculation. These charges were derived based on a $30,353,000 ACC jurisdictional original cost revenue requirement increase.

EXHIBIT
tabbies
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admitted

ARIZONA PUBLIC SERVICE COMPANY
Derivation of Attrition and CWIP Adj. Charges
(000's)

170 Basis Point Attrition Adj. Charge

Total Inc. in Orig. Cost Rev. Req. Staff Surrebuttal with 170 Basis Point Attrition Adj.	$	258,012	[1]
Less Staff Proposed Rev. Req.	$	191,563	[2]
Attrition Rev. Req. from Revised A-1 with 170 Basis Point Attrition Adj.	$	66,449	
APS S.F.R Schedule H-2 MWH sales		26,513,307	
170 Basis Point Attrition Adj. per kWh charge	**$**	**0.00251**	

350 Basis Point Attrition Adj. Charge

Total Inc. in Orig. Cost Rev. Req. Staff Surrebuttal with 350 Basis Point Attrition Adj.	$	328,798	[3]
Less Staff Proposed Rev. Req.	$	191,563	
Attrition Rev. Req. from Revised A-1 with 350 Basis Point Attrition Adj.	$	137,235	
APS S.F.R Schedule H-2 MWH sales		26,513,307	
350 Basis Point Attrition Adj. per kWh charge	**$**	**0.00518**	

CWIP Adj. Charge

Total Inc. in Orig. Cost Rev. Req. Staff Surrebuttal with CWIP Adj.		221,916	[4]
Less Staff Proposed Rev. Req.		191,563	
CWIP Rev. Req. from Revised A-1	$	30,353	
APS S.F.R Schedule H-2 MWH sales		26,513,307	
CWIP Adj. per kWh charge	**$**	**0.00114**	

[1] See APS Exhibit No. 63, Pg. 3, Column A, Ln. 8.
[2] See Staff witness Dittmer's Revised Schedule A, Pg. 1, Column E, Ln. 7 from Staff's Surrebuttal Testimony.
[3] See APS Exhibit No. 63, Pg. 4, Column A, Ln. 8.
[4] See APS Exhibit No. 63, Pg. 5, Column A, Ln. 8.

APS EXHIBIT 63

APS Exhibit 63 provides the SFR Schedules that would correspond with certain of the financial integrity adjustments proposed by APS witnesses Wheeler and Brandt. Its purpose is to demonstrate how such adjustments can be integrated into an adjusted test year revenue requirements calculation.

EXHIBIT
tabbies
APS 63
admitted

APS EXHIBIT 63 - INDEX

ARIZONA PUBLIC SERVICE COMPANY
Computation of Increase in Gross Revenue Requirements
ACC Jurisdictional
Adjusted Test Year Ended 09/30/2005
Schedule A-1
(Dollars in Thousands)

		(a)	(b)	(c)
		Staff Surrebuttal Proposal **With APS Attrition Adjustment of 170 Basis Points**		
Line No.	Description	Original Cost	RCND	Fair Value
1	**Adjusted Rate Base** 1/	**4,402,377**	**7,710,492**	**6,056,435**
2	Adjusted Operating Income 2/	237,636	237,636	237,636
3	Current Rate of Return	5.40%	3.08%	3.92%
4	Required Operating Income	394,893	394,893	394,893
5	**Required Rate of Return** 3/	**8.97%**	**5.12%**	**6.52%**
6	Operating Income Deficiency	157,257	157,257	157,257
7	Gross Revenue Conversion Factor	1.6407	1.6407	1.6407
8	**Total Increase in Revenue Requirements** 4/	258,012	258,012	258,012
9	Total Sales to Ultimate Retail Customers	2,127,322	2,127,322	2,127,322
10	**Percentage Rate Increase**	**12.13%**	**12.13%**	**12.13%**

1/ See Revised Joint Accounting Schedules of the ACC Utilities Division Staff filed with Staff Surrebuttal 9/27/06, Revised Schedule B, page 1 of 2, column (D)
2/ See Revised Joint Accounting Schedules of the ACC Utilities Division Staff filed with Staff Surrebuttal 9/27/06, Revised Schedule C, page 1 of 4, column (C)
3/ See APS Exhibit 63, page 28 of 28, column (h); includes attrition adjustment of 170 basis points
4/ Does not include EPS or EIC proposals

ARIZONA PUBLIC SERVICE COMPANY
Computation of Increase in Gross Revenue Requirements
ACC Jurisdictional
Adjusted Test Year Ended 09/30/2005
Schedule A-1
(Dollars in Thousands)

		(a)	*(b)*	*(c)*
		Staff Surrebuttal Proposal **With APS Attrition Adjustment of 350 Basis Points**		
Line No.	Description	Original Cost	RCND	Fair Value
1	**Adjusted Rate Base** [1/]	**4,402,377**	**7,710,492**	**6,056,435**
2	Adjusted Operating Income [2/]	237,636	237,636	237,636
3	Current Rate of Return	5.40%	3.08%	3.92%
4	Required Operating Income	438,037	438,037	438,037
5	**Required Rate of Return** [3/]	**9.95%**	**5.68%**	**7.23%**
6	Operating Income Deficiency	200,401	200,401	200,401
7	Gross Revenue Conversion Factor	1.6407	1.6407	1.6407
8	**Total Increase in Revenue Requirements** [4/]	328,798	328,798	328,798
9	Total Sales to Ultimate Retail Customers	2,127,322	2,127,322	2,127,322
10	**Percentage Rate Increase**	**15.46%**	**15.46%**	**15.46%**

1/ See Revised Joint Accounting Schedules of the ACC Utilities Division Staff filed with Staff Surrebuttal 9/27/06, Revised Schedule B, page 1 of 2, column (D)

2/ See Revised Joint Accounting Schedules of the ACC Utilities Division Staff filed with Staff Surrebuttal 9/27/06, Revised Schedule C, page 1 of 4, column (C)

3/ See APS Exhibit 63, page 28 of 28, column (I); includes attrition adjustment of 350 basis points

4/ Does not include EPS or EIC proposals

ARIZONA PUBLIC SERVICE COMPANY
Computation of Increase in Gross Revenue Requirements
ACC Jurisdictional
Adjusted Test Year Ended 09/30/2005
Schedule A-1
(Dollars in Thousands)

		(a)	(b)	(c)
		Staff Surrebuttal Proposal **with APS CWIP Adjustment**		
Line No.	Description	Original Cost	RCND	Fair Value
1	**Adjusted Rate Base** [1/]	**4,663,377**	**7,971,492**	**6,317,435**
2	Adjusted Operating Income [2/]	240,145	240,145	240,145
3	Current Rate of Return	5.15%	3.01%	3.80%
4	Required Operating Income	375,402	375,402	375,402
5	**Required Rate of Return** [3/]	**8.05%**	**4.71%**	**5.94%**
6	Operating Income Deficiency	135,257	135,257	135,257
7	Gross Revenue Conversion Factor	1.6407	1.6407	1.6407
8	**Total Increase in Revenue Requirement** [4/]	221,916	221,916	221,916
9	Total Sales to Ultimate Retail Customers	2,127,322	2,127,322	2,127,322
10	**Percentage Rate Increase**	**10.43%**	**10.43%**	**10.43%**

1/ See APS Exhibit 63, page 6 of 28; includes CWIP adjustment of $261,000,000
2/ See APS Exhibit 63, page 7 of 28
3/ See Revised Joint Accounting Schedules of the ACC Utilities Division Staff filed with Staff Surrebuttal 9/27/06, Schedule D, page 1 of 1, column (E)
4/ Does not include EPS or EIC proposals

ARIZONA PUBLIC SERVICE COMPANY
ACC Jurisdiction
Original Cost Rate Base
Schedule B
(Dollars in Thousands)

Line No.	Description	(a) Rate Base as Presented in Staff Surrebuttal 1/	(b) APS CWIP Adjustment 2/	(c) Revised Rate Base including CWIP Adjustment *Cols (a) + (b)*
1.	Gross Utility Plant in Service	9,296,308	261,000	9,557,308
2.	Less: Accumulated Depreciation & Amort.	3,546,560	-	3,546,560
3.	Net Utility Plant in Service	5,749,748	261,000	6,010,748
4.	Less: Total Deductions	1,829,251	-	1,829,251
5.	Total Additions	481,881	-	481,881
6.	Total Rate Base	4,402,377	261,000	4,663,377

1/ See Revised Joint Accounting Schedules of the ACC Utilities Division Staff filed with Staff Surrebuttal 9/27/06, Revised Schedule B, page 1 of 2, column (D)

2/ As presented in APS Witness Brandt Rebuttal Testimony page 25

ARIZONA PUBLIC SERVICE COMPANY
ACC Jurisdiction
Adjusted Test Year Statement of Income
Test Year 12 Months Ended 9/30/2005
Schedule C-1
(Dollars in Thousands)

Line No.	Description	(a) Staff Surrebuttal Operating Income Schedule C 1/	(b) Income Tax Effect of APS CWIP Adjustment 2/	(c) Revised Schedule C-1 Cols (a) + (b)
1.	Electric Operating Revenues	$ 2,591,008	-	$ 2,591,008
	Other Operating Expenses:			
2.	Purchased power and fuel	1,163,566	-	1,163,566
3.	Operations and maintenance	694,026	-	694,026
4.	Depreciation and amortization	306,229	-	306,229
5.	Income taxes	69,890	(2,509)	67,381
6.	Other taxes	119,661	-	119,661
7.	Total	2,353,372	(2,509)	2,350,863
8.	Subtotal Operating income	$ 237,636	$ 2,509	$ 240,145
9.	Operating Income	$ 237,636	$ 2,509	$ 240,145

1/ See Revised Joint Accounting Schedules of the ACC Utilities Division Staff filed with Staff Surrebuttal 9/27/06, Revised Schedule C, page 1 of 4, column (C)

2/ Additional plant generates additional interest expense and corresponding income tax deductions. Additional "operating income" of $2,509,000 is entirely attributable to such additional tax deductions.

ARIZONA PUBLIC SERVICE COMPANY
Computation of Increase in Gross Revenue Requirements
ACC Jurisdictional
Adjusted Test Year Ended 09/30/2005
Schedule A-1
(Dollars in Thousands)

		(a)	(b)	(c)
		Staff Surrebuttal Proposal **with APS Plant-in-Service Adjustment**		
Line No.	Description	Original Cost	RCND	Fair Value
1	**Adjusted Rate Base [1/]**	**4,904,894**	**8,213,009**	**6,558,952**
2	Adjusted Operating Income [2/]	242,466	242,466	242,466
3	Current Rate of Return	4.94%	2.95%	3.70%
4	Required Operating Income	394,844	394,844	394,844
5	**Required Rate of Return [3/]**	**8.05%**	**4.81%**	**6.02%**
6	Operating Income Deficiency	152,378	152,378	152,378
7	Gross Revenue Conversion Factor	1.6407	1.6407	1.6407
8	**Total Increase in Revenue Requirement [4/]**	250,007	250,007	250,007
9	Total Sales to Ultimate Retail Customers	2,127,322	2,127,322	2,127,322
10	**Percentage Rate Increase**	**11.75%**	**11.75%**	**11.75%**

1/ See APS Exhibit 63, page 9 of 28; includes Plant-in-Service adjustment of $502,517,000
2/ See APS Exhibit 63, page 10 of 28
3/ See Revised Joint Accounting Schedules of the ACC Utilities Division Staff filed with Staff Surrebuttal 9/27/06, Schedule D, page 1 of 1, column (E)
4/ Does not include EPS or EIC proposals

ARIZONA PUBLIC SERVICE COMPANY
ACC Jurisdiction
Original Cost Rate Base
Schedule B
(Dollars in Thousands)

Line No.	Description	(a) Rate Base as Presented in Staff Surrebuttal [1/]	(b) APS Plant-in-Service Adjustment [2/]	(c) Revised Rate Base including Plant-in-Service Adjustment Cols (a) + (b)
1.	Gross Utility Plant in Service	9,296,308	502,517	9,798,825
2.	Less: Accumulated Depreciation & Amort.	3,546,560	-	3,546,560
3.	Net Utility Plant in Service	5,749,748	502,517	6,252,265
4.	Less: Total Deductions	1,829,251	-	1,829,251
5.	Total Additions	481,881	-	481,881
6.	Total Rate Base	4,402,377	502,517	4,904,894

1/ See Revised Joint Accounting Schedules of the ACC Utilities Division Staff filed with Staff Surrebuttal 9/27/06, Revised Schedule B, page 1 of 2, column (D)

2/ ACC Jurisdictional Plant-in-Service calculated from Total Company Plant-in-Service as presented in APS Witness Rockenberger Rebuttal Testimony, page 28

ARIZONA PUBLIC SERVICE COMPANY
ACC Jurisdiction
Adjusted Test Year Statement of Income
Test Year 12 Months Ended 9/30/2005
Schedule C-1
(Dollars in Thousands)

Line No.	Description	(a) Operating Income as Presented in Staff Surrebuttal [1/]	(b) Income Tax Effect of APS Plant-in-Service Adjustment [2/]	(c) Revised Schedule C-1 Cols (a) + (b)
1.	Electric Operating Revenues	$ 2,591,008	-	$ 2,591,008
	Other Operating Expenses:			
2.	Purchased power and fuel	1,163,566	-	1,163,566
3.	Operations and maintenance	694,026	-	694,026
4.	Depreciation and amortization	306,229	-	306,229
5.	Income taxes	69,890	(4,830)	65,060
6.	Other taxes	119,661	-	119,661
7.	Total	2,353,372	(4,830)	2,348,542
8.	Subtotal Operating income	$ 237,636	$ 4,830	$ 242,466
9.	Operating Income	$ 237,636	$ 4,830	$ 242,466

1/ See Revised Joint Accounting Schedules of the ACC Utilities Division Staff filed with Staff Surrebuttal 9/27/06, Revised Schedule C, page 1 of 4, column (C)

2/ Additional plant generates additional interest expense and corresponding income tax deductions. Additional "operating income" of $4,830,000 is entirely attributable to such additional tax deductions.

ARIZONA PUBLIC SERVICE COMPANY
Computation of Increase in Gross Revenue Requirements
ACC Jurisdictional
Adjusted Test Year Ended 09/30/2005
Schedule A-1
(Dollars in Thousands)

		(a)	(b)	(c)
		Staff Surrebuttal Proposal **With APS Attrition Adjustment of 170 Basis Points And APS CWIP Adjustment**		
Line No.	Description	Original Cost	RCND	Fair Value
1	**Adjusted Rate Base** [1/]	**4,663,377**	**7,971,492**	**6,317,435**
2	Adjusted Operating Income [2/]	240,145	240,145	240,145
3	Current Rate of Return	5.15%	3.01%	3.80%
4	Required Operating Income	418,305	418,305	418,305
5	**Required Rate of Return** [3/]	**8.97%**	**5.25%**	**6.62%**
6	Operating Income Deficiency	178,160	178,160	178,160
7	Gross Revenue Conversion Factor	1.6407	1.6407	1.6407
8	**Total Increase in Revenue Requirement** [4/]	292,307	292,307	292,307
9	Total Sales to Ultimate Retail Customers	2,127,322	2,127,322	2,127,322
10	**Percentage Rate Increase**	**13.74%**	**13.74%**	**13.74%**

1/ See APS Exhibit 63, page 12 of 28; includes CWIP adjustment of $261,000,000
2/ See APS Exhibit 63, page 13 of 28
3/ See APS Exhibit 63, page 28 of 28, column (h); includes attrition adjustment of 170 basis points
4/ Does not include EPS or EIC proposals

ARIZONA PUBLIC SERVICE COMPANY
ACC Jurisdiction
Original Cost Rate Base
Schedule B
(Dollars in Thousands)

Line No.	Description	(a) Rate Base as Presented in Staff Surrebuttal [1/]	(b) APS CWIP Adjustment [2/]	(c) Revised Rate Base including CWIP Adjustment Cols (a) + (b)
1.	Gross Utility Plant in Service	9,296,308	261,000	9,557,308
2.	Less: Accumulated Depreciation & Amort.	3,546,560	-	3,546,560
3.	Net Utility Plant in Service	5,749,748	261,000	6,010,748
4.	Less: Total Deductions	1,829,251	-	1,829,251
5.	Total Additions	481,881	-	481,881
6.	Total Rate Base	4,402,377	261,000	4,663,377

1/ See Revised Joint Accounting Schedules of the ACC Utilities Division Staff filed with Staff Surrebuttal 9/27/06, Revised Schedule B, page 1 of 2, column (D)

2/ As presented in APS Witness Brandt Rebuttal Testimony page 25

ARIZONA PUBLIC SERVICE COMPANY
ACC Jurisdiction
Adjusted Test Year Statement of Income
Test Year 12 Months Ended 9/30/2005
Schedule C-1
(Dollars in Thousands)

Line No.	Description	(a) Staff Surrebuttal Operating Income Schedule C [1/]	(b) Income Tax Effect of APS CWIP Adjustment [2/]	(c) Revised Schedule C-1 Cols (a) + (b)
1.	Electric Operating Revenues	$ 2,591,008	-	$ 2,591,008
	Other Operating Expenses:			
2.	Purchased power and fuel	1,163,566	-	1,163,566
3.	Operations and maintenance	694,026	-	694,026
4.	Depreciation and amortization	306,229	-	306,229
5.	Income taxes	69,890	(2,509)	67,381
6.	Other taxes	119,661	-	119,661
7.	Total	2,353,372	(2,509)	2,350,863
8.	Subtotal Operating income	$ 237,636	$ 2,509	$ 240,145
9.	Operating Income	$ 237,636	$ 2,509	$ 240,145

1/ See Revised Joint Accounting Schedules of the ACC Utilities Division Staff filed with Staff Surrebuttal 9/27/06, Revised Schedule C, page 1 of 4, column (C)

2/ Additional plant generates additional interest expense and corresponding income tax deductions. Additional "operating income" of $2,509,000 is entirely attributable to such additional tax deductions.

ARIZONA PUBLIC SERVICE COMPANY
Computation of Increase in Gross Revenue Requirements
ACC Jurisdictional
Adjusted Test Year Ended 09/30/2005
Schedule A-1
(Dollars in Thousands)

		(a)	(b)	(c)
		Staff Surrebuttal Proposal **with APS Attrition Adjustment of 170 Basis Points And APS Plant-in-Service Adjustment**		
Line No.	Description	Original Cost	RCND	Fair Value
1	**Adjusted Rate Base** 1/	**4,904,894**	**8,213,009**	**6,558,952**
2	Adjusted Operating Income 2/	242,466	242,466	242,466
3	Current Rate of Return	4.94%	2.95%	3.70%
4	Required Operating Income	439,969	439,969	439,969
5	**Required Rate of Return** 3/	**8.97%**	**5.36%**	**6.71%**
6	Operating Income Deficiency	197,503	197,503	197,503
7	Gross Revenue Conversion Factor	1.6407	1.6407	1.6407
8	**Total Increase in Revenue Requirement** 4/	324,043	324,043	324,043
9	Total Sales to Ultimate Retail Customers	2,127,322	2,127,322	2,127,322
10	**Percentage Rate Increase**	**15.23%**	**15.23%**	**15.23%**

1/ See APS Exhibit 63, page 15 of 28; includes Plant-in-Service adjustment of $502,517,000
2/ See APS Exhibit 63, page 16 of 28
3/ See APS Exhibit 63, page 28 of 28, column (h); includes attrition adjustment of 170 basis points
4/ Does not include EPS or EIC proposals

ARIZONA PUBLIC SERVICE COMPANY
ACC Jurisdiction
Original Cost Rate Base
Schedule B
(Dollars in Thousands)

Line No.	Description	(a) Rate Base as Presented in Staff Surrebuttal 1/	(b) APS Plant-in-Service Adjustment 2/	(c) Revised Rate Base including Plant-in-Service Adjustment Cols (a) + (b)
1.	Gross Utility Plant in Service	9,296,308	502,517	9,798,825
2.	Less: Accumulated Depreciation & Amort.	3,546,560	-	3,546,560
3.	Net Utility Plant in Service	5,749,748	502,517	6,252,265
4.	Less: Total Deductions	1,829,251	-	1,829,251
5.	Total Additions	481,881	-	481,881
6.	Total Rate Base	4,402,377	502,517	4,904,894

1/ See Revised Joint Accounting Schedules of the ACC Utilities Division Staff filed with Staff Surrebuttal 9/27/06, Revised Schedule B, page 1 of 2, column (D)

2/ ACC Jurisdictional Plant-in-Service calculated from Total Company Plant-in-Service as presented in APS Witness Rockenberger Rebuttal Testimony, page 28

ARIZONA PUBLIC SERVICE COMPANY
ACC Jurisdiction
Adjusted Test Year Statement of Income
Test Year 12 Months Ended 9/30/2005
Schedule C-1
(Dollars in Thousands)

Line *No.*	Description	(a) Operating Income as Presented in Staff Surrebuttal [1/]	(b) Income Tax Effect of APS Plant-in-Service Adjustment [2/]	(c) Revised Schedule C-1 *Cols (a) + (b)*
1.	Electric Operating Revenues	$ 2,591,008	-	$ 2,591,008
	Other Operating Expenses:			
2.	Purchased power and fuel	1,163,566	-	1,163,566
3.	Operations and maintenance	694,026	-	694,026
4.	Depreciation and amortization	306,229	-	306,229
5.	Income taxes	69,890	(4,830)	65,060
6.	Other taxes	119,661	-	119,661
7.	Total	2,353,372	(4,830)	2,348,542
8.	Subtotal Operating income	$ 237,636	$ 4,830	$ 242,466
9.	Operating Income	$ 237,636	$ 4,830	$ 242,466

1/ See Revised Joint Accounting Schedules of the ACC Utilities Division Staff filed with Staff Surrebuttal 9/27/06, Revised Schedule C, page 1 of 4, column (C)

2/ Additional plant generates additional interest expense and corresponding income tax deductions. Additional "operating income" of $4,830,000 is entirely attributable to such additional tax deductions.

ARIZONA PUBLIC SERVICE COMPANY
Computation of Increase in Gross Revenue Requirements
ACC Jurisdictional
Adjusted Test Year Ended 09/30/2005
Schedule A-1
(Dollars in Thousands)

		(a)	(b)	(c)
		Staff Surrebuttal Proposal **With APS Attrition Adjustment of 350 Basis Points And APS CWIP Adjustment**		
Line No.	Description	Original Cost	RCND	Fair Value
1	**Adjusted Rate Base** [1/]	**4,663,377**	**7,971,492**	**6,317,435**
2	Adjusted Operating Income [2/]	240,145	240,145	240,145
3	Current Rate of Return	5.15%	3.01%	3.80%
4	Required Operating Income	464,006	464,006	464,006
5	**Required Rate of Return** [3/]	**9.95%**	**5.82%**	**7.34%**
6	Operating Income Deficiency	223,861	223,861	223,861
7	Gross Revenue Conversion Factor	1.6407	1.6407	1.6407
8	**Total Increase in Revenue Requirement** [4/]	367,289	367,289	367,289
9	Total Sales to Ultimate Retail Customers	2,127,322	2,127,322	2,127,322
10	**Percentage Rate Increase**	**17.27%**	**17.27%**	**17.27%**

1/ See APS Exhibit 63, page 18 of 28; includes CWIP adjustment of $261,000,000
2/ See APS Exhibit 63, page 19 of 28
3/ See APS Exhibit 63, page 28 of 28, column (I); includes attrition adjustment of 350 basis points
4/ Does not include EPS or EIC proposals

ARIZONA PUBLIC SERVICE COMPANY
ACC Jurisdiction
Original Cost Rate Base
Schedule B
(Dollars in Thousands)

Line No.	Description	(a) Rate Base as Presented in Staff Surrebuttal [1/]	(b) APS CWIP Adjustment [2/]	(c) Revised Rate Base including CWIP Adjustment Cols (a) + (b)
1.	Gross Utility Plant in Service	9,296,308	261,000	9,557,308
2.	Less: Accumulated Depreciation & Amort.	3,546,560	-	3,546,560
3.	Net Utility Plant in Service	5,749,748	261,000	6,010,748
4.	Less: Total Deductions	1,829,251	-	1,829,251
5.	Total Additions	481,881	-	481,881
6.	Total Rate Base	4,402,377	261,000	4,663,377

1/ See Revised Joint Accounting Schedules of the ACC Utilities Division Staff filed with Staff Surrebuttal 9/27/06, Revised Schedule B, page 1 of 2, column (D)

2/ As presented in APS Witness Brandt Rebuttal Testimony page 25

ARIZONA PUBLIC SERVICE COMPANY
ACC Jurisdiction
Adjusted Test Year Statement of Income
Test Year 12 Months Ended 9/30/2005
Schedule C-1
(Dollars in Thousands)

Line No.	Description	(a) Staff Surrebuttal Operating Income Schedule C [1/]	(b) Income Tax Effect of APS CWIP Adjustment [2/]	(c) Revised Schedule C-1 Cols (a) + (b)
1.	Electric Operating Revenues	$ 2,591,008	-	$ 2,591,008
	Other Operating Expenses:			
2.	Purchased power and fuel	1,163,566	-	1,163,566
3.	Operations and maintenance	694,026	-	694,026
4.	Depreciation and amortization	306,229	-	306,229
5.	Income taxes	69,890	(2,509)	67,381
6.	Other taxes	119,661	-	119,661
7.	Total	2,353,372	(2,509)	2,350,863
8.	Subtotal Operating income	$ 237,636	$ 2,509	$ 240,145
9.	Operating Income	$ 237,636	$ 2,509	$ 240,145

1/ See Revised Joint Accounting Schedules of the ACC Utilities Division Staff filed with Staff Surrebuttal 9/27/06, Revised Schedule C, page 1 of 4, column (C)

2/ Additional plant generates additional interest expense and corresponding income tax deductions. Additional "operating income" of $2,509,000 is entirely attributable to such additional tax deductions.

ARIZONA PUBLIC SERVICE COMPANY
Computation of Increase in Gross Revenue Requirements
ACC Jurisdictional
Adjusted Test Year Ended 09/30/2005
Schedule A-1
(Dollars in Thousands)

		(a)	*(b)*	*(c)*
		Staff Surrebuttal Proposal **with APS Attrition Adjustment of 350 Basis Points And APS Plant-in-Service Adjustment**		
Line No.	Description	Original Cost	RCND	Fair Value
1	**Adjusted Rate Base** [1/]	**4,904,894**	**8,213,009**	**6,558,952**
2	Adjusted Operating Income [2/]	242,466	242,466	242,466
3	Current Rate of Return	4.94%	2.95%	3.70%
4	Required Operating Income	488,037	488,037	488,037
5	**Required Rate of Return** [3/]	**9.95%**	**5.94%**	**7.44%**
6	Operating Income Deficiency	245,571	245,571	245,571
7	Gross Revenue Conversion Factor	1.6407	1.6407	1.6407
8	**Total Increase in Revenue Requirement** [4/]	402,908	402,908	402,908
9	Total Sales to Ultimate Retail Customers	2,127,322	2,127,322	2,127,322
10	**Percentage Rate Increase**	**18.94%**	**18.94%**	**18.94%**

1/ See APS Exhibit 63, page 21 of 28; includes Plant-in-Service adjustment of $502,517,000
2/ See APS Exhibit 63, page 22 of 28
3/ See APS Exhibit 63, page 28 of 28, column (I); includes attrition adjustment of 350 basis points
4/ Does not include EPS or EIC proposals

ARIZONA PUBLIC SERVICE COMPANY
ACC Jurisdiction
Original Cost Rate Base
Schedule B
(Dollars in Thousands)

		(a)	(b)	(c)
Line No.	Description	Rate Base as Presented in Staff Surrebuttal [1/]	APS Plant-in-Service Adjustment [2/]	Revised Rate Base including Plant-in-Service Adjustment Cols (a) + (b)
1.	Gross Utility Plant in Service	9,296,308	502,517	9,798,825
2.	Less: Accumulated Depreciation & Amort.	3,546,560	-	3,546,560
3.	Net Utility Plant in Service	5,749,748	502,517	6,252,265
4.	Less: Total Deductions	1,829,251	-	1,829,251
5.	Total Additions	481,881	-	481,881
6.	Total Rate Base	4,402,377	502,517	4,904,894

1/ See Revised Joint Accounting Schedules of the ACC Utilities Division Staff filed with Staff Surrebuttal 9/27/06, Revised Schedule B, page 1 of 2, column (D)

2/ ACC Jurisdictional Plant-in-Service calculated from Total Company Plant-in-Service as presented in APS Witness Rockenberger Rebuttal Testimony, page 28

ARIZONA PUBLIC SERVICE COMPANY
ACC Jurisdiction
Adjusted Test Year Statement of Income
Test Year 12 Months Ended 9/30/2005
Schedule C-1
(Dollars in Thousands)

Line No.	Description	(a) Operating Income as Presented in Staff Surrebuttal 1/	(b) Income Tax Effect of APS Plant-in-Service Adjustment 2/	(c) Revised Schedule C-1 Cols (a) + (b)
1.	Electric Operating Revenues	$ 2,591,008	-	$ 2,591,008
	Other Operating Expenses:			
2.	Purchased power and fuel	1,163,566	-	1,163,566
3.	Operations and maintenance	694,026	-	694,026
4.	Depreciation and amortization	306,229	-	306,229
5.	Income taxes	69,890	(4,830)	65,060
6.	Other taxes	119,661	-	119,661
7.	Total	2,353,372	(4,830)	2,348,542
8.	Subtotal Operating income	$ 237,636	$ 4,830	$ 242,466
9.	Operating Income	$ 237,636	$ 4,830	$ 242,466

1/ See Revised Joint Accounting Schedules of the ACC Utilities Division Staff filed with Staff Surrebuttal 9/27/06, Revised Schedule C, page 1 of 4, column (C)

2/ Additional plant generates additional interest expense and corresponding income tax deductions. Additional "operating income" of $4,830,000 is entirely attributable to such additional tax deductions.

ARIZONA PUBLIC SERVICE COMPANY
Computation of Increase in Gross Revenue Requirements
ACC Jurisdictional
Adjusted Test Year Ended 09/30/2005
Schedule A-1
(Dollars in Thousands)

		(a)	(b)	(c)
		Staff Surrebuttal Proposal With APS Depreciation Adjustment		
Line No.	Description	Original Cost	RCND	Fair Value
1	**Adjusted Rate Base** [1/]	**4,402,377**	**7,710,492**	**6,056,435**
2	Adjusted Operating Income [2/]	207,161	207,161	207,161
3	Current Rate of Return	4.71%	2.69%	3.42%
4	Required Operating Income	354,391	354,391	354,391
5	**Required Rate of Return** [3/]	**8.05%**	**4.60%**	**5.85%**
6	Operating Income Deficiency	147,230	147,230	147,230
7	Gross Revenue Conversion Factor	1.6407	1.6407	1.6407
8	**Total Increase in Revenue Requirement** [4/]	241,560	241,560	241,560
9	Total Sales to Ultimate Retail Customers	2,127,322	2,127,322	2,127,322
10	**Percentage Rate Increase**	**11.36%**	**11.36%**	**11.36%**

1/ See Revised Joint Accounting Schedules of the ACC Utilities Division Staff filed with Staff Surrebuttal 9/27/06, Revised Schedule B, page 1 of 2, column (D)

2/ See APS Exhibit 63, page 24 of 28

3/ See Revised Joint Accounting Schedules of the ACC Utilities Division Staff filed with Staff Surrebuttal 9/27/06, Schedule D, page 1 of 1, column (E)

4/ Does not include EPS or EIC proposals

ARIZONA PUBLIC SERVICE COMPANY
ACC Jurisdiction
Adjusted Test Year Statement of Income
Test Year 12 Months Ended 9/30/2005
Schedule C-1
(Dollars in Thousands)

Line No.	Description	(a) Operating Income as Presented in Staff Surrebuttal 1/	(b) APS Depreciation Adjustment 2/ 3/	(c) Revised Schedule C-1 Cols (a) + (b)
1.	Electric Operating Revenues	$ 2,591,008	-	$ 2,591,008
	Other Operating Expenses:			
2.	Purchased power and fuel	1,163,566	-	1,163,566
3.	Operations and maintenance	694,026	-	694,026
4.	Depreciation and amortization	306,229	50,000	356,229
5.	Income taxes	69,890	(19,525)	50,365
6.	Other taxes	119,661	-	119,661
7.	Total	2,353,372	30,475	2,383,847
8.	Subtotal Operating income	$ 237,636	$ (30,475)	$ 207,161
9.	Operating Income	$ 237,636	$ (30,475)	$ 207,161

1/ See Revised *Joint Accounting Schedules* of the *ACC Utilities Division Staff filed with Staff Surrebuttal 9/27/06*, Revised Schedule C, page 1 of 4, column (C)

2/ See APS Witness Brandt Rebuttal Testimony, page 24

3/ Including related income tax impacts

ARIZONA PUBLIC SERVICE COMPANY
Computation of Increase in Gross Revenue Requirements
ACC Jurisdictional
Adjusted Test Year Ended 09/30/2005
Schedule A-1
(Dollars in Thousands)

		(a)	*(b)*	*(c)*
		Staff Surrebuttal Proposal **With APS Attrition Adjustment of 350 Basis Points APS Depreciation Adjustment And APS Plant-in-Service Adjustment**		
Line No.	Description	Original Cost	RCND	Fair Value
1	**Adjusted Rate Base [1/]**	**4,904,894**	**8,213,009**	**6,558,952**
2	Adjusted Operating Income [2/]	211,991	211,991	211,991
3	Current Rate of Return	4.32%	2.58%	3.23%
4	Required Operating Income	488,037	488,037	488,037
5	**Required Rate of Return [3/]**	**9.95%**	**5.94%**	**7.44%**
6	Operating Income Deficiency	276,046	276,046	276,046
7	Gross Revenue Conversion Factor	1.6407	1.6407	1.6407
8	**Total Increase in Revenue Requirement [4/]**	452,909	452,909	452,909
9	Total Sales to Ultimate Retail Customers	2,127,322	2,127,322	2,127,322
10	**Percentage Rate Increase**	**21.29%**	**21.29%**	**21.29%**

1/ See APS Exhibit 63, page 26 of 28; includes Plant-in-Service adjustment of $502,517,000
2/ See APS Exhibit 63, page 27 of 28
3/ See APS Exhibit 63, page 28 of 28, column (I); includes attrition adjustment of 350 basis points
4/ Does not include EPS or EIC proposals

ARIZONA PUBLIC SERVICE COMPANY
ACC Jurisdiction
Original Cost Rate Base
Schedule B
(Dollars in Thousands)

Line No.	Description	(a) Rate Base as Presented in Staff Surrebuttal 1/	(b) APS Plant-in-Service Adjustment 2/	(c) Revised Rate Base including Plant-in-Service Adjustment Cols (a) + (b)
1.	Gross Utility Plant in Service	9,296,308	502,517	9,798,825
2.	Less: Accumulated Depreciation & Amort.	3,546,560	-	3,546,560
3.	Net Utility Plant in Service	5,749,748	502,517	6,252,265
4.	Less: Total Deductions	1,829,251	-	1,829,251
5.	Total Additions	481,881	-	481,881
6.	Total Rate Base	4,402,377	502,517	4,904,894

1/ See Revised Joint Accounting Schedules of the ACC Utilities Division Staff filed with Staff Surrebuttal 9/27/06, Revised Schedule B, page 1 of 2, column (D)

2/ ACC Jurisdictional Plant-in-Service calculated from Total Company Plant-in-Service as presented in APS Witness Rockenberger Rebuttal Testimony, page 28

ARIZONA PUBLIC SERVICE COMPANY
ACC Jurisdiction
Adjusted Test Year Statement of Income
Test Year 12 Months Ended 9/30/2005
Schedule C-1
(Dollars in Thousands)

Line No.	Description	(a) Operating Income as Presented in Staff Surrebuttal [1/]	(b) Income Tax Effect of APS Plant-in-Service Adjustment [2/]	(c) APS Depreciation Adjustment [3/]	(d) Revised Schedule C-1 Cols (a) + (b) + (c)
1.	Electric Operating Revenues	$ 2,591,008	-	-	$ 2,591,008
	Other Operating Expenses:				
2.	Purchased power and fuel	1,163,566	-	-	$ 1,163,566
3.	Operations and maintenance	694,026	-	-	$ 694,026
4.	Depreciation and amortization	306,229	-	50,000	$ 356,229
5.	Income taxes	69,890	(4,830)	(19,525)	$ 45,535
6.	Other taxes	119,661	-	-	$ 119,661
7.	Total	2,353,372	(4,830)	30,475	2,379,017
8.	Subtotal Operating income	$ 237,636	$ 4,830	$ (30,475)	$ 211,991
9.	Operating Income	$ 237,636	$ 4,830	$ (30,475)	$ 211,991

1/ See Revised Joint Accounting Schedules of the ACC Utilities Division Staff filed with Staff Surrebuttal 9/27/06, Revised Schedule C, page 1 of 4, column (C)

2/ Additional plant generates additional interest expense and corresponding income tax deductions. Additional "operating income" of $4,830,000 is entirely attributable to such additional tax deductions.

3/ Includes income tax effects

ARIZONA PUBLIC SERVICE COMPANY
Summary Cost of Capital - Including Attrition Adjustments
Schedule D-1
(Thousands of Dollars)

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
		Staff Proposed End of Test Year 9/30/2005 [1/]				Staff Proposed With **APS 170 Basis Points Attrition** [2/] End of Test Year 9/30/2005				Staff Proposed With **APS 350 Basis Points Attrition** [3/] End of Test Year 9/30/2005			
Line No.	Invested Capital	Amount	%	Cost Rate	Composite Cost	Amount	%	Cost Rate	Composite Cost	Amount	%	Cost Rate	Composite Cost
1.	Long-Term Debt	2,574,825	45.50%	5.41%	2.46%	$2,574,825	45.50%	5.41%	2.46%	$2,574,825	45.50%	5.41%	2.46%
2.	Preferred Stock	-	0.00%	0.00%	0.00%	-	0.00%	0.00%	0.00%	-	0.00%	0.00%	0.00%
3.	Common Equity	3,083,591	54.50%	10.25%	5.59%	$3,083,591	54.50%	11.95%	6.51%	$3,083,591	54.50%	13.75%	7.49%
4.	Short-Term Debt	-	0.00%	0.00%	0.00%	-	0.00%	0.00%	0.00%	-	0.00%	0.00%	0.00%
5.	Total	$5,658,416	100.00%		8.05%	$5,658,416	100.00%		8.97%	$5,658,416	100.00%		9.95%

1/ See Revised Joint Accounting Schedules of the ACC Utilities Division Staff filed with Staff Surrebuttal 9/27/06, Schedule D, page 1 of 1, column (E)
2/ As presented in APS Witness Brandt Rebuttal Testimony, page 29
3/ As presented in APS Witness Brandt Rebuttal Testimony, page 30

APS Exhibit 64
Submitted 11/3/2006

Impact of Hook-Up Fees on FFO to Debt Ratio
(Millions of Dollars)

No Income Tax Gross-Up

	Projected APS 12/31/2006 FFO to Debt (Rebuttal) (DEB_WP1RB)	Impact of Adding $82 million of Annual Hook-up Fees (1)	Projected APS 12/31/2006 FFO to Debt With Pro-Forma Hook-up Fees
FFO	$ 647	$ (32)	$ 615
Debt	3,667	(50)	3,617
FFO to debt	17.6%	-0.6%	17.0%

(1) Assumes $2,000 hook up fee charged to 41,000 "new" customers, generating $82 million. Current taxes increase by $32 million, which reduces FFO. Debt is reduced by $50 million.

With Income Tax Gross-Up

	Projected APS 12/31/2006 FFO to Debt (Rebuttal) (DEB_WP1RB)	Impact of Adding $136 million of Annual Hook-up Fees (2)	Projected APS 12/31/2006 FFO to Debt With Pro-Forma Hook-up Fees
FFO	$ 647	$ (54)	$ 593
Debt	3,667	(82)	3,585
FFO to debt	17.6%	-1.1%	16.5%

(2) Assumes $3,306 hook up fee ($2,000/(1-39.5%)) charged to 41,000 "new" customers, generating $136 million. Current taxes increase by $54 million, which reduces FFO. Debt is reduced by $82 million.

EXHIBIT
tabbles
APS 64
admitted

DIRECT TESTIMONY OF FRED H. BALLUFF

On Behalf of Arizona Public Service Company

Docket No. E-01345A-05-0816

January 31, 2006

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DIRECT TESTIMONY OF FRED H. BALLUFF

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

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND ADDRESS.

A. My name is Fred H. Balluff. My address is 238 Elm Park Avenue, Elmhurst, Illinois 60126.

Q. PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL QUALIFICATIONS.

A. I graduated from St. Ambrose College, Davenport, Iowa in 1963 with a Bachelor of Arts degree, majoring in accounting with a minor in economics. I received my MBA from Tulane University in 1985.

I joined the firm of Deloitte Haskins & Sells ("DH&S") in 1963. DH&S merged with Touche Ross & Co. in 1989, forming the firm of Deloitte & Touche ("D&T"). From 1963 to 1973, I was in the Chicago office of DH&S. During that time, I participated in audits of companies in a broad range of industries including public utilities, manufacturing, finance, retailing and construction. I was the audit manager responsible for such utility clients as Interstate Power Company, Wisconsin Southern Gas Company and Hot Springs Water Company. From 1973 to 1981, I was a member of the Public Utilities Department of DH&S located in Washington, D.C., where my activities included accounting research, preparation and presentation of training programs, consideration of specific accounting, auditing, and regulatory questions, consulting for clients in rate proceedings and management audits. As a Partner of DH&S, I held the position of National

Industry Accounting and Auditing Coordinator for the public utility industry, which was the top technical position at DH&S serving the utility industry.

From 1981 to 1988, I was the Director of Internal Auditing for MSS System Services, Inc. ("MSS"), a company serving the Middle South Utility System. Middle South Utilities has since changed its name to the Entergy Corporation. The Entergy system provides electric service to 2.4 million customers in Arkansas, Louisiana, Mississippi, and Texas. At MSS, I directed financial and management audits as well as consulted on financial and management matters.

I was a faculty member of the College of Business Administration at the University of Illinois at Chicago from August 1988 to September 1, 1999. I have taught accounting theory, financial and management accounting, and auditing. I have also provided consulting services as a Special Project Associate of NorthPoint Consulting Group or its predecessor, Bower Rohr & Associates since 1988.

I am a Certified Public Accountant and a member of the American Institute of Certified Public Accountants and the Illinois CPA Society. I have appeared as an expert witness in public utility rate proceedings before the Illinois Commerce Commission, the Indiana Utility Regulatory Commission, the Maryland Public Service Commission, the New Hampshire Public Utilities Commission, the New Jersey Board of Public Utilities, the New Jersey Department of Environmental Protection and Energy, the Public Utilities Commission of Ohio, the Pennsylvania Public Utility Commission, the Vermont Public Service Board and the Public Service Commission of the District of Columbia.

Q. PLEASE BRIEFLY DESCRIBE YOUR EXPERIENCE WITH RESPECT TO RATEMAKING?

A. I have participated in numerous rate proceedings involving electric, gas, water, sewer, cable, steam heat, chilled water, and solid waste entities. My experience includes:

- Prepared or reviewed class cost of service allocation and rate design studies for electric, gas, water, and sewer entities.
- Reviewed and analyzed working capital studies.
- Participated in and managed audits of electric, gas distribution, and water companies.
- Preparation of continuing education courses in accounting, auditing, and ratemaking.
- Testimony as an expert witness in rate proceedings for electric, gas, water, sewer, steam heat, chilled water, and solid waste entities on rate base including working capital requirements, cost of service including deferred income taxes and attrition, adjustment clauses, cost allocations including jurisdictional separations, class cost of service, rate design, and management of fuel procurement practices.

A more detailed description of my professional qualifications and experience is attached as Appendix A.

Q. WHAT IS YOUR ROLE IN THIS PROCEEDING?

A. Arizona Public Service Company ("APS") has engaged NorthPoint Consulting Group to help determine the Company's cash working capital requirement.

Q. WHAT WAS THE SCOPE OF YOUR WORK?

A. I provided consulting services to APS related to the determination of the Company's cash working capital requirements. I prepared the approach to be taken for a lead/lag study; discussed in detail the procedures used with appropriate APS personnel, and reviewed and tested the accuracy of their calculations.

Q. PLEASE IDENTIFY THE ATTACHMENTS WHICH YOU WILL BE SPONSORING AND FOR WHICH YOU WILL BE PROVIDING TESTIMONY.

A. I am sponsoring Attachment FHB-1, Cash Working Capital Required for Operating Expenses – Lead Lag Study.

II. SUMMARY OF TESTIMONY

Q. WOULD YOU PLEASE SUMMARIZE YOUR DIRECT TESTIMONY?

A. My testimony presents the lead/lag approach used by APS to determine the cash working capital to be included in rate base. Based on the lead/lag study, APS has a negative cash working capital requirement of $29,372,869, which reduced the APS test year rate base.

III. CASH WORKING CAPITAL REQUIREMENT

Q. PLEASE PROVIDE YOUR DEFINITION OF RATE BASE AND CASH WORKING CAPITAL.

A. Cash working capital is a part of the investment made to provide utility service to customers and thus is a component of rate base. It therefore has the same overall purpose of total rate base. Rate base represents the investment in plant and other assets used in providing utility service, for which a fair return must be provided to the sources of capital. In the determination of rate base, adjustments should be made to allow investors to earn a return on unrecovered investment, but not on funds provided by customers that may provide cost-free funds on a temporary basis. Recognition of depreciation as a cost-of-service item allows a utility to recover its investment in plant through the rate making process. Accordingly, rate base is reduced by accumulated depreciation. Deferred income taxes may also provide funds that are available for investment if deferred income tax expense is included in cost-of service because, as the name implies, deferred income taxes represent an expense that is not currently payable. Accordingly, rate base is reduced by accumulated deferred income taxes.

Cash working capital represents the amount of capital required of investors above the investment in plant and other rate base items to cover cash requirements. The primary reason why this capital is required at any point in time is generally due to the delay in the collection of revenues.

Q. PLEASE GIVE A BRIEF EXPLANATION OF THE LEAD/LAG APPROACH.

A. A lead/lag study measures the difference between the time services are rendered until cash for services are collected in rates (the revenue lag) and compares it to the time that operating services are incurred until they are paid (the expense lag). The difference between these two periods is expressed in days. The resulting number of days times the average daily operating expense produces the working capital requirement for most operating expenses.

Q. WHAT WAS THE OBJECTIVE OF THE STUDY OF CASH WORKING CAPITAL REQUIREMENTS?

A. The objective of the cash working capital study was to determine the amount that is necessary to include in rate base so that investors are adequately compensated for the funds needed to maintain cash operating requirements. In addition, one must also make adjustments to reflect the fact that certain offsets to rate base, specifically accumulated depreciation and deferred taxes, have not actually been recovered by investors at any single point of time due to the lag in receiving the associated revenues.

Q. WHAT WAS YOUR APPROACH TO THE CASH WORKING CAPITAL STUDY?

A. A lead/lag study was completed to determine the gap between the time that expenditures for current operations are made and when revenues are collected in rates. Consideration was given to the treatment accorded other working capital components and the special treatment required for prepayments, depreciation and amortization, deferred income taxes, inventories, and sales taxes.

Q. PLEASE DESCRIBE ATTACHMENT FHB-1.

A. Attachment FHB-1 lists the operating expenses and sales taxes accrued for the Test Year ending September 30, 2005. The revenue lag days represents the number of days between the time services are rendered and the time the related revenues are collected from customers. The expense lags generally represent the time between when expenses are incurred until the related expense is paid. Certain expenses don't have expense lags. These expenses are discussed later in my testimony.

Q. DOES THE REVENUE LAG RELATE ONLY TO REVENUES FROM ARIZONA RETAIL CONSUMERS?

A. No. The revenue lag represents a composite lag, which includes Arizona retail customers, transmission revenue, sales for resale, and other revenues that are part of the determination of revenue requirements for both state and federal purposes.

Q. PLEASE DESCRIBE HOW THE REVENUE LAG FOR RETAIL CUSTOMERS WAS DETERMINED.

A. The overall revenue lag is comprised of three components: the service lag, the billing lag, and the collection lag.

The service lag is an estimate of the time between the time service is provided and the end of the billing period. The Company reads its meters once a month on a cycle basis. The average midpoint of service for this purpose was calculated by dividing the normal year of 365 days by 12 months by 2 to arrive at a service lag of 15.21 days.

The billing lag is the lag days between the meter read date and billing date. To estimate this lag, APS calculated the billing lag for each billing cycle. The sum of these billing lags for each month were divided by the number of billing cycles in each month to produce average billing lags for each month. These monthly billing lags were multiplied by the average daily revenues (including sales tax) for each month to produce monthly revenue dollar days. These monthly revenue dollar days were summed. The total of the monthly dollar days for the year were divided by the total revenues (including sales tax) to arrive at a weighted average billing lag of 5.03 days.

The collection lag represents the time it takes to collect the amounts billed. This lag was calculated by dividing the average daily outstanding accounts receivable balances by the average daily revenues including sale taxes to arrive at a collection lag of 16.70 days.

Q. PLEASE DESCRIBE HOW THE EXPENSE LAGS WERE CALCULATED.

A. The lag for expenditures is the time between when a service or benefit is received and payment is made. This lag should represent the mid-point of the service period plus the time from the end of the service period to the date of payment. For an expenditure selected on a sample basis, the lag days for the selected item were multiplied by the dollar amount of the item to obtain the weighted dollar days. The total dollar days were divided by the related total sampled expenditures to obtain the weighted average lag days. For expenditures paid in installments, such as income taxes currently payable, percentages instead of dollars were used to obtain the weighted average lag days. As stated earlier in my testimony, special treatment was required for prepayments, depreciation and amortization, deferred income taxes, inventories, and sales taxes to avoid either over or under recovery of the cost of capital.

Q. **WHY DOES INSURANCE EXPENSE ONLY HAVE A REVENUE LAG?**

A. Insurance is paid in advance. Therefore, insurance has a lead time (negative lag). There are two basic methods used to permit utilities to recover their cost of capital related to a prepaid expense. Both methods produce similar results. Under the lead/lag formula, the insurance could be included in the cash working capital study as the difference between the payment date and the average expense date (the mid-point of the benefit period). This would produce a lead period or negative lag. However, APS has included prepayments as another component in rate base. Including prepaid expense as a separate component of rate base and including a negative lag in the cash working capital study would overstate rate base. To avoid duplicating the return on prepayments, we carefully considered the effect that rate base had on revenue requirements. Theoretically, a return on an investment is earned when it is in rate base. When the prepayment is charged to expense, rate base is reduced and recovery of the return stops. Therefore, insurance expense is included in the lead/lag study with only a revenue lag to bridge the gap between the time rate base is reduced by the charge to expense and when that amount is recovered in rates (the revenue lag).

Q. WHAT APPROACH DID YOU USE WITH RESPECT TO EXPENSE LAGS FOR INVENTORIES OF FUEL AND MATERIALS AND SUPPLIES?

A. Investors are entitled to earn a return on their investment in inventories, including fuel, materials and supplies and other inventories used in the utility business. These inventories are presumed to be included in rate base and a return earned when inventories are received. The expense lags represent an estimate of the time, on a dollar weighted basis, between the date inventory is received and the date the invoice is paid. These lags are applied to the fuel and inventory amounts expensed for the year.

Q. WHY DID YOU MEASURE ONLY THE REVENUE LAG FOR DEPRECIATION AND AMORTIZATION AMOUNTS IN THE LEAD/LAG CALCULATIONS?

A. Recognition of a revenue lag is necessary to bridge the gap between the time rate base is reduced by the charge to expense and when that amount is recovered in rates. Plant and nuclear fuel are presumed to be included in rate base at the time such plant is placed in service. Plant expenditures are made during the course of construction. There is not an "expense lag" as generally defined when depreciation and amortization are charged to expense. Cash is not expended at the time depreciation is recorded. Depreciation expense is an allocation of an investment already made. However, rate base is presumed to be reduced at the time depreciation is recorded. As stated above, accumulated depreciation is used to reduce rate base because depreciation for utilities represents both an allocation of costs and a recovery of costs. That means that rate base is reduced during the benefit period when the expense is incurred. The reason that rate base is reduced by accumulated depreciation is to prevent investors from earning a return on investments made with funds recovered from customers. However, depreciation is recorded before the Company recovers the revenues related to depreciation. Thus, investors would be prevented from earning a return on their investment between the time depreciation is expensed and the time that such depreciation is recovered in rates if the related lag in revenues is not recognized.

Q. WHY DID YOU MEASURE ONLY THE REVENUE LAG FOR DEFERRED INCOME TAXES IN THE LEAD/LAG CALCULATIONS?

A. As with depreciation, accumulated deferred income taxes are used to reduce rate base at the time deferred income taxes are recorded. Recognition of a revenue lag is necessary to bridge the gap between the time rate base is reduced by the charge to expense and when that amount is recovered in rates. Deferred income tax expense is not generally considered a cash expense. However, cash expenditures will normally be required in the future. For example, deferred tax procedures are generally required for the difference between tax and book depreciation. Assuming there are no basis differences in a depreciable plant, tax depreciation and book depreciation will be equal over the entire life of a plant item. However, accelerated tax depreciation for tax purposes will produce an excess of tax depreciation over book depreciation in the early years of an asset's life and will produce an excess of book depreciation over tax depreciation in later years. The increase in tax depreciation in the early years will reduce taxes currently payable in those years. These differences are timing differences. Deferred income taxes are recorded for the tax effect of these timing differences. Eventually, book depreciation will exceed tax depreciation thereby increasing taxes payable. The cash flows provided by a reduction in taxes payable in the early years are paid back in the later years. But the issue is not whether it is a cash or non-cash expense. As with depreciation expense, deferred income tax expenses that increase deferred tax liabilities are included in revenue requirements.

Rate base is reduced by deferred income taxes payable to prevent investors from earning a return on investments made with funds provided by consumers. However, the funds have not been provided by consumers until paid by consumers. That has to be recognized in the lead/lag study.

Q. PLEASE DESCRIBE HOW THE REVENUE AND EXPENSE LAGS RELATED TO SALES TAXES WERE DETERMINED.

A. Most of the sales tax shown in the lead/lag study represents amounts billed to customers. Sales taxes are paid on the 25th of the month after such accounts are billed. Thus, APS has temporary use of these funds, and thus we must recognize such funds as part of the cash working capital study. The revenue lag days represent the collection lag for revenues. The expense lag represents an estimate of the time between the time of billing and the end of the billing month (15.21 days), plus the 25 days APS has use of the funds in the month such taxes are paid. This method is also consistent with the approach proposed by the Commission Staff in the Company's last rate case.

Q. WHAT IS APS' CASH WORKING CAPITAL REQUIREMENT?

A. As set forth in Attachment FHB-1, APS has a negative cash working capital requirement of $29,372,869. As discussed in Ms. Rockenberger's testimony, the negative cash working capital requirement reduces the APS test year rate base.

Q. DOES THAT CONCLUDE YOUR PRE FILED DIRECT TESTIMONY?

A. Yes.

ARIZONA PUBLIC SERVICE COMPANY
CASH WORKING CAPITAL REQUIRED FOR OPERATING EXPENSES - LEAD LAG STUDY
TWELVE MONTHS ENDED SEPTEMBER 30, 2005

LINE	DESCRIPTION	AMOUNT	REVENUE LAG DAYS	EXPENSE LAG DAYS	NET LAG DAYS	CWC FACTOR	WORKING CAPITAL REQUIREMENT
		(1)	(2)	(3)	(4)	(5)	(6)
1	FUEL FOR ELECTRIC GENERATION:						
2	COAL	200,856,342	36.95027	32.36664	4.58363	0.01256	2,522,756
3	NATURAL GAS	237,557,927	36.95027	44.25857	-7.30830	-0.02002	(4,755,910)
4	FUEL OIL	1,077,082	36.95027	32.34060	4.60967	0.01263	13,604
5	NUCLEAR:						
6	AMORTIZATION	34,445,413	36.95027	0.00000	36.95027	0.10123	3,486,909
7	SPENT FUEL	7,336,099	36.95027	76.35359	-39.40333	-0.10795	(791,932)
8	TOTAL NUCLEAR FUEL	41,781,512					2,694,977
9							
10	TOTAL FUEL	481,272,863					475,427
11							
12	PURCHASED POWER	1,313,764,296	36.95027	38.15020	-1.19994	-0.00329	(4,322,285)
13	TRANSMISSION BY OTHERS	14,391,245	36.95027	33.69389	3.25638	0.00892	128,370
14	TOTAL PURCHASED POWER & TRANSMISSION	1,328,155,540					(4,193,915)
15							
16	TOTAL FUEL AND PURCHASED POWER	1,809,428,404					(3,718,488)
17							
18	OTHER OPERATIONS & MAINTENANCE:						
19	PAYROLL	240,714,447	36.95027	15.00192	21.94835	0.06013	14,474,160
20	INCENTIVE	8,653,091	36.95027	214.50000	-177.54973	-0.48644	(4,209,209)
21	PENSION AND OPEB	38,986,000	36.95027	77.71371	-40.76344	-0.11168	(4,353,956)
22	EMPLOYEE BENEFITS	26,995,515	36.95027	20.35895	16.59132	0.04546	1,227,216
23	PAYROLL TAXES	18,118,131	36.95027	21.78589	15.16438	0.04155	752,808
24	MATERIALS & SUPPLIES	53,466,114	36.95027	24.22000	12.73027	0.03488	1,864,898
25	FRANCHISE PAYMENTS	11,986,402	36.95027	52.83966	-15.88940	-0.04353	(521,768)
26	VEHICLE LEASE PAYMENTS	3,169,771	36.95027	7.43789	29.51238	0.08086	256,308
27	RENTS	6,776,038	36.95027	-33.48601	70.43627	0.19298	1,307,640
28	PALO VERDE LEASE	45,900,681	36.95027	47.31849	-10.36823	-0.02841	(1,304,038)
29	PALO VERDE S/L GAIN AMORT	(4,575,722)	36.95027	0.00000	36.95027	0.10123	(463,200)
30	INSURANCE	4,639,562	36.95027	0.00000	36.95027	0.10123	469,663
31	OTHER	119,131,971	36.95027	35.39000	1.56027	0.00427	508,694
32	TOTAL	573,962,000					10,009,216
33							
34	DEPRECIATION & AMORTIZATION	321,525,565	36.95027	0.00000	36.95027	0.10123	32,548,033
35	AMORT OF ELECTRIC PLT ACQ ADJ	0	36.95027	0.00000	36.95027	0.10123	0
36	AMORT OF PROP LOSSES & REG STUDY COSTS	(2,564,492)	36.95027	0.00000	36.95027	0.10123	(259,604)
37	TOTAL	318,961,073					32,288,429
38							
39	INCOME TAXES:						
40	CURRENT:						
41	FEDERAL	59,824,326	36.95027	58.95000	-21.99973	-0.06027	(3,605,612)
42	STATE	16,379,288	36.95027	58.95000	-21.99973	-0.06027	(987,180)
43	DEFERRED	77,758,889	36.95027	0.00000	36.95027	0.10123	7,871,532
44	TOTAL	153,962,503					3,278,740
45							
46	OTHER TAXES:						
47	PROPERTY TAXES	123,403,653	36.95027	211.94223	-174.99196	-0.47943	(59,163,413)
48	SALES TAXES	158,240,555	16.69615	40.21000	-23.51385	-0.06442	(10,193,857)
49	FRANCHISE TAXES	18,920,381	16.69615	52.83966	-36.14352	-0.09902	(1,873,496)
50	TOTAL OTHER TAXES	300,564,589					(71,230,766)
51							
52	TOTAL	3,156,878,568					(29,372,869)

Attachment FB-1

REBUTTAL TESTIMONY OF FRED BALLUFF

On Behalf of Arizona Public Service Company

Docket No. E-01345A-05-0816

September 15, 2006

EXHIBIT

APS 64

admitted

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REBUTTAL TESTIMONY OF FRED H. BALLUFF
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-05-0816)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND ADDRESS.

A. My name is Fred H. Balluff. My address is 238 Elm Park Avenue, Elmhurst, Illinois 60126.

Q. ARE YOU THE SAME FRED H. BALLUFF WHO PREVIOUSLY FILED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes.

Q. ARE YOUR CREDENTIALS SET FORTH IN THAT TESTIMONY?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. My purpose is to respond to the direct testimony of Staff witness James Dittmer and RUCO witness Marylee Diaz Cortez regarding the cash working capital requirements of APS. I have specific comments on the positions that Mr. Dittmer and Ms. Diaz Cortez took on items that they characterized as non-cash items and their positions on interest expense.

II. CASH WORKING CAPITAL: NON-CASH ITEMS

Q. DID STAFF OR RUCO IDENTIFY ANY ITEMS AS NON-CASH ITEMS?

A. Yes. They characterized depreciation and amortization of capital items as non-cash items. Additionally, Mr. Dittmer characterized deferred income tax expense and the amortization of prepaid insurance as non-cash items.

Q. DID STAFF OR RUCO MAKE ANY RECOMMENDATIONS CONCERNING THESE ITEMS?

A. Yes. They recommend eliminating the revenue lag applicable to the recovery of the items they characterized as non-cash items. Ms. Diaz Cortez also eliminated the revenue lag applicable to the recovery of deferred income tax expense, but provided no support for her elimination.

Q. HOW DOES YOUR TREATMENT OF DEPRECIATION, AMORTIZATION EXPENSE, AND DEFERRED INCOME TAXES DIFFER FROM THAT OF STAFF AND RUCO?

A. In its direct case filed on January 31, 2006, APS included depreciation and amortization expense, insurance expense and deferred income taxes in the calculation of cash working capital (Attachment FHB-1) with a zero expense lag and the revenue lag used for all other expenses. My support for this was provided in my Direct Testimony. Both Ms. Diaz Cortez and Mr. Dittmer indicate that non-cash items are properly excluded from cash working capital requirements.

I have acknowledged that these items are considered non-cash items <u>at the time they are expensed</u>. But that is not the issue. The issue deals with the timing of the recovery of depreciation expense in revenues. Both of these expenses are included in the determination of revenue requirements (cost of service). Thus, the recoveries of these expenses through the collection of revenues and more specifically, the lag in those recoveries represent a cash item.

As indicated beginning on page 9, line 14 through page 11, line 4 of my Direct Testimony, this method was used to recognize that these items are recorded (expensed) before such expenses are recovered from customers. When depreciation expense is recorded and deferred income tax charges are recorded, accumulated depreciation and deferred income tax credits are recorded. These are reductions from rate base. At that time, the expenses have not been recovered from customers because of the revenue lag. Unless the revenue lag is included with a zero expense lag in the calculation of cash working capital, it is clear that APS will not earn a return on a significant portion of its unrecovered invested capital.

Depreciation expense represents a significant portion of operating expenses. As shown on FHB-1, depreciation expense alone was $321,525,565 and amortization of nuclear fuel was $34,445,413. The incorrect exclusion of depreciation and amortization expense prevents APS from earning a return on over $35 million of unrecovered invested capital.

Q. DID STAFF OR RUCO ADDRESS THE REVENUE LAG APPLICABLE TO THE RECOVERY OF DEPRECIATION EXPENSE AND DEFERRED TAXES?

A. Ms. Diaz Cortez does not deal with the issue of recovery of depreciation and deferred income taxes in her testimony. As for Mr. Dittmer's testimony, it only addresses the issue on page 40 of his Direct Testimony. He states:

> Furthermore, the rate base valuation date for both the accumulated depreciation reserve and accumulated deferred income tax reserve, adopted by Company and Staff, is September 30, 2005. Because this valuation date materially precedes the expected rate-effective date of this proceeding, APS will have fully collected accruals to these September 2005 reserve balances from ratepayers months, if not over a year, before any rate change is granted by the Commission.

Q. WHAT IS THE RELEVANCE OF STAFF'S STATEMENT ON DEPRECIATION AND DEFERRED INCOME TAXES?

A. There is none — Mr. Dittmer's statement is not relevant to the issue at hand. Of course the depreciation and deferred income taxes recorded by September 30, 2005 will be collected by October 2006. But that is true with <u>all</u> other expenses with a revenue lag. APS calculated a revenue lag of over 36 days, and it is that lag in recovery and not the fact that costs are eventually recovered, which is relevant to cash working capital requirements. If his statement had any relevance, there would be no reason to do a lead/lag study.

Q. DID YOU CONSIDER THE OVERALL DETERMINATION OF REVENUE REQUIREMENTS IN THE CALCULATION OF CASH WORKING CAPITAL?

A. Yes. I believe it is important to keep in mind the relationship between rate base, operating expenses and the return on rate base in the determination of revenue requirements. APS used the traditional rate base/rate of return approach to determine its cost of providing service. Under this method, revenues equal the total of operation and maintenance expenses, depreciation, taxes including income taxes, and a return on rate base.

In the calculation of revenue requirements, pro forma adjustments to recorded data are made to reflect known and measurable changes and adjust for abnormal events. Rates are made for the future, not the past. In an ideal setting, rates that are set in a rate case will provide appropriate revenues for a number of future years. That does not mean that a year from now we will have the same items of uncollected accumulated depreciation and deferred income taxes that APS has included in its calculation of rate base as suggested by Mr. Dittmer. Clearly, at any point in time, depreciation expenses and deferred income tax expenses will be recorded before such expenses are recovered in the collection of revenues.

Q. COULD WE OMIT DEPRECIATION AND DEFERRED TAXES FROM THE CWC STUDY AND MAKE ADJUSTMENTS DIRECTLY TO THE ACCUMULATED DEPRECIATION AND DEFERRED TAX CREDITS INCLUDED IN RATE BASE.

A. Yes. It would have the same impact.

Q. DO YOU HAVE ANY OTHER COMMENTS CONCERNING STAFF'S TESTIMONY REGARDING PLANT OR DEPRECIATION?

A. Yes. On page 40, beginning on line 3 of his Direct Testimony, Mr. Dittmer indicates that "Certain payments for recently completed construction projects closed to plant in service or otherwise included in rate base would not have been fully paid for in cash as of September 30, 2005." On the same page, beginning on line 17, he indicates that the Company's proposal to include "…non-cash items in CWC fail to analyze or account for delayed cash outflows in payment of construction costs …"

This testimony does not discuss the relevancy of this speculation about plant-in-service balances to the cash recovery of depreciation expense. And, furthermore, Mr. Dittmer does not offer any proof that a significant portion of plant (if any) has not been paid for at the time that plant is transferred to completed plant, let alone that it would have a significant effect on total plant-in-service.

Again, the issue that depreciation expense should be disallowed because it is a non-cash item is not supported. The issue is related to the recovery of depreciation expense. Moreover, most of the cash is expended during the construction of plant with the balance paid before such plant is reclassified to plant-in-service.

Q. DOES STAFF ADDRESS THE REDUCTION IN RATE BASE FOR DEFERRED INCOME TAXES?

A. Yes. Mr. Dittmer discusses the treatment of deferred income taxes as a reduction in rate base because it is cost free capital.

I discussed this issue on page 10 and 11 of my testimony. I believe we are in general agreement with Staff as to the purpose of the reduction in rate base by deferred income taxes. I indicated that, "Rate base is reduced by deferred income taxes payable to prevent investors from earning a return on investments made with funds provided by consumers. However, the funds have not been provided by consumers until paid by consumers. That has to be recognized in the lead/lag study."

Q. HAS STAFF REFUTED THAT POSITION?

A. No.

Q. WHAT IS STAFF'S POSITION REGARDING DEFERRED INCOME TAXES?

A. On page 41, line 13, Mr. Dittmer states,

> Consequently, deferred income taxes should be excluded from the determination of the Company's cash working capital requirements, because there are no current period cash working capital requirements or outflows.

Q. IS STAFF'S POSITION REGARDING DEFERRED INCOME TAXES VALID?

A. No. Although the statement is true, the conclusion is clearly erroneous. There is no justification for excluding expenses from the calculation of cash working capital requirements simply because there are no <u>current</u> period cash working capital requirements.

Q. WHAT ARE THE IMPLICATIONS OF FOLLOWING STAFF'S RECOMMENDATION?

A. It would mean that expenses incurred in 2006 and paid in 2007 would not be included in the CWC calculation. For example, it would mean that utilities that pay property taxes in the year following the year that such taxes were accrued would exclude the expense lag in their calculation of cash working capital. If that makes sense, why not exclude the APS calculation of the expense lag with respect to Arizona property taxes. Assuming that it was logical to exclude property tax expense from the calculation of cash working capital because the entire payment was paid in the subsequent year, it would be logical to exclude the expense lag for Arizona property taxes from the calculation of cash working capital. Indeed in this case the 50% of the property taxes for Arizona are due on November 1 and 50% are due by May 1 of the following calendar year. Additionally, very few expenses are paid for currently. Operation and maintenance expense are recorded on the accrual basis of accounting. That means expenses are recorded when incurred. A portion of all of the expenditures shown on FHB-1 that are paid for in cash are paid in a later month. At the end of fiscal year, a portion of these expenses are paid in another fiscal year. *See* the purpose of a lead/lag study on page 5 of my Direct Testimony.

Q. DO DEFERRED INCOME TAX LIABILITIES AFFECT CASH WHEN THEY ARE REDUCED?

A. There is no question that deferred income taxes are expected to be paid in cash at some future date. That is why deferred income tax credits are properly recorded as a liability. There is a difference, however, in the way cash payments affect deferred tax liabilities and the way cash payments affect most liabilities, and that difference can create confusion. Most liabilities are charged or reduced at the time of payment. That is not directly observed when the deferred taxes liabilities are reduced.

Q. CAN YOU PROVIDE AN EXAMPLE OF THE CASH NATURE OF DEFERRED INCOME TAXES?

A. Yes. The following simple example is intended to explain the cash nature of deferred income taxes:

> Assume that a company sells a product that qualifies under the Internal Revenue Code as an installment sale. The sale price of $3,000 and related costs of $2,100 are recorded in the year of sale. The resulting profit of $900 is recognized in the year of sale for financial reporting purposes. If installments of $1,000 each are collected over the next three years, then one-third of the profit or $300 is recognized for income tax purposes in each of the years: 1, 2,

and 3. This deferral of income for income tax purposes creates what is called a timing difference.

A timing difference occurs when revenues or expenses are recognized in one period for financial reporting purposes but are reported in another period for income tax purposes. These differences originate in one period and reverse in one or more subsequent periods. In my example, at the end of the period in which the sale was made, the timing difference is $900. This represents the difference between the profit recognized for financial reporting purposes and the income reported for tax purposes in the year of sale. The deferred tax liability would be $225 (25% of $900). The contra entry would be to deferred tax expense.

For each year that an installment is collected, $300 will be recognized on the income tax return which reduces the timing difference. I have assumed an income tax rate of 25%.

Timing Difference-Year	1	2	3
Beginning of year	$900	$600	$300
Reversing in year	300	300	300
End of year	$600	$300	$0
Deferred tax at 25%			
Beginning balance	$225	$150	$75
Ending balance required	150	75	0
Change in balances	75	75	75

In each year, the profit of $300 increases taxable income and decreases the timing difference. Assuming only this timing difference, deferred income tax payables are reduced by $75 in each of the three years. Deferred income tax expense would be negative by $75 each year. No cash payment is recorded directly to the deferred tax liability account. However, taxable income is increased in comparison to book income by $300 per year. This increases current tax payables and current tax expense by $75 per year. The charge to current tax expense is offset by the credit to deferred income tax expense. When payments are made to the Internal Revenue Service, cash is disbursed and the current income tax liability is reduced.

Q. ARE YOU AWARE OF OTHER JURISDICTIONS WHERE PUPLIC UTILITY COMMISSIONS ADOPTED AN APPROACH SIMILAR TO YOURS WITH RESPECT TO DEPRECIATION EXPENSES AND DEFERRED INCOME TAXES?

A. Yes. Recognizing the revenue lag with respect to depreciation and deferred income tax expenses is often a contested ratemaking issue, and the determinations made by public utility commissions on these issues are varied. Some examples of those states that have included "non-cash" items, such as depreciation and deferred income taxes by recognizing the revenue lag and using a zero expense lag, include South Carolina where the Public Service Commission found "non-cash" items <u>must</u> be included in a lead lag study to reflect the delay in the collection of these components of revenue; and Connecticut, where the Department of Public Utility Control agreed that non-cash expenses such as depreciation, amortization, and deferred income taxes create a working capital requirement. Additionally, the California Public Utilities Commission has adopted a Standard Practice (U-16-W) which includes both depreciation expense and deferred income taxes at zero lag days because of the reduction of rate base by accumulated depreciation and deferred income taxes.

Q. DO YOU HAVE AN OPINION AS TO WHY THERE IS INCONSISTENCY AMONG PUBLIC UTILITY COMMISSIONS REGARDING THE TREATMENT

OF NON-CASH ITEMS IN DETERMINING A UTILITY COMPANY'S CASH WORKING CAPITAL NEEDS?

A. I believe that the calculations involved can be difficult to understand. Non-cash items can be particularly difficult for non-accountants to understand. There may be too much of a focus on the fact that these items do not require a cash outlay when expensed rather than the effect that expensing these items has on rate base and overall recovery of these expenses in rates. Also the cash nature of deferred income taxes is also difficult for non-accountants to understand.

Q. DOES STAFF CLASSIFY INSURANCE EXPENSES AS A NON-CASH CHARGE?

A. Yes.

Q. DOES STAFF PROVIDE A REASON FOR DRAWING THIS CONCLUSION?

A. No. Mr. Dittmer classifies this expense as a non-cash charge but does not explain why he arrived at that conclusion.

Q. HOW DID RUCO ADDRESS THE INSURANCE EXPENSES?

A. RUCO did not make an adjustment to the APS calculation, apparently recognizing that the cash was paid in advance.

Q. IS THERE ANYTHING ELSE YOU WOULD LIKE TO SAY ABOUT CLASSIFYING INSURANCE EXPENSES?

A. Nothing, aside from noting that the APS position is supported in my Direct Testimony beginning on page 8, line 12.

III. <u>CASH WORKING CAPITAL: INTEREST EXPENSE AND COST OF CAPITAL</u>

Q. HOW DO STAFF AND RUCO TREAT INTEREST EXPENSE?

A. Both Mr. Dittmer and Ms. Diaz Cortez include a provision for interest expense in their calculations of cash working capital requirements. Mr. Dittmer acknowledges that interest costs are included in the weighted cost of capital that is applied to rate base.

Q. **WHAT IS THE SIGNIFICANCE OF THEIR TREATMENT?**

A. By including interest expense in his working capital calculations, Mr. Dittmer has treated interest expense in the same way as you would operating expenses without justification for doing so.

I believe that what Mr. Dittmer and Ms. Diaz Cortez have done is unfair to APS. They included the interest cost component in the calculation of a working capital as opposed to including the entire return on rate base. If it is appropriate to include the interest component of the return in the calculation of cash working capital, it is necessary to include the entire return on rate base (including the weighted cost of debt) in the calculation of working capital. The revenue lag would not be different for any component of the cost of providing service.

Q. **ARE YOU RECOMMENDING THAT THE RETURN ON RATE BASE BE INCLDUDED IN THE CALCULATION OF CASH WORKING CAPITAL IN THIS CASE?**

A. No. Although there is some argument for including the return on rate base in the working capital calculations, it is a significant expansion of what I consider to be embraced by a lead/lag study. As such, the return on rate base, including the interest component, is properly excluded from the working capital calculations.

IV. <u>CONCLUSION</u>

Q. **ARE YOUR RECOMMENDATIONS CONCERNING THE TREATMENT OF DEPRECIATION AND AMORTIZATION, DEFERRED INCOME TAXES AND INTEREST EXPENSE CONSISTENT WITH PRIOR ARIZONA CORPORATION COMMISSION DECISIONS ON THESE ISSUES?**

A. No.

Q. **WHY DON'T YOU BELIEVE THAT IT IS NECESSARY TO FOLLOW PRIOR COMMISSION DECISIONS ON THESE ISSUES?**

First, I believe that my positions are correct. For APS, the last litigated case was eighteen years ago. I believe that the Commission should revisit these issues and I am confident that the Commission will consider the evidence provided in this case and decisions rendered by other regulatory commissions. Moreover, the order issued in the last case, Decision No. 55931, did not discuss the relevant issues regarding these expenses. For example, the order states that:

> However, neither depreciation nor deferred taxes require the expenditure of cash at the time the expense is recorded and thereby charged to the customers. They are not "current" cash expenses. (Decision No. 55931 at page 67)

There is no discussion concerning the revenue lag associated with depreciation or deferred income taxes. As I stated earlier in my testimony, the issue deals with the timing of the recovery of these expenses. The Company's rate base at September 30, 2005 includes deductions for accumulated depreciation and deferred income taxes that were not fully recovered from customers at September 30 due to the revenue lag.

Additionally, Mr. Dittmer attached JRD-B to his testimony. This attachment contains excerpts for ten different decisions of the Arizona Corporation Commission. Some of these excerpts indicate that the Commission excluded depreciation and deferred taxes from CWC, but none of those excerpts indicate that the Commission even discussed the issue of recovery of these expenses due to the revenue lag. Also, none of the excerpts indicate that the Commission addressed the incorrectness of including one component of the rate of return on rate base while excluding another component of the return on rate base.

Q. DOES THAT CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

REJOINDER TESTIMONY OF FRED H. BALLUFF

On Behalf of Arizona Public Service Company

Docket No. E-01345A-05-0816
Docket No. E-01345A-05-0826
Docket No. E-01345A-05-0827

October 4, 2006

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APS 67
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(Docket No. E-01345A-05-0816)
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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, ADDRESS AND OCCUPATION.

A. My name is Fred H. Balluff. My address is 238 Elm Park Avenue, Elmhurst, Illinois 60126.

Q. ARE YOU THE SAME FRED H. BALLUFF WHO PREVIOUSLY FILED DIRECT AND REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REJOINDER TESTIMONY?

A. My purpose is to respond to the Surrebuttal Testimony of Staff witness James Dittmer regarding the cash working capital requirements of APS. I have specific comments on the positions that Mr. Dittmer took on plant with respect to cash working capital requirements ("CWC").

II. REJOINDER TO JAMES DITTMER

Q. WHAT IS MR. DITTMER'S POSITION ON PLANT?

A. Mr. Dittmer apparently believes that depreciation expense should not be included in a lead lag study, in part because payments for some expenditures related to recently completed construction projects have not been paid at the end of the test year September 30, 2005.

Q. DO YOU AGREE?

A. I agree that at the time a construction project is completed and transferred to Plant-in-

Service there may be an insignificant amount of costs that have not been paid. However, I do not believe that it is relevant to our argument that the revenue lag applicable to depreciation expense should be included in the calculation of CWC.

Q. WHY DO YOU BELIEVE THAT THESE UNPAID BILLS ARE INSIGNIFICANT?

A. Based on information provided by APS, unpaid liabilities related to Plant-in-Service approximate $1.8 million dollars. That amount appears to be reasonable. Payments are made to contractors throughout the course of a construction project. Also, the Company must test the operations of major plant before it is deemed ready for service and transferred to Plant-in-Service.

Q. WHAT OTHER COMMENTS DO YOU WISH TO MAKE WITH RESPECT TO MR. DITTMER'S POSITION?

A. First, it is important to keep in mind the relationship between rate base, operating expenses and the return on rate base in the determination of revenue requirements. I discussed this issue in my rebuttal testimony on page 4. Second, it is important to consider our arguments that address why the revenue lag related to depreciation expense should be included in the calculation of CWC. I discussed this in my direct and rebuttal testimony. See my rebuttal testimony beginning on line 9 of page 2 and ending on line 9 of page 3. The primary issue is that depreciation expense is recorded and rate base is reduced before such expenses are recovered from customers. The issue regarding unpaid liabilities existing at the time plant is placed in service is another issue.

Q. DO YOU BELIEVE THAT THE EXISTING UNPAID LIABILITIES SHOULD BE REFLECTED IN THE CALCULATION OF RATE BASE IN THIS CASE?

A. No. First, the amounts involved are insignificant. There are other considerations. There are significant differences between an investment in plant and a recovery of plant. In my rebuttal testimony, I explained why Mr. Dittmer's comments that recovery of the accumulated depreciation by the time rates are in effect were not relevant to the recovery of depreciation expense. However, it is relevant to plant. In the absence of new plant completed from the time rates are placed into effect (January 1, 2007), there would still be a revenue lag associated with the recovery of depreciation at any intervening month, as well as at January 1, 2007. There would be no unpaid liabilities related to Plant-in-Service.. If construction projects are completed in the time frame, the amount of investment completed varies by month.

Additionally, there is generally a regulatory lag between the time new plant is placed in service and recovery of the cost of capital associated with that plant is realized in revenues. In this case, rates will not be changed to reflect new plant for over a year after September 30, 2005. New plant additions have been an important cause of earnings erosion (attrition) over the past thirty-five years because of regulatory lag. Plant generally is placed in service at a higher unit cost than replaced plant. Plant placed in service for environmental purposes does not increase revenues. Such plant will not produce revenues until a new rate case is decided. Even when new revenue producing facilities are placed in service, there may be substantial delays in full utilization of facilities.

III. CONCLUSION

Q. DOES THAT CONCLUDE YOUR REJOINDER TESTIMONY IN THIS PROCEEDING?

A. Yes.

DIRECT TESTIMONY
OF
DR. RONALD E. WHITE

ARIZONA PUBLIC SERVICE COMPANY

DOCKET NO. E01345A-05-0816

January 31, 2006

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DIRECT TESTIMONY
OF
DR. RONALD E. WHITE
ARIZONA PUBLIC SERVICE COMPANY
DOCKET NO. E01345A-05-0816

Q. WOULD YOU PLEASE STATE YOUR NAME AND BUSINESS ADDRESS?

A. My name is Ronald E. White. My business address is 17595 S. Tamiami Trail, Suite 212, Fort Myers, Florida 33908.

Q. WHAT IS YOUR OCCUPATION?

A. I am an Executive Vice President and Senior Consultant of Foster Associates, Inc.

I. QUALIFICATIONS

Q. WOULD YOU BRIEFLY DESCRIBE YOUR EDUCATIONAL TRAINING AND PROFESSIONAL BACKGROUND?

A. I received a B.S. degree in Engineering Operations and an M.S. degree and Ph.D. (1977) in Engineering Valuation from Iowa State University. I have taught graduate and undergraduate courses in industrial engineering, engineering economics, and engineering valuation at Iowa State University and previously served on the faculty for Depreciation Programs for public utility commissions, companies, and consultants, sponsored by Depreciation Programs, Inc., in cooperation with Western Michigan University. I also conduct courses in depreciation and public utility economics for clients of the firm.

I have prepared and presented a number of papers to professional organizations, committees, and conferences and have published several articles on matters relating to depreciation, valuation and economics. I am a past member of the Board of Directors of the Iowa State Regulatory Conference and an affiliate member of the joint American Gas Association (A.G.A.) – Edison Electric Institute (EEI) Depreciation Accounting Committee, where I previously served as chairman of a standing committee on capital recovery and its effect on corporate economics. I am also a member of the American Economic Association, the Financial Management Association, the Midwest Finance Association, the Electric Cooperatives Accounting Association (ECAA), and a founding member of the Society of Depreciation Professionals.

Q. WHAT IS YOUR PROFESSIONAL EXPERIENCE?

A. I joined the firm of Foster Associates in 1979, as a specialist in depreciation, the economics of capital investment decisions, and cost of capital studies for ratemaking applications. Prior to joining Foster Associates, I was employed by Northern States Power Company (1968–1979) in various assignments related to finance and treasury activities. As Manager of the Corporate Economics Department, I was responsible for book depreciation studies, studies involving staff assistance from the Corporate Economics Department in evaluating the economics of capital investment decisions, and the development and execution of innovative forms of project financing. As Assistant Treasurer at Northern States, I was responsible for bank relations, cash requirements planning, and short–term borrowings and investments.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE A REGULATORY BODY?

A. Yes. I have testified in numerous proceedings before administrative and judicial bodies in Alabama, Arizona, California, Colorado, Connecticut, Delaware, Hawaii, Idaho, Illinois, Iowa, Kansas, Maryland, Massachusetts, Michigan, Minnesota, Missouri, Montana, Nevada, New Hampshire, New Jersey, North Carolina, North Dakota, Ohio, Oregon, Pennsylvania, Rhode Island, South Carolina, South Dakota, Tennessee, Vermont, Virginia, Wisconsin, and the District of Columbia. I have also testified before the Federal Energy Regulatory Commission, the Federal Power Commission, the Alberta Energy Board, the Ontario Energy Board, and the Securities and Exchange Commission. I have sponsored position statements before the Federal Communication Commission and numerous local franchising authorities in matters relating to the regulation of telephone and cable television. A more detailed description of my professional qualifications is attached as Appendix A.

II. PURPOSE OF TESTIMONY

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

A. Foster Associates was engaged by Arizona Public Service Company (APS or Company) to conduct 2005 technical updates of depreciation rates for APS and for certain Pinnacle West Energy Corporation generating units (PWEC Units) acquired by APS. The purpose of my testimony is to sponsor and describe the studies conducted by Foster Associates. Depreciation rates currently used by APS and for the PWEC Units were approved by the Arizona Corporation Commission (ACC) pursuant to a settlement agreement in Docket No. E–01345A–03–0437 (Decision No. 67744, dated April 7, 2005).

III. IDENTIFICATION OF ATTACHMENTS

Q. DO YOU SPONSOR ANY ATTACHMENTS IN SUPPORT OF YOUR TESTIMONY?

A. Yes, I do. I sponsor Attachment REW–1, a document titled "2005 Technical Update (Arizona Public Service Company)." I also sponsor Attachment REW–2, a document titled "2005 Technical Update (PWEC Units Acquired by Arizona Public Service Company)." These documents were prepared by me or under my direction and supervision.

IV. DEVELOPMENT OF DEPRECIATION RATES

Q. WHY ARE DEPRECIATION STUDIES NEEDED FOR ACCOUNTING AND RATEMAKING PURPOSES?

A. *The goal of depreciation accounting is to charge to operations a reasonable estimate* of the cost of the service potential of an asset (or group of assets) consumed during an accounting interval. A number of depreciation systems have been developed to achieve this objective, most of which employ time as the apportionment base.

Implementation of a time–based (or age–life) system of depreciation accounting requires the estimation of several parameters or statistics related to a plant account. The average service life of a vintage, for example, is a statistic that will not be known with certainty until all units from the original placement have been retired from service. A vintage average service life, therefore, must be estimated initially and periodically revised as indications of the eventual average service life become more certain. Future net salvage rates and projection curves, which describe the expected distribution of retirements over time, are also estimated parameters of a depreciation system that are subject to future revisions. Depreciation studies should be conducted periodically to assess the continuing reasonableness of parameters and accrual rates derived from prior estimates.

The need for periodic depreciation studies is also a derivative of the ratemaking process that establishes prices for utility services based on costs. Absent regulation, deficient or excessive depreciation rates will produce no adverse consequence other than a systematic over or understatement of the accounting measurement of earnings. While a continuance of such practices may not comport with the goals of depreciation accounting, the achievement of capital recovery is not dependent upon either the amount or the timing of depreciation expense for an unregulated firm. In the case of a regulated utility, however, recovery of investor–supplied capital is dependent upon allowed revenues, which are in turn dependent upon approved levels of depreciation expense. Periodic reviews of depreciation rates are, therefore, essential to the achievement of timely capital recovery for a regulated utility.

It is also important to recognize that revenue associated with depreciation is a significant source of internally generated funds used to finance plant replacements and new capacity additions. It can be shown that, given the same financing requirements and the same dividend payout ratio, an increase in internal cash generation will accelerate per–share growth in earnings, dividends, and book value over the business life of a firm. Financial theory provides that the marginal cost of external financing will be reduced by these enhanced measurements of financial performance. This is not to suggest that internal cash generation should be substituted for the goals of depreciation accounting. However, the potential for realizing a reduction in the 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 UNDERTAKEN IN CONDUCTING A FULL DEPRECIATION STUDY?

A. The first step in conducting a depreciation study is the collection of plant accounting data needed to conduct a statistical analysis of past retirement experience. Data are also collected to permit an analysis of the relationship between retirements and realized gross salvage and removal expense. The data collection phase should include a verification of the accuracy of the plant accounting records and a reconciliation of the assembled data to the official plant records of the company.

The next step in a depreciation study is the estimation of service life statistics from an analysis of past retirement experience. The term *life analysis* is used to describe the activities undertaken in this step to obtain a mathematical description of the forces of retirement acting upon a plant category. The mathematical expressions used to describe these forces are known as survival functions or survivor curves.

Life indications obtained from an analysis of past retirement experience are blended with expectations about the future to obtain an appropriate projection life curve. This step, called *life estimation*, is concerned with predicting the expected remaining life of property units still exposed to the forces of retirement. The amount of weight given to the analysis of historical data will depend upon the extent to which past retirement experience is considered descriptive of the future.

An estimate of the net salvage rate applicable to future retirements is usually obtained from an analysis of the gross salvage and removal expense realized in the past. An analysis of past experience (including an examination of trends over time) provides a baseline for estimating future salvage and cost of removal. Consideration, however, should be given to events that may cause deviations from the net salvage realized in the past. Among the factors that should be considered are the age of plant retirements, the portion of retirements that will be reused, changes in the method of removing plant, the type of plant to be retired in the future, inflation expectations, the shape of the projection life curve, and economic conditions that may warrant greater or lesser weight to be given to the net salvage observed in the past.

A comprehensive depreciation study will also include an analysis of the adequacy of the recorded depreciation reserve. The purpose of such an analysis is to compare the current balance in the recorded reserve with the balance required to achieve the goals and objectives of depreciation accounting if the amount and timing of future retirements and net salvage are realized exactly as predicted. The difference between the required (or theoretical) reserve and the recorded reserve provides a measurement of the expected excess or shortfall that will remain in the depreciation reserve if corrective action is not taken to extinguish the reserve imbalance.

Although reserve records are typically maintained by various account classifications, the total reserve for a company is the most important reflection of the company's depreciation practices. Differences between the theoretical reserve and the recorded reserve will arise as a normal occurrence when service lives, dispersion patterns and salvage estimates are adjusted in the course of depreciation reviews. Differences will also arise due to plant accounting activity such as transfers and adjustments, which require an identification of reserves at a different level from that maintained in the accounting system. It is appropriate, therefore, and consistent with group depreciation theory, to periodically redistribute recorded reserves among primary accounts based on the most recent estimates of retirement dispersion and salvage. A redistribution of the recorded reserve will provide an initial reserve balance for each primary account consistent with the estimates of retirement dispersion selected to describe mortality characteristics of the accounts and establish a baseline against which future comparisons can be made.

Finally, parameters estimated from service life and net salvage studies are integrated into an appropriate formulation of an accrual rate based upon a selected depreciation system. Three elements are needed to describe a depreciation system. These elements (*i.e.*, method, procedure and technique) can be visualized as three dimensions of a cube in which each face describes a variety of sub–elements that can be combined to form a system. A depreciation system is therefore formed by selecting a sub–element from each face such that the system contains one method, one procedure and one technique. The sub–elements most widely used in constructing a depreciation system are shown in Table 1.

Methods	Procedures	Techniques
Retirement	Total Company	Whole-Life
Compound-Interest	Broad Group	Remaining-Life
Sinking-Fund	Vintage Group	Probable-Life
Straight-Line	Equal-Life Group	
Declining Balance	Unit Summation	
Sum-of-Years'-Digits	Item	
Expensing		
Unit-of-Production		
Net Revenue		

Table 1. Elements of a Depreciation System

V. 2005 TECHNICAL UPDATES

Q. WOULD YOU PLEASE DESCRIBE THE SCOPE OF A TECHNICAL UPDATE?

A. Unlike a full depreciation study in which projection curves, projection lives and future net salvage rates are estimated from a statistical analysis of recorded retirements and net salvage realized in the past, a technical update generally retains the parameters currently used or proposed by the utility and adjusts depreciation rates for known and measurable changes in the age distributions of surviving plant, depreciation reserves, and average net salvage rates due to the passage of time. A technical update, therefore, is intended to align depreciation rates with the accounting year the rates will become effective. The steps involved in preparing a technical update generally include a) data collection; b) calculation of service life statistics; c) computation of average net salvage rates; d) rebalancing of depreciation reserves; and e) development of accrual rates.

Q. DID APS PROVIDE FOSTER ASSOCIATES PLANT ACCOUNTING DATA FOR CONDUCTING THE 2005 TECHNICAL UPDATES?

A. Yes, they did. The databases used in the 2005 updates for APS and the PWEC Units were provided to Foster Associates in an electronic format containing plant and reserve activity over the period 1972–2004 and age distributions of surviving plant at December 31, 2004. Data used in the updates were limited to the age distributions of surviving plant. Depreciation rates currently used by APS and for the PWEC Units were developed using a broad–group procedure. The realized life of surviving vintages derived from the dollar–years of service provided by each vintage is not relevant to an update of broad–group depreciation rates. Therefore, plant transactions recorded in prior activity years were not used in the update.

Reserve transactions recorded in prior activity years were also not used in the 2005 updates. Depreciation rates currently used by APS and for the PWEC Units were derived without consideration of the distinction between average and future net salvage rates. The assumed equivalency between average and future net salvage rates was retained in the 2005 updates without introducing prior realized net salvage amounts in the computation of average net salvage rates.

Q. DID FOSTER ASSOCIATES CALCULATE SERVICE LIFE STATISTICS IN THE 2005 TECHNICAL UPDATES FOR APS AND THE PWEC UNITS?

A. Yes, we did. The scope of the updates and calculations performed by Foster Associates are described in the Study Procedures section of Attachment REW–1 and Attachment REW–2.

Q. DID FOSTER ASSOCIATES DERIVE AVERAGE NET SALVAGE RATES IN THE 2005 TECHNICAL UPDATES FOR APS AND THE PWEC UNITS?

A. No, we did not. As noted earlier, depreciation rates currently used by APS and for the PWEC Units were derived without consideration of the distinction between average and future net salvage rates. The assumed equivalency between average and future net salvage rates was retained in the 2005 updates without introducing prior realized net salvage amounts in the computation of average net salvage rates.

However, future net salvage rates for steam production facilities were adjusted in the 2005 update for estimated terminal dismantlement costs. The treatment of dismantlement costs in prior studies (and in the depreciation rates currently used by APS) reflects an assumption that interim and future net salvage rates will be equal. This assumption was relaxed in the 2005 update by: a) retaining an interim net salvage rate of –20 percent; and b) adjusting terminal dismantlement costs to reflect costs per kW estimated in dismantling studies conducted in 2002 for the Navajo and Four Corners generating stations. An inflation rate of three percent was used to escalate 2002 dollars to estimated years of final retirement.

Q. DID FOSTER ASSOCIATES REBALANCE DEPRECIATION RESERVES IN THE 2005 TECHNICAL UPDATES FOR APS AND THE PWEC UNITS?

A. Yes, we did. A rebalancing of recorded reserves is consistent with the objectives of a technical update and is considered appropriate for both APS and the PWEC Units. Depreciation rates adopted in Docket No. E–01345A–03–0437 were derived from rebalanced reserves obtained from a set of parameters different from those used in the formulation of the settled remaining–life accrual rates. Reserve imbalances amortized in the settled rates are therefore inconsistent with the realigned depreciation reserves. The rebalancing of reserves undertaken in the 2005 updates will reestablish consistency between measured reserve imbalances and the parameters used in the formulation of updated remaining–life accrual rates.

A redistribution of the recorded reserve was achieved for both APS and the PWEC Units by multiplying the calculated reserve for each primary account within a function (or plant location) by the ratio of the function (or location) total recorded reserve to the function (or location) total calculated reserve. The sum of the redistributed reserves within a function (or location) is, therefore, equal to the function (or location) total recorded depreciation reserve before the redistribution.

Q. HOW DO THE DEPRECIATION RATES AND ACCRUALS DERIVED IN THE 2005 TECHNICAL UPDATES COMPARE WITH THOSE CURRENTLY USED BY APS AND FOR THE PWEC UNITS?

A. Table 2 provides a comparison of present and proposed depreciation rates and accruals derived in the 2005 Technical Update for APS.

Function	Accrual Rate Present	Accrual Rate Proposed	Accrual Rate Difference	2005 Annualized Accrual Present	2005 Annualized Accrual Proposed	2005 Annualized Accrual Difference
A	B	C	D=C-B	E	F	G=F-E
Production						
Steam	3.34%	3.83%	0.49%	$45,731,277	$52,392,026	$6,660,749
Nuclear	2.95%	2.78%	-0.17%	70,195,368	66,186,908	(4,008,460)
Other	2.93%	2.93%	0.00%	6,039,806	6,030,434	(9,372)
Transmission	1.55%	1.12%	-0.43%	685,384	496,457	(188,927)
Distribution	2.43%	2.47%	0.04%	81,502,058	82,773,852	1,271,794
General Plant	5.30%	5.75%	0.45%	17,462,319	18,958,703	1,496,384
Total	2.89%	2.95%	0.06%	$221,616,212	$226,838,380	$5,222,168

Table 2. Present and Proposed APS Depreciation Rates and Accruals

Adjustments developed in the technical update for APS produce a composite depreciation rate of 2.95 percent. Depreciation expense is presently accrued at an equivalent rate of 2.89 percent. The proposed change in the composite depreciation rate represents an increase of 0.06 percentage points.

A continued application of rates currently approved would provide annual depreciation expense of $221,616,212 compared with an annual expense of $226,838,380 using the rates developed in the update. The proposed expense increase of $5,222,168 is largely attributable to: a) a change in the mix of plant investments among primary accounts; b) changes in the age distributions of surviving plant; and c) plant additions to Four Corners generating station.

Table 3 provides a comparison of present and proposed depreciation rates and accruals derived in the 2005 Technical Update for the PWEC Units.

Function	Accrual Rate Present	Accrual Rate Proposed	Accrual Rate Difference	2005 Annualized Accrual Present	2005 Annualized Accrual Proposed	2005 Annualized Accrual Difference
A	B	C	D=C-B	E	F	G=F-E
Production	2.92%	2.71%	-0.21%	$28,002,769	$26,066,384	($1,936,385)
Transmission	1.83%	1.73%	-0.10%	787,163	742,858	(44,305)
Total	2.87%	2.67%	-0.20%	$28,789,932	$26,809,242	($1,980,690)

Table 3. Present and Proposed PWEC Assets Depreciation Rates and Accruals

Adjustments developed in the technical update for the PWEC Units produce a composite depreciation rate of 2.67 percent. Depreciation expense is presently accrued at an equivalent rate of 2.87 percent. The proposed change in the composite depreciation rate represents a reduction of 0.20 percentage points.

A continued application of rates currently approved would provide annual depreciation expense of $28,789,932 compared with an annual expense of $26,809,242 using the rates developed in the update. The proposed expense decrease of $1,980,690 is largely attributable to: a) a change in the mix of plant investments among primary accounts; b) changes in the age distributions of surviving plant; and c) the estimation of parameters for West Phoenix Unit 5.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

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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

1996 - Present Foster Associates, Inc.
Executive Vice President

1988 - 1996 Foster Associates, Inc.
Senior Vice President

1979 - 1988 Foster Associates, Inc.
Vice President

1978 - 1979 Northern States Power Company
Assistant Treasurer

1974 - 1978 Northern States Power Company
Manager, Corporate Economics

1972 - 1974 Northern States Power Company
Corporate Economist

1970 - 1972 Iowa State University
Graduate Student and Instructor

1968 - 1970 Northern States Power Company
Valuation Engineer

1965 - 1968 Iowa State University
Graduate Student and Teaching Assistant

Publications

A New Set of Generalized Survivor Tables, Journal of the Society of Depreciation Professionals, October, 1992.

The Theory and Practice of Depreciation Accounting Under Public Utility Regulation, Journal of the Society of Depreciation Professionals, December, 1989.

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.

Expert Opinion

Alabama Public Service Commission, Docket No. 18488, General Telephone Company of the Southeast; testimony concerning engineering economy study techniques.

Alabama Public Service Commission, Docket No. 20208, General Telephone Company of the South; testimony concerning the equal-life group procedure and remaining-life technique.

Alberta Energy and Utilities Board, Application No. 1250392, Aquila Networks Canada; rebuttal testimony supporting proposed depreciation rates.

Alberta Energy and Utilities Board, Case No. RE95081, Edmonton Power Inc.; rebuttal evidence concerning appropriate depreciation rates.

Alberta Energy and Utilities Board, 1999/2000 General Tariff Application, Edmonton Power Inc.; direct and rebuttal evidence concerning appropriate depreciation rates.

Arizona Corporation Commission, Docket No. T-01051B-97-0689, U S West Communications, Inc.; testimony concerning appropriate depreciation rates.

Arizona Corporation Commission, Docket No. G-1032A-02-0598, Citizens Communications Company; testimony supporting proposed depreciation rates.

Arizona Corporation Commission, Docket No. E–0135A–03–0437, Arizona Public Service Company; rebuttal testimony supporting net salvage rates.

Arizona State Board of Equalization, Docket No. 6302-07-2, Arizona Public Service Company; testimony concerning valuation and assessment of contributions in aid of construction.

California Public Utilities Commission, Case Nos. A.92-06-040, 92-06-042, GTE California Incorporated; rebuttal testimony supporting depreciation study techniques.

Public Utilities Commission of the State of Colorado, Application No. 36883-Reopened. U S WEST Communications; testimony concerning equal-life group procedure.

State of Connecticut Department of Public Utility Control, Docket No. 05–03–17, The Southern Connecticut Gas Company; testimony supporting recommended depreciation rates.

Delaware Public Service Commission, Docket No. 81-8, Diamond State Telephone Company; testimony concerning the amortization of inside wiring.

Delaware Public Service Commission, Docket No. 82-32, Diamond State Telephone Company; testimony concerning the equal-life group procedure and remaining-life technique.

Public Service Commission of the District of Columbia, Formal Case No. 842, District of Columbia Natural Gas; testimony concerning depreciation rates.

Public Service Commission of the District of Columbia, Formal Case No. 1016, Washington Gas Light Company - District of Columbia; testimony supporting proposed depreciation rates.

Federal Communications Commission, Prescription of Revised Depreciation Rates for AT&T Communications; statement concerning depreciation, regulation and competition.

Federal Communications Commission, Petition for Modification of FCC Depreciation Prescription Practices for AT&T; statement concerning alignment of depreciation expense used for financial reporting and regulatory purposes.

Federal Communications Commission, Docket No. 99-117, Bell Atlantic; affidavit concerning revenue requirement and capital recovery implications of omitted plant retirements.

Federal Energy Regulatory Commission, Docket No. ER95-267-000, New England Power Company; testimony supporting proposed depreciation rates.

Federal Energy Regulatory Commission, Docket No. RP89-248, Mississippi River Transmission Corporation; rebuttal testimony concerning appropriateness of net salvage component in depreciation rates.

Federal Energy Regulatory Commission, Docket No. ER91-565, New England Power Company; testimony supporting proposed depreciation rates.

Federal Energy Regulatory Commission, Docket No. ER78-291, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Federal Energy Regulatory Commission, Docket Nos. RP80-97 and RP81-54, Tennessee Gas Pipeline Company; testimony concerning offshore plant depreciation rates.

Federal Power Commission, Docket No. E-8252, Northern States Power Company; testimony concerning general financial requirements and measurements of financial performance.

Federal Power Commission, Docket No. E-9148, Northern States Power Company; testimony concerning general financial requirements and measurements of financial performance.

Federal Power Commission, Docket No. ER76-818, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Federal Power Commission, Docket No. RP74-80, *Northern* Natural Gas Company; testimony concerning depreciation expense.

Public Utilities Commission of the State of Hawaii, Docket No. 00-0309, The Gas Company; testimony supporting proposed depreciation rates.

Public Utilities Commission of the State of Hawaii, Docket No. 94-0298, GTE Hawaiian Telephone Company Incorporated; testimony concerning the need for shortened service lives and disclosure of asset impairment losses.

Idaho Public Utilities Commission, Case No. U-1002-59, General Telephone Company of the Northwest, Inc.; testimony concerning the remaining-life technique and the equal-life group procedure.

Illinois Commerce Commission, Case No. 04–0476, Illinois Power Company, testimony supporting proposed depreciation rates.

Illinois Commerce Commission, Docket No. 94-0481, Citizens Utilities Company of Illinois; rebuttal testimony concerning applications of the Simulated Plant-Record method of life analysis.

Iowa State Commerce Commission, Docket No. RPU 82-47, North Central Public Service Company; testimony on depreciation rates.

Iowa State Commerce Commission, Docket No. RPU 84-34, General Telephone Company of the Midwest; testimony concerning the remaining-life technique and the equal-life group procedure.

Iowa State Utilities Board, Docket No. DPU-86-2, Northwestern Bell Telephone Company; testimony concerning capital recovery in competition.

Iowa State Utilities Board, Docket No. RPU-84-7, Northwestern Bell Telephone Company; testimony concerning the deduction of a reserve deficiency from the rate base.

Iowa State Utilities Board, Docket No. DPU-88-6, U S WEST Communications; testimony concerning depreciation subject to refund.

Iowa State Utilities Board, Docket No. RPU-90-9, Central Telephone Company of Iowa; testimony concerning depreciation rates.

Iowa State Utilities Board, Docket No. RPU-93-9, U S WEST Communications; testimony concerning principles of depreciation accounting and abandonment of FASB 71.

Iowa State Utilities Board, Docket No. DPU-96-1, U S WEST Communications; testimony concerning principles of depreciation accounting and abandonment of FASB 71.

Iowa State Utilities Board, Docket No. RPU-05-2, Aquila Networks; testimony supporting recommended depreciation rates.

Kansas Corporation Commission, Docket No. 04–AQLE–1065–RTS, testimony supporting proposed depreciation rates.

Kansas Corporation Commission, Docket No. 03–KGSG–602–RTS, Kansas Gas Service, a Division of ONEOK, Inc., rebuttal testimony supporting net salvage rates.

Kentucky Public Service Commission, Case No. 97-224, Jackson Purchase Electric Cooperative Corporation; rebuttal testimony supporting proposed depreciation rates.

Maryland Public Service Commission, Case No. 8485, Baltimore Gas and Electric Company; testimony supporting proposed depreciation rates.

Maryland Public Service Commission, Case No. 7689, Washington Gas Light Company; testimony concerning life analysis and net salvage.

Maryland Public Service Commission, Case No. 8960, Washington Gas Light Company; testimony supporting proposed depreciation rates.

Massachusetts Department of Public Utilities, Case No. DPU 91-52, Massachusetts Electric Company; testimony supporting proposed depreciation rates which include a net salvage component.

Michigan Public Service Commission, Case No. U13899, Michigan Consolidated Gas Company, testimony concerning service life estimates.

Michigan Public Service Commission, Case No. U-13393, Aquila Networks – MGU; testimony supporting proposed depreciation rates.

Michigan Public Service Commission, Case No. U-12395, Michigan Gas Utilities; testimony supporting proposed depreciation rates including amortization accounting and redistribution of recorded reserves.

Michigan Public Service Commission, Case No. U-6587, General Telephone Company of Michigan; testimony concerning use of a theoretical depreciation reserve with the remaining-life technique.

Michigan Public Service Commission, Case No. U-7134, General Telephone Company of Michigan; testimony concerning the equal-life group depreciation procedure.

Minnesota District Court. In Re: Northern States Power Company v. Ronald G. Blank, *et. al.* File No. 394126; testimony concerning depreciation and engineering economics.

Minnesota Public Service Commission, Docket No. E-611, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Minnesota Public Service Commission, Docket No. E-1086, Northern States Power Company; testimony concerning depreciation rates.

Minnesota Public Service Commission, Docket No. G-1015, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Public Service Commission of the State of Missouri, Case No. ER-2001-672, Missouri Public Service, a division of Utilicorp United Inc.; surrebuttal testimony regarding computation of income tax expense.

Public Service Commission of the State of Missouri, Case No. TO-82-3, Southwestern Bell Telephone Company; rebuttal testimony concerning the remaining-life technique and the equal-life group procedure.

Public Service Commission of the State of Missouri, Case No. GO-97-79, Laclede Gas Company; rebuttal testimony concerning adequacy of database for conducting depreciation studies.

Public Service Commission of the State of Missouri, Case No. GR-99-315, Laclede Gas Company; rebuttal testimony concerning treatment of net salvage in development of depreciation rates.

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Public Service Commission of the State of Montana, Docket No. 88.2.5, Mountain State Telephone and Telegraph Company; rebuttal testimony concerning the equal-life group procedure and amortization of reserve imbalances.

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New Jersey Board of Regulatory Commissioners, Docket No. GR93040114J, New Jersey Natural Gas Company; testimony concerning depreciation rates.

North Carolina Utilities Commission, Docket No. E-7, SUB 487, Duke Power Company; rebuttal testimony concerning proposed depreciation rates.

North Carolina Utilities Commission, Docket No. P-19, SUB 207, General Telephone Company of the South; rebuttal testimony concerning the equal-life group depreciation procedure.

North Dakota Public Service Commission, Case No. 8860, Northern States Power Company; testimony concerning general financial requirements.

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North Dakota Public Service Commission, Case No. 9666, Northern States Power Company; testimony concerning rate of return and general financial requirements.

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Power Company; testimony concerning rate of return and general financial requirements.

Ontario Energy Board, E.B.R.O. 385, Tecumseh Gas Storage Limited; testimony concerning depreciation rates.

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Public Utilities Commission of Ohio, Case No. 81-383-TP-AIR, General Telephone Company of Ohio; testimony in support of the remaining-life technique.

Public Utilities Commission of Ohio, Case No. 82-886-TP-AIR, General Telephone Company of Ohio; testimony concerning the remaining-life technique and the equal-life group procedure.

Public Utilities Commission of Ohio, Case No. 84-1026-TP-AIR, General Telephone Company of Ohio; testimony in support of the equal-life group procedure and the remaining-life technique.

Public Utilities Commission of Ohio, Case No. 81-1433, The Ohio Bell Telephone Company; testimony concerning the remaining-life technique and the equal-life group procedure.

Public Utilities Commission of Ohio, Case No. 83-300-TP-AIR, The Ohio Bell Telephone Company; testimony concerning straight-line age-life depreciation.

Public Utilities Commission of Ohio, Case No. 84-1435-TP-AIR, The Ohio Bell Telephone Company; testimony in support of test period depreciation expense.

Public Utilities Commission of Oregon, Docket No. UM 204, GTE of the Northwest; testimony concerning the theory and practice of depreciation accounting under public utility regulation.

Public Utilities Commission of Oregon, Docket No. UM 840, GTE Northwest Incorporated; rebuttal testimony concerning principles of capital recovery.

Pennsylvania Public Utility Commission, Docket No. R-80061235, The Bell Telephone Company of Pennsylvania; testimony concerning the proper depreciation reserve to be used with an original cost rate base.

Pennsylvania Public Utility Commission, Docket No. R-811512, General Telephone Company of Pennsylvania; testimony concerning the proper depreciation reserve to be used with an original cost rate base.

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Pennsylvania Public Utility Commission, Docket No. C-860923, The Bell 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.

Public Utilities Commission of the State of South Dakota, Case No. F-3188, Northern States Power Company; testimony concerning rate of return and general financial requirements.

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Tennessee Public Service Commission, Docket No. 89-11041, United Inter-Mountain Telephone Company; testimony concerning depreciation principles and capital recovery under competition.

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Commonwealth of Virginia State Corporation Commission, Case No. PUE-2002-00364, Washington Gas Light Company; testimony supporting proposed depreciation rates.

Public Service Commission of Wisconsin, Docket No. 2180-DT-3, General Telephone Company of Wisconsin; testimony concerning the equal-life group depreciation procedure.

Other Consulting Activities

Moran Towing Corporation. In Re: Barge TEXAS-97 CIV. 2272 (ADS) and Tug HEIDE MORAN – 97 CIV. 1947 (ADS), United States District Court, Southern District of New York.

John Reigle, *et al.* v. *Baltimore Gas & Electric Co.*, *et al.*, Case No. C-2001-73230-CN, Circuit Court for Anne Arundel County, Maryland.

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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.

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Office of Chief Counsel, Internal Revenue Service. In Re: Northern Pacific Railway Co., Docket No. 4489-69.

United States Department of Justice. In Re: Burlington Northern Inc. v. United States, Ct. Cl. No. 30-72.

Faculty

Depreciation Programs for public utility commissions, companies, and consultants, sponsored by Depreciation Programs, Inc., in cooperation with Western Michigan University. (1980 - 1999)

United States Telephone Association (USTA), Depreciation Training Seminar, November 1999.

Depreciation Advocacy Workshop, a three-day team-training workshop on preparation, presentation, and defense of contested depreciation issues, sponsored by Gilbert Associates, Inc., October, 1979.

Corporate Economics Course, Employee Education Program, Northern States Power Company. (1968 - 1979)

Perspectives of Top Financial Executives, Course No. 5-300, University of Minnesota, September, 1978.

Depreciation Programs for public utility commissions, companies, and consultants, jointly sponsored by Western Michigan University and Michigan Technological University, 1973.

Professional Associations

Advisory Committee to the Institute for Study of Regulation, sponsored by the American University and The University of Missouri-Columbia.

American Economic Association.

American Gas Association - Edison Electric Institute Depreciation Accounting Committee.

Board of Directors, Iowa State Regulatory Conference.

Edison Electric Institute, Energy Analysis Division, Economic Advisory Committee, 1976-1980.

Financial Management Association.

The Institute of Electrical and Electronics Engineers, Inc., Power Engineering Society, Engineering and Planning Economics Working Group.

Midwest Finance Association.

Society of Depreciation Professionals (Founding Member and Chairman, Policy Committee

Moderator

Depreciation Open Forum, Iowa State University Regulatory Conference, May 1991.

The Quantification of Risk and Uncertainty in Engineering Economic Studies, Iowa State University Regulatory Conference, May 1989.

Plant Replacement Decisions with Added Revenue from New Service Offerings, Iowa State University Regulatory Conference, May 1988.

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Concepts of Economic Depreciation, Iowa State University Regulatory Conference, May 1984.

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New Developments in Engineering Economics, Iowa State University Regulatory Conference, May 1980.

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The Real Time Problem of Capital Recovery, Missouri Public Service Commission, Regulatory Information Systems Conference, September 1974.

Speaker

Depreciation Studies for Cooperatives and Small Utilities. TELERGEE CFO and Controllers Conference, November, 2004.

Finding the "D" in RCNLD (Valuation Applications of Depreciation), Society of Depreciation Professionals Annual Meeting, September 2001.

Capital Asset and Depreciation Accounting, City of Edmonton Value Engineering Workshop, April 2001.

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Capital Recovery in a Changing Regulatory Environment, Pennsylvania Electric Association Financial-Accounting Conference, May 1999.

Depreciation Theory and Practice, Southern Natural Gas Company Accounting and Regulatory Seminar, March 1999.

Depreciation Theory Applied to Special Franchise Property, New York Office of Real Property Services, March 1999.

Capital Recovery in a Changing Regulatory Environment, PowerPlan Consultants Annual Client Forum, November 1998.

Economic Depreciation, AGA Accounting Services Committee and EEI Property Accounting and Valuation Committee, May 1998.

Discontinuation of Application of FASB Statement No. 71, Southern Natural Gas Company Accounting Seminar, April 1998.

Forecasting in Depreciation, Society of Depreciation Professionals Annual Meeting, September 1997.

Economic Depreciation In Response to Competitive Market Pricing, 1997 TELUS Depreciation Conference, June 1997.

Valuation of Special Franchise Property, City of New York, Department of Finance Valuation Seminar, March 1997.

Depreciation Implications of FAS Exposure Draft 158-B, 1996 TLG

Decommissioning Conference, October 1996.

Why Economic Depreciation?, American Gas Association Depreciation Accounting Committee Meeting, August 1995.

The Theory of Economic Depreciation, Society of Depreciation Professionals Annual Meeting, November 1994.

Vintage Depreciation Issues, G & T Accounting and Finance Association Conference, June 1994.

Pricing and Depreciation Strategies for Segmented Markets (Regulated and Competitive), Iowa State Regulatory Conference, May 1990.

Principles and Practices of Depreciation Accounting, Canadian Electrical Association and Nova Scotia Power Electric Utility Regulatory Seminar, December 1989.

Principles and Practices of Depreciation Accounting, Duke Power Accounting Seminar, September 1989.

The Theory and Practice of Depreciation Accounting Under Public Utility Regulation, GTE Capital Recovery Managers Conference, February 1989.

Valuation Methods for Regulated Utilities, GTE Capital Recovery Managers Conference, January 1988.

Depreciation Principles and Practices for REA Borrowers, NRECA 1985 National Accounting and Finance Conference, September 1985.

Depreciation Principles and Practices for REA Borrowers, Kentucky Association of Electric Cooperatives, Inc., Summer Accountants Association Meeting, June 1985.

Considerations in Conducting a Depreciation Study, NRECA 1984 National Accounting and Finance Conference, October 1984.

Software for Conducting Depreciation Studies on a Personal Computer, United States Independent Telephone Association, September 1984.

Depreciation—An Assessment of Current Practices, NRECA 1983 National Accounting and Finance Conference, September 1983

Depreciation—An Assessment of Current Practices, REA National Field Conference, September 1983.

An Overview of Depreciation Systems, Iowa State Commerce Commission, October 1982.

Depreciation Practices for Gas Utilities, Regulatory Committee of the Canadian Gas Association, September 1981.

Practice, Theory, and Needed Research on Capital Investment Decisions in the Energy Supply Industry, workshop, sponsored by Michigan State University and the Electric Power Research Institute, November 1977.

Depreciation Concepts Under Regulation, Public Utilities Conference, sponsored by The University of Texas at Dallas, July 1976.

Electric Utility Economics, Mid-Continent Area Power Pool, May 1974.

Honors and Awards

The Society of Sigma Xi.

Professional Achievement Citation in Engineering, Iowa State University, 1993.

Attachment REW–1

2005 Technical Update

Arizona Public Service Company

Prepared by
Foster Associates, Inc.

CONTENTS

EXECUTIVE SUMMARY

INTRODUCTION

This report presents the findings and recommendations developed in a 2005 Technical Update of depreciation rates for Arizona Public Service Company (APS) prepared by Foster Associates, Inc. Parameters (*i.e.*, projection curves, projection lives and future net salvage rates) used in the update were accepted by the Arizona Corporation Commission (ACC) pursuant to a settlement agreement in Docket No. E–01345A–03–0437 (Decision No. 67744, dated April 7, 2005). Age distributions of surviving plant at December 31, 2004 were used in the 2005 update to derive composite service life statistics and computed or theoretical depreciation reserves.

Foster Associates is a public utility economic consulting firm headquartered in Bethesda, Maryland offering economic research and consulting services on issues and problems arising from governmental regulation of business. Areas of specialization supported by our Fort Myers office include property service–life forecasting, depreciation estimation, and valuation of industrial property.

Foster Associates has undertaken numerous depreciation engagements for both public and privately owned business entities, including detailed statistical life studies, analyses of required net salvage rates, and the selection of depreciation systems that will most nearly achieve the goals of depreciation accounting under the constraints of either government regulation or competitive market pricing. Foster Associates is widely recognized for industry leadership in the development of depreciation systems, life analysis techniques and computer software for conducting depreciation and valuation studies.

The purpose of a technical update is to adjust depreciation rates for changes in the variables associated with a remaining–life accrual rate. The variables for a plant account include the age distribution of surviving plant, the recorded depreciation reserve and the average net salvage rate used in the calculation of a theoretical reserve. A technical update retains the parameters developed and/or approved in the most recent full depreciation study and adjusts depreciation rates for subsequent changes in plant, reserves and realized net salvage activity.

The principal findings from the 2005 review are summarized in the attached statements. Statement A provides a comparative summary of present and proposed annual depreciation rates for each rate category. Statement B provides a comparison of present and proposed annual depreciation accruals. Statement C provides a comparison of the computed and redistributed depreciation reserve for each rate category. Statement D provides a summary of the components used to obtain a weighted–average net salvage rate for each plant account. Statement E provides a computation of the estimated future net salvage rate for steam production facilities. Statement F contains the computation of terminal dismantlement costs for steam production facilities. Statement G provides a comparative summary of present and proposed parameters and statistics including projection life, projection curve, average service life, average remaining life, and average and future net salvage rates.

SCOPE OF STUDY

Unlike a full depreciation study in which service life and net salvage parameters are estimated from a blending of quantitative analyses and informed judgment, the current study retains the parameters accepted in Docket No. E–01345A–03–0437 and provides an update of depreciation rates based on account age distributions and reserve balances at December 31, 2004.

The principal activities undertaken in the course of conducting the 2005 Technical Update included:

- Collection of plant data;
- Reconciliation of data to the official records of the Company;
- Computation of future net salvage rates for steam production facilities;
- Rebalancing of depreciation reserves; and
- Development of adjusted accrual rates for each rate category.

DEPRECIATION SYSTEM

A depreciation rate is formed by combining the elements of a depreciation system. A depreciation system is composed of a method, a procedure and a technique. A depreciation method (*e.g.*, straight–line) describes the component of the system that determines the acceleration or deceleration of depreciation accruals in relation to either time or use. A depreciation procedure (*e.g.*, vintage group) identifies the level of grouping or sub–grouping of assets within a plant category. The level of grouping dictates the weighting used to obtain composite life statistics for an account. A depreciation technique (*e.g.*, remaining–life) describes the life statistic used in the system.

APS is currently using a depreciation system composed of the straight–line method, broad group procedure, and remaining–life technique for all plant categories. The present system was accepted by the ACC in Docket No. E–01345A–03–0437 without comment as to the appropriateness of the system or a consideration of alternative systems. Accordingly, depreciation rates in the 2005 update were developed using the currently approved system.

PROPOSED DEPRECIATION RATES

Table 1 provides a summary of the changes in annual rates and accruals resulting from the 2005 Technical Update. Rates proposed for each primary account include an allowance for net salvage.

Function	Accrual Rate			2005 Annualized Accrual		
	Present	Proposed	Difference	Present	Proposed	Difference
A	B	C	D=C-B	E	F	G=F-E
Production						
Steam	3.34%	3.83%	0.49%	$45,731,277	$52,392,026	$6,660,749
Nuclear	2.95%	2.78%	-0.17%	70,195,368	66,186,908	(4,008,460)
Other	2.93%	2.93%	0.00%	6,039,806	6,030,434	(9,372)
Transmission	1.55%	1.12%	-0.43%	685,384	496,457	(188,927)
Distribution	2.43%	2.47%	0.04%	81,502,058	82,773,852	1,271,794
General Plant	5.30%	5.75%	0.45%	17,462,319	18,958,703	1,496,384
Total Utility	2.89%	2.95%	0.06%	$221,616,212	$226,838,380	$5,222,168

Table 1. Present and Proposed Rates and Accruals

Adjustments developed in the technical update produce a composite depreciation rate of 2.95 percent. Depreciation expense is presently accrued at an equivalent rate of 2.89 percent. The proposed change in the composite depreciation rate represents an increase of 0.06 percentage points.

A continued application of rates currently approved would provide annual depreciation expense of $221,616,212 compared with an annual expense of $226,838,380 using the rates developed in the update. The proposed expense increase of $5,222,168 is largely attributable to: a) a change in the mix of plant investments among primary accounts; b) changes in the age distributions of surviving plant; and c) plant additions to Four Corners generating station.

STUDY PROCEDURE

INTRODUCTION

Unlike a full depreciation study in which projection curves, projection lives and future net salvage rates are estimated from a statistical analysis of recorded retirements and net salvage realized in the past, a technical update generally retains the parameters currently used by the utility and adjusts depreciation rates for known and measurable changes in the age distributions of surviving plant, depreciation reserves, and average net salvage rates due to the passage of time. A technical update is intended to align depreciation rates with the accounting year the rates will become effective.

SCOPE

The steps involved in preparing a technical update can be grouped into five principal activities:

- Data collection;
- Calculation of service life statistics;
- Computation of average net salvage rates;
- Rebalancing of depreciation reserves; and
- Development of accrual rates.

The scope of the 2005 update for APS included a consideration of each of these tasks as described below.

DATA COLLECTION

The database used in the 2005 update was provided to Foster Associates in an electronic format containing plant and reserve activity over the period 1972–2004 and age distributions of surviving plant at December 31, 2004. Data used in the update were limited to the age distributions of surviving plant. Depreciation rates currently used by APS were developed using a broad–group procedure. The realized life of surviving vintages derived from the dollar–years of service provided by each vintage is not relevant to an update of broad–group depreciation rates. Therefore, plant transactions recorded in prior activity years were not used in the update.

Reserve transactions recorded in prior activity years were also not used in the 2005 update. Depreciation rates currently used by APS were derived without consideration of the distinction between average and future net salvage rates. The assumed equivalency between average and future net salvage rates was retained in the 2005 update without introducing prior realized net salvage amounts in the computation of average net salvage rates.

Calculation of Service Life Statistics

The composite remaining life and average service life of a plant category used in the calculation of depreciation rates are derived from a tabular arrangement of the age distribution of surviving plant and related statistics. The format of such a table is called a *generation arrangement*.

The age distribution of surviving plant is a column of numbers showing the dollar amount of investment remaining in service at the beginning of a study year from each of the vintages installed in prior years. The sum of an age distribution is the total plant in service for a plant category. The source of data used to construct an age distribution is a company's Continuing Property Record (CPR).

Statistics for each vintage (*i.e.*, average service life and remaining life) contained in a generation arrangement are derived from a mathematical function called a *survivor curve*. The survivor curve most descriptive of the forces of retirement acting upon a plant category is identified from a statistical analysis of past retirement experience, coupled with a consideration of how these forces are likely to change in the future. The collection of past retirements used in the statistical analysis can be viewed as a random sample from an unknown parent population. The objective of a life analysis is to estimate the parameters (*i.e.*, mean service life and dispersion characteristics) of the parent population. The mean service life of the population which best describes the timing of past and future retirements is called a *projection life* and the survivor curve selected to describe the forces of retirement acting upon the population is called a *projection curve*. A technical update generally retains the service life parameters estimated in a full depreciation study. Statistics for each vintage, however, are updated to reflect known and measurable changes in the age distributions of surviving plant.

Computation of Average Net Salvage Rates

Estimates of the net salvage rates applicable to future retirements are derived in a full depreciation study from an analysis of gross salvage and removal expense realized in the past and a consideration of future expectations which may dictate a departure from historical indications. Future net salvage rates adopted from such an analysis are retained as fixed parameters in a technical update.

The average net salvage rate for an account or plant function is derived from a direct dollar weighting of a) historical retirements with historical (or realized) net salvage rates and b) future retirements (*i.e.*, surviving plant) with the estimated future net salvage rate. Average net salvage rates will change, therefore, as additional years of retirement and net salvage activity become available and as subsequent plant additions alter the weighting of future net salvage estimates.

As noted earlier, depreciation rates currently used by APS were derived without consideration of the distinction between average and future net salvage rates. The assumed equivalency between average and future net salvage rates was retained in the 2005 update without introducing prior realized net salvage amounts in the computation of average net salvage rates.

Although arguably beyond the scope of a technical update, future net salvage rates for steam production facilities were adjusted in the 2005 update for estimated terminal dismantlement costs. The treatment of dismantlement costs in prior studies (and in the depreciation rates currently used by APS) reflects an assumption that interim and future net salvage rates will be equal. This assumption was relaxed in the 2005 update by: a) retaining an interim net salvage rate of –20 percent; and b) adjusting terminal dismantlement costs to reflect costs per kW estimated in dismantling studies conducted in 2002 for the Navajo and Four Corners generating stations. An inflation rate of three percent was used to escalate 2002 dollars to estimated years of final retirement. Statement F provides a computation of terminal dismantlement costs used in Statement E to derive future net salvage rates for steam production facilities. The retained equivalency of average and future net salvage rates is shown in Statement D.

REBALANCING OF DEPRECIATION RESERVES

Although reserve records are typically maintained by various account classifications, the total reserve for a company is the most important measure of the status of the company's depreciation practices and procedures. If a company has not previously conducted statistical life studies or considered retirement dispersion in setting depreciation rates, it is likely that some accounts will be overdepreciated and other accounts will be underdepreciated relative to a calculated theoretical reserve. Differences between theoretical and recorded reserves will also arise as a normal occurrence when service lives, dispersion patterns and net salvage estimates are changed in the course of depreciation reviews. It is appropriate, therefore, and consistent with group depreciation theory to periodically redistribute recorded reserves among the various primary accounts based upon the most recent estimates of retirement dispersion and net salvage rates.

A rebalancing of recorded reserves is consistent with the objectives of a technical update and is considered appropriate for APS. Depreciation rates adopted in Docket No. E–01345A–03–0437 were derived from rebalanced reserves obtained from a set of parameters different from those used in the formulation of the settled remaining–life accrual rates. Reserve imbalances amortized in the settled rates are therefore inconsistent with the realigned depreciation reserves. The rebalancing of reserves undertaken in the 2005 update will reestablish consistency between measured reserve imbalances and the parameters used in the formulation of updated remaining–life accrual rates.

A redistribution of the recorded reserve was achieved for APS by multiplying the calculated reserve for each primary account within a function (or plant location) by the ratio of the function (or location) total recorded reserve to the function (or location) total calculated reserve. The sum of the redistributed reserves within a function (or location) is, therefore, equal to the function (or location) total recorded depreciation reserve before the redistribution.

Statement C provides a comparison of the recorded, computed and rebalanced reserves for APS at December 31, 2004. The recorded reserve was $3,114,473,674, or 50.0 percent of the depreciable plant investment. The corresponding computed reserve is $2,771,955,374 or 48.0 percent of the depreciable plant investment. A proportionate amount of the measured reserve excess of $342,518,300 will be amortized over the composite weighted–average remaining life of each rate category.

Development of Accrual Rates

The goal or objective of depreciation accounting is cost allocation over the economic life of an asset in proportion to the consumption of service potential. *Ideally, the cost of an asset—which represents the cost of obtaining a bundle of* service units—should be allocated to future periods of operation in proportion to the amount of service potential expended during an accounting interval. The service potential of an asset is the present value of future net revenue (*i.e.*, revenue less expenses exclusive of depreciation and other non-cash expenses) or cash inflows attributable to the use of that asset alone.

Depreciation rates currently used by APS were developed using a system composed of the straight–line method, broad–group procedure, remaining–life technique. Depreciation rates proposed in the update were developed using the currently approved system.

STATEMENTS

INTRODUCTION

This section provides a comparative summary of depreciation rates, annual depreciation accruals, recorded and computed depreciation reserves, and present and proposed service life and net salvage parameters for APS. The content of these statements is briefly described below.

- Statement A provides a comparative summary of present and proposed annual depreciation rates for calendar year 2005 using the straight–line method, broad group procedure, remaining–life technique.
- Statement B provides a comparison of present and proposed annualized depreciation accruals for calendar year 2005 based upon the rates developed in Statement A.
- Statement C provides a comparison of recorded and computed reserves for each rate category and sets forth the computations used to redistribute recorded reserves among primary plant accounts.
- Statement D provides a summary of the components used to obtain a weighted average net salvage rate for each rate category.
- Statement E provides a computation of the estimated future net salvage rate for steam production facilities.
- Statement F contains the computation of terminal dismantlement costs for steam production facilities.
- Statement G provides a comparative summary of present and proposed parameters including projection life, projection curve and future net salvage rates. The statement also contains present and proposed statistics including average service life, average remaining life, and average net salvage rates.

Present depreciation accruals shown on Statement B are the product of plant investments (Column B) and the present depreciation rates (Column D) shown on Statement A. These are the effective rates used by APS for the mix of investments recorded on December 31, 2004. Similarly, proposed depreciation accruals shown on Statement B are the product of plant investments and proposed depreciation rates (Column H) shown on Statement A. Proposed accrual rates shown on Statement A are given by:

$$\textit{Accrual Rate} = \frac{1.0 - \textit{Reserve Ratio} - \textit{Future Net Salvage Rate}}{\textit{Remaining Life}}.$$

ARIZONA PUBLIC SERVICE COMPANY

Statement A

Comparison of Present and Proposed Accrual Rates
Present: BG Procedure / RL Technique
Proposed: BG Procedure / RL Technique

	Present			Proposed (at December 31, 2004)			
Account Description	Rem. Life	Net Salvage	Accrual Rate	Rem. Life	Net Salvage	Reserve Ratio	Accrual Rate
A	B	C	D	E	F	G	H
STEAM PRODUCTION							
311.00 Structures and Improvements			2.96%	18.47	-18.7%	50.17%	3.75%
312.00 Boiler Plant Equipment			3.52%	15.64	-18.8%	57.35%	3.97%
314.00 Turbogenerator Units			3.00%	17.74	-20.6%	57.01%	3.64%
315.00 Accessory Electric Equipment			2.71%	20.34	-19.2%	60.07%	2.95%
316.00 Misc. Power Plant Equipment			4.21%	16.98	-21.1%	43.49%	4.60%
Total Steam Production Plant			3.34%	16.64	-19.2%	56.27%	3.83%
NUCLEAR PRODUCTION							
321.00 Structures and Improvements			2.60%	20.63		45.97%	2.62%
322.00 Reactor Plant Equipment			2.86%	19.58	-0.2%	44.69%	2.84%
322.10 Steam Generators			8.39%	1.71		95.73%	2.17%
323.00 Turbogenerator Units			2.90%	19.08	-0.4%	45.83%	2.86%
324.00 Accessory Electric Equipment			2.78%	18.99	-0.5%	49.17%	2.70%
325.00 Misc. Power Plant Equipment			3.59%	17.27	-0.8%	43.01%	3.35%
Total Nuclear Production Plant			2.95%	18.78	-0.2%	46.75%	2.78%
OTHER PRODUCTION							
341.00 Structures and Improvements			2.71%	18.52	-4.8%	48.33%	2.43%
342.00 Fuel Holders, Products and Accessories			2.87%	22.27	-5.0%	39.18%	2.78%
343.00 Prime Movers			1.25%	11.58		83.08%	1.45%
344.00 Generators and Devices			3.59%	17.27	-1.4%	36.00%	3.55%
345.00 Accessory Electric Equipment			2.27%	19.53		48.77%	2.40%
346.00 Misc. Power Plant Equipment			2.56%	16.90		52.37%	2.71%
Total Other Production Plant			2.93%	17.35	-1.6%	46.10%	2.93%
TOTAL PRODUCTION PLANT			3.08%	17.92		50.02%	3.15%
TRANSMISSION							
352.00 Structures and Improvements	35.20	-5.0%	1.70%	21.69	-5.0%	110.65%	-0.26%
353.00 Station Equipment	45.70		1.52%	39.98		55.57%	1.11%
354.00 Towers and Fixtures	38.30	-35.0%	2.08%	42.49	-35.0%	73.33%	1.45%
355.00 Poles and Fixtures - Wood	38.50	-35.0%	2.72%	18.51	-15.0%	142.00%	-1.46%
356.00 Overhead Conductors and Devices	38.50	-35.0%	2.32%	37.51	-35.0%	79.90%	1.47%
Total Transmission Plant			1.55%	39.97	-1.5%	56.57%	1.12%
DISTRIBUTION							
361.00 Structures and Improvements	33.10	-10.0%	2.10%	33.18	-10.0%	38.78%	2.15%
362.00 Station Equipment	36.90		2.04%	36.73		22.18%	2.12%
364.00 Poles, Towers and Fixtures - Wood	30.90	-10.0%	2.64%	29.41	-10.0%	33.37%	2.61%
364.10 Poles, Towers and Fixtures - Steel	46.60	-5.0%	2.03%	46.78	-5.0%	9.08%	2.05%
365.00 Overhead Conductors and Devices	47.70	-10.0%	1.99%	46.65	-10.0%	17.69%	1.98%
366.00 Underground Conduit	82.40	-5.0%	1.20%	82.10	-5.0%	6.39%	1.20%
367.00 Underground Conductors and Devices	22.90	-5.0%	3.18%	22.28	-5.0%	32.66%	3.25%
368.00 Line Transformers	24.60	-5.0%	2.30%	23.63	-5.0%	48.43%	2.39%
369.00 Services	27.90	-10.0%	2.60%	26.72	-10.0%	41.02%	2.58%
370.00 Meters	21.80		2.84%	21.24		35.92%	3.02%
370.10 Meters - Electronic	23.30		3.61%	23.06		15.18%	3.68%
371.00 Installations on Customers' Premises	45.00	-20.0%	2.33%	45.48	-20.0%	14.56%	2.32%
373.00 Street Lighting and Signal Systems	25.90	-20.0%	3.10%	24.32	-20.0%	49.15%	2.91%
Total Distribution Plant			2.43%	30.41	-6.1%	29.53%	2.47%

ARIZONA PUBLIC SERVICE COMPANY Statement A

Comparison of Present and Proposed Accrual Rates
Present: BG Procedure / RL Technique
Proposed: BG Procedure / RL Technique

	Present			Proposed (at December 31, 2004)			
Account Description	Rem. Life	Net Salvage	Accrual Rate	Rem. Life	Net Salvage	Reserve Ratio	Accrual Rate
A	B	C	D	E	F	G	H
GENERAL							
390.00 Structures and Improvements	30.70	-15.0%	2.93%	29.54	-15.0%	28.01%	2.94%
391.00 Office Furn. and Equip. - Furniture	10.10		4.16%	12.23		39.00%	4.99%
391.10 Office Furn. and Equip. - PC Equipment	5.30		11.43%	4.28		46.69%	12.46%
391.20 Office Furn. and Equip. - Other	14.80		4.17%	13.44		39.06%	4.53%
393.00 Stores Equipment	2.80			2.14		89.66%	4.83%
394.00 Tools, Shop and Garage Equipment	13.70		4.61%	12.20		39.16%	4.99%
395.00 Laboratory Equipment	12.00		5.07%	11.99		40.21%	4.99%
397.00 Communication Equipment	12.00		4.74%	11.53		39.47%	5.25%
398.HH Miscellaneous Equipment - Hydrogen			20.00%	2.50		50.20%	19.92%
398.00 Miscellaneous Equipment	16.60		3.85%	20.91		12.93%	4.16%
Total General			5.30%	11.41	-4.7%	36.88%	5.75%
TOTAL UTILITY			2.89%	22.24	-5.9%	40.55%	2.95%
STEAM PRODUCTION (BY UNIT)							
Cholla							
311.00 Structures and Improvements			2.27%	27.11	-19.2%	57.24%	2.28%
312.00 Boiler Plant Equipment			2.78%	19.78	-19.4%	63.40%	2.83%
314.00 Turbogenerator Units			2.63%	24.85	-19.9%	49.55%	2.81%
315.00 Accessory Electric Equipment			2.33%	24.71	-19.4%	61.20%	2.35%
316.00 Misc. Power Plant Equipment			3.38%	20.65	-19.2%	48.43%	3.42%
Total Cholla			2.66%	21.89	-19.5%	59.71%	2.72%
Cholla Unit 1							
311.00 Structures and Improvements	14.00	-20.0%	2.44%	11.97	-15.8%	84.63%	2.60%
312.00 Boiler Plant Equipment	13.40	-20.0%	3.98%	11.20	-16.3%	68.47%	4.27%
314.00 Turbogenerator Units	14.00	-20.0%	3.46%	11.90	-15.8%	74.85%	3.44%
315.00 Accessory Electric Equipment	13.90	-20.0%	3.20%	11.86	-15.9%	75.87%	3.38%
316.00 Misc. Power Plant Equipment	13.50	-20.0%	5.08%	11.63	-16.1%	56.79%	5.10%
Total Cholla Unit 1			3.77%	11.44	-16.1%	70.74%	3.97%
Cholla Unit 2							
311.00 Structures and Improvements	29.00	-20.0%	2.69%	26.78	-18.1%	49.48%	2.56%
312.00 Boiler Plant Equipment	22.00	-20.0%	2.65%	20.46	-19.0%	65.37%	2.62%
314.00 Turbogenerator Units	27.50	-20.0%	2.39%	25.56	-18.3%	59.67%	2.29%
315.00 Accessory Electric Equipment	26.80	-20.0%	2.26%	25.09	-18.4%	62.71%	2.22%
316.00 Misc. Power Plant Equipment	22.10	-20.0%	2.97%	20.74	-19.1%	56.37%	3.02%
Total Cholla Unit 2			2.55%	21.99	-18.8%	63.58%	2.51%
Cholla Unit 3							
311.00 Structures and Improvements	29.90	-20.0%	2.20%	27.97	-21.7%	58.20%	2.27%
312.00 Boiler Plant Equipment	22.90	-20.0%	2.62%	21.56	-20.9%	62.35%	2.72%
314.00 Turbogenerator Units	29.70	-20.0%	2.60%	28.16	-21.8%	37.15%	3.01%
315.00 Accessory Electric Equipment	28.50	-20.0%	2.30%	26.87	-21.5%	58.38%	2.35%
316.00 Misc. Power Plant Equipment	23.80	-20.0%	3.02%	21.91	-20.8%	53.53%	3.07%
Total Cholla Unit 3			2.55%	24.25	-21.2%	55.38%	2.72%
Cholla Common							
311.00 Structures and Improvements	29.90	-20.0%	2.23%	28.01	-18.9%	56.45%	2.23%
312.00 Boiler Plant Equipment	24.80	-20.0%	2.82%	23.38	-19.3%	50.89%	2.93%
314.00 Turbogenerator Units	29.00	-20.0%	2.30%	27.18	-19.0%	58.21%	2.24%
315.00 Accessory Electric Equipment	28.70	-20.0%	2.33%	27.19	-19.0%	50.96%	2.50%
316.00 Misc. Power Plant Equipment	25.80	-20.0%	3.32%	24.23	-19.3%	38.04%	3.35%
Total Cholla Common			2.55%	25.69	-19.1%	52.31%	2.60%

ARIZONA PUBLIC SERVICE COMPANY Statement A

Comparison of Present and Proposed Accrual Rates
Present: BG Procedure / RL Technique
Proposed: BG Procedure / RL Technique

	Present			Proposed (at December 31, 2004)			
Account Description	Rem. Life	Net Salvage	Accrual Rate	Rem. Life	Net Salvage	Reserve Ratio	Accrual Rate
A	B	C	D	E	F	G	H
Four Corners							
311.00 Structures and Improvements			3.49%	13.52	-18.5%	42.70%	5.54%
312.00 Boiler Plant Equipment			4.13%	12.87	-18.1%	53.27%	5.01%
314.00 Turbogenerator Units			3.58%	13.24	-17.8%	53.95%	4.79%
315.00 Accessory Electric Equipment			3.70%	14.61	-19.3%	55.04%	4.36%
316.00 Misc. Power Plant Equipment			4.72%	15.90	-21.7%	41.99%	4.96%
Total Four Corners			4.00%	13.18	-18.3%	52.12%	4.98%
Four Corners Units 1-3							
311.00 Structures and Improvements	13.30	-20.0%	4.02%	11.39	-14.1%	36.62%	6.80%
312.00 Boiler Plant Equipment	12.70	-20.0%	4.84%	10.76	-14.8%	50.84%	5.94%
314.00 Turbogenerator Units	13.10	-20.0%	3.96%	11.08	-14.5%	53.98%	5.46%
315.00 Accessory Electric Equipment	13.20	-20.0%	4.68%	11.21	-14.3%	53.65%	5.41%
316.00 Misc. Power Plant Equipment	13.10	-20.0%	7.53%	11.15	-14.4%	29.52%	7.61%
Total Four Corners Units 1-3			4.68%	10.90	-14.7%	49.72%	5.96%
Four Corners Units 4-5							
311.00 Structures and Improvements	26.80	-20.0%	2.40%	24.80	-26.8%	57.08%	2.81%
312.00 Boiler Plant Equipment	22.10	-20.0%	2.82%	20.40	-24.1%	57.62%	3.26%
314.00 Turbogenerator Units	26.30	-20.0%	2.70%	24.09	-26.4%	50.68%	3.14%
315.00 Accessory Electric Equipment	25.90	-20.0%	2.51%	24.24	-26.4%	50.75%	3.12%
316.00 Misc. Power Plant Equipment	23.00	-20.0%	3.37%	20.22	-23.8%	49.96%	3.65%
Total Four Corners Units 4-5			2.77%	21.23	-24.6%	56.30%	3.22%
Four Corners Common							
311.00 Structures and Improvements	26.80	-20.0%	2.37%	24.71	-29.0%	51.89%	3.12%
312.00 Boiler Plant Equipment	22.80	-20.0%	2.39%	19.62	-25.3%	63.41%	3.15%
314.00 Turbogenerator Units	23.30	-20.0%	1.79%	21.73	-26.4%	81.01%	2.09%
315.00 Accessory Electric Equipment	21.00	-20.0%	1.85%	20.44	-25.2%	79.18%	2.25%
316.00 Misc. Power Plant Equipment	23.20	-20.0%	3.33%	21.37	-25.8%	47.46%	3.67%
Total Four Corners Common			2.64%	21.73	-26.4%	57.96%	3.15%
Navajo Units 1-3							
311.00 Structures and Improvements	22.80	-20.0%	3.29%	20.78	-14.5%	44.27%	3.38%
312.00 Boiler Plant Equipment	20.60	-20.0%	3.55%	18.52	-15.8%	48.18%	3.65%
314.00 Turbogenerator Units	22.00	-20.0%	2.76%	20.00	-14.9%	57.66%	2.86%
315.00 Accessory Electric Equipment	22.00	-20.0%	2.82%	19.88	-15.1%	56.77%	2.93%
316.00 Misc. Power Plant Equipment	20.20	-20.0%	3.74%	18.57	-15.9%	40.79%	4.04%
Total Navajo Units 1-3			3.39%	19.00	-15.5%	48.96%	3.50%
Ocotillo Units 1-2							
311.00 Structures and Improvements	17.10	-20.0%	3.80%	15.05	-37.9%	61.04%	5.11%
312.00 Boiler Plant Equipment	15.20	-20.0%	3.02%	12.89	-32.9%	77.61%	4.29%
314.00 Turbogenerator Units	16.80	-20.0%	2.76%	14.30	-36.1%	78.82%	4.01%
315.00 Accessory Electric Equipment	16.30	-20.0%	2.20%	13.90	-35.0%	77.01%	4.17%
316.00 Misc. Power Plant Equipment	16.20	-20.0%	5.24%	14.61	-36.8%	29.79%	7.32%
Total Octillo Units 1-2			3.18%	13.77	-34.7%	71.81%	4.57%
Saguaro Units 1-2							
311.00 Structures and Improvements	11.30	-20.0%	3.42%	9.28	-29.0%	72.94%	6.04%
312.00 Boiler Plant Equipment	11.10	-20.0%	4.69%	8.61	-27.8%	79.46%	5.61%
314.00 Turbogenerator Units	11.20	-20.0%	3.44%	9.15	-28.8%	85.64%	4.72%
315.00 Accessory Electric Equipment	11.20	-20.0%	2.79%	8.99	-28.5%	89.22%	4.37%
316.00 Misc. Power Plant Equipment	10.90	-20.0%	7.16%	8.96	-28.4%	55.15%	8.18%
Total Saguaro Units 1-2			4.24%	8.87	-28.3%	80.06%	5.44%

ARIZONA PUBLIC SERVICE COMPANY

Statement A

Comparison of Present and Proposed Accrual Rates

Present: BG Procedure / RL Technique

Proposed: BG Procedure / RL Technique

	Present			Proposed (at December 31, 2004)			
Account Description	Rem. Life	Net Salvage	Accrual Rate	Rem. Life	Net Salvage	Reserve Ratio	Accrual Rate
A	B	C	D	E	F	G	H
NUCLEAR PRODUCTION (BY UNIT)							
Palo Verde							
321.00 Structures and Improvements			2.60%	20.63		45.97%	2.62%
322.00 Reactor Plant Equipment			2.86%	19.58	-0.2%	44.69%	2.84%
322.10 Steam Generators			8.39%	1.71		95.73%	2.17%
323.00 Turbogenerator Units			2.90%	19.08	-0.4%	45.83%	2.86%
324.00 Accessory Electric Equipment			2.78%	18.99	-0.5%	49.17%	2.70%
325.00 Misc. Power Plant Equipment			3.59%	17.27	-0.8%	43.01%	3.35%
Total Palo Verde			2.95%	18.78	-0.2%	46.75%	2.78%
Palo Verde Unit 1							
321.00 Structures and Improvements	21.20		2.68%	18.78		50.61%	2.63%
322.00 Reactor Plant Equipment	20.60	-2.0%	2.88%	18.37	-0.2%	49.47%	2.76%
322.10 Steam Generators	3.00	-17.0%	9.09%	1.00		98.53%	1.47%
323.00 Turbogenerator Units	19.90	-2.0%	2.93%	17.81	-0.4%	49.80%	2.84%
324.00 Accessory Electric Equipment	20.00	-2.0%	2.79%	17.80	-0.4%	52.35%	2.70%
325.00 Misc. Power Plant Equipment	17.70	-2.0%	3.52%	15.87	-0.8%	48.80%	3.28%
Total Palo Verde Unit 1			3.07%	17.85	-0.2%	51.79%	2.71%
Palo Verde Unit 2							
321.00 Structures and Improvements	22.00		2.55%	19.70		46.20%	2.73%
322.00 Reactor Plant Equipment	21.50	-2.0%	2.83%	19.32	-0.2%	38.02%	3.22%
322.10 Steam Generators	1.00	-17.0%	17.01%				
323.00 Turbogenerator Units	20.80	-2.0%	2.87%	18.74	-0.4%	41.76%	3.13%
324.00 Accessory Electric Equipment	20.90	-2.0%	2.78%	18.71	-0.5%	46.96%	2.86%
325.00 Misc. Power Plant Equipment	18.70	-2.0%	3.69%	16.82	-0.7%	39.57%	3.63%
Total Palo Verde Unit 2			2.83%	19.06	-0.3%	41.25%	3.10%
Palo Verde Unit 3							
321.00 Structures and Improvements	23.30		2.59%	21.58		45.56%	2.52%
322.00 Reactor Plant Equipment	22.60	-2.0%	2.85%	21.03	-0.3%	44.21%	2.67%
322.10 Steam Generators	5.00	-17.0%	7.63%	2.50		92.71%	2.92%
323.00 Turbogenerator Units	21.80	-2.0%	2.89%	20.33	-0.4%	44.88%	2.73%
324.00 Accessory Electric Equipment	22.10	-2.0%	2.77%	20.40	-0.5%	47.03%	2.62%
325.00 Misc. Power Plant Equipment	19.20	-2.0%	3.51%	17.88	-0.8%	43.64%	3.20%
Total Palo Verde Unit 3			2.98%	20.13	-0.3%	46.52%	2.67%
Palo Verde Water Reclamation							
321.00 Structures and Improvements	23.20		2.56%	21.55		42.72%	2.66%
322.00 Reactor Plant Equipment	23.00	-2.0%	4.18%	21.36	-0.2%	13.25%	4.07%
322.10 Steam Generators							
323.00 Turbogenerator Units	22.00	-2.0%	3.04%	20.51	-0.4%	37.48%	3.07%
324.00 Accessory Electric Equipment							
325.00 Misc. Power Plant Equipment	19.50	-2.0%	3.63%	18.15	-0.8%	38.20%	3.45%
Total Palo Verde Water Reclamation			2.56%	21.53	0.0%	42.68%	2.66%
Palo Verde Common							
321.00 Structures and Improvements	23.20		2.58%	21.59		43.59%	2.61%
322.00 Reactor Plant Equipment	22.60	-2.0%	2.91%	21.05	-0.3%	42.59%	2.74%
322.10 Steam Generators							
323.00 Turbogenerator Units	22.20	-2.0%	3.32%	20.63	-0.4%	35.84%	3.13%
324.00 Accessory Electric Equipment	22.00	-2.0%	2.78%	20.36	-0.5%	45.85%	2.68%
325.00 Misc. Power Plant Equipment	19.40	-2.0%	3.62%	18.04	-0.8%	40.98%	3.32%
Total Palo Verde Common			2.90%	20.40	-0.3%	42.99%	2.81%

ARIZONA PUBLIC SERVICE COMPANY Statement A

Comparison of Present and Proposed Accrual Rates
Present: BG Procedure / RL Technique
Proposed: BG Procedure / RL Technique

	Present			Proposed (at December 31, 2004)			
Account Description	Rem. Life	Net Salvage	Accrual Rate	Rem. Life	Net Salvage	Reserve Ratio	Accrual Rate
A	B	C	D	E	F	G	H
OTHER PRODUCTION (BY UNIT)							
Douglas CT							
341.00 Structures and Improvements	13.90	-5.0%	1.01%	12.01	-5.0%	96.08%	0.74%
342.00 Fuel Holders, Products and Accessories	14.00	-5.0%	2.31%	12.08	-5.0%	80.67%	2.01%
343.00 Prime Movers	14.20		0.65%	11.65		91.77%	0.71%
344.00 Generators and Devices	9.70		0.17%	8.41		98.99%	0.12%
345.00 Accessory Electric Equipment	13.10		0.86%	11.06		90.19%	0.89%
346.00 Misc. Power Plant Equipment	13.80		1.90%	11.86		78.04%	1.85%
Total Douglas CT			0.69%	11.44	-0.3%	92.39%	0.69%
Ocotillo CT Units 1-2							
341.00 Structures and Improvements	14.50	-5.0%	2.40%	12.12	-5.0%	75.23%	2.46%
342.00 Fuel Holders, Products and Accessories	14.00	-5.0%	2.36%	12.11	-5.0%	77.54%	2.27%
343.00 Prime Movers	14.10		1.06%	11.73		83.82%	1.38%
344.00 Generators and Devices	13.60		3.33%	11.60		61.21%	3.34%
345.00 Accessory Electric Equipment	13.20		1.08%	11.29		80.92%	1.69%
346.00 Misc. Power Plant Equipment	14.00		1.74%	11.81		76.69%	1.97%
Total Ocotillo CT Units 1-2			2.07%	11.66	-0.4%	73.86%	2.27%
Saguaro CT Units 1-2							
341.00 Structures and Improvements	14.40	-5.0%	4.77%	12.34	-5.0%	44.74%	4.88%
342.00 Fuel Holders, Products and Accessories	14.00	-5.0%	1.92%	12.00	-5.0%	83.06%	1.83%
343.00 Prime Movers	13.80		1.29%	11.77		83.03%	1.44%
344.00 Generators and Devices	13.00		3.09%	10.88		60.02%	3.67%
345.00 Accessory Electric Equipment	13.40		1.42%	11.28		84.83%	1.34%
346.00 Misc. Power Plant Equipment	14.10		3.41%	12.00		59.00%	3.42%
Total Saguaro CT Units 1-2			2.15%	11.56	-0.8%	73.64%	2.35%
Solar Units							
341.00 Structures and Improvements	3.60			2.03		121.49%	-10.59%
342.00 Fuel Holders, Products and Accessories							
343.00 Prime Movers				11.50		6.09%	8.17%
344.00 Generators and Devices	7.80		6.74%	7.56		54.10%	6.07%
345.00 Accessory Electric Equipment	9.90		7.71%	7.86		50.45%	6.30%
346.00 Misc. Power Plant Equipment							
Total Solar Units			6.58%	7.82		55.59%	5.68%
West Phoenix							
341.00 Structures and Improvements			2.38%	24.31	-5.0%	43.23%	2.51%
342.00 Fuel Holders, Products and Accessories			3.20%	24.77	-5.0%	26.12%	3.15%
343.00 Prime Movers			2.07%	11.86		72.42%	2.33%
344.00 Generators and Devices			3.24%	23.01	-1.9%	25.79%	3.28%
345.00 Accessory Electric Equipment			2.64%	23.25		33.87%	2.77%
346.00 Misc. Power Plant Equipment			2.69%	20.03		43.10%	2.80%
Total West Pheonix			3.03%	22.53	-2.2%	31.12%	3.09%
West Phoenix CT Units 1-2							
341.00 Structures and Improvements	14.20	-5.0%	1.61%	12.12	-5.0%	85.24%	1.63%
342.00 Fuel Holders, Products and Accessories	14.00	-5.0%	1.92%	12.03	-5.0%	82.07%	1.91%
343.00 Prime Movers	14.20		2.07%	11.86		72.42%	2.33%
344.00 Generators and Devices	12.30		1.80%	10.75		68.68%	2.91%
345.00 Accessory Electric Equipment	13.20		1.18%	11.27		83.49%	1.46%
346.00 Misc. Power Plant Equipment	14.10		3.33%	12.02		57.98%	3.50%
Total West Ploenix CT Units 1-2			1.96%	11.49	-0.5%	72.76%	2.42%

ARIZONA PUBLIC SERVICE COMPANY Statement A

Comparison of Present and Proposed Accrual Rates
Present: BG Procedure / RL Technique
Proposed: BG Procedure / RL Technique

	Present			Proposed (at December 31, 2004)			
Account Description	Rem. Life	Net Salvage	Accrual Rate	Rem. Life	Net Salvage	Reserve Ratio	Accrual Rate
A	B	C	D	E	F	G	H
West Phoenix CC Units 1-3							
341.00 Structures and Improvements	28.10	-5.0%	2.44%	25.21	-5.0%	40.18%	2.57%
342.00 Fuel Holders, Products and Accessories	27.70	-5.0%	3.30%	25.65	-5.0%	21.95%	3.24%
343.00 Prime Movers							
344.00 Generators and Devices	26.20	-2.0%	3.33%	23.95	-2.0%	23.04%	3.30%
345.00 Accessory Electric Equipment	27.80		2.82%	24.59		27.63%	2.94%
346.00 Misc. Power Plant Equipment	26.60		2.47%	24.26		38.00%	2.56%
Total West Phoenix CC Units 1-3			3.20%	24.35	-2.4%	24.71%	3.19%
Yucca CT Units 1-4							
341.00 Structures and Improvements	13.40	-5.0%	4.16%	11.35	-5.0%	61.13%	3.87%
342.00 Fuel Holders, Products and Accessories	12.90	-5.0%	1.28%	11.00	-5.0%	94.51%	0.95%
343.00 Prime Movers	14.20		0.55%	10.81		93.27%	0.62%
344.00 Generators and Devices	11.60		1.64%	9.09		87.36%	1.39%
345.00 Accessory Electric Equipment	13.00		1.24%	10.37		87.09%	1.24%
346.00 Misc. Power Plant Equipment	13.20		1.23%	10.90		80.29%	1.81%
Total Yucca CT Units 1-4			1.14%	10.24	-0.9%	90.11%	1.06%

ARIZONA PUBLIC SERVICE COMPANY — Statement B

Comparison of Present and Proposed Accruals
Present: BG Procedure / RL Technique
Proposed: BG Procedure / RL Technique

Account Description	12/31/04 Plant Investment	2005 Annualized Accrual Present	Proposed	Difference
A	B	C	D	E=D-C
STEAM PRODUCTION				
311.00 Structures and Improvements	$131,870,408	$3,902,247	$4,939,665	$1,037,418
312.00 Boiler Plant Equipment	837,866,945	29,500,044	33,265,700	3,765,656
314.00 Turbogenerator Units	201,179,564	6,040,327	7,332,245	1,291,918
315.00 Accessory Electric Equipment	138,223,358	3,742,018	4,071,592	329,574
316.00 Misc. Power Plant Equipment	60,433,389	2,546,641	2,782,824	236,183
Total Steam Production Plant	$1,369,573,664	$45,731,277	$52,392,026	$6,660,749
NUCLEAR PRODUCTION				
321.00 Structures and Improvements	$640,003,980	$16,629,867	$16,763,507	$133,640
322.00 Reactor Plant Equipment	939,061,294	26,844,521	26,663,549	(180,972)
322.10 Steam Generators	52,865,345	4,434,434	1,145,606	(3,288,828)
323.00 Turbogenerator Units	342,424,222	9,933,350	9,796,470	(136,880)
324.00 Accessory Electric Equipment	272,624,619	7,581,450	7,365,529	(215,921)
325.00 Misc. Power Plant Equipment	132,963,906	4,771,746	4,452,247	(319,499)
Total Nuclear Production Plant	$2,379,943,366	$70,195,368	$66,186,908	($4,008,460)
OTHER PRODUCTION				
341.00 Structures and Improvements	$10,180,396	$275,443	$247,818	($27,625)
342.00 Fuel Holders, Products and Accessories	26,096,001	749,643	725,004	(24,639)
343.00 Prime Movers	32,466,268	406,130	469,913	63,783
344.00 Generators and Devices	111,753,871	4,017,508	3,963,121	(54,387)
345.00 Accessory Electric Equipment	19,867,012	451,140	476,544	25,404
346.00 Misc. Power Plant Equipment	5,460,622	139,942	148,034	8,092
Total Other Production Plant	$205,824,170	$6,039,806	$6,030,434	($9,372)
TOTAL PRODUCTION PLANT	$3,955,341,200	$121,966,451	$124,609,368	$2,642,917
TRANSMISSION				
352.00 Structures and Improvements	$95,935	$1,631	($249)	($1,880)
353.00 Station Equipment	42,249,917	642,199	468,974	(173,225)
354.00 Towers and Fixtures	1,329,316	27,650	19,275	(8,375)
355.00 Poles and Fixtures - Wood	11,064	301	(162)	(463)
356.00 Overhead Conductors and Devices	586,319	13,603	8,619	(4,984)
Total Transmission Plant	$44,272,551	$685,384	$496,457	($188,927)
DISTRIBUTION				
361.00 Structures and Improvements	$30,704,475	$644,794	$660,146	$15,352
362.00 Station Equipment	242,575,593	4,948,542	5,142,603	194,061
364.00 Poles, Towers and Fixtures - Wood	296,506,680	7,827,776	7,738,824	(88,952)
364.10 Poles, Towers and Fixtures - Steel	73,766,423	1,497,458	1,512,212	14,754
365.00 Overhead Conductors and Devices	233,951,705	4,655,639	4,632,244	(23,395)
366.00 Underground Conduit	509,266,861	6,111,202	6,111,202	
367.00 Underground Conductors and Devices	908,715,823	28,897,163	29,533,264	636,101
368.00 Line Transformers	537,581,653	12,364,378	12,848,202	483,824
369.00 Services	268,098,185	6,970,553	6,916,933	(53,620)
370.00 Meters	91,949,592	2,611,368	2,776,878	165,510
370.10 Meters - Electronic	65,427,927	2,361,948	2,407,748	45,800
371.00 Installations on Customers' Premises	31,927,745	743,916	740,724	(3,192)
373.00 Street Lighting and Signal Systems	60,236,149	1,867,321	1,752,872	(114,449)
Total Distribution Plant	$3,350,708,811	$81,502,058	$82,773,852	$1,271,794

ARIZONA PUBLIC SERVICE COMPANY Statement B

Comparison of Present and Proposed Accruals

Present: BG Procedure / RL Technique

Proposed: BG Procedure / RL Technique

Account Description	12/31/04 Plant Investment	2005 Annualized Accrual Present	Proposed	Difference
A	B	C	D	E=D-C
GENERAL				
390.00 Structures and Improvements	$103,793,498	$3,041,149	$3,051,529	$10,380
391.00 Office Furn. and Equip. - Furniture	31,890,832	1,326,659	1,591,353	264,694
391.10 Office Furn. and Equip. - PC Equipment	49,510,133	5,659,008	6,168,963	509,955
391.20 Office Furn. and Equip. - Other	9,016,492	375,988	408,447	32,459
393.00 Stores Equipment	1,235,839		59,691	59,691
394.00 Tools, Shop and Garage Equipment	14,047,955	647,611	700,993	53,382
395.00 Laboratory Equipment	1,609,510	81,602	80,315	(1,287)
397.00 Communication Equipment	109,319,204	5,181,730	5,739,258	557,528
398.HH Miscellaneous Equipment - Hydrogen	4,904,211	980,842	976,919	(3,923)
398.00 Miscellaneous Equipment	4,356,614	167,730	181,235	13,505
Total General	$329,684,288	$17,462,319	$18,958,703	$1,496,384
TOTAL UTILITY	$7,680,006,850	$221,616,212	$226,838,380	$5,222,168
STEAM PRODUCTION (BY UNIT)				
Cholla				
311.00 Structures and Improvements	$53,689,761	$1,221,222	$1,225,028	$3,806
312.00 Boiler Plant Equipment	299,852,771	8,323,190	8,490,406	167,216
314.00 Turbogenerator Units	85,609,508	2,251,696	2,406,285	154,589
315.00 Accessory Electric Equipment	82,574,161	1,926,680	1,941,557	14,877
316.00 Misc. Power Plant Equipment	20,057,407	677,442	685,125	7,683
Total Cholla	$541,783,608	$14,400,230	$14,748,401	$348,171
Cholla Unit 1				
311.00 Structures and Improvements	$2,116,308	$51,638	$55,024	$3,386
312.00 Boiler Plant Equipment	27,464,546	1,093,089	1,172,736	79,647
314.00 Turbogenerator Units	10,355,816	358,311	356,240	(2,071)
315.00 Accessory Electric Equipment	4,790,621	153,300	161,923	8,623
316.00 Misc. Power Plant Equipment	2,432,224	123,557	124,043	486
Total Cholla Unit 1	$47,159,515	$1,779,895	$1,869,966	$90,071
Cholla Unit 2				
311.00 Structures and Improvements	$4,866,784	$130,916	$124,590	($6,326)
312.00 Boiler Plant Equipment	144,102,635	3,818,720	3,775,489	(43,231)
314.00 Turbogenerator Units	29,198,775	697,851	668,652	(29,199)
315.00 Accessory Electric Equipment	42,759,226	966,359	949,255	(17,104)
316.00 Misc. Power Plant Equipment	5,232,429	155,403	158,019	2,616
Total Cholla Unit 2	$226,159,849	$5,769,249	$5,676,005	($93,244)
Cholla Unit 3				
311.00 Structures and Improvements	$9,637,296	$212,021	$218,767	$6,746
312.00 Boiler Plant Equipment	103,136,479	2,702,176	2,805,312	103,136
314.00 Turbogenerator Units	45,423,639	1,181,015	1,367,252	186,237
315.00 Accessory Electric Equipment	30,152,547	693,509	708,585	15,076
316.00 Misc. Power Plant Equipment	4,319,200	130,440	132,599	2,159
Total Cholla Unit 3	$192,669,161	$4,919,161	$5,232,515	$313,354
Cholla Common				
311.00 Structures and Improvements	$37,069,373	$826,647	$826,647	
312.00 Boiler Plant Equipment	25,149,111	709,205	736,869	27,664
314.00 Turbogenerator Units	631,278	14,519	14,141	(378)
315.00 Accessory Electric Equipment	4,871,767	113,512	121,794	8,282
316.00 Misc. Power Plant Equipment	8,073,554	268,042	270,464	2,422
Total Cholla Common	$75,795,083	$1,931,925	$1,969,915	$37,990

ARIZONA PUBLIC SERVICE COMPANY Statement B

Comparison of Present and Proposed Accruals
Present: BG Procedure / RL Technique
Proposed: BG Procedure / RL Technique

Account Description	12/31/04 Plant Investment	2005 Annualized Accrual Present	Proposed	Difference
A	B	C	D	E=D-C
Four Corners				
311.00 Structures and Improvements	$43,005,911	$1,500,545	$2,380,558	$880,013
312.00 Boiler Plant Equipment	335,046,039	13,842,074	16,769,459	2,927,385
314.00 Turbogenerator Units	59,158,016	2,120,544	2,831,863	711,319
315.00 Accessory Electric Equipment	29,825,484	1,104,477	1,301,339	196,862
316.00 Misc. Power Plant Equipment	17,243,295	813,806	855,859	42,053
Total Four Corners	$484,278,745	$19,381,446	$24,139,078	$4,757,632
Four Corners Units 1-3				
311.00 Structures and Improvements	$29,002,681	$1,165,908	$1,972,182	$806,274
312.00 Boiler Plant Equipment	218,326,908	10,567,022	12,968,618	2,401,596
314.00 Turbogenerator Units	42,777,597	1,693,993	2,335,657	641,664
315.00 Accessory Electric Equipment	17,232,291	806,471	932,267	125,796
316.00 Misc. Power Plant Equipment	5,676,014	427,404	431,945	4,541
Total Four Corners Units 1-3	$313,015,491	$14,660,798	$18,640,669	$3,979,871
Four Corners Units 4-5				
311.00 Structures and Improvements	$9,201,539	$220,837	$258,563	$37,726
312.00 Boiler Plant Equipment	112,898,782	3,183,746	3,680,500	496,754
314.00 Turbogenerator Units	14,652,943	395,629	460,102	64,473
315.00 Accessory Electric Equipment	9,853,384	247,320	307,426	60,106
316.00 Misc. Power Plant Equipment	3,029,198	102,084	110,566	8,482
Total Four Corners Units 4-5	$149,635,846	$4,149,616	$4,817,157	$667,541
Four Corners Common				
311.00 Structures and Improvements	$4,801,691	$113,800	$149,813	$36,013
312.00 Boiler Plant Equipment	3,820,349	91,306	120,341	29,035
314.00 Turbogenerator Units	1,727,476	30,922	36,104	5,182
315.00 Accessory Electric Equipment	2,739,809	50,686	61,646	10,960
316.00 Misc. Power Plant Equipment	8,538,083	284,318	313,348	29,030
Total Four Corners Common	$21,627,408	$571,032	$681,252	$110,220
Navajo Units 1-3				
311.00 Structures and Improvements	$28,391,046	$934,065	$959,617	$25,552
312.00 Boiler Plant Equipment	156,202,698	5,545,196	5,701,398	156,202
314.00 Turbogenerator Units	24,699,305	681,701	706,400	24,699
315.00 Accessory Electric Equipment	20,448,549	576,649	599,142	22,493
316.00 Misc. Power Plant Equipment	14,618,062	546,716	590,570	43,854
Total Navajo Units 1-3	$244,359,660	$8,284,327	$8,557,127	$272,800
Ocotillo Units 1-2				
311.00 Structures and Improvements	$3,792,708	$144,123	$193,807	$49,684
312.00 Boiler Plant Equipment	24,174,538	730,071	1,037,088	307,017
314.00 Turbogenerator Units	15,372,486	424,281	616,437	192,156
315.00 Accessory Electric Equipment	2,670,248	58,745	111,349	52,604
316.00 Misc. Power Plant Equipment	5,258,871	275,565	384,949	109,384
Total Ocotillo Units 1-2	$51,268,851	$1,632,785	$2,343,630	$710,845
Saguaro Units 1-2				
311.00 Structures and Improvements	$2,990,982	$102,292	$180,655	$78,363
312.00 Boiler Plant Equipment	22,590,899	1,059,513	1,267,349	207,836
314.00 Turbogenerator Units	16,340,249	562,105	771,260	209,155
315.00 Accessory Electric Equipment	2,704,916	75,467	118,205	42,738
316.00 Misc. Power Plant Equipment	3,255,754	233,112	266,321	33,209
Total Saguaro Units 1-2	$47,882,800	$2,032,489	$2,603,790	$571,301

ARIZONA PUBLIC SERVICE COMPANY Statement B

Comparison of Present and Proposed Accruals
Present: BG Procedure / RL Technique
Proposed: BG Procedure / RL Technique

Account Description	12/31/04 Plant Investment	2005 Annualized Accrual Present	Proposed	Difference
A	B	C	D	E=D-C
NUCLEAR PRODUCTION (BY UNIT)				
Palo Verde				
321.00 Structures and Improvements	$640,003,980	$16,629,867	$16,763,507	$133,640
322.00 Reactor Plant Equipment	939,061,294	26,844,521	26,663,549	(180,972)
322.10 Steam Generators	52,865,345	4,434,434	1,145,606	(3,288,828)
323.00 Turbogenerator Units	342,424,222	9,933,350	9,796,470	(136,880)
324.00 Accessory Electric Equipment	272,624,619	7,581,450	7,365,529	(215,921)
325.00 Misc. Power Plant Equipment	132,963,906	4,771,746	4,452,247	(319,499)
Total Palo Verde	$2,379,943,366	$70,195,368	$66,186,908	($4,008,460)
Palo Verde Unit 1				
321.00 Structures and Improvements	$154,544,487	$4,141,792	$4,064,520	($77,272)
322.00 Reactor Plant Equipment	361,739,876	10,418,108	9,984,021	(434,087)
322.10 Steam Generators	27,452,571	2,495,439	403,553	(2,091,886)
323.00 Turbogenerator Units	118,250,432	3,464,738	3,358,312	(106,426)
324.00 Accessory Electric Equipment	114,359,460	3,190,629	3,087,705	(102,924)
325.00 Misc. Power Plant Equipment	29,942,323	1,053,970	982,108	(71,862)
Total Palo Verde Unit 1	$806,289,149	$24,764,676	$21,880,219	($2,884,457)
Palo Verde Unit 2				
321.00 Structures and Improvements	$90,520,213	$2,308,265	$2,471,202	$162,937
322.00 Reactor Plant Equipment	226,227,486	6,402,238	7,284,525	882,287
322.10 Steam Generators				
323.00 Turbogenerator Units	78,129,616	2,242,320	2,445,457	203,137
324.00 Accessory Electric Equipment	50,011,285	1,390,314	1,430,323	40,009
325.00 Misc. Power Plant Equipment	26,698,465	985,173	969,154	(16,019)
Total Palo Verde Unit 2	$471,587,065	$13,328,310	$14,600,661	$1,272,351
Palo Verde Unit 3				
321.00 Structures and Improvements	$160,291,956	$4,151,562	$4,039,357	($112,205)
322.00 Reactor Plant Equipment	323,919,702	9,231,712	8,648,656	(583,056)
322.10 Steam Generators	25,412,774	1,938,995	742,053	(1,196,942)
323.00 Turbogenerator Units	144,585,131	4,178,510	3,947,174	(231,336)
324.00 Accessory Electric Equipment	89,504,541	2,479,276	2,345,019	(134,257)
325.00 Misc. Power Plant Equipment	27,547,817	966,928	881,530	(85,398)
Total Palo Verde Unit 3	$771,261,921	$22,946,983	$20,603,789	($2,343,194)
Palo Verde Water Reclamation				
321.00 Structures and Improvements	$128,265,752	$3,283,603	$3,411,869	$128,266
322.00 Reactor Plant Equipment	133,326	5,573	5,426	(147)
322.10 Steam Generators				
323.00 Turbogenerator Units	235,152	7,149	7,219	70
324.00 Accessory Electric Equipment				
325.00 Misc. Power Plant Equipment	88,819	3,224	3,064	(160)
Total Palo Verde Water Reclamation	$128,723,049	$3,299,549	$3,427,578	$128,029
Palo Verde Common				
321.00 Structures and Improvements	$106,381,572	$2,744,645	$2,776,559	$31,914
322.00 Reactor Plant Equipment	27,040,904	786,890	740,921	(45,969)
322.10 Steam Generators				
323.00 Turbogenerator Units	1,223,891	40,633	38,308	(2,325)
324.00 Accessory Electric Equipment	18,749,333	521,231	502,482	(18,749)
325.00 Misc. Power Plant Equipment	48,686,482	1,762,451	1,616,391	(146,060)
Total Palo Verde Common	$202,082,182	$5,855,850	$5,674,661	($181,189)

ARIZONA PUBLIC SERVICE COMPANY

Statement B

Comparison of Present and Proposed Accruals
Present: BG Procedure / RL Technique
Proposed: BG Procedure / RL Technique

Account Description	12/31/04 Plant Investment	2005 Annualized Accrual Present	Proposed	Difference
A	B	C	D	E=D-C
OTHER PRODUCTION (BY UNIT)				
Douglas CT				
341.00 Structures and Improvements	$4,562	$46	$34	($12)
342.00 Fuel Holders, Products and Accessories	137,759	3,182	2,769	(413)
343.00 Prime Movers	1,101,449	7,159	7,820	661
344.00 Generators and Devices	551,765	938	662	(276)
345.00 Accessory Electric Equipment	353,277	3,038	3,144	106
346.00 Misc. Power Plant Equipment	40,913	777	757	(20)
Total Douglas CT	$2,189,725	$15,140	$15,186	$46
Ocotillo CT Units 1-2				
341.00 Structures and Improvements	$430,899	$10,342	$10,600	$258
342.00 Fuel Holders, Products and Accessories	719,859	16,989	16,341	(648)
343.00 Prime Movers	6,540,275	69,327	90,256	20,929
344.00 Generators and Devices	6,424,357	213,931	214,574	643
345.00 Accessory Electric Equipment	1,590,924	17,182	26,887	9,705
346.00 Misc. Power Plant Equipment	558,648	9,720	11,005	1,285
Total Ocotillo CT Units 1-2	$16,264,962	$337,491	$369,663	$32,172
Saguaro CT Units 1-2				
341.00 Structures and Improvements	$1,380,611	$65,855	$67,374	$1,519
342.00 Fuel Holders, Products and Accessories	1,304,977	25,056	23,881	(1,175)
343.00 Prime Movers	8,047,527	103,813	115,884	12,071
344.00 Generators and Devices	4,001,509	123,647	146,855	23,208
345.00 Accessory Electric Equipment	1,626,802	23,101	21,799	(1,302)
346.00 Misc. Power Plant Equipment	790,906	26,970	27,049	79
Total Saguaro CT Units 1-2	$17,152,332	$368,442	$402,842	$34,400
Solar Units				
341.00 Structures and Improvements	$352,259		($37,304)	($37,304)
342.00 Fuel Holders, Products and Accessories				
343.00 Prime Movers	20,596		1,683	1,683
344.00 Generators and Devices	14,326,036	965,575	869,590	(95,985)
345.00 Accessory Electric Equipment	166,465	12,834	10,487	(2,347)
346.00 Misc. Power Plant Equipment				
Total Solar Units	$14,865,356	$978,409	$844,456	($133,953)
West Phoenix				
341.00 Structures and Improvements	$7,550,035	$179,980	$189,233	$9,253
342.00 Fuel Holders, Products and Accessories	20,688,419	662,880	651,186	(11,694)
343.00 Prime Movers	8,794,167	182,039	204,904	22,865
344.00 Generators and Devices	81,091,743	2,625,538	2,656,957	31,419
345.00 Accessory Electric Equipment	13,957,323	368,049	387,291	19,242
346.00 Misc. Power Plant Equipment	3,590,505	96,575	100,541	3,966
Total West Pheonix	$135,672,192	$4,115,061	$4,190,112	$75,051
West Phoenix CT Units 1-2				
341.00 Structures and Improvements	$510,951	$8,226	$8,329	$103
342.00 Fuel Holders, Products and Accessories	1,437,533	27,601	27,457	(144)
343.00 Prime Movers	8,794,167	182,039	204,904	22,865
344.00 Generators and Devices	4,889,963	88,019	142,298	54,279
345.00 Accessory Electric Equipment	1,557,744	18,381	22,743	4,362
346.00 Misc. Power Plant Equipment	917,431	30,550	32,110	1,560
Total West Ploenix CT Units 1-2	$18,107,789	$354,816	$437,841	$83,025

ARIZONA PUBLIC SERVICE COMPANY Statement B

Comparison of Present and Proposed Accruals
Present: BG Procedure / RL Technique
Proposed: BG Procedure / RL Technique

Account Description	12/31/04 Plant Investment	2005 Annualized Accrual Present	Proposed	Difference
A	B	C	D	E=D-C
West Phoenix CC Units 1-3				
341.00 Structures and Improvements	$7,039,084	$171,754	$180,904	$9,150
342.00 Fuel Holders, Products and Accessories	19,250,886	635,279	623,729	(11,550)
343.00 Prime Movers				
344.00 Generators and Devices	76,201,780	2,537,519	2,514,659	(22,860)
345.00 Accessory Electric Equipment	12,399,579	349,668	364,548	14,880
346.00 Misc. Power Plant Equipment	2,673,074	66,025	68,431	2,406
Total West Phoenix CC Units 1-3	$117,564,403	$3,760,245	$3,752,271	($7,974)
Yucca CT Units 1-4				
341.00 Structures and Improvements	$462,030	$19,220	$17,881	($1,339)
342.00 Fuel Holders, Products and Accessories	3,244,987	41,536	30,827	(10,709)
343.00 Prime Movers	7,962,254	43,792	49,366	5,574
344.00 Generators and Devices	5,358,461	87,879	74,483	(13,396)
345.00 Accessory Electric Equipment	2,172,221	26,936	26,936	
346.00 Misc. Power Plant Equipment	479,650	5,900	8,682	2,782
Total Yucca CT Units 1-4	$19,679,603	$225,263	$208,175	($17,088)

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Account Description	Plant Investment	Recorded Reserve Amount	Recorded Reserve Ratio	Computed Reserve Amount	Computed Reserve Ratio	Redistributed Reserve Amount	Redistributed Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
STEAM PRODUCTION							
311.00 Structures and Improvements	$131,870,408	$67,445,386	51.15%	$64,733,598	49.09%	$66,163,395	50.17%
312.00 Boiler Plant Equipment	837,866,945	479,297,335	57.20%	477,835,629	57.03%	480,552,478	57.35%
314.00 Turbogenerator Units	201,179,564	114,837,083	57.08%	114,972,594	57.15%	114,684,530	57.01%
315.00 Accessory Electric Equipment	138,223,358	83,976,384	60.75%	80,076,560	57.93%	83,029,523	60.07%
316.00 Misc. Power Plant Equipment	60,433,389	25,153,908	41.62%	25,811,216	42.71%	26,280,170	43.49%
Total *Steam Production* Plant	$1,369,573,664	$770,710,095	56.27%	$763,429,596	55.74%	$770,710,095	56.27%
NUCLEAR PRODUCTION							
321.00 Structures and Improvements	$640,003,980	$294,926,651	46.08%	$280,574,366	43.84%	$294,231,705	45.97%
322.00 Reactor Plant Equipment	939,061,294	418,593,472	44.58%	400,836,955	42.68%	419,696,028	44.69%
322.10 Steam Generators	52,865,345	44,686,406	84.53%	47,690,929	90.21%	50,608,283	95.73%
323.00 Turbogenerator Units	342,424,222	158,086,020	46.17%	149,701,098	43.72%	156,938,919	45.83%
324.00 Accessory Electric Equipment	272,624,619	135,152,824	49.57%	127,776,396	46.87%	134,042,038	49.17%
325.00 Misc. Power Plant Equipment	132,963,906	61,253,702	46.07%	54,195,350	40.76%	57,182,102	43.01%
Total Nuclear Production Plant	$2,379,943,366	$1,112,699,075	46.75%	$1,060,775,093	44.57%	$1,112,699,075	46.75%
OTHER PRODUCTION							
341.00 Structures and Improvements	$10,180,396	$4,948,991	48.61%	$3,967,997	38.98%	$4,920,040	48.33%
342.00 Fuel Holders, Products and Accessories	26,096,001	10,109,160	38.74%	8,278,795	31.72%	10,224,943	39.18%
343.00 Prime Movers	32,466,268	27,452,832	84.56%	21,743,886	66.97%	26,971,556	83.08%
344.00 Generators and Devices	111,753,871	39,690,442	35.52%	31,766,947	28.43%	40,227,388	36.00%
345.00 Accessory Electric Equipment	19,867,012	9,740,972	49.03%	7,850,706	39.52%	9,688,695	48.77%
346.00 Misc. Power Plant Equipment	5,460,622	2,949,944	54.02%	2,327,457	42.62%	2,859,718	52.37%
Total Other Production Plant	$205,824,170	$94,892,341	46.10%	$75,935,790	36.89%	$94,892,341	46.10%
TOTAL PRODUCTION PLANT	$3,955,341,200	$1,978,301,511	50.02%	$1,900,140,479	48.04%	$1,978,301,511	50.02%
TRANSMISSION							
352.00 Structures and Improvements	$95,935	$54,278	56.58%	$57,034	59.45%	$106,151	110.65%
353.00 Station Equipment	42,249,917	23,903,897	56.58%	12,615,677	29.86%	23,480,053	55.57%
354.00 Towers and Fixtures	1,329,316	752,092	56.58%	523,717	39.40%	974,732	73.33%
355.00 Poles and Fixtures - Wood	11,064	3,130	28.29%	8,442	76.30%	15,711	142.00%
356.00 Overhead Conductors and Devices	586,319	331,724	56.58%	251,707	42.93%	468,472	79.90%
Total Transmission Plant	$44,272,551	$25,045,120	56.57%	$13,456,577	30.39%	$25,045,120	56.57%

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A	B	C	D=C/B	E	F=E/B	G	H=G/B
DISTRIBUTION							
361.00 Structures and Improvements	$30,704,475	$12,042,606	39.22%	$8,871,546	28.89%	$11,907,311	38.78%
362.00 Station Equipment	242,575,593	64,729,721	26.68%	40,080,104	16.52%	53,795,161	22.18%
364.00 Poles, Towers and Fixtures - Wood	296,506,680	89,060,664	30.04%	73,728,727	24.87%	98,958,045	33.37%
364.10 Poles, Towers and Fixtures - Steel	73,766,423			4,988,086	6.76%	6,694,964	9.08%
365.00 Overhead Conductors and Devices	233,951,705	30,388,795	12.99%	30,833,069	13.18%	41,383,873	17.69%
366.00 Underground Conduit	509,266,861	40,709,016	7.99%	24,249,393	4.76%	32,547,321	6.39%
367.00 Underground Conductors and Devices	908,715,823	304,969,939	33.56%	221,099,960	24.33%	296,758,411	32.66%
368.00 Line Transformers	537,581,653	260,493,316	48.46%	193,954,981	36.08%	260,324,660	48.43%
369.00 Services	268,098,185	108,995,654	40.66%	81,936,602	30.56%	109,974,583	41.02%
370.00 Meters	91,949,592	48,455,598	52.70%	24,604,443	26.76%	33,023,865	35.92%
370.10 Meters - Electronic	65,427,927			7,398,389	11.31%	9,930,052	15.18%
371.00 Installations on Customers' Premises	31,927,745	4,779,055	14.97%	3,463,522	10.85%	4,648,708	14.56%
373.00 Street Lighting and Signal Systems	60,236,149	24,926,973	41.38%	22,056,757	36.62%	29,604,384	49.15%
Total Distribution Plant	$3,350,708,811	$989,551,337	29.53%	$737,265,577	22.00%	$989,551,337	29.53%
GENERAL							
390.00 Structures and Improvements	$103,793,498	$20,371,993	19.63%	$28,953,063	27.89%	$29,068,539	28.01%
391.00 Office Furn. and Equip. - Furniture	31,890,832	12,370,125	38.79%	12,389,588	38.85%	12,439,003	39.00%
391.10 Office Furn. and Equip. - PC Equipment	49,510,133	26,510,343	53.55%	23,022,212	46.50%	23,114,033	46.69%
391.20 Office Furn. and Equip. - Other	9,016,492	4,147,881	46.00%	3,508,235	38.91%	3,522,227	39.06%
393.00 Stores Equipment	1,235,839	1,302,760	105.42%	1,103,604	89.30%	1,108,006	89.66%
394.00 Tools, Shop and Garage Equipment	14,047,955	4,371,066	31.12%	5,478,702	39.00%	5,500,554	39.16%
395.00 Laboratory Equipment	1,609,510	739,810	45.96%	644,609	40.05%	647,180	40.21%
397.00 Communication Equipment	109,319,204	49,673,034	45.44%	42,979,708	39.32%	43,151,128	39.47%
398.HH Miscellaneous Equipment - Hydrogen	4,904,211	1,458,353	29.74%	2,452,106	50.00%	2,461,885	50.20%
398.00 Miscellaneous Equipment	4,356,614	630,341	14.47%	560,914	12.88%	563,151	12.93%
Total General	$329,684,288	$121,575,706	36.88%	$121,092,741	36.73%	$121,575,706	36.88%
TOTAL UTILITY	$7,680,006,850	$3,114,473,674	40.55%	$2,771,955,374	36.09%	$3,114,473,674	40.55%

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Account Description	Plant Investment	Recorded Reserve 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 (BY UNIT)							
Cholla							
311.00 Structures and Improvements	$53,689,761	$31,497,995	58.67%	$28,184,072	52.49%	$30,734,212	57.24%
312.00 Boiler Plant Equipment	299,852,771	189,075,083	63.06%	175,407,073	58.50%	190,104,861	63.40%
314.00 Turbogenerator Units	85,609,508	41,625,055	48.62%	39,353,428	45.97%	42,415,335	49.55%
315.00 Accessory Electric Equipment	82,574,161	51,127,041	61.92%	46,576,654	56.41%	50,535,008	61.20%
316.00 Misc. Power Plant Equipment	20,057,407	10,178,638	50.75%	8,960,322	44.67%	9,714,396	48.43%
Total Cholla	$541,783,608	$323,503,812	59.71%	$298,481,548	55.09%	$323,503,812	59.71%
Cholla Unit 1							
311.00 Structures and Improvements	$2,116,308	$1,925,703	90.99%	$1,714,372	81.01%	$1,791,033	84.63%
312.00 Boiler Plant Equipment	27,464,546	18,449,220	67.17%	17,999,638	65.54%	18,804,526	68.47%
314.00 Turbogenerator Units	10,355,816	7,812,007	75.44%	7,419,615	71.65%	7,751,397	74.85%
315.00 Accessory Electric Equipment	4,790,621	3,804,092	79.41%	3,478,947	72.62%	3,634,515	75.87%
316.00 Misc. Power Plant Equipment	2,432,224	1,371,741	56.40%	1,322,169	54.36%	1,381,292	56.79%
Total Cholla Unit 1	$47,159,515	$33,362,763	70.74%	$31,934,742	67.72%	$33,362,763	70.74%
Cholla Unit 2							
311.00 Structures and Improvements	$4,866,784	$2,522,137	51.82%	$2,194,517	45.09%	$2,408,131	49.48%
312.00 Boiler Plant Equipment	144,102,635	94,756,814	65.76%	85,845,707	59.57%	94,201,913	65.37%
314.00 Turbogenerator Units	29,198,775	16,595,620	56.84%	15,876,244	54.37%	17,421,635	59.67%
315.00 Accessory Electric Equipment	42,759,226	27,059,465	63.28%	24,436,624	57.15%	26,815,281	62.71%
316.00 Misc. Power Plant Equipment	5,232,429	2,862,430	54.71%	2,687,869	51.37%	2,949,505	56.37%
Total Cholla Unit 2	$226,159,849	$143,796,466	63.58%	$131,040,962	57.94%	$143,796,466	63.58%
Cholla Unit 3							
311.00 Structures and Improvements	$9,637,296	$5,722,402	59.38%	$5,226,138	54.23%	$5,608,972	58.20%
312.00 Boiler Plant Equipment	103,136,479	63,860,217	61.92%	59,912,254	58.09%	64,301,046	62.35%
314.00 Turbogenerator Units	45,423,639	16,851,724	37.10%	15,723,045	34.61%	16,874,816	37.15%
315.00 Accessory Electric Equipment	30,152,547	17,916,292	59.42%	16,401,188	54.39%	17,602,636	58.38%
316.00 Misc. Power Plant Equipment	4,319,200	2,349,081	54.39%	2,154,424	49.88%	2,312,244	53.53%
Total Cholla Unit 3	$192,669,161	$106,699,716	55.38%	$99,417,050	51.60%	$106,699,716	55.38%
Cholla Common							
311.00 Structures and Improvements	$37,069,373	$21,327,753	57.53%	$19,049,044	51.39%	$20,926,075	56.45%
312.00 Boiler Plant Equipment	25,149,111	12,008,832	47.75%	11,649,474	46.32%	12,797,375	50.89%
314.00 Turbogenerator Units	631,278	365,704	57.93%	334,523	52.99%	367,486	58.21%

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A	B	C	D=C/B	E	F=E/B	G	H=G/B
315.00 Accessory Electric Equipment	4,871,767	2,347,192	48.18%	2,259,894	46.39%	2,482,577	50.96%
316.00 Misc. Power Plant Equipment	8,073,554	3,595,386	44.53%	2,795,859	34.63%	3,071,354	38.04%
Total Cholla Common	$75,795,083	$39,644,867	52.31%	$36,088,794	47.61%	$39,644,867	52.31%
Four Corners							
311.00 Structures and Improvements	$43,005,911	$18,727,855	43.55%	$19,291,732	44.86%	$18,363,290	42.70%
312.00 Boiler Plant Equipment	335,046,039	179,324,368	53.52%	188,726,706	56.33%	178,472,313	53.27%
314.00 Turbogenerator Units	59,158,016	32,032,214	54.15%	33,859,657	57.24%	31,917,842	53.95%
315.00 Accessory Electric Equipment	29,825,484	15,933,859	53.42%	17,236,471	57.79%	16,415,425	55.04%
316.00 Misc. Power Plant Equipment	17,243,295	6,391,419	37.07%	7,369,456	42.74%	7,240,844	41.99%
Total Four Corners	$484,278,745	$252,409,714	52.12%	$266,484,021	55.03%	$252,409,714	52.12%
Four Corners Units 1-3							
311.00 Structures and Improvements	$29,002,681	$11,052,292	38.11%	$11,417,617	39.37%	$10,619,761	36.62%
312.00 Boiler Plant Equipment	218,326,908	110,558,755	50.64%	119,340,422	54.66%	111,000,988	50.84%
314.00 Turbogenerator Units	42,777,597	23,891,374	55.85%	24,828,045	58.04%	23,093,077	53.98%
315.00 Accessory Electric Equipment	17,232,291	9,133,612	53.00%	9,939,643	57.68%	9,245,067	53.65%
316.00 Misc. Power Plant Equipment	5,676,014	998,137	17.59%	1,801,139	31.73%	1,675,277	29.52%
Total Four Corners Units 1-3	$313,015,491	$155,634,170	49.72%	$167,326,866	53.46%	$155,634,170	49.72%
Four Corners Units 4-5							
311.00 Structures and Improvements	$9,201,539	$5,343,337	58.07%	$5,408,515	58.78%	$5,251,860	57.08%
312.00 Boiler Plant Equipment	112,898,782	65,985,603	58.45%	66,989,181	59.34%	65,048,878	57.62%
314.00 Turbogenerator Units	14,652,943	6,759,235	46.13%	7,646,872	52.19%	7,425,385	50.68%
315.00 Accessory Electric Equipment	9,853,384	4,634,182	47.03%	5,150,023	52.27%	5,000,855	50.75%
316.00 Misc. Power Plant Equipment	3,029,198	1,518,064	50.11%	1,558,587	51.45%	1,513,444	49.96%
Total Four Corners Units 4-5	$149,635,846	$84,240,421	56.30%	$86,753,178	57.98%	$84,240,421	56.30%
Four Corners Common							
311.00 Structures and Improvements	$4,801,691	$2,332,226	48.57%	$2,465,601	51.35%	$2,491,669	51.89%
312.00 Boiler Plant Equipment	3,820,349	2,780,010	72.77%	2,397,103	62.75%	2,422,447	63.41%
314.00 Turbogenerator Units	1,727,476	1,381,605	79.98%	1,384,740	80.16%	1,399,381	81.01%
315.00 Accessory Electric Equipment	2,739,809	2,166,064	79.06%	2,146,805	78.36%	2,169,502	79.18%
316.00 Misc. Power Plant Equipment	8,538,083	3,875,218	45.39%	4,009,729	46.96%	4,052,123	47.46%
Total Four Corners Common	$21,627,408	$12,535,123	57.96%	$12,403,978	57.35%	$12,535,123	57.96%

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A	B	C	D=C/B	E	F=E/B	G	H=G/B
Navajo Units 1-3		$12,873,807					
311.00 Structures and Improvements	$28,391,046		45.34%	$12,492,607	44.00%	$12,569,144	44.27%
312.00 Boiler Plant Equipment	156,202,698	73,810,721	47.25%	74,804,572	47.89%	75,262,869	48.18%
314.00 Turbogenerator Units	24,699,305	14,876,258	60.23%	14,154,187	57.31%	14,240,904	57.66%
315.00 Accessory Electric Equipment	20,448,549	12,198,031	59.65%	11,538,812	56.43%	11,609,506	56.77%
316.00 Misc. Power Plant Equipment	14,618,062	5,886,171	40.27%	5,926,258	40.54%	5,962,565	40.79%
Total Navajo Units 1-3	$244,359,660	$119,644,988	48.96%	$118,916,436	48.66%	$119,644,988	48.96%
Ocotillo Units 1-2							
311.00 Structures and Improvements	$3,792,708	$2,209,808	58.26%	$2,507,430	66.11%	$2,315,191	61.04%
312.00 Boiler Plant Equipment	24,174,538	19,181,771	79.35%	20,319,309	84.05%	18,761,475	77.61%
314.00 Turbogenerator Units	15,372,486	12,138,271	78.96%	13,122,581	85.36%	12,116,503	78.82%
315.00 Accessory Electric Equipment	2,670,248	2,096,391	78.51%	2,227,128	83.41%	2,056,379	77.01%
316.00 Misc. Power Plant Equipment	5,258,871	1,190,149	22.63%	1,696,943	32.27%	1,566,842	29.79%
Total Ocotillo Units 1-2	$51,268,851	$36,816,390	71.81%	$39,873,391	77.77%	$36,816,390	71.81%
Saguaro Units 1-2							
311.00 Structures and Improvements	$2,990,982	$2,135,921	71.41%	$2,257,757	75.49%	$2,181,557	72.94%
312.00 Boiler Plant Equipment	22,590,899	17,905,392	79.26%	18,577,970	82.24%	17,950,961	79.46%
314.00 Turbogenerator Units	16,340,249	14,165,285	86.69%	14,482,740	88.63%	13,993,946	85.64%
315.00 Accessory Electric Equipment	2,704,916	2,621,062	96.90%	2,497,495	92.33%	2,413,205	89.22%
316.00 Misc. Power Plant Equipment	3,255,754	1,507,531	46.30%	1,858,238	57.08%	1,795,522	55.15%
Total Saguaro Units 1-2	$47,882,800	$38,335,191	80.06%	$39,674,200	82.86%	$38,335,191	80.06%
NUCLEAR PRODUCTION (BY UNIT)							
Palo Verde							
321.00 Structures and Improvements	$640,003,980	$294,926,651	46.08%	$280,574,366	43.84%	$294,231,705	45.97%
322.00 Reactor Plant Equipment	939,061,294	418,593,472	44.58%	400,836,955	42.68%	419,696,028	44.69%
322.10 Steam Generators	52,865,345	44,686,406	84.53%	47,690,929	90.21%	50,608,283	95.73%
323.00 Turbogenerator Units	342,424,222	158,086,020	46.17%	149,701,098	43.72%	156,938,919	45.83%
324.00 Accessory Electric Equipment	272,624,619	135,152,824	49.57%	127,776,396	46.87%	134,042,038	49.17%
325.00 Misc. Power Plant Equipment	132,963,906	61,253,702	46.07%	54,195,350	40.76%	57,182,102	43.01%
Total Palo Verde	$2,379,943,366	$1,112,699,075	46.75%	$1,060,775,093	44.57%	$1,112,699,075	46.75%

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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
Palo Verde Unit 1							
321.00 Structures and Improvements	$154,544,487	$78,515,153	50.80%	$74,765,887	48.38%	$78,210,215	50.61%
322.00 Reactor Plant Equipment	361,739,876	180,009,884	49.76%	171,073,536	47.29%	178,954,580	49.47%
322.10 Steam Generators	27,452,571	25,026,450	91.16%	25,857,419	94.19%	27,048,623	98.53%
323.00 Turbogenerator Units	118,250,432	58,348,538	49.34%	56,294,607	47.61%	58,887,997	49.80%
324.00 Accessory Electric Equipment	114,359,460	60,327,856	52.75%	57,230,513	50.04%	59,867,018	52.35%
325.00 Misc. Power Plant Equipment	29,942,323	15,351,016	51.27%	13,967,029	46.65%	14,610,465	48.80%
Total Palo Verde Unit 1	$806,289,149	$417,578,897	51.79%	$399,188,991	49.51%	$417,578,897	51.79%
Palo Verde Unit 2							
321.00 Structures and Improvements	$90,520,213	$43,834,353	48.42%	$42,009,653	46.41%	$41,822,707	46.20%
322.00 Reactor Plant Equipment	226,227,486	84,750,018	37.46%	86,402,668	38.19%	86,018,171	38.02%
322.10 Steam Generators							
323.00 Turbogenerator Units	78,129,616	29,449,584	37.69%	32,775,604	41.95%	32,629,751	41.76%
324.00 Accessory Electric Equipment	50,011,285	24,628,890	49.25%	23,591,185	47.17%	23,486,203	46.96%
325.00 Misc. Power Plant Equipment	26,698,465	11,859,655	44.42%	10,612,894	39.75%	10,565,666	39.57%
Total Palo Verde Unit 2	$471,587,065	$194,522,500	41.25%	$195,392,005	41.43%	$194,522,500	41.25%
Palo Verde Unit 3							
321.00 Structures and Improvements	$160,291,956	$72,430,006	45.19%	$67,678,826	42.22%	$73,029,492	45.56%
322.00 Reactor Plant Equipment	323,919,702	142,473,826	43.98%	132,698,285	40.97%	143,189,369	44.21%
322.10 Steam Generators	25,412,774	19,659,956	77.36%	21,833,510	85.92%	23,559,660	92.71%
323.00 Turbogenerator Units	144,585,131	69,756,458	48.25%	60,139,750	41.59%	64,894,380	44.88%
324.00 Accessory Electric Equipment	89,504,541	41,716,681	46.61%	39,007,530	43.58%	42,091,453	47.03%
325.00 Misc. Power Plant Equipment	27,547,817	12,748,970	46.28%	11,140,758	40.44%	12,021,543	43.64%
Total Palo Verde Unit 3	$771,261,921	$358,785,897	46.52%	$332,498,658	43.11%	$358,785,897	46.52%
Palo Verde Water Reclamation							
321.00 Structures and Improvements	$128,265,752	$54,775,645	42.70%	$53,255,523	41.52%	$54,797,862	42.72%
322.00 Reactor Plant Equipment	133,326	15,679	11.76%	17,169	12.88%	17,666	13.25%
322.10 Steam Generators							
323.00 Turbogenerator Units	235,152	108,203	46.01%	85,665	36.43%	88,146	37.48%
324.00 Accessory Electric Equipment							
325.00 Misc. Power Plant Equipment	88,819	38,072	42.86%	32,970	37.12%	33,925	38.20%
Total Palo Verde Water Reclamation	$128,723,049	$54,937,599	42.68%	$53,391,327	41.48%	$54,937,599	42.68%

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A	B	C	D=C/B	E	F=E/B	G	H=G/B
Palo Verde Common							
321.00 Structures and Improvements	$106,381,572	$45,371,494	42.65%	$42,864,477	40.29%	$46,371,429	43.59%
322.00 Reactor Plant Equipment	27,040,904	11,344,065	41.95%	10,645,298	39.37%	11,516,241	42.59%
322.10 Steam Generators							
323.00 Turbogenerator Units	1,223,891	423,237	34.58%	405,472	33.13%	438,645	35.84%
324.00 Accessory Electric Equipment	18,749,333	8,479,397	45.23%	7,947,167	42.39%	8,597,363	45.85%
325.00 Misc. Power Plant Equipment	48,686,482	21,255,989	43.66%	18,441,698	37.88%	19,950,503	40.98%
Total Palo Verde Common	$202,082,182	$86,874,182	42.99%	$80,304,111	39.74%	$86,874,182	42.99%
OTHER PRODUCTION (BY UNIT)							
Douglas CT							
341.00 Structures and Improvements	$4,562	$4,408	96.62%	$3,458	75.81%	$4,383	96.08%
342.00 Fuel Holders, Products and Accessories	137,759	108,165	78.52%	87,675	63.64%	111,124	80.67%
343.00 Prime Movers	1,101,449	999,227	90.72%	797,520	72.41%	1,010,821	91.77%
344.00 Generators and Devices	551,765	548,900	99.48%	430,954	78.10%	546,215	98.99%
345.00 Accessory Electric Equipment	353,277	329,529	93.28%	251,393	71.16%	318,630	90.19%
346.00 Misc. Power Plant Equipment	40,913	32,871	80.34%	25,189	61.57%	31,927	78.04%
Total Douglas CT	$2,189,725	$2,023,100	92.39%	$1,596,190	72.89%	$2,023,100	92.39%
Ocotillo CT Units 1-2							
341.00 Structures and Improvements	$430,899	$226,540	52.57%	$263,744	61.21%	$324,148	75.23%
342.00 Fuel Holders, Products and Accessories	719,859	559,611	77.74%	454,159	63.09%	558,173	77.54%
343.00 Prime Movers	6,540,275	5,631,883	86.11%	4,460,648	68.20%	5,482,249	83.82%
344.00 Generators and Devices	6,424,357	3,791,607	59.02%	3,199,669	49.81%	3,932,473	61.21%
345.00 Accessory Electric Equipment	1,590,924	1,347,573	84.70%	1,047,459	65.84%	1,287,353	80.92%
346.00 Misc. Power Plant Equipment	558,648	455,619	81.56%	348,599	62.40%	428,437	76.69%
Total Ocotillo CT Units 1-2	$16,264,962	$12,012,833	73.86%	$9,774,278	60.09%	$12,012,833	73.86%
Saguaro CT Units 1-2							
341.00 Structures and Improvements	$1,380,611	$565,934	40.99%	$501,149	36.30%	$617,623	44.74%
342.00 Fuel Holders, Products and Accessories	1,304,977	1,094,962	83.91%	879,545	67.40%	1,083,964	83.06%
343.00 Prime Movers	8,047,527	6,900,269	85.74%	5,421,539	67.37%	6,681,580	83.03%
344.00 Generators and Devices	4,001,509	2,246,764	56.15%	1,948,873	48.70%	2,401,818	60.02%
345.00 Accessory Electric Equipment	1,626,802	1,360,609	83.64%	1,119,747	68.83%	1,379,992	84.83%
346.00 Misc. Power Plant Equipment	790,906	463,051	58.55%	378,618	47.87%	466,614	59.00%
Total Saguaro CT Units 1-2	$17,152,332	$12,631,589	73.64%	$10,249,470	59.76%	$12,631,589	73.64%

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A	B	C	D=C/B	E	F=E/B	G	H=G/B
Solar Units							
341.00 Structures and Improvements	$352,259	$550,087	156.16%	$292,669	83.08%	$427,943	121.49%
342.00 Fuel Holders, Products and Accessories							
343.00 Prime Movers	20,596			858	4.17%	1,255	6.09%
344.00 Generators and Devices	14,326,036	7,656,927	53.45%	5,300,633	37.00%	7,750,639	54.10%
345.00 Accessory Electric Equipment	166,465	56,798	34.12%	57,430	34.50%	83,975	50.45%
346.00 Misc. Power Plant Equipment							
Total Solar Units	$14,865,356	$8,263,812	55.59%	$5,651,590	38.02%	$8,263,812	55.59%
West Phoenix							
341.00 Structures and Improvements	$7,550,035	$3,346,000	44.32%	$2,684,799	35.56%	$3,263,509	43.23%
342.00 Fuel Holders, Products and Accessories	20,688,419	5,296,086	25.60%	4,444,862	21.48%	5,404,818	26.12%
343.00 Prime Movers	8,794,167	6,378,511	72.53%	5,221,066	59.37%	6,368,916	72.42%
344.00 Generators and Devices	81,091,743	20,856,645	25.72%	17,204,490	21.22%	20,915,229	25.79%
345.00 Accessory Electric Equipment	13,957,323	4,740,678	33.97%	3,886,511	27.85%	4,726,974	33.87%
346.00 Misc. Power Plant Equipment	3,590,505	1,609,136	44.82%	1,272,088	35.43%	1,547,611	43.10%
Total West Pheonix	$135,672,192	$42,227,056	31.12%	$34,713,816	25.59%	$42,227,056	31.12%
West Phoenix CT Units 1-2							
341.00 Structures and Improvements	$510,951	$466,054	91.21%	$357,024	69.87%	$435,516	85.24%
342.00 Fuel Holders, Products and Accessories	1,437,533	1,201,191	83.56%	967,212	67.28%	1,179,853	82.07%
343.00 Prime Movers	8,794,167	6,378,511	72.53%	5,221,066	59.37%	6,368,916	72.42%
344.00 Generators and Devices	4,889,963	3,219,230	65.83%	2,753,089	56.30%	3,358,355	68.68%
345.00 Accessory Electric Equipment	1,557,744	1,382,142	88.73%	1,066,123	68.44%	1,300,510	83.49%
346.00 Misc. Power Plant Equipment	917,431	527,987	57.55%	436,090	47.53%	531,964	57.98%
Total West Ploenix CT Units 1-2	$18,107,789	$13,175,115	72.76%	$10,800,604	59.65%	$13,175,115	72.76%
West Phoenix CC Units 1-3							
341.00 Structures and Improvements	$7,039,084	$2,879,946	40.91%	$2,327,775	33.07%	$2,827,993	40.18%
342.00 Fuel Holders, Products and Accessories	19,250,886	4,094,895	21.27%	3,477,650	18.06%	4,224,964	21.95%
343.00 Prime Movers							
344.00 Generators and Devices	76,201,780	17,637,415	23.15%	14,451,401	18.96%	17,556,874	23.04%
345.00 Accessory Electric Equipment	12,399,579	3,358,536	27.09%	2,820,388	22.75%	3,426,463	27.63%
346.00 Misc. Power Plant Equipment	2,673,074	1,081,149	40.45%	835,998	31.27%	1,015,647	38.00%
Total West Phoenix CC Units 1-3	$117,564,403	$29,051,941	24.71%	$23,913,212	20.34%	$29,051,941	24.71%

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Account Description	Plant Investment	Recorded Reserve		Computed Reserve		Redistributed Reserve	
		Amount	Ratio	Amount	Ratio	Amount	Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
Yucca CT Units 1-4							
341.00 Structures and Improvements	$462,030	$256,022	55.41%	$222,178	48.09%	$282,435	61.13%
342.00 Fuel Holders, Products and Accessories	3,244,987	3,050,336	94.00%	2,412,555	74.35%	3,066,865	94.51%
343.00 Prime Movers	7,962,254	7,542,942	94.73%	5,842,255	73.37%	7,426,735	93.27%
344.00 Generators and Devices	5,358,461	4,589,599	85.65%	3,682,328	68.72%	4,681,014	87.36%
345.00 Accessory Electric Equipment	2,172,221	1,905,785	87.73%	1,488,166	68.51%	1,891,772	87.09%
346.00 Misc. Power Plant Equipment	479,650	389,267	81.16%	302,962	63.16%	385,129	80.29%
Total Yucca CT Units 1-4	$19,679,603	$17,733,951	90.11%	$13,950,445	70.89%	$17,733,951	90.11%

ARIZONA PUBLIC SERVICE COMPANY
Average Net Salvage

Statement D

Account Description	Plant Investment Additions	Retirements	Survivors	Salvage Rate Realized	Future	Net Salvage Realized	Future	Total	Average Rate
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
STEAM PRODUCTION									
311.00 Structures and Improvements	$131,870,408		$131,870,408		-18.7%		($24,682,073)	($24,682,073)	-18.7%
312.00 Boiler Plant Equipment	837,866,945		837,866,945		-18.8%		(157,666,781)	(157,666,781)	-18.8%
314.00 Turbogenerator Units	201,179,564		201,179,564		-20.6%		(41,464,729)	(41,464,729)	-20.6%
315.00 Accessory Electric Equipment	138,223,358		138,223,358		-19.2%		(26,587,001)	(26,587,001)	-19.2%
316.00 Misc. Power Plant Equipment	60,433,389		60,433,389		-21.1%		(12,772,863)	(12,772,863)	-21.1%
Total Steam Production Plant	$1,369,573,664		$1,369,573,664		-19.2%		($263,173,446)	($263,173,446)	-19.2%
NUCLEAR PRODUCTION									
321.00 Structures and Improvements	$640,003,980		$640,003,980						
322.00 Reactor Plant Equipment	939,061,294		939,061,294		-0.2%		(2,229,083)	(2,229,083)	-0.2%
322.10 Steam Generators	52,865,345		52,865,345						
323.00 Turbogenerator Units	342,424,222		342,424,222		-0.4%		(1,369,697)	(1,369,697)	-0.4%
324.00 Accessory Electric Equipment	272,624,619		272,624,619		-0.5%		(1,248,764)	(1,248,764)	-0.5%
325.00 Misc. Power Plant Equipment	132,963,906		132,963,906		-0.8%		(1,037,013)	(1,037,013)	-0.8%
Total Nuclear Production Plant	$2,379,943,366		$2,379,943,366		-0.2%		($5,884,557)	($5,884,557)	-0.2%
OTHER PRODUCTION									
341.00 Structures and Improvements	$10,180,396		$10,180,396		-4.8%		($491,407)	($491,407)	-4.8%
342.00 Fuel Holders, Products and Accessories	26,096,001		26,096,001		-5.0%		(1,304,800)	(1,304,800)	-5.0%
343.00 Prime Movers	32,466,268		32,466,268						
344.00 Generators and Devices	111,753,871		111,753,871		-1.4%		(1,524,036)	(1,524,036)	-1.4%
345.00 Accessory Electric Equipment	19,867,012		19,867,012						
346.00 Misc. Power Plant Equipment	5,460,622		5,460,622						
Total Other Production Plant	$205,824,170		$205,824,170		-1.6%		($3,320,243)	($3,320,243)	-1.6%
TOTAL PRODUCTION PLANT	$3,955,341,200		$3,955,341,200		-6.9%		($272,378,245)	($272,378,245)	-6.9%
TRANSMISSION									
352.00 Structures and Improvements	$95,935		$95,935		-5.0%		($4,797)	($4,797)	-5.0%
353.00 Station Equipment	42,249,917		42,249,917						
354.00 Towers and Fixtures	1,329,316		1,329,316		-35.0%		(465,261)	(465,261)	-35.0%
355.00 Poles and Fixtures - Wood	11,064		11,064		-15.0%		(1,660)	(1,660)	-15.0%
356.00 Overhead Conductors and Devices	586,319		586,319		-35.0%		(205,212)	(205,212)	-35.0%
Total Transmission Plant	$44,272,551		$44,272,551		-1.5%		($676,929)	($676,929)	-1.5%
DISTRIBUTION									
361.00 Structures and Improvements	$30,704,475		$30,704,475		-10.0%		($3,070,448)	($3,070,448)	-10.0%
362.00 Station Equipment	242,575,593		242,575,593						
364.00 Poles, Towers and Fixtures - Wood	296,506,680		296,506,680		-10.0%		(29,650,668)	(29,650,668)	-10.0%
364.10 Poles, Towers and Fixtures - Steel	73,766,423		73,766,423		-5.0%		(3,688,321)	(3,688,321)	-5.0%
365.00 Overhead Conductors and Devices	233,951,705		233,951,705		-10.0%		(23,395,171)	(23,395,171)	-10.0%
366.00 Underground Conduit	509,266,861		509,266,861		-5.0%		(25,463,343)	(25,463,343)	-5.0%
367.00 Underground Conductors and Devices	908,715,823		908,715,823		-5.0%		(45,435,791)	(45,435,791)	-5.0%

ARIZONA PUBLIC SERVICE COMPANY
Average Net Salvage

Account Description	Plant Investment Additions	Retirements	Survivors	Salvage Rate Realized	Future	Net Salvage Realized	Future	Total	Average Rate
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
368.00 Line Transformers	537,581,653		537,581,653		-5.0%		(26,879,083)	(26,879,083)	-5.0%
369.00 Services	268,098,185		268,098,185		-10.0%		(26,809,819)	(26,809,819)	-10.0%
370.00 Meters	91,949,592		91,949,592						
370.10 Meters - Electronic	65,427,927		65,427,927						
371.00 Installations on Customers' Premises	31,927,745		31,927,745		-20.0%		(6,385,549)	(6,385,549)	-20.0%
373.00 Street Lighting and Signal Systems	60,236,149		60,236,149		-20.0%		(12,047,230)	(12,047,230)	-20.0%
Total Distribution Plant	$3,350,708,811		$3,350,708,811		-6.1%		($202,825,421)	($202,825,421)	-6.1%
GENERAL									
390.00 Structures and Improvements	$103,793,498		$103,793,498		-15.0%		($15,569,025)	($15,569,025)	-15.0%
391.00 Office Furn. and Equip. - Furniture	31,890,832		31,890,832						
391.10 Office Furn. and Equip. - PC Equipment	49,510,133		49,510,133						
391.20 Office Furn. and Equip. - Other	9,016,492		9,016,492						
393.00 Stores Equipment	1,235,839		1,235,839						
394.00 Tools, Shop and Garage Equipment	14,047,955		14,047,955						
395.00 Laboratory Equipment	1,609,510		1,609,510						
397.00 Communication Equipment	109,319,204		109,319,204						
398.HH Miscellaneous Equipment - Hydrogen	4,904,211		4,904,211						
398.00 Miscellaneous Equipment	4,356,614		4,356,614						
Total General	$329,684,288		$329,684,288		-4.7%		($15,569,025)	($15,569,025)	-4.7%
TOTAL UTILITY	$3,680,990,482		$3,680,990,482		-5.9%		($218,601,317)	($218,601,317)	-5.9%
STEAM PRODUCTION (BY UNIT)									
Cholla									
311.00 Structures and Improvements	$53,689,761		$53,689,761		-19.2%		($10,312,669)	($10,312,669)	-19.2%
312.00 Boiler Plant Equipment	299,852,771		299,852,771		-19.4%		(58,265,524)	(58,265,524)	-19.4%
314.00 Turbogenerator Units	85,609,508		85,609,508		-19.9%		(17,001,891)	(17,001,891)	-19.9%
315.00 Accessory Electric Equipment	82,574,161		82,574,161		-19.4%		(16,037,840)	(16,037,840)	-19.4%
316.00 Misc. Power Plant Equipment	20,057,407		20,057,407		-19.2%		(3,847,572)	(3,847,572)	-19.2%
Total Cholla	$541,783,608		$541,783,608		-19.5%		($105,465,496)	($105,465,496)	-19.5%
Cholla Unit 1									
311.00 Structures and Improvements	$2,116,308		$2,116,308		-15.8%		($334,377)	($334,377)	-15.8%
312.00 Boiler Plant Equipment	27,464,546		27,464,546		-16.3%		(4,476,721)	(4,476,721)	-16.3%
314.00 Turbogenerator Units	10,355,816		10,355,816		-15.8%		(1,636,219)	(1,636,219)	-15.8%
315.00 Accessory Electric Equipment	4,790,621		4,790,621		-15.9%		(761,709)	(761,709)	-15.9%
316.00 Misc. Power Plant Equipment	2,432,224		2,432,224		-16.1%		(391,588)	(391,588)	-16.1%
Total Cholla Unit 1	$47,159,515		$47,159,515		-16.1%		($7,600,613)	($7,600,613)	-16.1%

ARIZONA PUBLIC SERVICE COMPANY

Average Net Salvage

Statement D

Account Description	Plant Investment: Additions	Plant Investment: Retirements	Plant Investment: Survivors	Salvage Rate: Realized	Salvage Rate: Future	Net Salvage: Realized	Net Salvage: Future	Net Salvage: Total	Average Rate
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
Cholla Unit 2									
311.00 Structures and Improvements	$4,866,784		$4,866,784		-18.1%		($880,888)	($880,888)	-18.1%
312.00 Boiler Plant Equipment	144,102,635		144,102,635		-19.0%		(27,379,501)	(27,379,501)	-19.0%
314.00 Turbogenerator Units	29,198,775		29,198,775		-18.3%		(5,343,376)	(5,343,376)	-18.3%
315.00 Accessory Electric Equipment	42,759,226		42,759,226		-18.4%		(7,867,698)	(7,867,698)	-18.4%
316.00 Misc. Power Plant Equipment	5,232,429		5,232,429		-19.1%		(999,394)	(999,394)	-19.1%
Total Cholla Unit 2	$226,159,849		$226,159,849		-18.8%		($42,470,856)	($42,470,856)	-18.8%
Cholla Unit 3									
311.00 Structures and Improvements	$9,637,296		$9,637,296		-21.7%		($2,091,293)	($2,091,293)	-21.7%
312.00 Boiler Plant Equipment	103,136,479		103,136,479		-20.9%		(21,555,524)	(21,555,524)	-20.9%
314.00 Turbogenerator Units	45,423,639		45,423,639		-21.8%		(9,902,353)	(9,902,353)	-21.8%
315.00 Accessory Electric Equipment	30,152,547		30,152,547		-21.5%		(6,482,798)	(6,482,798)	-21.5%
316.00 Misc. Power Plant Equipment	4,319,200		4,319,200		-20.8%		(898,394)	(898,394)	-20.8%
Total Cholla Unit 3	$192,669,161		$192,669,161		-21.2%		($40,930,362)	($40,930,362)	-21.2%
Cholla Common									
311.00 Structures and Improvements	$37,069,373		$37,069,373		-18.9%		($7,006,111)	($7,006,111)	-18.9%
312.00 Boiler Plant Equipment	25,149,111		25,149,111		-19.3%		(4,853,778)	(4,853,778)	-19.3%
314.00 Turbogenerator Units	631,278		631,278		-19.0%		(119,943)	(119,943)	-19.0%
315.00 Accessory Electric Equipment	4,871,767		4,871,767		-19.0%		(925,636)	(925,636)	-19.0%
316.00 Misc. Power Plant Equipment	8,073,554		8,073,554		-19.3%		(1,558,196)	(1,558,196)	-19.3%
Total Cholla Common	$75,795,083		$75,795,083		-19.1%		($14,463,664)	($14,463,664)	-19.1%
Four Corners									
311.00 Structures and Improvements	$43,005,911		$43,005,911		-18.5%		($7,947,881)	($7,947,881)	-18.5%
312.00 Boiler Plant Equipment	335,046,039		335,046,039		-18.1%		(60,487,537)	(60,487,537)	-18.1%
314.00 Turbogenerator Units	59,158,016		59,158,016		-17.8%		(10,527,182)	(10,527,182)	-17.8%
315.00 Accessory Electric Equipment	29,825,484		29,825,484		-19.3%		(5,755,943)	(5,755,943)	-19.3%
316.00 Misc. Power Plant Equipment	17,243,295		17,243,295		-21.7%		(3,741,121)	(3,741,121)	-21.7%
Total Four Corners	$484,278,745		$484,278,745		-18.3%		($88,459,664)	($88,459,664)	-18.3%
Four Corners Units 1-3									
311.00 Structures and Improvements	$29,002,681		$29,002,681		-14.1%		($4,089,378)	($4,089,378)	-14.1%
312.00 Boiler Plant Equipment	218,326,908		218,326,908		-14.8%		(32,312,382)	(32,312,382)	-14.8%
314.00 Turbogenerator Units	42,777,597		42,777,597		-14.5%		(6,202,752)	(6,202,752)	-14.5%
315.00 Accessory Electric Equipment	17,232,291		17,232,291		-14.3%		(2,464,218)	(2,464,218)	-14.3%
316.00 Misc. Power Plant Equipment	5,676,014		5,676,014		-14.4%		(817,346)	(817,346)	-14.4%
Total Four Corners Units 1-3	$313,015,491		$313,015,491		-14.7%		($45,886,076)	($45,886,076)	-14.7%
Four Corners Units 4-5									
311.00 Structures and Improvements	$9,201,539		$9,201,539		-26.8%		($2,466,012)	($2,466,012)	-26.8%
312.00 Boiler Plant Equipment	112,898,782		112,898,782		-24.1%		(27,208,606)	(27,208,606)	-24.1%
314.00 Turbogenerator Units	14,652,943		14,652,943		-26.4%		(3,868,377)	(3,868,377)	-26.4%
315.00 Accessory Electric Equipment	9,853,384		9,853,384		-26.4%		(2,601,293)	(2,601,293)	-26.4%

ARIZONA PUBLIC SERVICE COMPANY
Average Net Salvage

Statement D

Account Description	Plant Investment			Salvage Rate		Net Salvage			Average
	Additions	Retirements	Survivors	Realized	Future	Realized	Future	Total	Rate
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
316.00 Misc. Power Plant Equipment	3,029,198		3,029,198		-23.8%		(720,949)	(720,949)	-23.8%
Total Four Corners Units 4-5	$149,635,846		$149,635,846		-24.6%		($36,865,238)	($36,865,238)	-24.6%
Four Corners Common									
311.00 Structures and Improvements	$4,801,691		$4,801,691		-29.0%		($1,392,490)	($1,392,490)	-29.0%
312.00 Boiler Plant Equipment	3,820,349		3,820,349		-25.3%		(966,548)	(966,548)	-25.3%
314.00 Turbogenerator Units	1,727,476		1,727,476		-26.4%		(456,054)	(456,054)	-26.4%
315.00 Accessory Electric Equipment	2,739,809		2,739,809		-25.2%		(690,432)	(690,432)	-25.2%
316.00 Misc. Power Plant Equipment	8,538,083		8,538,083		-25.8%		(2,202,825)	(2,202,825)	-25.8%
Total Four Corners Common	$21,627,408		$21,627,408		-26.4%		($5,708,350)	($5,708,350)	-26.4%
Navajo Units 1-3									
311.00 Structures and Improvements	$28,391,046		$28,391,046		-14.5%		($4,116,702)	($4,116,702)	-14.5%
312.00 Boiler Plant Equipment	156,202,698		156,202,698		-15.8%		(24,680,026)	(24,680,026)	-15.8%
314.00 Turbogenerator Units	24,699,305		24,699,305		-14.9%		(3,680,196)	(3,680,196)	-14.9%
315.00 Accessory Electric Equipment	20,448,549		20,448,549		-15.1%		(3,087,731)	(3,087,731)	-15.1%
316.00 Misc. Power Plant Equipment	14,618,062		14,618,062		-15.9%		(2,324,272)	(2,324,272)	-15.9%
Total Navajo Units 1-3	$244,359,660		$244,359,660		-15.5%		($37,888,927)	($37,888,927)	-15.5%
Ocotillo Units 1-2									
311.00 Structures and Improvements	$3,792,708		$3,792,708		-37.9%		($1,437,436)	($1,437,436)	-37.9%
312.00 Boiler Plant Equipment	24,174,538		24,174,538		-32.9%		(7,953,423)	(7,953,423)	-32.9%
314.00 Turbogenerator Units	15,372,486		15,372,486		-36.1%		(5,549,467)	(5,549,467)	-36.1%
315.00 Accessory Electric Equipment	2,670,248		2,670,248		-35.0%		(934,587)	(934,587)	-35.0%
316.00 Misc. Power Plant Equipment	5,258,871		5,258,871		-36.8%		(1,935,265)	(1,935,265)	-36.8%
Total Octillo Units 1-2	$51,268,851		$51,268,851		-34.7%		($17,810,178)	($17,810,178)	-34.7%
Saguaro Units 1-2									
311.00 Structures and Improvements	$2,990,982		$2,990,982		-29.0%		($867,385)	($867,385)	-29.0%
312.00 Boiler Plant Equipment	22,590,899		22,590,899		-27.8%		(6,280,270)	(6,280,270)	-27.8%
314.00 Turbogenerator Units	16,340,249		16,340,249		-28.8%		(4,705,992)	(4,705,992)	-28.8%
315.00 Accessory Electric Equipment	2,704,916		2,704,916		-28.5%		(770,901)	(770,901)	-28.5%
316.00 Misc. Power Plant Equipment	3,255,754		3,255,754		-28.4%		(924,634)	(924,634)	-28.4%
Total Saguaro Units 1-2	$47,882,800		$47,882,800		-28.3%		($13,549,182)	($13,549,182)	-28.3%
NUCLEAR PRODUCTION (BY UNIT)									
Palo Verde									
321.00 Structures and Improvements	$640,003,980		$640,003,980						
322.00 Reactor Plant Equipment	939,061,294		939,061,294		-0.2%		(2,229,083)	(2,229,083)	-0.2%
322.10 Steam Generators	52,865,345		52,865,345						
323.00 Turbogenerator Units	342,424,222		342,424,222		-0.4%		(1,369,697)	(1,369,697)	-0.4%
324.00 Accessory Electric Equipment	272,624,619		272,624,619		-0.5%		(1,248,764)	(1,248,764)	-0.5%
325.00 Misc. Power Plant Equipment	132,963,906		132,963,906		-0.8%		(1,037,013)	(1,037,013)	-0.8%
Total Palo Verde	$2,379,943,366		$2,379,943,366		-0.2%		($5,884,557)	($5,884,557)	-0.2%

ARIZONA PUBLIC SERVICE COMPANY
Average Net Salvage

Statement D

Account Description	Plant Investment Additions	Retirements	Survivors	Salvage Rate Realized	Future	Net Salvage Realized	Future	Total	Average Rate
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
Palo Verde Unit 1									
321.00 Structures and Improvements	$154,544,487		$154,544,487						
322.00 Reactor Plant Equipment	361,739,876		361,739,876		-0.2%		(723,480)	(723,480)	-0.2%
322.10 Steam Generators	27,452,571		27,452,571						
323.00 Turbogenerator Units	118,250,432		118,250,432		-0.4%		(473,002)	(473,002)	-0.4%
324.00 *Accessory Electric Equipment*	114,359,460		114,359,460		-0.4%		(457,438)	(457,438)	-0.4%
325.00 Misc. Power Plant Equipment	29,942,323		29,942,323		-0.8%		(239,539)	(239,539)	-0.8%
Total Palo Verde Unit 1	$806,289,149		$806,289,149		-0.2%		($1,893,458)	($1,893,458)	-0.2%
Palo Verde Unit 2									
321.00 Structures and Improvements	$90,520,213		$90,520,213						
322.00 Reactor Plant Equipment	226,227,486		226,227,486		-0.2%		(452,455)	(452,455)	-0.2%
322.10 Steam Generators									
323.00 Turbogenerator Units	78,129,616		78,129,616		-0.4%		(312,518)	(312,518)	-0.4%
324.00 Accessory Electric Equipment	50,011,285		50,011,285		-0.5%		(250,056)	(250,056)	-0.5%
325.00 Misc. Power Plant Equipment	26,698,465		26,698,465		-0.7%		(186,889)	(186,889)	-0.7%
Total Palo Verde Unit 2	$471,587,065		$471,587,065		-0.3%		($1,201,919)	($1,201,919)	-0.3%
Palo Verde Unit 3									
321.00 Structures and Improvements	$160,291,956		$160,291,956						
322.00 Reactor Plant Equipment	323,919,702		323,919,702		-0.3%		(971,759)	(971,759)	-0.3%
322.10 Steam Generators	25,412,774		25,412,774						
323.00 Turbogenerator Units	144,585,131		144,585,131		-0.4%		(578,341)	(578,341)	-0.4%
324.00 Accessory Electric Equipment	89,504,541		89,504,541		-0.5%		(447,523)	(447,523)	-0.5%
325.00 Misc. Power Plant Equipment	27,547,817		27,547,817		-0.8%		(220,383)	(220,383)	-0.8%
Total Palo Verde Unit 3	$771,261,921		$771,261,921		-0.3%		($2,218,005)	($2,218,005)	-0.3%
Palo Verde Water Reclamation									
321.00 Structures and Improvements	$128,265,752		$128,265,752						
322.00 Reactor Plant Equipment	133,326		133,326		-0.2%		(267)	(267)	-0.2%
322.10 Steam Generators									
323.00 Turbogenerator Units	235,152		235,152		-0.4%		(941)	(941)	-0.4%
324.00 Accessory Electric Equipment									
325.00 Misc. Power Plant Equipment	88,819		88,819		-0.8%		(711)	(711)	-0.8%
Total Palo Verde Water Reclamation	$128,723,049		$128,723,049		0.0%		($1,918)	($1,918)	
Palo Verde Common									
321.00 Structures and Improvements	$106,381,572		$106,381,572						
322.00 Reactor Plant Equipment	27,040,904		27,040,904		-0.3%		(81,123)	(81,123)	-0.3%
322.10 Steam Generators									
323.00 Turbogenerator Units	1,223,891		1,223,891		-0.4%		(4,896)	(4,896)	-0.4%
324.00 *Accessory Electric Equipment*	18,749,333		18,749,333		-0.5%		(93,747)	(93,747)	-0.5%
325.00 Misc. Power Plant Equipment	48,686,482		48,686,482		-0.8%		(389,492)	(389,492)	-0.8%
Total Palo Verde Common	$202,082,182		$202,082,182		-0.3%		($569,257)	($569,257)	-0.3%

ARIZONA PUBLIC SERVICE COMPANY
Average Net Salvage

Statement D

Account Description	Plant Investment			Salvage Rate		Net Salvage			Average
	Additions	Retirements	Survivors	Realized	Future	Realized	Future	Total	Rate
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
OTHER PRODUCTION (BY UNIT)									
Douglas CT									
341.00 Structures and Improvements	$4,562		$4,562		-5.0%		($228)	($228)	-5.0%
342.00 Fuel Holders, Products and Accessories	137,759		137,759		-5.0%		(6,888)	(6,888)	-5.0%
343.00 Prime Movers	1,101,449		1,101,449						
344.00 Generators and Devices	551,765		551,765						
345.00 Accessory Electric Equipment	353,277		353,277						
346.00 Misc. Power Plant Equipment	40,913		40,913						
Total Douglas CT	$2,189,725		$2,189,725		-0.3%		($7,116)	($7,116)	-0.3%
Ocotillo CT Units 1-2									
341.00 Structures and Improvements	$430,899		$430,899		-5.0%		($21,545)	($21,545)	-5.0%
342.00 Fuel Holders, Products and Accessories	719,859		719,859		-5.0%		(35,993)	(35,993)	-5.0%
343.00 Prime Movers	6,540,275		6,540,275						
344.00 Generators and Devices	6,424,357		6,424,357						
345.00 Accessory Electric Equipment	1,590,924		1,590,924						
346.00 Misc. Power Plant Equipment	558,648		558,648						
Total Ocotillo CT Units 1-2	$16,264,962		$16,264,962		-0.4%		($57,538)	($57,538)	-0.4%
Saguaro CT Units 1-2									
341.00 Structures and Improvements	$1,380,611		$1,380,611		-5.0%		($69,031)	($69,031)	-5.0%
342.00 Fuel Holders, Products and Accessories	1,304,977		1,304,977		-5.0%		(65,249)	(65,249)	-5.0%
343.00 Prime Movers	8,047,527		8,047,527						
344.00 Generators and Devices	4,001,509		4,001,509						
345.00 Accessory Electric Equipment	1,626,802		1,626,802						
346.00 Misc. Power Plant Equipment	790,906		790,906						
Total Saguaro CT Units 1-2	$17,152,332		$17,152,332		-0.8%		($134,279)	($134,279)	-0.8%
Solar Units									
341.00 Structures and Improvements	$352,259		$352,259						
342.00 Fuel Holders, Products and Accessories									
343.00 Prime Movers	20,596		20,596						
344.00 Generators and Devices	14,326,036		14,326,036						
345.00 Accessory Electric Equipment	166,465		166,465						
346.00 Misc. Power Plant Equipment									
Total Solar Units	$14,865,356		$14,865,356						
West Phoenix									
341.00 Structures and Improvements	$7,550,035		$7,550,035		-5.0%		($377,502)	($377,502)	-5.0%
342.00 Fuel Holders, Products and Accessories	20,688,419		20,688,419		-5.0%		(1,034,421)	(1,034,421)	-5.0%
343.00 Prime Movers	8,794,167		8,794,167						

ARIZONA PUBLIC SERVICE COMPANY
Average Net Salvage

Statement D

Account Description	Plant Investment			Salvage Rate		Net Salvage			Average
	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
344.00 Generators and Devices	81,091,743		81,091,743		-1.9%		(1,524,036)	(1,524,036)	-1.9%
345.00 Accessory Electric Equipment	13,957,323		13,957,323						
346.00 Misc. Power Plant Equipment	3,590,505		3,590,505						
Total West Pheonix	$135,672,192		$135,672,192		-2.2%		($2,935,958)	($2,935,958)	-2.2%
West Phoenix CT Units 1-2									
341.00 Structures and Improvements	$510,951		$510,951		-5.0%		($25,548)	($25,548)	-5.0%
342.00 Fuel Holders, Products and Accessories	1,437,533		1,437,533		-5.0%		(71,877)	(71,877)	-5.0%
343.00 Prime Movers	8,794,167		8,794,167						
344.00 Generators and Devices	4,889,963		4,889,963						
345.00 Accessory Electric Equipment	1,557,744		1,557,744						
346.00 Misc. Power Plant Equipment	917,431		917,431						
Total West Ploenix CT Units 1-2	$18,107,789		$18,107,789		-0.5%		($97,424)	($97,424)	-0.5%
West Phoenix CC Units 1-3									
341.00 Structures and Improvements	$7,039,084		$7,039,084		-5.0%		($351,954)	($351,954)	-5.0%
342.00 Fuel Holders, Products and Accessories	19,250,886		19,250,886		-5.0%		(962,544)	(962,544)	-5.0%
343.00 Prime Movers									
344.00 Generators and Devices	76,201,780		76,201,780		-2.0%		(1,524,036)	(1,524,036)	-2.0%
345.00 Accessory Electric Equipment	12,399,579		12,399,579						
346.00 Misc. Power Plant Equipment	2,673,074		2,673,074						
Total West Phoenix CC Units 1-3	$117,564,403		$117,564,403		-2.4%		($2,838,534)	($2,838,534)	-2.4%
Yucca CT Units 1-4									
341.00 Structures and Improvements	$462,030		$462,030		-5.0%		($23,102)	($23,102)	-5.0%
342.00 Fuel Holders, Products and Accessories	3,244,987		3,244,987		-5.0%		(162,249)	(162,249)	-5.0%
343.00 Prime Movers	7,962,254		7,962,254						
344.00 Generators and Devices	5,358,461		5,358,461						
345.00 Accessory Electric Equipment	2,172,221		2,172,221						
346.00 Misc. Power Plant Equipment	479,650		479,650						
Total Yucca CT Units 1-4	$19,679,603		$19,679,603		-0.9%		($185,351)	($185,351)	-0.9%

ARIZONA PUBLIC SERVICE COMPANY
Future Net Salvage
Steam and Nuclear Production

Statement E

Account Description	12/31/04 Plant Investment	Future Retirements		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	$53,689,761	$10,375,910	$43,313,851	-20.0%	-19.1%	($2,075,182)	($8,256,542)	($10,331,724)	-19.2%
312.00 Boiler Plant Equipment	299,852,771	159,093,636	140,759,135	-20.0%	-18.8%	(31,818,727)	(26,498,336)	(58,317,063)	-19.4%
314.00 Turbogenerator Units	85,609,508	16,496,198	69,113,310	-20.0%	-19.8%	(3,299,240)	(13,707,416)	(17,006,656)	-19.9%
315.00 Accessory Electric Equipment	82,574,161	23,510,891	59,063,270	-20.0%	-19.2%	(4,702,178)	(11,362,910)	(16,065,088)	-19.5%
316.00 Misc. Power Plant Equipment	20,057,407	10,288,403	9,769,004	-20.0%	-18.3%	(2,057,681)	(1,791,991)	(3,849,672)	-19.2%
Total Cholla	$541,783,608	$219,765,038	$322,018,570	-20.0%	-19.1%	($43,953,008)	($61,617,194)	($105,570,202)	-19.5%
Cholla Unit 1									
311.00 Structures and Improvements	$2,116,308	$186,585	$1,929,723	-20.0%	-15.4%	($37,317)	($296,750)	($334,067)	-15.8%
312.00 Boiler Plant Equipment	27,464,546	5,583,370	21,881,176	-20.0%	-15.4%	(1,116,674)	(3,364,856)	(4,481,530)	-16.3%
314.00 Turbogenerator Units	10,355,816	1,024,966	9,330,850	-20.0%	-15.4%	(204,993)	(1,434,885)	(1,639,878)	-15.8%
315.00 Accessory Electric Equipment	4,790,621	518,533	4,272,088	-20.0%	-15.4%	(103,707)	(656,956)	(760,662)	-15.9%
316.00 Misc. Power Plant Equipment	2,432,224	354,729	2,077,495	-20.0%	-15.4%	(70,946)	(319,474)	(390,420)	-16.1%
Total Cholla Unit 1	$47,159,515	$7,668,182	$39,491,333	-20.0%	-15.4%	($1,533,636)	($6,072,921)	($7,606,557)	-16.1%
Cholla Unit 2									
311.00 Structures and Improvements	$4,866,784	$736,061	$4,130,723	-20.0%	-17.8%	($147,212)	($734,392)	($881,604)	-18.1%
312.00 Boiler Plant Equipment	144,102,635	80,560,476	63,542,159	-20.0%	-17.8%	(16,112,095)	(11,297,013)	(27,409,108)	-19.0%
314.00 Turbogenerator Units	29,198,775	6,981,868	22,216,907	-20.0%	-17.8%	(1,396,374)	(3,949,892)	(5,346,266)	-18.3%
315.00 Accessory Electric Equipment	42,759,226	12,620,318	30,138,908	-20.0%	-17.8%	(2,524,064)	(5,358,327)	(7,882,390)	-18.4%
316.00 Misc. Power Plant Equipment	5,232,429	3,175,378	2,057,051	-20.0%	-17.8%	(635,076)	(365,718)	(1,000,794)	-19.1%
Total Cholla Unit 2	$226,159,849	$104,074,101	$122,085,746	-20.0%	-17.8%	($20,814,820)	($21,705,342)	($42,520,162)	-18.8%
Cholla Unit 3									
311.00 Structures and Improvements	$9,637,296	$1,975,388	$7,661,908	-20.0%	-22.2%	($395,078)	($1,700,873)	($2,095,951)	-21.7%
312.00 Boiler Plant Equipment	103,136,479	60,480,584	42,655,895	-20.0%	-22.2%	(12,096,117)	(9,469,216)	(21,565,333)	-20.9%
314.00 Turbogenerator Units	45,423,639	8,327,471	37,096,168	-20.0%	-22.2%	(1,665,494)	(8,235,008)	(9,900,502)	-21.8%
315.00 Accessory Electric Equipment	30,152,547	9,040,163	21,112,384	-20.0%	-22.2%	(1,808,033)	(4,686,755)	(6,494,788)	-21.5%
316.00 Misc. Power Plant Equipment	4,319,200	2,764,303	1,554,897	-20.0%	-22.2%	(552,861)	(345,173)	(898,033)	-20.8%
Total Cholla Unit 3	$192,669,161	$82,587,910	$110,081,251	-20.0%	-22.2%	($16,517,582)	($24,437,025)	($40,954,607)	-21.3%
Cholla Common									
311.00 Structures and Improvements	$37,069,373	$7,477,876	$29,591,497	-20.0%	-18.7%	($1,495,575)	($5,524,527)	($7,020,102)	-18.9%
312.00 Boiler Plant Equipment	25,149,111	12,469,206	12,679,905	-20.0%	-18.7%	(2,493,841)	(2,367,250)	(4,861,091)	-19.3%
314.00 Turbogenerator Units	631,278	161,892	469,386	-20.0%	-18.7%	(32,378)	(87,631)	(120,010)	-19.0%
315.00 Accessory Electric Equipment	4,871,767	1,331,877	3,539,890	-20.0%	-18.7%	(266,375)	(660,873)	(927,248)	-19.0%
316.00 Misc. Power Plant Equipment	8,073,554	3,993,993	4,079,561	-20.0%	-18.7%	(798,799)	(761,626)	(1,560,424)	-19.3%
Total Cholla Common	$75,795,083	$25,434,845	$50,360,238	-20.0%	-18.7%	($5,086,969)	($9,401,906)	($14,488,875)	-19.1%

ARIZONA PUBLIC SERVICE COMPANY Statement E

Future Net Salvage

Steam and Nuclear Production

Account Description	12/31/04 Plant Investment	Future Retirements Interim	Future Retirements Final	Net Salvage Rate Interim	Net Salvage Rate Final	Future Net Salvage Interim	Future Net Salvage Final	Future Net Salvage Total	Future Rate
A	B	C	D=B-C	E	F	G=C*E	H=D*F	I=G+H	J=I/B
Four Corners									
311.00 Structures and Improvements	$43,005,911	$2,805,904	$40,200,007	-20.0%	-18.4%	($561,181)	($7,396,835)	($7,958,016)	-18.5%
312.00 Boiler Plant Equipment	335,046,039	85,660,518	249,385,521	-20.0%	-17.4%	(17,132,104)	(43,366,910)	(60,499,014)	-18.1%
314.00 Turbogenerator Units	59,158,016	6,918,532	52,239,484	-20.0%	-17.5%	(1,383,706)	(9,127,052)	(10,510,758)	-17.8%
315.00 Accessory Electric Equipment	29,825,484	4,372,258	25,453,226	-20.0%	-19.2%	(874,452)	(4,885,256)	(5,759,708)	-19.3%
316.00 Misc. Power Plant Equipment	17,243,295	5,830,409	11,412,886	-20.0%	-22.6%	(1,166,082)	(2,577,497)	(3,743,579)	-21.7%
Total Four Corners	$484,278,745	$105,587,621	$378,691,124	-20.0%	-19.1%	($21,117,524)	($67,353,550)	($88,471,074)	-18.3%
Four Corners Units 1-3									
311.00 Structures and Improvements	$29,002,681	$609,936	$28,392,745	-20.0%	-14.0%	($121,987)	($3,980,847)	($4,102,834)	-14.1%
312.00 Boiler Plant Equipment	218,326,908	28,507,881	189,819,027	-20.0%	-14.0%	(5,701,576)	(26,613,860)	(32,315,436)	-14.8%
314.00 Turbogenerator Units	42,777,597	3,201,876	39,575,721	-20.0%	-14.0%	(640,375)	(5,548,773)	(6,189,148)	-14.5%
315.00 Accessory Electric Equipment	17,232,291	921,516	16,310,775	-20.0%	-14.0%	(184,303)	(2,286,877)	(2,471,180)	-14.3%
316.00 Misc. Power Plant Equipment	5,676,014	369,045	5,306,969	-20.0%	-14.0%	(73,809)	(744,072)	(817,881)	-14.4%
Total Four Corners Units 1-3	$313,015,491	$33,610,254	$279,405,237	-20.0%	-14.0%	($6,722,051)	($39,174,428)	($45,896,479)	-14.7%
Four Corners Units 4-5									
311.00 Structures and Improvements	$9,201,539	$1,434,534	$7,767,005	-20.0%	-28.0%	($286,907)	($2,177,958)	($2,464,865)	-26.8%
312.00 Boiler Plant Equipment	112,898,782	55,251,132	57,647,650	-20.0%	-28.0%	(11,050,226)	(16,165,071)	(27,215,298)	-24.1%
314.00 Turbogenerator Units	14,652,943	3,035,336	11,617,607	-20.0%	-28.0%	(607,067)	(3,257,712)	(3,864,779)	-26.4%
315.00 Accessory Electric Equipment	9,853,384	2,046,089	7,807,295	-20.0%	-28.0%	(409,218)	(2,189,256)	(2,598,474)	-26.4%
316.00 Misc. Power Plant Equipment	3,029,198	1,584,816	1,444,382	-20.0%	-28.0%	(316,963)	(405,022)	(721,985)	-23.8%
Total Four Corners Units 4-5	$149,635,846	$63,351,907	$86,283,939	-20.0%	-28.0%	($12,670,381)	($24,195,020)	($36,865,401)	-24.6%
Four Corners Common									
311.00 Structures and Improvements	$4,801,691	$761,434	$4,040,257	-20.0%	-30.6%	($152,287)	($1,238,030)	($1,390,316)	-29.0%
312.00 Boiler Plant Equipment	3,820,349	1,901,505	1,918,844	-20.0%	-30.6%	(380,301)	(587,979)	(968,280)	-25.3%
314.00 Turbogenerator Units	1,727,476	681,320	1,046,156	-20.0%	-30.6%	(136,264)	(320,567)	(456,831)	-26.4%
315.00 Accessory Electric Equipment	2,739,809	1,404,654	1,335,155	-20.0%	-30.6%	(280,931)	(409,123)	(690,054)	-25.2%
316.00 Misc. Power Plant Equipment	8,538,083	3,876,548	4,661,535	-20.0%	-30.6%	(775,310)	(1,428,404)	(2,203,713)	-25.8%
Total Four Corners Common	$21,627,408	$8,625,461	$13,001,947	-20.0%	-30.6%	($1,725,092)	($3,984,102)	($5,709,194)	-26.4%
Navajo Units 1-3									
311.00 Structures and Improvements	$28,391,046	$2,287,537	$26,103,509	-20.0%	-14.0%	($457,507)	($3,659,761)	($4,117,269)	-14.5%
312.00 Boiler Plant Equipment	156,202,698	46,699,705	109,502,993	-20.0%	-14.0%	(9,339,941)	(15,352,527)	(24,692,468)	-15.8%
314.00 Turbogenerator Units	24,699,305	3,811,459	20,887,846	-20.0%	-14.0%	(762,292)	(2,928,516)	(3,690,807)	-14.9%
315.00 Accessory Electric Equipment	20,448,549	3,569,128	16,879,421	-20.0%	-14.0%	(713,826)	(2,366,527)	(3,080,352)	-15.1%
316.00 Misc. Power Plant Equipment	14,618,062	4,527,393	10,090,669	-20.0%	-14.0%	(905,479)	(1,414,731)	(2,320,209)	-15.9%
Total Navajo Units 1-3	$244,359,660	$60,895,222	$183,464,438	-20.0%	-14.0%	($12,179,044)	($25,722,062)	($37,901,106)	-15.5%

ARIZONA PUBLIC SERVICE COMPANY
Future Net Salvage
Steam and Nuclear Production

Statement E

Account Description	12/31/04 Plant Investment	Future Retirements Interim	Future Retirements Final	Net Salvage Rate Interim	Net Salvage Rate Final	Future Net Salvage Interim	Future Net Salvage Final	Future Net Salvage Total	Future Rate
A	B	C	D=B-C	E	F	G=C*E	H=D*F	I=G+H	J=I/B
Ocotillo Units 1-2									
311.00 Structures and Improvements	$3,792,708	$239,811	$3,552,897	-20.0%	-39.1%	($47,962)	($1,390,767)	($1,438,730)	-37.9%
312.00 Boiler Plant Equipment	24,174,538	7,885,863	16,288,675	-20.0%	-39.1%	(1,577,173)	(6,376,138)	(7,953,311)	-32.9%
314.00 Turbogenerator Units	15,372,486	2,484,703	12,887,783	-20.0%	-39.1%	(496,941)	(5,044,872)	(5,541,813)	-36.1%
315.00 Accessory Electric Equipment	2,670,248	584,327	2,085,921	-20.0%	-39.1%	(116,865)	(816,526)	(933,391)	-35.0%
316.00 Misc. Power Plant Equipment	5,258,871	654,022	4,604,849	-20.0%	-39.1%	(130,804)	(1,802,550)	(1,933,354)	-36.8%
Total Ocotillo Units 1-2	$51,268,851	$11,848,726	$39,420,125	-20.0%	-39.1%	($2,369,745)	($15,430,853)	($17,800,599)	-34.7%
Saguaro Units 1-2									
311.00 Structures and Improvements	$2,990,982	$141,155	$2,849,827	-20.0%	-29.5%	($28,231)	($840,140)	($868,371)	-29.0%
312.00 Boiler Plant Equipment	22,590,899	4,039,244	18,551,655	-20.0%	-29.5%	(807,849)	(5,469,100)	(6,276,948)	-27.8%
314.00 Turbogenerator Units	16,340,249	1,209,818	15,130,431	-20.0%	-29.5%	(241,964)	(4,460,509)	(4,702,473)	-28.8%
315.00 Accessory Electric Equipment	2,704,916	291,926	2,412,990	-20.0%	-29.5%	(58,385)	(711,359)	(769,744)	-28.5%
316.00 Misc. Power Plant Equipment	3,255,754	356,960	2,898,794	-20.0%	-29.5%	(71,392)	(854,576)	(925,968)	-28.4%
Total Saguaro Units 1-2	$47,882,800	$6,039,103	$41,843,697	-20.0%	-29.5%	($1,207,821)	($12,335,683)	($13,543,504)	-28.3%
NUCLEAR PRODUCTION (BY UNIT)									
Palo Verde									
321.00 Structures and Improvements	$640,003,980	$60,095,953	$579,908,027						
322.00 Reactor Plant Equipment	939,061,294	116,478,646	822,582,648	-2.0%		(2,329,573)		(2,329,573)	-0.2%
322.10 Steam Generators	52,865,345		52,865,345						
323.00 Turbogenerator Units	342,424,222	65,002,666	277,421,556	-2.0%		(1,300,053)		(1,300,053)	-0.4%
324.00 Accessory Electric Equipment	272,624,619	63,727,095	208,897,524	-2.0%		(1,274,542)		(1,274,542)	-0.5%
325.00 Misc. Power Plant Equipment	132,963,906	52,869,726	80,094,180	-2.0%		(1,057,395)		(1,057,395)	-0.8%
Total Palo Verde	$2,379,943,366	$358,174,085	$2,021,769,281	-1.7%	-19.1%	($5,961,563)		($5,961,563)	-0.3%
Palo Verde Unit 1									
321.00 Structures and Improvements	$154,544,487	$13,159,762	$141,384,725						
322.00 Reactor Plant Equipment	361,739,876	42,619,943	319,119,933	-2.0%		(852,399)		(852,399)	-0.2%
322.10 Steam Generators	27,452,571		27,452,571	-17.0%					
323.00 Turbogenerator Units	118,250,432	21,267,191	96,983,241	-2.0%		(425,344)		(425,344)	-0.4%
324.00 Accessory Electric Equipment	114,359,460	25,373,943	88,985,517	-2.0%		(507,479)		(507,479)	-0.4%
325.00 Misc. Power Plant Equipment	29,942,323	11,388,165	18,554,158	-2.0%		(227,763)		(227,763)	-0.8%
Total Palo Verde Unit 1	$806,289,149	$113,809,004	$692,480,145	-1.8%		($2,012,985)		($2,012,985)	-0.2%

Statement E

ARIZONA PUBLIC SERVICE COMPANY
Future Net Salvage
Steam and Nuclear Production

Account Description	12/31/04 Plant Investment	Future Retirements Interim	Future Retirements Final	Net Salvage Rate Interim	Net Salvage Rate Final	Future Net Salvage Interim	Future Net Salvage Final	Future Net Salvage Total	Future Rate
A	B	C	D=B-C	E	F	G=C*E	H=D*F	I=G+H	J=I/B
Palo Verde Unit 2									
321.00 Structures and Improvements	$90,520,213	$8,240,388	$82,279,825						
322.00 Reactor Plant Equipment	226,227,486	26,699,745	199,527,741	-2.0%		(533,995)		(533,995)	-0.2%
322.10 Steam Generators									
323.00 Turbogenerator Units	78,129,616	14,061,735	64,067,881	-2.0%		(281,235)		(281,235)	-0.4%
324.00 Accessory Electric Equipment	50,011,285	11,287,835	38,723,450	-2.0%		(225,757)		(225,757)	-0.5%
325.00 Misc. Power Plant Equipment	26,698,465	9,831,171	16,867,294	-2.0%		(196,623)		(196,623)	-0.7%
Total Palo Verde Unit 2	$471,587,065	$70,120,874	$401,466,191	-1.8%		($1,237,610)		($1,237,610)	-0.3%
Palo Verde Unit 3									
321.00 Structures and Improvements	$160,291,956	$15,554,217	$144,737,739						
322.00 Reactor Plant Equipment	323,919,702	43,548,455	280,371,247	-2.0%		(870,969)		(870,969)	-0.3%
322.10 Steam Generators	25,412,774		25,412,774	-17.0%					
323.00 Turbogenerator Units	144,585,131	29,410,073	115,175,058	-2.0%		(588,201)		(588,201)	-0.4%
324.00 Accessory Electric Equipment	89,504,541	22,323,751	67,180,790	-2.0%		(446,475)		(446,475)	-0.5%
325.00 Misc. Power Plant Equipment	27,547,817	11,675,724	15,872,093	-2.0%		(233,514)		(233,514)	-0.8%
Total Palo Verde Unit 3	$771,261,921	$122,512,219	$648,749,702	-1.7%		($2,139,160)		($2,139,160)	-0.3%
Palo Verde Water Reclamation									
321.00 Structures and Improvements	$128,265,752	$12,883,471	$115,382,281						
322.00 Reactor Plant Equipment	133,326	14,018	119,308	-2.0%		(280)		(280)	-0.2%
322.10 Steam Generators									
323.00 Turbogenerator Units	235,152	44,537	190,615	-2.0%		(891)		(891)	-0.4%
324.00 Accessory Electric Equipment									
325.00 Misc. Power Plant Equipment	88,819	35,558	53,261	-2.0%		(711)		(711)	-0.8%
Total Palo Verde Water Reclamation	$128,723,049	$12,977,584	$115,745,465	0.0%		($1,882)		($1,882)	
Palo Verde Common									
321.00 Structures and Improvements	$108,381,572	$10,258,114	$96,123,458						
322.00 Reactor Plant Equipment	27,040,904	3,596,486	23,444,418	-2.0%		(71,930)		(71,930)	-0.3%
322.10 Steam Generators									
323.00 Turbogenerator Units	1,223,891	219,130	1,004,761	-2.0%		(4,383)		(4,383)	-0.4%
324.00 Accessory Electric Equipment	18,749,333	4,741,566	14,007,767	-2.0%		(94,831)		(94,831)	-0.5%
325.00 Misc. Power Plant Equipment	48,686,482	19,939,109	28,747,373	-2.0%		(398,782)		(398,782)	-0.8%
Total Palo Verde Common	$202,082,182	$38,754,405	$163,327,777	-1.5%		($569,926)		($569,926)	-0.3%

ARIZONA PUBLIC SERVICE COMPANY
Dismantlement Costs
Steam Production

Statement F

Unit	Capacity (MW)	Cost per kW	2002 Cost	Plant	Distributed Cost	Inflation Rate	Year Spent	Trended Cost	Accrual Rate
A	B	C	D=B*C*1000	E	F	G	H	I	J=I/E
Cholla									
1	110	40.00	$4,400,000	$47,159,515	$3,784,444	3.00%	2017	$6,072,921	12.9%
2	245	40.00	9,800,000	226,159,849	8,428,988	3.00%	2033	21,705,342	9.6%
3	260	40.00	10,400,000	192,669,161	8,945,049	3.00%	2035	24,437,025	12.7%
C				75,795,083	3,441,520	3.00%	2035	9,401,906	12.4%
	615		$24,600,000	$541,783,608	$24,600,000			$61,617,194	11.4%
	Allocated to Common:		3,441,520						
	Allocated to Units:		$21,158,480						
Four Corners									
1-3	560	47.00	$26,320,000	$313,015,491	$25,144,575	3.00%	2016	$39,174,428	12.5%
4-5	222	47.00	10,434,000	149,635,846	9,968,028	3.00%	2031	24,195,020	16.2%
C				21,627,408	1,641,397	3.00%	2031	3,984,102	18.4%
	782		$36,754,000	$484,278,745	$36,754,000			$67,353,550	13.9%
	Allocated to Common:		1,641,397						
	Allocated to Units:		$35,112,603						
Navajo									
1-3	315	39.00	$12,285,000	$244,359,660	$12,285,000	3.00%	2026	$25,722,062	10.5%
C									
	315		$12,285,000	$244,359,660	$12,285,000			$25,722,062	10.5%
	Allocated to Common:								
	Allocated to Units:		$12,285,000						
Ocotillo									
1-2	220	40.00	$8,800,000	$51,268,851	$8,800,000	3.00%	2020	$15,430,853	30.1%
C									
	220		$8,800,000	$51,268,851	$8,800,000			$15,430,853	30.1%
	Allocated to Common:								
	Allocated to Units:		$8,800,000						
Saguaro									
1-2	210	40.00	$8,400,000	$47,882,800	$8,400,000	3.00%	2014	$12,335,683	25.8%
C									
	210		$8,400,000	$47,882,800	$8,400,000			$12,335,683	25.8%
	Allocated to Common:								
	Allocated to Units:		$8,400,000						
Palo Verde									
1	1243			$806,289,149		3.00%	2024		
2	1335			471,587,065		3.00%	2025		
3	1247			771,261,921		3.00%	2027		
WR				128,723,049		3.00%	2027		
C				202,082,182		3.00%	2027		
	3825			$2,379,943,366					
	Allocated to WR:								
	Allocated to Common:								
	Allocated to Units:								

ARIZONA PUBLIC SERVICE COMPANY
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	Present Parameters						Proposed Parameters (at December 31, 2004)					
Account Description	P-Life/ AYFR	Curve Shape	BG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	BG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
STEAM PRODUCTION												
311.00 Structures and Improvements									31.41	18.47	-18.7	-18.7
312.00 Boiler Plant Equipment									30.01	15.64	-18.8	-18.8
314.00 Turbogenerator Units									33.62	17.74	-20.6	-20.6
315.00 Accessory Electric Equipment									39.56	20.34	-19.2	-19.2
316.00 Misc. Power Plant Equipment									26.26	16.98	-21.1	-21.1
Total Steam Production Plant									31.20	16.64	-19.2	-19.2
NUCLEAR PRODUCTION												
321.00 Structures and Improvements									36.73	20.63		
322.00 Reactor Plant Equipment									34.10	19.58	-0.2	-0.2
322.10 Steam Generators									17.47	1.71		
323.00 Turbogenerator Units									33.80	19.08	-0.4	-0.4
324.00 Accessory Electric Equipment									35.60	18.99	-0.5	-0.5
325.00 Misc. Power Plant Equipment									29.00	17.27	-0.8	-0.8
Total Nuclear Production Plant									33.82	18.78	-0.2	-0.2
OTHER PRODUCTION												
341.00 Structures and Improvements									29.51	18.52	-4.8	-4.8
342.00 Fuel Holders, Products and Accessories									31.92	22.27	-5.0	-5.0
343.00 Prime Movers									35.08	11.58		
344.00 Generators and Devices									24.04	17.27	-1.4	-1.4
345.00 Accessory Electric Equipment									32.29	19.53		
346.00 Misc. Power Plant Equipment									29.45	16.90		
Total Other Production Plant									27.31	17.35	-1.6	-1.6
TOTAL PRODUCTION PLANT									32.47	17.92		
TRANSMISSION												
352.00 Structures and Improvements	50.00	R4	50.00	35.20		-5.0	50.00	R4	50.00	21.69	-5.0	-5.0
353.00 Station Equipment	57.00	R1.5	57.00	45.70			57.00	R1.5	57.00	39.98		
354.00 Towers and Fixtures	60.00	R3	60.00	38.30		-35.0	60.00	R3	60.00	42.49	-35.0	-35.0
355.00 Poles and Fixtures - Wood	48.00	R1.5	48.00	38.50		-35.0	55.00	R3	55.00	18.51	-15.0	-15.0
356.00 Overhead Conductors and Devices	55.00	R3	55.00	38.50		-35.0	55	R3	55.00	37.51	-35.0	-35.0

ARIZONA PUBLIC SERVICE COMPANY
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Account Description	Present Parameters P-Life/ AYFR	Curve Shape	BG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	Proposed Parameters (at December 31, 2004) P-Life/ AYFR	Curve Shape	BG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
Total Transmission Plant									57.04	39.97	-1.5	-1.5
DISTRIBUTION												
361.00 Structures and Improvements	45.00	R2.5	45.00	33.10		-10.0	45.00	R2.5	45.00	33.18	-10.0	-10.0
362.00 Station Equipment	44.00	L0.5	44.00	36.90			44.00	L0.5	44.00	36.73		
364.00 Poles, Towers and Fixtures - Wood	38.00	R0.5	38.00	30.90		-10.0	38.00	R0.5	38.00	29.41	-10.0	-10.0
364.10 Poles, Towers and Fixtures - Steel	50.00	R3	50.00	46.60		-5.0	50.00	R3	50.00	46.78	-5.0	-5.0
365.00 Overhead Conductors and Devices	53.00	O1	53.00	47.70		-10.0	53.00	SC	53.00	46.65	-10.0	-10.0
366.00 Underground Conduit	86.00	O1	86.00	82.40		-5.0	86.00	SC	86.00	82.10	-5.0	-5.0
367.00 Underground Conductors and Devices	29.00	L1	29.00	22.90		-5.0	29.00	L1	29.00	22.28	-5.0	-5.0
368.00 Line Transformers	36.00	R3	36.00	24.60		-5.0	36.00	R3	36.00	23.63	-5.0	-5.0
369.00 Services	37.00	S2	37.00	27.90		-10.0	37.00	S2	37.00	26.72	-10.0	-10.0
370.00 Meters	29.00	L0	29.00	21.80			29.00	L0	29.00	21.24		
370.10 Meters - Electronic	26.00	R1.5	26.00	23.30			26.00	R1.5	26.00	23.06		
371.00 Installations on Customers' Premises	50.00	O2	50.00	45.00		-20.0	50.00	O2	50.00	45.48	-20.0	-20.0
373.00 Street Lighting and Signal Systems	35.00	R2.5	35.00	25.90		-20.0	35.00	R2.5	35.00	24.32	-20.0	-20.0
Total Distribution Plant									38.35	30.41	-6.1	-6.1
GENERAL												
390.00 Structures and Improvements	39.00	R1	39.00	30.70		-15.0	39.00	R1	39.00	29.54	-15.0	-15.0
391.00 Office Furn. and Equip. - Furniture	20.00	SQ	20.00	10.10			20.00	SQ	20.00	12.23		
391.10 Office Furn. and Equip. - PC Equipment	8.00	R3	8.00	5.30			8.00	R3	8.00	4.28		
391.20 Office Furn. and Equip. - Other	22.00	R4	22.00	14.80			22.00	R4	22.00	13.44		
393.00 Stores Equipment	20.00	SQ	20.00	2.80			20.00	SQ	20.00	2.14		
394.00 Tools, Shop and Garage Equipment	20.00	SQ	20.00	13.70			20.00	SQ	20.00	12.20		
395.00 Laboratory Equipment	20.00	L1	20.00	12.00			20.00	L1	20.00	11.99		
397.00 Communication Equipment	19.00	S1.5	19.00	12.00			19.00	S1.5	19.00	11.53		

ARIZONA PUBLIC SERVICE COMPANY

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Statement G

	Present Parameters						Proposed Parameters (at December 31, 2004)					
Account Description	P-Life/ AYFR	Curve Shape	BG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	BG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
398.HH Miscellaneous Equipment - Hydrogen	5.00	SQ	5.00				5.00	SQ	5.00	2.50		
398.00 Miscellaneous Equipment	24.00	S1.5	24.00	16.60			24.00	S1.5	24.00	20.91		
Total General									17.71	11.41	-4.7	-4.7
TOTAL UTILITY									33.60	22.24	-5.9	-5.9
STEAM PRODUCTION (BY UNIT)												
Cholla												
311.00 Structures and Improvements									48.46	27.11	-19.2	-19.2
312.00 Boiler Plant Equipment									38.79	19.78	-19.4	-19.4
314.00 Turbogenerator Units									40.45	24.85	-19.9	-19.9
315.00 Accessory Electric Equipment									46.87	24.71	-19.4	-19.4
316.00 Misc. Power Plant Equipment									33.05	20.65	-19.2	-19.2
Total Cholla									40.66	21.89	-19.5	-19.5
Cholla Unit 1												
311.00 Structures and Improvements	2017	75-S1.5		14.00		-20.0	2017	75-S1.5	39.84	11.97	-15.8	-15.8
312.00 Boiler Plant Equipment	2017	48-L2		13.40		-20.0	2017	48-L2	25.66	11.20	-16.3	-16.3
314.00 Turbogenerator Units	2017	65-R2		14.00		-20.0	2017	65-R2	31.21	11.90	-15.8	-15.8
315.00 Accessory Electric Equipment	2017	60-R2.5		13.90		-20.0	2017	60-R2.5	31.76	11.86	-15.9	-15.9
316.00 Misc. Power Plant Equipment	2017	40-R2		13.50		-20.0	2017	40-R2	21.87	11.63	-16.1	-16.1
Total Cholla Unit 1									27.46	11.44	-16.1	-16.1
Cholla Unit 2												
311.00 Structures and Improvements	2033	75-S1.5		29.00		-20.0	2033	75-S1.5	43.32	26.78	-18.1	-18.1
312.00 Boiler Plant Equipment	2033	48-L2		22.00		-20.0	2033	48-L2	40.97	20.46	-19.0	-19.0
314.00 Turbogenerator Units	2033	65-R2		27.50		-20.0	2033	65-R2	47.30	25.56	-18.3	-18.3
315.00 Accessory Electric Equipment	2033	60-R2.5		26.80		-20.0	2033	60-R2.5	48.50	25.09	-18.4	-18.4
316.00 Misc. Power Plant Equipment	2033	40-R2		22.10		-20.0	2033	40-R2	36.47	20.74	-19.1	-19.1
Total Cholla Unit 2									42.90	21.99	-18.8	-18.8
Cholla Unit 3												
311.00 Structures and Improvements	2035	75-S1.5		29.90		-20.0	2035	75-S1.5	50.45	27.97	-21.7	-21.7
312.00 Boiler Plant Equipment	2035	48-L2		22.90		-20.0	2035	48-L2	41.50	21.56	-20.9	-20.9
314.00 Turbogenerator Units	2035	65-R2		29.70		-20.0	2035	65-R2	39.34	28.16	-21.8	-21.8

ARIZONA PUBLIC SERVICE COMPANY
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Account Description	Present Parameters						Proposed Parameters (at December 31, 2004)					
	P-Life/ AYFR	Curve Shape	BG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	BG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
315.00 Accessory Electric Equipment	2035	60-R2.5		28.50		-20.0	2035	60-R2.5	48.65	26.87	-21.5	-21.5
316.00 Misc. Power Plant Equipment	2035	40-R2		23.80		-20.0	2035	40-R2	37.32	21.91	-20.8	-20.8
Total Cholla Unit 3									42.19	24.25	-21.2	-21.2
Cholla Common												
311.00 Structures and Improvements	2035	75-S1.5		29.90		-20.0	2035	75-S1.5	49.33	28.01	-18.9	-18.9
312.00 Boiler Plant Equipment	2035	48-L2		24.80		-20.0	2035	48-L2	38.22	23.38	-19.3	-19.3
314.00 Turbogenerator Units	2035	65-R2		29.00		-20.0	2035	65-R2	49.00	27.18	-19.0	-19.0
315.00 Accessory Electric Equipment	2035	60-R2.5		28.70		-20.0	2035	60-R2.5	44.56	27.19	-19.0	-19.0
316.00 Misc. Power Plant Equipment	2035	40-R2		25.80		-20.0	2035	40-R2	34.14	24.23	-19.3	-19.3
Total Cholla Common									42.87	25.69	-19.1	-19.1
Four Corners												
311.00 Structures and Improvements									21.68	13.52	-18.5	-18.5
312.00 Boiler Plant Equipment									24.61	12.87	-18.1	-18.1
314.00 Turbogenerator Units									25.83	13.24	-17.8	-17.8
315.00 Accessory Electric Equipment									28.40	14.61	-19.3	-19.3
316.00 Misc. Power Plant Equipment									24.43	15.90	-21.7	-21.7
Total Four Corners									24.65	13.18	-18.3	-18.3
Four Corners Units 1-3												
311.00 Structures and Improvements	2016	75-S1.5		13.30		-20.0	2016	75-S1.5	17.39	11.39	-14.1	-14.1
312.00 Boiler Plant Equipment	2016	48-L2		12.70		-20.0	2016	48-L2	20.54	10.76	-14.8	-14.8
314.00 Turbogenerator Units	2016	65-R2		13.10		-20.0	2016	65-R2	22.47	11.08	-14.5	-14.5
315.00 Accessory Electric Equipment	2016	60-R2.5		13.20		-20.0	2016	60-R2.5	22.63	11.21	-14.3	-14.3
316.00 Misc. Power Plant Equipment	2016	40-R2		13.10		-20.0	2016	40-R2	15.43	11.15	-14.4	-14.4
Total Four Corners Units 1-3									20.42	10.90	-14.7	-14.7
Four Corners Units 4-5												
311.00 Structures and Improvements	2031	75-S1.5		26.80		-20.0	2031	75-S1.5	46.23	24.80	-26.8	-26.8
312.00 Boiler Plant Equipment	2031	48-L2		22.10		-20.0	2031	48-L2	39.09	20.40	-24.1	-24.1
314.00 Turbogenerator Units	2031	65-R2		26.30		-20.0	2031	65-R2	41.03	24.09	-26.4	-26.4

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	Present Parameters						Proposed Parameters (at December 31, 2004)					
Account Description	P-Life/ AYFR	Curve Shape	BG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	BG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
315.00 Accessory Electric Equipment	2031	60-R2.5		25.90		-20.0	2031	60-R2.5	41.33	24.24	-26.4	-26.4
316.00 Misc. Power Plant Equipment	2031	40-R2		23.00		-20.0	2031	40-R2	34.60	20.22	-23.8	-23.8
Total Four Corners Units 4-5									39.69	21.23	-24.6	-24.6
Four Corners Common												
311.00 Structures and Improvements	2031	75-S1.5		26.80		-20.0	2031	75-S1.5	41.05	24.71	-29.0	-29.0
312.00 Boiler Plant Equipment	2031	48-L2		22.80		-20.0	2031	48-L2	39.30	19.62	-25.3	-25.3
314.00 Turbogenerator Units	2031	65-R2		23.30		-20.0	2031	65-R2	59.40	21.73	-26.4	-26.4
315.00 Accessory Electric Equipment	2031	60-R2.5		21.00		-20.0	2031	60-R2.5	54.63	20.44	-25.2	-25.2
316.00 Misc. Power Plant Equipment	2031	40-R2		23.20		-20.0	2031	40-R2	34.10	21.37	-25.8	-25.8
Total Four Corners Common									39.77	21.73	-26.4	-26.4
Navajo Units 1-3												
311.00 Structures and Improvements	2026	75-S1.5		22.80		-20.0	2026	75-S1.5	33.75	20.78	-14.5	-14.5
312.00 Boiler Plant Equipment	2026	48-L2		20.60		-20.0	2026	48-L2	31.58	18.52	-15.8	-15.8
314.00 Turbogenerator Units	2026	65-R2		22.00		-20.0	2026	65-R2	39.90	20.00	-14.9	-14.9
315.00 Accessory Electric Equipment	2026	60-R2.5		22.00		-20.0	2026	60-R2.5	39.00	19.88	-15.1	-15.1
316.00 Misc. Power Plant Equipment	2026	40-R2		20.20		-20.0	2026	40-R2	28.56	18.57	-15.9	-15.9
Total Navajo Units 1-3									32.83	19.00	-15.5	-15.5
Ocotillo Units 1-2												
311.00 Structures and Improvements	2020	75-S1.5		17.10		-20.0	2020	75-S1.5	28.91	15.05	-37.9	-37.9
312.00 Boiler Plant Equipment	2020	48-L2		15.20		-20.0	2020	48-L2	35.07	12.89	-32.9	-32.9
314.00 Turbogenerator Units	2020	65-R2		16.80		-20.0	2020	65-R2	38.36	14.30	-36.1	-36.1
315.00 Accessory Electric Equipment	2020	60-R2.5		16.30		-20.0	2020	60-R2.5	36.37	13.90	-35.0	-35.0
316.00 Misc. Power Plant Equipment	2020	40-R2		16.20		-20.0	2020	40-R2	19.12	14.61	-36.8	-36.8
Total Ocotillo Units 1-2									32.66	13.77	-34.7	-34.7
Saguaro Units 1-2												
311.00 Structures and Improvements	2014	75-S1.5		11.30		-20.0	2014	75-S1.5	22.37	9.28	-29.0	-29.0
312.00 Boiler Plant Equipment	2014	48-L2		11.10		-20.0	2014	48-L2	24.15	8.61	-27.8	-27.8
314.00 Turbogenerator Units	2014	65-R2		11.20		-20.0	2014	65-R2	29.34	9.15	-28.8	-28.8

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	Present Parameters						Proposed Parameters (at December 31, 2004)					
Account Description	P-Life/ AYFR	Curve Shape	BG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	BG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
315.00 Accessory Electric Equipment	2014	60-R2.5		11.20		-20.0	2014	60-R2.5	31.94	8.99	-28.5	-28.5
316.00 Misc. Power Plant Equipment	2014	40-R2		10.90		-20.0	2014	40-R2	16.13	8.96	-28.4	-28.4
Total Saguaro Units 1-2									25.04	8.87	-28.3	-28.3
NUCLEAR PRODUCTION (BY UNIT)												
Palo Verde												
321.00 Structures and Improvements									36.73	20.63		
322.00 Reactor Plant Equipment									34.10	19.58	-0.2	-0.2
322.10 Steam Generators									17.47	1.71		
323.00 Turbogenerator Units									33.80	19.08	-0.4	-0.4
324.00 Accessory Electric Equipment									35.60	18.99	-0.5	-0.5
325.00 Misc. Power Plant Equipment									29.00	17.27	-0.8	-0.8
Total Palo Verde									33.82	18.78	-0.2	-0.2
Palo Verde Unit 1												
321.00 Structures and Improvements	2024	65-R2.5		21.20			2024	65-R2.5	36.38	18.78		
322.00 Reactor Plant Equipment	2024	70-R1		20.60		-2.0	2024	70-R1	34.79	18.37	-0.2	-0.2
322.10 Steam Generators	2005	25-SQ		3.00		-17.0	2005	25-SQ	17.21	1.00		
323.00 Turbogenerator Units	2024	60-S0		19.90		-2.0	2024	60-S0	33.87	17.81	-0.4	-0.4
324.00 Accessory Electric Equipment	2024	45-R3		20.00		-2.0	2024	45-R3	35.49	17.80	-0.4	-0.4
325.00 Misc. Power Plant Equipment	2024	35-R0.5		17.70		-2.0	2024	35-R0.5	29.54	15.87	-0.8	-0.8
Total Palo Verde Unit 1									33.64	17.85	-0.2	-0.2
Palo Verde Unit 2												
321.00 Structures and Improvements	2025	65-R2.5		22.00			2025	65-R2.5	36.76	19.70		
322.00 Reactor Plant Equipment	2025	70-R1		21.50		-2.0	2025	70-R1	31.22	19.32	-0.2	-0.2
322.10 Steam Generators	2003	25-SQ		1.00		-17.0						
323.00 Turbogenerator Units	2025	60-S0		20.80		-2.0	2025	60-S0	32.19	18.74	-0.4	-0.4
324.00 Accessory Electric Equipment	2025	45-R3		20.90		-2.0	2025	45-R3	35.26	18.71	-0.5	-0.5
325.00 Misc. Power Plant Equipment	2025	35-R0.5		18.70		-2.0	2025	35-R0.5	27.79	16.82	-0.7	-0.7
Total Palo Verde Unit 2									32.49	19.06	-0.3	-0.3

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	Present Parameters						Proposed Parameters (at December 31, 2004)					
Account Description	P-Life/ AYFR	Curve Shape	BG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	BG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
Palo Verde Unit 3												
321.00 Structures and Improvements	2027	65-R2.5		23.30			2027	65-R2.5	37.35	21.58		
322.00 Reactor Plant Equipment	2027	70-R1		22.60		-2.0	2027	70-R1	35.55	21.03	-0.3	-0.3
322.10 Steam Generators	2007	25-SQ		5.00		-17.0	2007	25-SQ	17.75	2.50		
323.00 Turbogenerator Units	2027	60-S0		21.80		-2.0	2027	60-S0	34.71	20.33	-0.4	-0.4
324.00 Accessory Electric Equipment	2027	45-R3		22.10		-2.0	2027	45-R3	36.02	20.40	-0.5	-0.5
325.00 Misc. Power Plant Equipment	2027	35-R0.5		19.20		-2.0	2027	35-R0.5	29.86	17.88	-0.8	-0.8
Total Palo Verde Unit 3									34.42	20.13	-0.3	-0.3
Palo Verde Water Reclamation												
321.00 Structures and Improvements	2027	65-R2.5		23.20			2027	65-R2.5	36.85	21.55		
322.00 Reactor Plant Equipment	2027	70-R1		23.00		-2.0	2027	70-R1	24.51	21.36	-0.2	-0.2
322.10 Steam Generators												
323.00 Turbogenerator Units	2027	60-S0		22.00		-2.0	2027	60-S0	32.19	20.51	-0.4	-0.4
324.00 Accessory Electric Equipment												
325.00 *Misc. Power Plant Equipment*	2027	35-R0.5		19.50		-2.0	2027	35-R0.5	28.73	18.15	-0.8	-0.8
Total Palo Verde Water Reclamation									36.81	21.53		0.0
Palo Verde Common												
321.00 Structures and Improvements	2027	65-R2.5		23.20			2027	65-R2.5	36.16	21.59		
322.00 Reactor Plant Equipment	2027	70-R1		22.60		-2.0	2027	70-R1	34.65	21.05	-0.3	-0.3
322.10 Steam Generators												
323.00 Turbogenerator Units	2027	60-S0		22.20		-2.0	2027	60-S0	30.79	20.63	-0.4	-0.4
324.00 *Accessory Electric Equipment*	2027	45-R3		22.00		-2.0	2027	45-R3	35.21	20.36	-0.5	-0.5
325.00 Misc. Power Plant Equipment	2027	35-R0.5		19.40		-2.0	2027	35-R0.5	28.90	18.04	-0.8	-0.8
Total Palo Verde Common									33.80	20.40	-0.3	-0.3
OTHER PRODUCTION (BY UNIT)												
Douglas CT												
341.00 Structures and Improvements	2017	80-S1		13.90		-5.0	2017	80-S1	43.20	12.01	-5.0	-5.0
342.00 Fuel Holders, Products and Accessories	2017	70-S1		14.00		-5.0	2017	70-S1	30.67	12.08	-5.0	-5.0
343.00 Prime Movers	2017	70-L1.5		14.20			2017	70-L1.5	42.22	11.65		
344.00 Generators and Devices	2017	37-R3		9.70			2017	37-R3	38.41	8.41		

ARIZONA PUBLIC SERVICE COMPANY
Present and Proposed Parameters
Company Broad Group Procedure

Statement G

Account Description	Present Parameters						Proposed Parameters (at December 31, 2004)					
	P-Life/ AYFR	Curve Shape	BG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	BG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
345.00 Accessory Electric Equipment	2017	50-S2		13.10			2017	50-S2	38.35	11.06		
346.00 Misc. Power Plant Equipment	2017	70-L1		13.80			2017	70-L1	30.86	11.86		
Total Douglas CT									39.39	11.44	-0.3	-0.3
Ocotillo CT Units 1-2												
341.00 Structures and Improvements	2017	80-S1		14.50		-5.0	2017	80-S1	29.06	12.12	-5.0	-5.0
342.00 Fuel Holders, Products and Accessories	2017	70-S1		14.00		-5.0	2017	70-S1	30.34	12.11	-5.0	-5.0
343.00 Prime Movers	2017	70-L1.5		14.10			2017	70-L1.5	36.89	11.73		
344.00 Generators and Devices	2017	37-R3		13.60			2017	37-R3	23.11	11.60		
345.00 Accessory Electric Equipment	2017	50-S2		13.20			2017	50-S2	33.05	11.29		
346.00 Misc. Power Plant Equipment	2017	70-L1		14.00			2017	70-L1	31.41	11.81		
Total Ocotillo CT Units 1-2									29.06	11.66	-0.4	-0.4
Saguaro CT Units 1-2												
341.00 Structures and Improvements	2017	80-S1		14.40		-5.0	2017	80-S1	18.86	12.34	-5.0	-5.0
342.00 Fuel Holders, Products and Accessories	2017	70-S1		14.00		-5.0	2017	70-S1	33.51	12.00	-5.0	-5.0
343.00 Prime Movers	2017	70-L1.5		13.80			2017	70-L1.5	36.07	11.77		
344.00 Generators and Devices	2017	37-R3		13.00			2017	37-R3	21.21	10.88		
345.00 Accessory Electric Equipment	2017	50-S2		13.40			2017	50-S2	36.19	11.28		
346.00 Misc. Power Plant Equipment	2017	70-L1		14.10			2017	70-L1	23.02	12.00		
Total Saguaro CT Units 1-2									28.43	11.56	-0.8	-0.8
Solar Units												
341.00 Structures and Improvements	12.00	SQ		3.60			12	SQ	12.00	2.03		
342.00 Fuel Holders, Products and Accessories												
343.00 Prime Movers							12	SQ	12.00	11.50		
344.00 Generators and Devices	12.00	SQ		7.80			12	SQ	12.00	7.56		
345.00 Accessory Electric Equipment	12.00	SQ		9.90			12	SQ	12.00	7.86		
346.00 Misc. Power Plant Equipment												
Total Solar Units									12.00	7.82		
West Phoenix												
341.00 Structures and Improvements									36.76	24.31	-5.0	-5.0
342.00 Fuel Holders, Products and Accessories									31.14	24.77	-5.0	-5.0

ARIZONA PUBLIC SERVICE COMPANY
Present and Proposed Parameters
Company Broad Group Procedure

Statement G

	Present Parameters						Proposed Parameters (at December 31, 2004)					
Account Description	P-Life/ AYFR	Curve Shape	BG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	BG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
343.00 Prime Movers									29.19	11.86		
344.00 Generators and Devices									29.08	23.01	-1.9	-1.9
345.00 Accessory Electric Equipment									32.22	23.25		
346.00 Misc. Power Plant Equipment									31.01	20.03		
Total West Pheonix									30.09	22.53	-2.2	-2.2
West Phoenix CT Units 1-2												
341.00 Structures and Improvements	2017	80-S1		14.20		-5.0	2017	80-S1	36.23	12.12	-5.0	-5.0
342.00 Fuel Holders, Products and Accessories	2017	70-S1		14.00		-5.0	2017	70-S1	33.49	12.03	-5.0	-5.0
343.00 Prime Movers	2017	70-L1.5		14.20			2017	70-L1.5	29.19	11.86		
344.00 Generators and Devices	2017	37-R3		12.30			2017	37-R3	24.60	10.75		
345.00 Accessory Electric Equipment	2017	50-S2		13.20			2017	50-S2	35.71	11.27		
346.00 Misc. Power Plant Equipment	2017	70-L1		14.10			2017	70-L1	22.91	12.02		
Total West Ploenix CT Units 1-2									28.26	11.49	-0.5	-0.5
West Phoenix CC Units 1-3												
341.00 Structures and Improvements	2031	80-S1		28.10		-5.0	2031	80-S1	36.80	25.21	-5.0	-5.0
342.00 Fuel Holders, Products and Accessories	2031	70-S1		27.70		-5.0	2031	70-S1	30.98	25.65	-5.0	-5.0
343.00 Prime Movers												
344.00 Generators and Devices	2031	37-R3		26.20		-2.0	2031	37-R3	29.42	23.95	-2.0	-2.0
345.00 Accessory Electric Equipment	2031	50-S2		27.80			2031	50-S2	31.83	24.59		
346.00 Misc. Power Plant Equipment	2031	70-L1		26.60			2031	70-L1	35.30	24.26		
Total West Phoenix CC Units 1-3									30.39	24.35	-2.4	-2.4
Yucca CT Units 1-4												
341.00 Structures and Improvements	2016	80-S1		13.40		-5.0	2016	80-S1	20.94	11.35	-5.0	-5.0
342.00 Fuel Holders, Products and Accessories	2016	70-S1		12.90		-5.0	2016	70-S1	37.68	11.00	-5.0	-5.0
343.00 Prime Movers	2016	70-L1.5		14.20			2016	70-L1.5	40.60	10.81		
344.00 Generators and Devices	2016	37-R3		11.60			2016	37-R3	29.06	9.09		
345.00 Accessory Electric Equipment	2016	50-S2		13.00			2016	50-S2	32.93	10.37		
346.00 Misc. Power Plant Equipment	2016	70-L1		13.20			2016	70-L1	29.59	10.90		
Total Yucca CT Units 1-4									34.47	10.24	-0.9	-0.9

Attachment REW–2

2005 Technical Update

PWEC Units Acquired by Arizona Public Service Company

Prepared by
Foster Associates, Inc.

CONTENTS

EXECUTIVE SUMMARY

INTRODUCTION

This report presents the findings and recommendations developed in a 2005 Technical Update of depreciation rates prepared by Foster Associates, Inc., for certain Pinnacle West Energy Corporation generating units (PWEC Units) acquired by Arizona Public Service Company. Parameters (*i.e.*, projection curves, projection lives and future net salvage rates) used in the update were accepted by the Arizona Corporation Commission (ACC) pursuant to a settlement agreement in Docket No. E–01345A–03–0437 (Decision No. 67744, dated April 7, 2005). Age distributions of surviving plant at December 31, 2004 were used in the 2005 update to derive composite service life statistics and computed or theoretical depreciation reserves.

Foster Associates is a public utility economic consulting firm headquartered in Bethesda, Maryland offering economic research and consulting services on issues and problems arising from governmental regulation of business. Areas of specialization supported by our Fort Myers office include property service–life forecasting, depreciation estimation, and valuation of industrial property.

Foster Associates has undertaken numerous depreciation engagements for both public and privately owned business entities, including detailed statistical life studies, analyses of required net salvage rates, and the selection of depreciation systems that will most nearly achieve the goals of depreciation accounting under the constraints of either government regulation or competitive market pricing. Foster Associates is widely recognized for industry leadership in the development of depreciation systems, life analysis techniques and computer software for conducting depreciation and valuation studies.

The purpose of a technical update is to adjust depreciation rates for changes in the variables associated with a remaining–life accrual rate. The variables for a plant account include the age distribution of surviving plant, the recorded depreciation reserve and the average net salvage rate used in the calculation of a theoretical reserve. A technical update retains the parameters developed and/or approved in the most recent full depreciation study and adjusts depreciation rates for subsequent changes in plant, reserves and realized net salvage activity.

The principal findings from the 2005 review are summarized in the attached statements. Statement A provides a comparative summary of present and proposed annual depreciation rates for each rate category. Statement B provides a comparison of present and proposed annual depreciation accruals. Statement C provides a comparison of the computed and redistributed depreciation reserve for each rate category. Statement D provides a summary of the components used to obtain a weighted–average net salvage rate for each plant account. Statement E provides a comparative summary of present and proposed parameters and statistics including projection life, projection curve, average service life, average remaining life, and average and future net salvage rates.

SCOPE OF STUDY

Unlike a full depreciation study in which service life and net salvage parameters are estimated from a blending of quantitative analyses and informed judgment, the current study retains the parameters accepted in Docket No. E–01345A–03–0437 and provides an update of depreciation rates based on account age distributions and reserve balances at December 31, 2004.

The principal activities undertaken in the course of conducting the 2005 Technical Update included:

- Collection of plant data;
- Reconciliation of data to the official records of the Company;
- Rebalancing of depreciation reserves; and
- Development of adjusted accrual rates for each rate category.

DEPRECIATION SYSTEM

A depreciation rate is formed by combining the elements of a depreciation system. A depreciation system is composed of a method, a procedure and a technique. A depreciation method (*e.g.*, straight–line) describes the component of the system that determines the acceleration or deceleration of depreciation accruals in relation to either time or use. A depreciation procedure (*e.g.*, vintage group) identifies the level of grouping or sub–grouping of assets within a plant category. The level of grouping dictates the weighting used to obtain composite life statistics for an account. A depreciation technique (*e.g.*, remaining–life) describes the life statistic used in the system.

The depreciation system currently used for PWEC Units is composed of the straight–line method, broad group procedure, and remaining–life technique for all plant categories. The present system was accepted by the ACC in Docket No. E–01345A–03–0437 without comment as to the appropriateness of the system or a consideration of alternative systems. Accordingly, depreciation rates in the 2005 update were developed using the currently approved system.

PROPOSED DEPRECIATION RATES

Table 1 provides a summary of the changes in annual rates and accruals resulting from the 2005 Technical Update. Rates proposed for each primary account include an allowance for net salvage.

Function	Accrual Rate			2005 Annualized Accrual		
	Present	Proposed	Difference	Present	Proposed	Difference
A	B	C	D=C-B	E	F	G=F-E
Production	2.92%	2.71%	-0.21%	$28,002,769	$26,066,384	($1,936,385)
Transmission	1.83%	1.73%	-0.10%	787,163	742,858	(44,305)
Total Utility	*2.87%*	*2.67%*	*-0.20%*	*$28,789,932*	*$26,809,242*	*($1,980,690)*

Table 1. Present and Proposed Rates and Accruals

Adjustments developed in the technical update produce a composite depreciation rate of 2.67 percent. Depreciation expense is presently accrued at an equivalent rate of 2.87 percent. The proposed change in the composite depreciation rate represents a reduction of 0.20 percentage points.

A continued application of rates currently approved would provide annual depreciation expense of $28,789,932 compared with an annual expense of $26,809,242 using the rates developed in the update. The proposed expense decrease of $1,980,690 is largely attributable to: a) a change in the mix of plant investments among primary accounts; b) changes in the age distributions of surviving plant; and c) the estimation of parameters for West Phoenix Unit 5.

Study Procedure

Introduction

Unlike a full depreciation study in which projection curves, projection lives and future net salvage rates are estimated from a statistical analysis of recorded retirements and net salvage realized in the past, a technical update generally retains the parameters currently used by the utility and adjusts depreciation rates for known and measurable changes in the age distributions of surviving plant, depreciation reserves, and average net salvage rates due to the passage of time. A technical update is intended to align depreciation rates with the accounting year the rates will become effective.

Scope

The steps involved in preparing a technical update can be grouped into five principal activities:

- Data collection;
- Calculation of service life statistics;
- Computation of average net salvage rates;
- Rebalancing of depreciation reserves; and
- Development of accrual rates.

The scope of the 2005 update for PWEC Units included a consideration of each of these tasks as described below.

Data Collection

The database used in the 2005 update was provided to Foster Associates in an electronic format containing plant and reserve activity over the period 2001–2004 and age distributions of surviving plant at December 31, 2004. Data used in the update were limited to the age distributions of surviving plant. Depreciation rates currently used by for PWEC Units were developed using a broad–group procedure. The realized life of surviving vintages derived from the dollar–years of service provided by each vintage is not relevant to an update of broad–group depreciation rates. Therefore, plant transactions recorded in prior activity years were not used in the update.

Reserve transactions recorded in prior activity years were also not used in the 2005 update. Depreciation rates currently used for PWEC Units were derived without consideration of the distinction between average and future net salvage rates. The assumed equivalency between average and future net salvage rates was retained in the 2005 update without introducing prior realized net salvage amounts in the computation of average net salvage rates.

Calculation of Service Life Statistics

The composite remaining life and average service life of a plant category used in the calculation of depreciation rates are derived from a tabular arrangement of the age distribution of surviving plant and related statistics. The format of such a table is called a *generation arrangement.*

The age distribution of surviving plant is a column of numbers showing the dollar amount of investment remaining in service at the beginning of a study year from each of the vintages installed in prior years. The sum of an age distribution is the total plant in service for a plant category. The source of data used to construct an age distribution is a company's Continuing Property Record (CPR).

Statistics for each vintage (*i.e.*, average service life and remaining life) contained in a generation arrangement are derived from a mathematical function called a *survivor curve*. The survivor curve most descriptive of the forces of retirement acting upon a plant category is identified from a statistical analysis of past retirement experience, coupled with a consideration of how these forces are likely to change in the future. The collection of past retirements used in the statistical analysis can be viewed as a random sample from an unknown parent population. The objective of a life analysis is to estimate the parameters (*i.e.*, mean service life and dispersion characteristics) of the parent population. The mean service life of the population which best describes the timing of past and future retirements is called a *projection life* and the survivor curve selected to describe the forces of retirement acting upon the population is called a *projection curve*. A technical update generally retains the service life parameters estimated in a full depreciation study. Statistics for each vintage, however, are updated to reflect known and measurable changes in the age distributions of surviving plant.

Computation of Average Net Salvage Rates

Estimates of net salvage rates applicable to future retirements are derived in a full depreciation study from an analysis of gross salvage and removal expense realized in the past and a consideration of future expectations that may dictate a departure from historical indications. Future net salvage rates adopted from such an analysis are retained as fixed parameters in a technical update.

The average net salvage rate for an account or plant function is derived from a direct dollar weighting of a) historical retirements with historical (or realized) net salvage rates and b) future retirements (*i.e.*, surviving plant) with the estimated future net salvage rate. Average net salvage rates will change, therefore, as additional years of retirement and net salvage activity become available and as subsequent plant additions alter the weighting of future net salvage estimates.

As noted earlier, Depreciation rates currently used by PWEC were derived without consideration of the distinction between average and future net salvage rates. The assumed equivalency between average and future net salvage rates was retained in the 2005 update without introducing prior realized net salvage amounts in the computation of average net salvage rates. The retained equivalency of average and future net salvage rates is shown in Statement D.

REBALANCING OF DEPRECIATION RESERVES

Although reserve records are typically maintained by various account classifications, the total reserve for a company is the most important measure of the status of the company's depreciation practices and procedures. If a company has not previously conducted statistical life studies or considered retirement dispersion in setting depreciation rates, it is likely that some accounts will be overdepreciated and other accounts will be underdepreciated relative to a calculated theoretical reserve. Differences between theoretical and recorded reserves will also arise as a normal occurrence when service lives, dispersion patterns and net salvage estimates are changed in the course of depreciation reviews. It is appropriate, therefore, and consistent with group depreciation theory to periodically redistribute recorded reserves among the various primary accounts based upon the most recent estimates of retirement dispersion and net salvage rates.

A rebalancing of recorded reserves is consistent with the objectives of a technical update and is considered appropriate for PWEC Units. Depreciation rates adopted in Docket No. E–01345A–03–0437 were derived from rebalanced reserves obtained from a set of parameters different from those used in the formulation of the settled remaining–life accrual rates. Reserve imbalances amortized in the settled rates are therefore inconsistent with the realigned depreciation reserves. The rebalancing of reserves undertaken in the 2005 update will reestablish consistency between measured reserve imbalances and the parameters used in the formulation of updated remaining–life accrual rates.

A redistribution of the recorded reserve was achieved for PWEC Units by multiplying the calculated reserve for each primary account within a function (or plant location) by the ratio of the function (or location) total recorded reserve to the function (or location) total calculated reserve. The sum of the redistributed reserves within a function (or location) is, therefore, equal to the function (or location) total recorded depreciation reserve before the redistribution.

Statement C provides a comparison of the recorded, computed and rebalanced reserves for PWEC at December 31, 2004. The recorded reserve was $87,128,993, or 8.7 percent of the depreciable plant investment. The corresponding computed reserve is $33,816,272 or 3.4 percent of the depreciable plant investment. A proportionate amount of the measured reserve excess of $53,312,721 will be amortized over the composite weighted–average remaining life of each rate category.

Development of Accrual Rates

The goal or objective of depreciation accounting is cost allocation over the economic life of an asset in proportion to the consumption of service potential. Ideally, the cost of an asset—which represents the cost of obtaining a bundle of service units—should be allocated to future periods of operation in proportion to the amount of service potential expended during an accounting interval. The service potential of an asset is the present value of future net revenue (*i.e.*, revenue less expenses exclusive of depreciation and other non-cash expenses) or cash inflows attributable to the use of that asset alone.

Depreciation rates currently used for PWEC Units were developed using a system composed of the straight–line method, broad–group procedure, remaining–life technique. Depreciation rates proposed in the update were developed using the currently approved system.

STATEMENTS

INTRODUCTION

This section provides a comparative summary of depreciation rates, annual depreciation accruals, recorded and computed depreciation reserves, and present and proposed service life and net salvage parameters for PWEC Units. The content of these statements is briefly described below.

- Statement A provides a comparative summary of present and proposed annual depreciation rates for calendar year 2005 using the straight–line method, broad group procedure, remaining–life technique.
- Statement B provides a comparison of present and proposed annualized depreciation accruals for calendar year 2005 based upon the rates developed in Statement A.
- Statement C provides a comparison of recorded and computed reserves for each rate category and sets forth the computations used to redistribute recorded reserves among primary plant accounts.
- Statement D provides a summary of the components used to obtain a weighted average net salvage rate for each rate category.
- Statement E provides a comparative summary of present and proposed parameters including projection life, projection curve and future net salvage rates. The statement also contains present and proposed statistics including average service life, average remaining life, and average net salvage rates.

Present depreciation accruals shown on Statement B are the product of plant investments (Column B) and the present depreciation rates (Column D) shown on Statement A. These are the effective rates used for PWEC Units for the mix of investments recorded on December 31, 2004. Similarly, proposed depreciation accruals shown on Statement B are the product of plant investments and proposed depreciation rates (Column H) shown on Statement A. Proposed accrual rates shown on Statement A are given by:

$$\textit{Accrual Rate} = \frac{1.0 - \textit{Reserve Ratio} - \textit{Future Net Salvage Rate}}{\textit{Remaining Life}}.$$

PWEC UNITS Statement A

Comparison of Present and Proposed Accrual Rates
Present: BG Procedure / RL Technique
Proposed: BG Procedure / RL Technique

	Present			Proposed (at December 31, 2004)			
Account Description	Rem. Life	Net Salvage	Accrual Rate	Rem. Life	Net Salvage	Reserve Ratio	Accrual Rate
A	B	C	D	E	F	G	H
OTHER PRODUCTION							
341.00 Structures and Improvements			2.89%	35.00	-3.8%	8.76%	2.72%
342.00 Fuel Holders, Products and Accessories			2.14%	46.34	-5.0%	12.74%	1.99%
343.00 Prime Movers			2.86%	35.22	-2.6%	8.90%	2.66%
344.00 Generators and Devices			2.96%	34.04	-2.4%	8.60%	2.76%
345.00 Accessory Electric Equipment			2.98%	34.11	-3.7%	8.37%	2.80%
346.00 Misc. Power Plant Equipment			2.14%	46.63	-5.0%	9.28%	2.05%
Total Other Production Plant			2.92%	34.60	-2.6%	8.74%	2.71%
TRANSMISSION							
353.00 Station Equipment			1.80%	55.02		7.18%	1.68%
355.00 Poles and Fixtures - Wood			2.08%	45.95	-15.0%	10.21%	2.28%
356.00 Overhead Conductors and Devices			2.45%	52.54	-35.0%	12.55%	2.33%
Total Transmission Plant			1.83%	54.56	-1.7%	7.47%	1.73%
TOTAL UTILITY			2.87%	35.15	-25.0%	8.68%	2.67%
OTHER PRODUCTION (BY UNIT)							
Redhawk CC Units 1-2							
341.00 Structures and Improvements	34.03	-3.0%	2.95%	33.94	-3.0%	9.75%	2.75%
342.00 Fuel Holders, Products and Accessories							
343.00 Prime Movers	34.03	-3.0%	2.95%	33.94	-3.0%	9.75%	2.75%
344.00 Generators and Devices	34.03	-3.0%	2.95%	33.94	-3.0%	9.75%	2.75%
345.00 Accessory Electric Equipment	34.03	-3.0%	2.95%	33.94	-3.0%	9.75%	2.75%
346.00 Misc. Power Plant Equipment							
Total Redhawk CC Units 1-2			2.95%	33.91	-3.0%	9.75%	2.75%
Saguaro CT Unit 3							
341.00 Structures and Improvements							
342.00 Fuel Holders, Products and Accessories							
343.00 Prime Movers	35.49		2.81%	33.54		8.86%	2.72%
344.00 Generators and Devices	35.49		2.81%	33.54		8.86%	2.72%
345.00 Accessory Electric Equipment	35.49		2.81%	33.54		8.86%	2.72%
346.00 Misc. Power Plant Equipment							
Total Saguaro CT Unit 3			2.81%	33.51		8.86%	2.72%
West Phoenix							
341.00 Structures and Improvements			2.82%	36.57	-5.0%	7.40%	2.67%
342.00 Fuel Holders, Products and Accessories			2.14%	46.34	-5.0%	12.74%	1.99%
343.00 Prime Movers			2.75%	36.98	-2.0%	7.84%	2.55%
344.00 Generators and Devices			3.02%	34.30	-2.0%	6.69%	2.78%
345.00 Accessory Electric Equipment			3.03%	34.41	-5.0%	5.92%	2.88%
346.00 Misc. Power Plant Equipment			2.14%	46.63	-5.0%	9.28%	2.05%
Total West Pheonix			2.88%	35.69	-2.3%	7.29%	2.66%
West Phoenix CC Unit 4							
341.00 Structures and Improvements	49.71	-5.0%	2.08%	47.72	-5.0%	12.46%	1.94%
342.00 Fuel Holders, Products and Accessories	48.32	-5.0%	2.14%	46.34	-5.0%	12.74%	1.99%
343.00 Prime Movers	46.94	-2.0%	2.14%	45.03	-2.0%	12.47%	1.99%
344.00 Generators and Devices	35.47	-2.0%	2.87%	33.60	-2.0%	16.10%	2.56%
345.00 Accessory Electric Equipment	48.32	-5.0%	2.14%	47.20	-5.0%	1.91%	2.18%
346.00 Misc. Power Plant Equipment	48.32	-5.0%	2.14%	46.63	-5.0%	9.28%	2.05%
Total West Ploenix CC Unit 4			2.28%	42.48	-2.3%	13.18%	2.10%

PWEC UNITS Statement A

Comparison of Present and Proposed Accrual Rates
Present: BG Procedure / RL Technique
Proposed: BG Procedure / RL Technique

	Present			Proposed (at December 31, 2004)			
Account Description	Rem. Life	Net Salvage	Accrual Rate	Rem. Life	Net Salvage	Reserve Ratio	Accrual Rate
A	B	C	D	E	F	G	H
West Phoenix CC Unit 5							
341.00 Structures and Improvements			3.03%	34.37	-5.0%	5.94%	2.88%
342.00 Fuel Holders, Products and Accessories							
343.00 Prime Movers			3.03%	34.37	-2.0%	5.77%	2.80%
344.00 Generators and Devices			3.03%	34.37	-2.0%	5.77%	2.80%
345.00 Accessory Electric Equipment			3.03%	34.37	-5.0%	5.94%	2.88%
346.00 Misc. Power Plant Equipment							
Total West Phoenix CC Unit 5			3.03%	34.37	-2.3%	5.78%	2.81%
TRANSMISSION (BY UNIT)							
Redhawk CC Units 1-2							
353.00 Station Equipment	56.59		1.75%	54.95		7.47%	1.68%
355.00 Poles and Fixtures - Wood	54.50	-15.0%	2.08%	45.95	-15.0%	10.21%	2.28%
356.00 Overhead Conductors and Devices	54.50	-35.0%	2.45%	52.54	-35.0%	12.55%	2.33%
Total Redhawk CC Units 1-2			1.80%	54.39	-2.2%	7.82%	1.74%
Saguaro CT Unit 3							
353.00 Station Equipment	35.49		2.81%	54.95		8.25%	1.67%
355.00 Poles and Fixtures - Wood							
356.00 Overhead Conductors and Devices							
Total Saguaro CT Unit 3			2.81%	54.94		8.25%	1.67%
West Phoenix							
353.00 Station Equipment			1.74%	55.35		5.71%	1.70%
355.00 Poles and Fixtures - Wood							
356.00 Overhead Conductors and Devices							
Total West Pheonix			1.74%	55.35		5.71%	1.70%
West Phoenix CC Unit 4							
353.00 Station Equipment	55.77		1.73%	54.14		10.84%	1.65%
355.00 Poles and Fixtures - Wood							
356.00 Overhead Conductors and Devices							
Total West Ploenix CC Unit 4			1.73%	54.04		10.84%	1.65%
West Phoenix CC Unit 5							
353.00 Station Equipment	56.59		1.75%	55.77		3.91%	1.72%
355.00 Poles and Fixtures - Wood							
356.00 Overhead Conductors and Devices							
Total West Phoenix CC Unit 5			1.75%	55.87		3.91%	1.72%

PWEC UNITS Statement B

Comparison of Present and Proposed Accruals

Present: BG Procedure / RL Technique

Proposed: BG Procedure / RL Technique

Account Description	12/31/04 Plant Investment	2005 Annualized Accrual Present	Proposed	Difference
A	B	C	D	E=D-C
OTHER PRODUCTION				
341.00 Structures and Improvements	$40,104,209	$1,160,733	$1,089,316	($71,417)
342.00 Fuel Holders, Products and Accessories	4,135,109	88,491	82,289	(6,202)
343.00 Prime Movers	399,447,583	11,437,064	10,629,666	(807,398)
344.00 Generators and Devices	476,614,814	14,123,897	13,145,180	(978,717)
345.00 Accessory Electric Equipment	40,055,435	1,192,405	1,119,761	(72,644)
346.00 Misc. Power Plant Equipment	8,374	179	172	(7)
Total Other Production Plant	$960,365,524	$28,002,769	$26,066,384	($1,936,385)
TRANSMISSION				
353.00 Station Equipment	$40,015,163	$719,213	$673,708	($45,505)
355.00 Poles and Fixtures - Wood	1,500,000	31,200	34,200	3,000
356.00 Overhead Conductors and Devices	1,500,000	36,750	34,950	(1,800)
Total Transmission Plant	$43,015,163	$787,163	$742,858	($44,305)
TOTAL UTILITY	$1,003,380,687	$28,789,932	$26,809,242	($1,980,690)
OTHER PRODUCTION (BY UNIT)				
Redhawk CC Units 1-2				
341.00 Structures and Improvements	$23,274,636	$686,602	$640,052	($46,550)
342.00 Fuel Holders, Products and Accessories				
343.00 Prime Movers	221,481,610	6,533,707	6,090,744	(442,963)
344.00 Generators and Devices	273,599,371	8,071,181	7,523,983	(547,198)
345.00 Accessory Electric Equipment	25,524,567	752,975	701,926	(51,049)
346.00 Misc. Power Plant Equipment				
Total Redhawk CC Units 1-2	$543,880,184	$16,044,465	$14,956,705	($1,087,760)
Saguaro CT Unit 3				
341.00 Structures and Improvements				
342.00 Fuel Holders, Products and Accessories				
343.00 Prime Movers	775,091	21,780	21,082	(698)
344.00 Generators and Devices	33,896,968	952,505	921,998	(30,507)
345.00 Accessory Electric Equipment	148,212	4,165	4,031	(134)
346.00 Misc. Power Plant Equipment				
Total Saguaro CT Unit 3	$34,820,271	$978,450	$947,111	($31,339)
West Phoenix				
341.00 Structures and Improvements	$16,829,573	$474,131	$449,264	($24,867)
342.00 Fuel Holders, Products and Accessories	4,135,109	88,491	82,289	(6,202)
343.00 Prime Movers	177,190,882	4,881,577	4,517,840	(363,737)
344.00 Generators and Devices	169,118,475	5,100,211	4,699,199	(401,012)
345.00 Accessory Electric Equipment	14,382,656	435,265	413,804	(21,461)
346.00 Misc. Power Plant Equipment	8,374	179	172	(7)
Total West Pheonix	$381,665,069	$10,979,854	$10,162,568	($817,286)
West Phoenix CC Unit 4				
341.00 Structures and Improvements	$3,768,898	$78,393	$73,117	($5,276)
342.00 Fuel Holders, Products and Accessories	4,135,109	88,491	82,289	(6,202)
343.00 Prime Movers	54,753,590	1,171,727	1,089,596	(82,131)
344.00 Generators and Devices	15,049,070	431,908	385,256	(46,652)
345.00 Accessory Electric Equipment	59,412	1,271	1,295	24
346.00 Misc. Power Plant Equipment	8,374	179	172	(7)
Total West Ploenix CC Unit 4	$77,774,453	$1,771,969	$1,631,725	($140,244)

PWEC UNITS

Statement B

Comparison of Present and Proposed Accruals
Present: BG Procedure / RL Technique
Proposed: BG Procedure / RL Technique

Account Description	12/31/04 Plant Investment	2005 Annualized Accrual Present	Proposed	Difference
A	B	C	D	E=D-C
West Phoenix CC Unit 5				
341.00 Structures and Improvements	$13,060,675	$395,738	$376,147	($19,591)
342.00 Fuel Holders, Products and Accessories				
343.00 Prime Movers	122,437,292	3,709,850	3,428,244	(281,606)
344.00 Generators and Devices	154,069,405	4,668,303	4,313,943	(354,360)
345.00 Accessory Electric Equipment	14,323,244	433,994	412,509	(21,485)
346.00 Misc. Power Plant Equipment				
Total West Phoenix CC Unit 5	$303,890,616	$9,207,885	$8,530,843	($677,042)
TRANSMISSION (BY UNIT)				
Redhawk CC Units 1-2				
353.00 Station Equipment	$30,683,150	$536,955	$515,477	($21,478)
355.00 Poles and Fixtures - Wood	1,500,000	31,200	34,200	3,000
356.00 Overhead Conductors and Devices	1,500,000	36,750	34,950	(1,800)
Total Redhawk CC Units 1-2	$33,683,150	$604,905	$584,627	($20,278)
Saguaro CT Unit 3				
353.00 Station Equipment	$1,824,367	$51,265	$30,467	($20,798)
355.00 Poles and Fixtures - Wood				
356.00 Overhead Conductors and Devices				
Total Saguaro CT Unit 3	$1,824,367	$51,265	$30,467	($20,798)
West Phoenix				
353.00 Station Equipment	$7,507,646	$130,993	$127,764	($3,229)
355.00 Poles and Fixtures - Wood				
356.00 Overhead Conductors and Devices				
Total West Pheonix	$7,507,646	$130,993	$127,764	($3,229)
West Phoenix CC Unit 4				
353.00 Station Equipment	$1,953,105	$33,789	$32,226	($1,563)
355.00 Poles and Fixtures - Wood				
356.00 Overhead Conductors and Devices				
Total West Ploenix CC Unit 4	$1,953,105	$33,789	$32,226	($1,563)
West Phoenix CC Unit 5				
353.00 Station Equipment	$5,554,541	$97,204	$95,538	($1,666)
355.00 Poles and Fixtures - Wood				
356.00 Overhead Conductors and Devices				
Total West Phoenix CC Unit 5	$5,554,541	$97,204	$95,538	($1,666)

PWEC UNITS
Depreciation Reserve Summary
Company Broad Group Procedure
December 31, 2004

Statement C

Account Description	Plant Investment	Recorded Reserve 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
OTHER PRODUCTION							
341.00 Structures and Improvements	$40,104,209	$3,292,671	8.21%	$1,305,072	3.25%	$3,513,414	8.76%
342.00 Fuel Holders, Products and Accessories	4,135,109	536,579	12.98%	303,286	7.33%	526,716	12.74%
343.00 Prime Movers	399,447,583	35,949,342	9.00%	13,722,765	3.44%	35,543,746	8.90%
344.00 Generators and Devices	476,614,814	40,779,645	8.56%	15,788,049	3.31%	40,978,113	8.60%
345.00 Accessory Electric Equipment	40,055,435	3,356,149	8.38%	1,145,419	2.86%	3,352,291	8.37%
346.00 Misc. Power Plant Equipment	8,374	672	8.02%	447	5.34%	777	9.28%
Total Other Production Plant	$960,365,524	$83,915,057	8.74%	$32,265,039	3.36%	$83,915,057	8.74%
TRANSMISSION							
353.00 Station Equipment	$40,015,163	$3,010,030	7.52%	$1,386,989	3.47%	$2,872,587	7.18%
355.00 Poles and Fixtures - Wood	1,500,000	101,953	6.80%	73,672	4.91%	153,112	10.21%
356.00 Overhead Conductors and Devices	1,500,000	101,953	6.80%	90,573	6.04%	188,237	12.55%
Total Transmission Plant	$43,015,163	$3,213,936	7.47%	$1,551,234	3.61%	$3,213,936	7.47%
TOTAL UTILITY	$1,003,380,687	$87,128,993	8.68%	$33,816,272	3.37%	$87,128,993	8.68%
OTHER PRODUCTION (BY UNIT)							
Redhawk CC Units 1-2							
341.00 Structures and Improvements	$23,274,636	$2,045,863	8.79%	$772,437	3.32%	$2,268,143	9.75%
342.00 Fuel Holders, Products and Accessories							
343.00 Prime Movers	221,481,610	21,471,522	9.69%	7,350,512	3.32%	21,583,668	9.75%
344.00 Generators and Devices	273,599,371	26,977,169	9.86%	9,080,191	3.32%	26,662,611	9.75%
345.00 Accessory Electric Equipment	25,524,567	2,507,271	9.82%	847,107	3.32%	2,487,402	9.75%
346.00 Misc. Power Plant Equipment							
Total Redhawk CC Units 1-2	$543,880,184	$53,001,824	9.75%	$18,050,247	3.32%	$53,001,824	9.75%
Saguaro CT Unit 3							
341.00 Structures and Improvements							
342.00 Fuel Holders, Products and Accessories							
343.00 Prime Movers	775,091	68,682	8.86%	52,764	6.81%	68,682	8.86%
344.00 Generators and Devices	33,896,968	3,003,648	8.86%	2,307,518	6.81%	3,003,648	8.86%
345.00 Accessory Electric Equipment	148,212	13,133	8.86%	10,089	6.81%	13,133	8.86%
346.00 Misc. Power Plant Equipment							
Total Saguaro CT Unit 3	$34,820,271	$3,085,463	8.86%	$2,370,371	6.81%	$3,085,463	8.86%

PWEC UNITS
Depreciation Reserve Summary
Company Broad Group Procedure
December 31, 2004

Statement C

Account Description	Plant Investment	Recorded Reserve 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							
341.00 Structures and Improvements	$16,829,573	$1,246,808	7.41%	$532,636	3.16%	$1,245,271	7.40%
342.00 Fuel Holders, Products and Accessories	4,135,109	536,579	12.98%	303,286	7.33%	526,716	12.74%
343.00 Prime Movers	177,190,882	14,409,138	8.13%	6,319,489	3.57%	13,891,396	7.84%
344.00 Generators and Devices	169,118,475	10,798,829	6.39%	4,400,340	2.60%	11,311,854	6.69%
345.00 Accessory Electric Equipment	14,382,656	835,745	5.81%	288,222	2.00%	851,756	5.92%
346.00 Misc. Power Plant Equipment	8,374	672	8.02%	447	5.34%	777	9.28%
Total West Pheonix	$381,665,069	$27,827,770	7.29%	$11,844,421	3.10%	$27,827,770	7.29%
West Phoenix CC Unit 4							
341.00 Structures and Improvements	$3,768,898	$486,569	12.91%	$270,416	7.17%	$469,631	12.46%
342.00 Fuel Holders, Products and Accessories	4,135,109	536,579	12.98%	303,286	7.33%	526,716	12.74%
343.00 Prime Movers	54,753,590	7,282,275	13.30%	3,931,543	7.18%	6,827,913	12.47%
344.00 Generators and Devices	15,049,070	1,941,561	12.90%	1,395,459	9.27%	2,423,495	16.10%
345.00 Accessory Electric Equipment	59,412	2,013	3.39%	654	1.10%	1,136	1.91%
346.00 Misc. Power Plant Equipment	8,374	672	8.02%	447	5.34%	777	9.28%
Total West Ploenix CC Unit 4	$77,774,453	$10,249,668	13.18%	$5,901,805	7.59%	$10,249,668	13.18%
West Phoenix CC Unit 5							
341.00 Structures and Improvements	$13,060,675	$760,239	5.82%	$262,220	2.01%	$775,640	5.94%
342.00 Fuel Holders, Products and Accessories							
343.00 Prime Movers	122,437,292	7,126,864	5.82%	2,387,946	1.95%	7,063,483	5.77%
344.00 Generators and Devices	154,069,405	8,857,268	5.75%	3,004,881	1.95%	8,888,359	5.77%
345.00 Accessory Electric Equipment	14,323,244	833,731	5.82%	287,569	2.01%	850,620	5.94%
346.00 Misc. Power Plant Equipment							
Total West Phoenix CC Unit 5	$303,890,616	$17,578,102	5.78%	$5,942,616	1.96%	$17,578,102	5.78%
TRANSMISSION (BY UNIT)							
Redhawk CC Units 1-2							
353.00 Station Equipment	$30,683,150	$2,430,879	7.92%	$1,103,517	3.60%	$2,293,436	7.47%
355.00 Poles and Fixtures - Wood	1,500,000	101,953	6.80%	73,672	4.91%	153,112	10.21%
356.00 Overhead Conductors and Devices	1,500,000	101,953	6.80%	90,573	6.04%	188,237	12.55%
Total Redhawk CC Units 1-2	$33,683,150	$2,634,785	7.82%	$1,267,761	3.76%	$2,634,785	7.82%

PWEC UNITS
Depreciation Reserve Summary
Company Broad Group Procedure
December 31, 2004

Statement C

Account Description	Plant Investment	Recorded Reserve 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 CT Unit 3							
353.00 Station Equipment	$1,824,367	$150,428	8.25%	$65,613	3.60%	$150,428	8.25%
355.00 Poles and Fixtures - Wood							
356.00 Overhead Conductors and Devices							
Total Saguaro CT Unit 3	$1,824,367	$150,428	8.25%	$65,613	3.60%	$150,428	8.25%
West Phoenix							
353.00 Station Equipment	$7,507,646	$428,724	5.71%	$217,859	2.90%	$428,724	5.71%
355.00 Poles and Fixtures - Wood							
356.00 Overhead Conductors and Devices							
Total West Pheonix	$7,507,646	$428,724	5.71%	$217,859	2.90%	$428,724	5.71%
West Phoenix CC Unit 4							
353.00 Station Equipment	$1,953,105	$211,789	10.84%	$97,998	5.02%	$211,789	10.84%
355.00 Poles and Fixtures - Wood							
356.00 Overhead Conductors and Devices							
Total West Ploenix CC Unit 4	$1,953,105	$211,789	10.84%	$97,998	5.02%	$211,789	10.84%
West Phoenix CC Unit 5							
353.00 Station Equipment	$5,554,541	$216,935	3.91%	$119,861	2.16%	$216,935	3.91%
355.00 Poles and Fixtures - Wood							
356.00 Overhead Conductors and Devices							
Total West Phoenix CC Unit 5	$5,554,541	$216,935	3.91%	$119,861	2.16%	$216,935	3.91%

PWEC UNITS
Average Net Salvage

Statement D

Account Description	Plant Investment Additions	Retirements	Survivors	Salvage Rate Realized	Future	Net Salvage Realized	Future	Total	Average Rate
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
OTHER PRODUCTION									
341.00 Structures and Improvements	$40,104,209		$40,104,209		-3.8%		($1,539,718)	($1,539,718)	-3.8%
342.00 Fuel Holders, Products and Accessories	4,135,109		4,135,109		-5.0%		(206,755)	(206,755)	-5.0%
343.00 Prime Movers	399,447,583		399,447,583		-2.6%		(10,188,266)	(10,188,266)	-2.6%
344.00 Generators and Devices	476,732,853	118,039	476,614,814		-2.4%		(11,590,351)	(11,590,351)	-2.4%
345.00 Accessory Electric Equipment	40,055,435		40,055,435		-3.7%		(1,484,870)	(1,484,870)	-3.7%
346.00 Misc. Power Plant Equipment	8,374		8,374		-5.0%		(419)	(419)	-5.0%
Total Other Production Plant	$960,483,563	$118,039	$960,365,524		-2.6%		($25,010,378)	($25,010,378)	-2.6%
TRANSMISSION									
353.00 Station Equipment	$40,015,163		$40,015,163						
355.00 Poles and Fixtures - Wood	1,500,000		1,500,000		-15.0%		(225,000)	(225,000)	-15.0%
356.00 Overhead Conductors and Devices	1,500,000		1,500,000		-35.0%		(525,000)	(525,000)	-35.0%
Total Transmission Plant	$43,015,163		$43,015,163		-1.7%		($750,000)	($750,000)	-1.7%
TOTAL UTILITY	$3,000,000		$3,000,000		-25.0%		($750,000)	($750,000)	-25.0%
OTHER PRODUCTION (BY UNIT)									
Redhawk CC Units 1-2									
341.00 Structures and Improvements	$23,274,636		$23,274,636		-3.0%		($698,239)	($698,239)	-3.0%
342.00 Fuel Holders, Products and Accessories									
343.00 Prime Movers	221,481,610		221,481,610		-3.0%		(6,644,448)	(6,644,448)	-3.0%
344.00 Generators and Devices	273,599,371		273,599,371		-3.0%		(8,207,981)	(8,207,981)	-3.0%
345.00 Accessory Electric Equipment	25,524,567		25,524,567		-3.0%		(765,737)	(765,737)	-3.0%
346.00 Misc. Power Plant Equipment									
Total Redhawk CC Units 1-2	$543,880,184		$543,880,184		-3.0%		($16,316,406)	($16,316,406)	-3.0%
Saguaro CT Unit 3									
341.00 Structures and Improvements									
342.00 Fuel Holders, Products and Accessories									
343.00 Prime Movers	775,091		775,091						
344.00 Generators and Devices	33,896,968		33,896,968						
345.00 Accessory Electric Equipment	148,212		148,212						
346.00 Misc. Power Plant Equipment									
Total Saguaro CT Unit 3	$34,820,271		$34,820,271						
West Phoenix									
341.00 Structures and Improvements	$16,829,573		$16,829,573		-5.0%		($841,479)	($841,479)	-5.0%
342.00 Fuel Holders, Products and Accessories	4,135,109		4,135,109		-5.0%		(206,755)	(206,755)	-5.0%
343.00 Prime Movers	177,190,882		177,190,882		-2.0%		(3,543,818)	(3,543,818)	-2.0%
344.00 Generators and Devices	169,236,514	118,039	169,118,475		-2.0%		(3,382,370)	(3,382,370)	-2.0%
345.00 Accessory Electric Equipment	14,382,656		14,382,656		-5.0%		(719,133)	(719,133)	-5.0%
346.00 Misc. Power Plant Equipment	8,374		8,374		-5.0%		(419)	(419)	-5.0%
Total West Pheonix	$381,783,108	$118,039	$381,665,069		-2.3%		($8,693,973)	($8,693,973)	-2.3%

PWEC UNITS
Average Net Salvage

Account Description	Plant Investment: Additions	Plant Investment: Retirements	Plant Investment: Survivors	Salvage Rate: Realized	Salvage Rate: Future	Net Salvage: Realized	Net Salvage: Future	Net Salvage: Total	Average Rate
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
West Phoenix CC Unit 4									
341.00 Structures and Improvements	$3,768,898		$3,768,898		-5.0%		($188,445)	($188,445)	-5.0%
342.00 Fuel Holders, Products and Accessories	4,135,109		4,135,109		-5.0%		(206,755)	(206,755)	-5.0%
343.00 Prime Movers	54,753,590		54,753,590		-2.0%		(1,095,072)	(1,095,072)	-2.0%
344.00 Generators and Devices	15,167,109	118,039	15,049,070		-2.0%		(300,981)	(300,981)	-2.0%
345.00 Accessory Electric Equipment	59,412		59,412		-5.0%		(2,971)	(2,971)	-5.0%
346.00 Misc. Power Plant Equipment	8,374		8,374		-5.0%		(419)	(419)	-5.0%
Total West Ploenix CC Unit 4	$77,892,492	$118,039	$77,774,453		-2.3%		($1,794,643)	($1,794,643)	-2.3%
West Phoenix CC Unit 5									
341.00 Structures and Improvements	$13,060,675		$13,060,675		-5.0%		($653,034)	($653,034)	-5.0%
342.00 Fuel Holders, Products and Accessories									
343.00 Prime Movers	122,437,292		122,437,292		-2.0%		(2,448,746)	(2,448,746)	-2.0%
344.00 Generators and Devices	154,069,405		154,069,405		-2.0%		(3,081,388)	(3,081,388)	-2.0%
345.00 Accessory Electric Equipment	14,323,244		14,323,244		-5.0%		(716,162)	(716,162)	-5.0%
346.00 Misc. Power Plant Equipment									
Total West Phoenix CC Unit 5	$303,890,616		$303,890,616		-2.3%		($6,899,330)	($6,899,330)	-2.3%
TRANSMISSION (BY UNIT)									
Redhawk CC Units 1-2									
353.00 Station Equipment	$30,683,150		$30,683,150						
355.00 Poles and Fixtures - Wood	1,500,000		1,500,000		-15.0%		(225,000)	(225,000)	-15.0%
356.00 Overhead Conductors and Devices	1,500,000		1,500,000		-35.0%		(525,000)	(525,000)	-35.0%
Total Redhawk CC Units 1-2	$33,683,150		$33,683,150		-2.2%		($750,000)	($750,000)	-2.2%
Saguaro CT Unit 3									
353.00 Station Equipment	$1,824,367		$1,824,367						
355.00 Poles and Fixtures - Wood									
356.00 Overhead Conductors and Devices									
Total Saguaro CT Unit 3	$1,824,367		$1,824,367						
West Phoenix									
353.00 Station Equipment	$7,507,646		$7,507,646						
355.00 Poles and Fixtures - Wood									
356.00 Overhead Conductors and Devices									
Total West Pheonix	$7,507,646		$7,507,646						
West Phoenix CC Unit 4									
353.00 Station Equipment	$1,953,105		$1,953,105						
355.00 Poles and Fixtures - Wood									
356.00 Overhead Conductors and Devices									
Total West Ploenix CC Unit 4	$1,953,105		$1,953,105						
West Phoenix CC Unit 5									
353.00 Station Equipment	$5,554,541		$5,554,541						
355.00 Poles and Fixtures - Wood									
356.00 Overhead Conductors and Devices									
Total West Phoenix CC Unit 5	$5,554,541		$5,554,541						

PWEC UNITS Statement E

Present and Proposed Parameters
Company Broad Group Procedure

	Present Parameters						Proposed Parameters (at December 31, 2004)					
Account Description	P-Life/ AYFR	Curve Shape	BG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	BG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
OTHER PRODUCTION												
341.00 Structures and Improvements									36.13	35.00	-3.8	-3.8
342.00 Fuel Holders, Products and Accessories									49.82	46.34	-5.0	-5.0
343.00 Prime Movers									36.44	35.22	-2.6	-2.6
344.00 Generators and Devices									35.18	34.04	-2.4	-2.4
345.00 Accessory Electric Equipment									35.08	34.11	-3.7	-3.7
346.00 Misc. Power Plant Equipment									49.13	46.63	-5.0	-5.0
Total Other Production Plant									35.78	34.60	-2.6	-2.6
TRANSMISSION												
353.00 Station Equipment									57.00	55.02		
355.00 Poles and Fixtures - Wood									48.00	45.95	-15.0	-15.0
356.00 Overhead Conductors and Devices									55.00	52.54	-35.0	-35.0
Total Transmission Plant									56.56	54.56	-1.7	-1.7
TOTAL UTILITY									36.35	35.15	-25.0	-25.0
OTHER PRODUCTION (BY UNIT)												
Redhawk CC Units 1-2												
341.00 Structures and Improvements	2057	70-O4		34.03		-3.0	2057	70-O4	35.07	33.94	-3.0	-3.0
342.00 Fuel Holders, Products and Accessories												
343.00 Prime Movers	2057	70-O4		34.03		-3.0	2057	70-O4	35.07	33.94	-3.0	-3.0
344.00 Generators and Devices	2057	70-O4		34.03		-3.0	2057	70-O4	35.07	33.94	-3.0	-3.0
345.00 Accessory Electric Equipment	2057	70-O4		34.03		-3.0	2057	70-O4	35.07	33.94	-3.0	-3.0
346.00 Misc. Power Plant Equipment												
Total Redhawk CC Units 1-2									35.07	33.91	-3.0	-3.0

PWEC UNITS

Statement E

Present and Proposed Parameters
Company Broad Group Procedure

Account Description	Present Parameters						Proposed Parameters (at December 31, 2004)					
	P-Life/ AYFR	Curve Shape	BG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	BG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
Saguaro CT Unit 3												
341.00 Structures and Improvements												
342.00 Fuel Holders, Products and Accessories												
343.00 Prime Movers	2047	37-R3		35.49			2047	37-R3	35.99	33.54		
344.00 Generators and Devices	2047	37-R3		35.49			2047	37-R3	35.99	33.54		
345.00 *Accessory Electric Equipment*	2047	37-R3		35.49			2047	37-R3	35.99	33.54		
346.00 Misc. Power Plant Equipment												
Total Saguaro CT Unit 3									35.99	33.51		
West Phoenix												
341.00 Structures and Improvements									37.71	36.57	-5.0	-5.0
342.00 Fuel Holders, Products and Accessories									49.82	46.34	-5.0	-5.0
343.00 Prime Movers									38.32	36.98	-2.0	-2.0
344.00 Generators and Devices									35.20	34.30	-2.0	-2.0
345.00 Accessory Electric Equipment									35.08	34.41	-5.0	-5.0
346.00 Misc. Power Plant Equipment									49.13	46.63	-5.0	-5.0
Total West Pheonix									36.81	35.69	-2.3	-2.3
West Phoenix CC Unit 4												
341.00 Structures and Improvements	2056	80-S1		49.71		-5.0	2056	80-S1	51.22	47.72	-5.0	-5.0
342.00 Fuel Holders, Products and Accessories	2056	70-S1		48.32		-5.0	2056	70-S1	49.82	46.34	-5.0	-5.0
343.00 Prime Movers	2056	70-L1.5		46.94		-2.0	2056	70-L1.5	48.44	45.03	-2.0	-2.0
344.00 Generators and Devices	2056	37-R3		35.47		-2.0	2056	37-R3	36.96	33.60	-2.0	-2.0
345.00 Accessory Electric Equipment	2056	70-S1		48.32		-5.0	2056	70-S1	47.70	47.20	-5.0	-5.0
346.00 Misc. Power Plant Equipment	2056	70-S1		48.32		-5.0	2056	70-S1	49.13	46.63	-5.0	-5.0
Total West Ploenix CC Unit 4									45.87	42.48	-2.3	-2.3
West Phoenix CC Unit 5												
341.00 Structures and Improvements							2058	70-O4	35.04	34.37	-5.0	-5.0
342.00 Fuel Holders, Products and Accessories												
343.00 Prime Movers							2058	70-O4	35.04	34.37	-2.0	-2.0

PWEC UNITS
Present and Proposed Parameters
Company Broad Group Procedure

	Present Parameters						Proposed Parameters (at December 31, 2004)					
Account Description	P-Life/ AYFR	Curve Shape	BG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	BG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
344.00 Generators and Devices							2058	70-O4	35.04	34.37	-2.0	-2.0
345.00 Accessory Electric Equipment							2058	70-O4	35.04	34.37	-5.0	-5.0
346.00 Misc. Power Plant Equipment												
Total West Phoenix CC Unit 5									35.04	34.37	-2.3	-2.3
TRANSMISSION (BY UNIT)												
Redhawk CC Units 1-2												
353.00 Station Equipment	57.00	R1.5	42.00	56.59			57.00	R1.5	57.00	54.95		
355.00 Poles and Fixtures - Wood	55.00	R3	55.00	54.50		-15.0	48.00	R1.5	48.00	45.95	-15.0	-15.0
356.00 Overhead Conductors and Devices	55.00	R3	55.00	54.50		-35.0	55.00	R3	55.00	52.54	-35.0	-35.0
Total Redhawk CC Units 1-2									56.44	54.39	-2.2	-2.2
Saguaro CT Unit 3												
353.00 Station Equipment	2047	37-R3		35.49			57.00	R1.5	57.00	54.95		
355.00 Poles and Fixtures - Wood												
356.00 Overhead Conductors and Devices												
Total Saguaro CT Unit 3									57.00	54.94		
West Phoenix												
353.00 Station Equipment									57.00	55.35		
355.00 Poles and Fixtures - Wood												
356.00 Overhead Conductors and Devices												
Total West Pheonix									57.00	55.35		
<u>West Phoenix CC Unit 4</u>												
353.00 Station Equipment	57.00	R1.5	57.00	55.77			57.00	R1.5	57.00	54.14		
355.00 Poles and Fixtures - Wood												
356.00 Overhead Conductors and Devices												
Total West Ploenix CC Unit 4									57.00	54.04		
<u>West Phoenix CC Unit 5</u>												
353.00 Station Equipment	57.00	R1.5	42.00	56.59			57.00	R1.5	57.00	55.77		
355.00 Poles and Fixtures - Wood												
356.00 Overhead Conductors and Devices												
Total West Phoenix CC Unit 5									57.00	55.87		

EXHIBIT
APS-69
admitted

DIRECT TESTIMONY OF DAVID J. RUMOLO

On Behalf of Arizona Public Service Company

Docket No. E-01345A-05-0816

January 31, 2006

TABLE OF CONTENTS

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

I. <u>INTRODUCTION</u>

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is David Rumolo. My business address is 400 North Fifth Street, Phoenix, Arizona 85004.

Q. BY WHOM ARE YOU EMPLOYED AND WHAT IS YOUR POSITION?

A. I am employed by Arizona Public Service Company ("APS" or "Company") as Manager of Regulation and Pricing. I am responsible for the establishment and administration of APS tariffs and contract provisions that are under the jurisdiction of the Arizona Corporation Commission ("Commission") or the Federal Energy Regulatory Commission ("FERC").

Q. WOULD YOU DISCUSS YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE?

A. My background and experience are set forth in Appendix A to this testimony.

Q. ARE YOU SPONSORING ANY STANDARD FILING REQUIREMENTS ("SFR") SCHEDULES?

A. Yes. I am sponsoring required SFR Schedules G, and H, and portions of SFR Schedules B-1, B-2, C-1, and C-2, as well as the proposed rate schedules. Although not specifically required by the SFR, I am also sponsoring some additional schedules that have been designated as Schedule GJ (Attachment DJR-1), Schedule GE1 (Attachment DJR-2), Schedule GE2 (Attachment DJR-3), and Schedule GE3 (Attachment DJR-4) and are attached to my testimony.

II. SUMMARY

Q. WOULD YOU SUMMARIZE YOUR TESTIMONY?

A. My testimony addresses two general areas. The first area discusses the cost-of-service study prepared to Functionalize, Classify, and then Allocate test year costs and revenues first between wholesale and retail customers and then to the various classes of retail service. It is this cost allocation study that allows us to determine the rate of return produced by each class and subclass of customer, as well as the unit costs to provide service to each customer grouping. The second area discusses the proposed rate schedules and related service provisions which will recover the costs of providing service to our customers.

Q. WOULD YOU PLEASE SUMMARIZE THE PROPOSED RESIDENTIAL RATE SCHEDULE CHANGES?

A. We are proposing the following:

- Each residential rate schedule will be adjusted to improve cost tracking and reflect increased revenue requirements. The residential class base rate increase is comparable to the overall requested revenue increase of 21.14 %. The increases in Rate Schedules ET-1, ECT-1R, and E-12 are 24%, 19.7% and 15.6% respectively.
- Frozen Rate Schedules E-10 and EC-1 will be eliminated, and customers will select another rate option or be transferred to Schedule E-12 or Schedule ECT-1R by default, as meters are exchanged.
- The discounts available under the low income and medical equipment rates, Rate Schedules E-3 and E-4 respectively, will remain unchanged from the levels found in Decision No. 67744.

Q. WOULD YOU PLEASE SUMMARIZE THE PROPOSED CHANGES TO THE GENERAL SERVICE SCHEDULES?

A. Yes, the most significant changes are:

- All rate schedules have increased charges to reflect increased revenue requirements. The majority of the increases reflects increased fuel and purchased power expenses and is reflected in the power supply component of the unbundled rates.
- Rate Schedule E-32 will be increased to reflect increased revenue requirements, especially higher energy costs.
- Rate Schedules E-34 and E-35 will be increased slightly more than the average overall rate increase proposed in this application because customers on these rates use large amounts of energy and thus are more impacted by increased fuel and purchased power expenses.
- Time of Use ("TOU") Rate Schedules E-21, E-22, E-23, and E-24 will be eliminated and customers on those rates transferred to E-32TOU.
- Schedules E-38 and E-38-8T will be eliminated and customers on those rates transferred to Schedule E-221 in accordance with Decision No 67744.
- The basis for computing the energy portion of Schedule E-36 bills will change from system incremental cost to an index-based cost that is consistent with the computation of energy imbalances charges under the Company's OATT.

Q. ARE YOU PROPOSING ANY OTHER CHANGES TO THE APS TARIFF?

A. Yes. I am proposing modifications to the APS line extension policy found in Service Schedule 3. The primary modifications are to eliminate the existing

$25,000 extension condition and to change the policy from one based on a footage allowance to an equipment-based allowance for residential extensions.

III. COST-OF-SERVICE STUDY

Q. WAS AN EMBEDDED CLASS COST-OF-SERVICE STUDY USED IN THE DEVELOPMENT OF APS' PROPOSED RATE SCHEDULES?

A. Yes. An embedded and fully allocated cost-of-service study, with the twelve-month period ending September 30, 2005 as the test period, was a major input for designing the proposed rates. The study results provided both rate of return for the customer classes as well as Functionalization, Classification, and Allocation of costs.

Q. WAS THE USE OF A TWELVE-MONTH TEST YEAR ENDING SEPTEMBER 30, 2005 SUITABLE FOR THIS COST-OF-SERVICE STUDY?

A. Yes. The test year data provides the most recent calendar year financial and operational information, and is, therefore, consistent with the Company's revenue requirements. Although a future test year is more reflective of the period in which the proposed rates will be in effect, such a future test period is not generally used in Arizona. However, the Company's analysis does include a number of pro forma adjustments to the test year to reflect known changes and to better match the costs and revenues with the period in which the proposed rates will be in effect, as well as other adjustments to normalize the test period. For example, wages and salaries are adjusted through a pro forma adjustment to account for current levels and employee count.

Q. WHAT DO YOU MEAN BY NORMALIZING THE TEST YEAR INFORMATION?

A. Normalization refers to eliminating the effect of conditions or situations that would not ordinarily occur or be expected to occur in a normal test year, or that recur periodically but should be averaged out over a period of years. The purpose of normalization is to produce a test year that will be more representative of conditions that will exist during the period in which the proposed rates will be in effect.

Q. HOW DO YOU TREAT PRO FORMA AND NORMALIZATION ADJUSTMENTS TO THE TEST YEAR IN YOUR COST-OF-SERVICE STUDY?

A. Other APS witnesses' testimony sponsor a number of pro forma adjustments that were incorporated into the adjusted test year cost-of-service study. Testimony of APS witnesses Chris Froggatt, Laura Rockenberger, and Peter Ewen list, by rate base and expense category, the monetized amount of each proposed pro forma adjustment. These amounts were then Functionalized, Classified, and Allocated to the retail and wholesale customer classes as part of the process in performing the cost-of-service study. The adjusted test year cost-of-service study reflects all the proposed pro forma adjustments.

Q. WOULD YOU DISCUSS THE DEVELOPMENT OF THE EMBEDDED COST ALLOCATION STUDY?

A. This study was prepared using industry accepted cost-of-service principles of Functionalization, Classification, and Allocation and is generally consistent with historical APS practices.

"Functionalizaton" refers to the process of attributing a particular rate base or expense item to a particular function, namely Production, Transmission, or Distribution, in the provision of electric service. An easy and obvious example is the assignment of the costs of building and operating the Company's power plants to the Production function.

"Classification" refers to the process of determining the factor or factors that compel the magnitude of the cost. For example, if a cost is driven by the amount of energy consumed, it is classified as Energy; if a cost is driven by the rate at which energy is consumed, it is classified as Demand; or if a cost is driven by the number of customers taking service on the APS system irrespective of either demand or energy utilized, it is classified as Customer.

"Allocation" occurs once a cost has been functionalized and classified. This is the process in which allocation factors are applied to spread the costs to particular jurisdictions, customer classes, and rate schedules. A simple example is the allocation of energy related costs by kilowatt-hour ("kWh") consumption.

In the cost-of-service study, the expense and rate base items that comprise APS' costs were grouped into major categories, such as Plant in Service or Operating & Maintenance Expense. Each of these categories was first functionalized into Production, Transmission, or Distribution related costs, then classified as Demand, Energy, or Customer related. Allocation factors based on kilowatts, kilowatt-hours, and number of customers were then developed so that allocations of the functionalized and classified costs could be made to the federal and state jurisdictions and to the various retail customer classes and sub-classes. When necessary, procedures were used to reflect unusual or changing circumstances, as discussed later in my testimony.

Q. **WHAT BASIS IS USED TO ALLOCATE FUNCTIONALIZED COSTS BETWEEN JURISDICTIONS AND AMONG CUSTOMER CLASSES?**

A. Production-related and Transmission-related assets, and their associated costs, are generally designed and built to enable the Company to meet its system peak load. Therefore, they are allocated on the basis of the average of the system peak demands occurring in the months of June, July, August, and September ("4CP"). Distribution plant, unlike Production and Transmission plant is generally designed to meet a customer class' peak load, which may or may not be coincident with the system peak load. Thus, allocations of costs related to Distribution substations and primary Distribution lines are made on the basis of non-coincident peak loads ("NCP"). Allocations of costs related to Distribution transformers and secondary Distribution lines are made on the basis of the summation of the individual peak loads or demands of all customers within a particular customer class ("ΣNCP").

Q. WHAT IS THE BASIS OF THE "ALL OTHER" OR NON-JURISDICTION SEGMENT OF YOUR COST-OF-SERVICE STUDY?

A. The "All Other" segment, which appears as a column in the cost-of-service study, represents the rate base, expenses, and revenues associated with service to long-term firm FERC jurisdictional resale customers that APS serves, as well as transmission services APS provides to a number of entities. Because APS plans and utilizes Company facilities in order to fulfill these obligations, we have allocated and assigned a portion of APS Production, Transmission, and Distribution facilities to these non-jurisdictional customers in the same manner as we would to our classes of retail jurisdictional customers in preparing the cost-of-service study.

Q. WOULD YOU EXPLAIN THE USE OF REVENUE CREDITS IN THE COST-OF-SERVICE STUDY?

A. In addition to the transactions described for inclusion in the All Other column depicted in the cost-of-service study, APS makes off-system sales to third-party entities. In order to be certain that the benefits of such transactions flow through to our retail customers, the revenues derived from these transactions, which more than cover the incremental costs associated with producing or acquiring the required energy, are allocated to all customers. Thus, the margin or profit that APS realizes from such non-retail transactions is attributed to each class through the Revenue Credit, which benefits all customers by lowering their otherwise determined revenue requirement.

The somewhat opportunistic and non-firm short-term transactions that are included in Transmission for Others and a number of small items such as Rent from Electric Property, Forfeited Discounts, Miscellaneous Service Revenues, sales to Rate Schedule E-36 customers, and Other Electric Revenues are also treated as Revenue Credits.

Q. IS THIS THE SAME REVENUE CREDIT TREATMENT USED BY THE COMMISSION IN PRIOR APS RATE PROCEEDINGS?

A. Yes.

IV. <u>PRO FORMA ADJUSTMENTS</u>

Q. WERE YOU RESPONSIBLE FOR THE PREPARATION OF ANY PRO FORMA ADJUSTMENTS?

A. Yes.

Q. WERE YOU RESPONSIBLE FOR THE PREPARATION OF ANY PRO FORMA ADJUSTMENTS?

A. Yes, I was responsible for preparing three pro forma adjustments. The first pro forma adjustment was to annualize the revenue APS receives from retail customers to reflect the change in retail rates that became effective April 1,

2005. This was accomplished by taking test year billing determinants from our Customer Information System ("CIS") and applying the April 1, 2005 rates to those determinants. The revenue annualization proforma is summarized in Attachment DJR-5.

The second pro forma adjustment was an adjustment to test year operating expenses to reflect the increased promotional expenses for our low-income rate options. These promotional expenses are consistent with what was required by Decision No. 67744. This pro forma is shown on Attachment DJR-6.

The third pro forma adjustment I developed was an income adjustment to reflect the increased revenue levels that resulted in changes in miscellaneous customer charges in accordance with Service Schedule 1. These customer charges are consistent with those authorized and approved in Decision No. 67744 and the pro forma adjustment to reflect them is shown on Attachment DJR-7.

V. SPECIALLY-HANDLED COST ITEMS

Q. HAVE ANY SPECIALIZED PROCEDURES BEEN USED IN PERFORMING THIS COST ALLOCATION STUDY?

A. Yes. Consistent with the methods adopted in our last rate case, transmission-related costs were treated in a different manner.

Q. WOULD YOU EXPLAIN HOW TRANSMISSION COSTS WERE TREATED IN THE COST-OF-SERVICE STUDY?

A. The revenue requirement for transmission services was computed based on the FERC jurisdictional rates found in the APS Open Access Transmission Tariff (OATT).

The APS Scheduling Coordinator for Standard Offer customers is responsible for procuring transmission service, including ancillary services, and pays APS' OATT rates for Transmission and Ancillary Services needed to deliver electric power and energy to APS retail customers. Since FERC has jurisdiction over setting transmission rates, we removed transmission rate base and expenses from the retail customer class. This was accomplished by allocating all transmission and ancillary service cost to the "All Other" class in the cost-of-service study. Test year average OATT expense was determined by using the amount APS billed itself for retail network transmission service and ancillary services. The total OATT service charges were then divided by the corresponding OATT-billed kWh to determine the test year average OATT expense.

Q. HOW HAVE YOU HANDLED FRANCHISE FEES?

A. The APS Rate Schedules currently in effect (approved in Decision No. 67744) exclude franchise fees. Historically, franchise fees were recovered in base rates but Decision No. 67744 unbundled franchise fees so that the fees are collected directly from customers through location-specific charges in a manner similar to transaction privilege taxes. For the purpose of the cost-of-service study, expenses associated with Franchise Fees and associated revenues have been excluded.

Q. HAVE YOU CALCULATED THE COSTS, RATE BASE, AND RATE OF RETURN BASED ON THE ADJUSTED TEST YEAR?

A. Yes. In addition to establishing the Production, Transmission, and Distribution functions and the Demand, Energy, and Customer classifications for each class of retail business, the rate of return for each class under test year and proposed

Rate Schedules appear in the SFR "G" Schedules associated with this application.

VI. <u>"G" SCHEDULES</u>

Q. MR. RUMOLO, WOULD YOU DESCRIBE THE SFR "G" SCHEDULES?

A. Yes. The following is a summary of these Schedules:

- SFR Schedule G-1 shows the rate-of-return at existing rates by customer class, based on the adjusted test year cost-of-service study.
- SFR Schedule G-2 is similar to Schedule G-1, except this Schedule reflects returns by class that would result under APS' proposed rates.
- SFR Schedule G-3 shows the $ and % amount of adjusted Rate Base allocated to each retail customer class.
- SFR Schedule G-4 shows the amount of operating expenses allocated to each retail customer class.
- SFR Schedule G-5 shows the amount of functionalized adjusted Rate Base allocated to ACC jurisdictional customers.
- SFR Schedule G-6 shows the amount of functionalized adjusted operating expense allocated to the ACC jurisdictional customers.
- SFR Schedule G-7 lists the allocation factors used in preparing the test year cost-of-service study.

Q. DO YOU HAVE ANY ADDITIONAL SCHEDULES RELATED TO THE COST-OF-SERVICE STUDY THAT YOU ARE SPONSORING?

A. Yes. The following filed additional Schedules relate to the study:

- Schedule GJ is a summary of the cost-of-service study showing the jurisdictional separation of Rate Base costs, revenues, and operating expenses.

- Schedule GE1 is a summary of the cost-of-service study showing, by retail customer class, the allocation of total ACC allocated rate base costs, revenues, and operating expenses and the rate-of-return for each major customer class.
- Schedule GE2 is a summary of the cost-of-service study showing, by each General Service sub-class, the allocation of rate base costs, revenues, and operating expenses and the rate-of-return.
- Schedule GE3 is a summary cost-of-service study showing, by each Residential sub-class, the allocation of rate base costs, revenues, and operating expenses and the rate-of-return.

Q. BASED ON THE RESULTS OF YOUR ADJUSTED TEST YEAR COST-OF-SERVICE STUDY, WHAT CONCLUSIONS HAVE YOU MADE?

A. I believe it is apparent from the "G", GJ, and GE Schedules that there are disparities in the rates of return that the different customer classes are providing to the Company. Although the disparities have decreased due to the rate designs implemented as a result of the settlement reached in our last case, the residential class continues to provide a lower rate of return than the general service class. Specifically, under current rates and adjusted operating expenses, the residential class rate of return is 1.52% while the general service class rate of return is 3.91%. Overall, the retail rate of return under current rates is 2.59% based on an adjusted original cost rate base. This is significantly below cost of service.

VII. RATE DESIGN

Q. WOULD YOU DESCRIBE THE OVERALL OBJECTIVES OF THE PROPOSED RATE DESIGNS?

A. In the APS rate case and settlement that resulted in Decision No. 67744, APS' retail rates were significantly modified. The principal modification was to unbundle the retail rates in accordance with the objectives established by the Commission in the Commission's Electric Competition Rules. We also strove to improve the rate designs by improving cost tracking, offering additional rate options and improving rate clarity. In this case, we are building on the improvements established in Decision No. 67744.

Q. WOULD YOU EXPLAIN WHAT YOU MEAN BY "IMPROVE THE COST TRACKING OF THE VARIOUS ELEMENTS OF OUR RATE SCHEDULES?"

A. Historically, many rate changes were made on the basis of "across the board" percentage changes as a result of rate case settlements. This resulted in some rate distortions that took our rates away from tracking costs, both as to rate level and rate design. In our last case, the process of unbundling our retail rates identified instances in which our rates were obviously not following costs. While the last case made improvements in that regard, the proposed rates in this case continue to address this concern.

Q. WOULD YOU DESCRIBE THE PROCESS USED TO DEVELOP THE PROPOSED RATES?

A. The starting point in the rate design process is the cost-of-service study discussed earlier in my testimony. The cost-of-service study allocates the costs of providing service to each of the major classes of customers, as well as various sub-classes and rate schedules. If the cost-of-service study was the only determinant for setting rates, each rate classification would recover APS' proposed rate of return, and all rate schedules would be expressed in the form of unit costs and expressed as Demand Charges, Energy Charges, and Customer Charges. However, many other considerations were taken into account in designing the proposed rates, which resulted in individual rate schedules that differ from the overall proposed rate of return and rate designs that differ in appearance and application.

Q. OTHER THAN THE COST-OF-SERVICE STUDY, WHAT OTHER FACTORS WERE CONSIDERED WHEN DESIGNING THE PROPOSED RATES?

A. We considered several other factors. Among the most important were rate stability and continuity. For this reason, the major classes of customers—Residential, General Service, Irrigation, Street Lighting, and Dusk to Dawn—have each been given a percentage increase that is approximately the same as the overall requested increase, even though strict adherence to the results of the cost-of-service study would indicate higher increases are supportable. In addition, the individual rate schedules have been designed to depart from strict cost-of-service adherence as necessary, so that differences in the increases that individual customers will experience will be moderated to the extent we believe reasonable. An additional consideration in developing the proposed rate schedules was customer understandability and ease of administration. In other words, we attempted to simplify the specific rate schedules and the presentation of the tariff in general. Consideration of these factors is in conformance with the traditional aspects of rate design.

VIII. RECOVERY OF OTHER COST ELEMENTS

Q. ARE THERE ANY COST ELEMENTS THAT RECEIVE RECOVERY TREATMENT OUTSIDE OF THE BASE RATE SCHEDULES?

A. Yes. Decision No. 67744 authorized a series of adjustment clauses including the Power Supply Adjustment ("PSA"), the Demand Side Management Adjustment Clause ("DSMAC"), the Transmission Cost Adjuster ("TCA"), the Environmental Portfolio Surcharge ("EPS-1"), the Competition Rules

Compliance Charge ("CRCC"), the Returning Customer Direct Assignment Charge ("RCDAC"), and the System Benefits Adjustment Charge ("SBAC"). Regulatory Assessments, sales/transaction privilege taxes, and franchise fees are also charged outside of base rates.

Q. ARE YOU PROPOSING ANY ADDITIONAL ADJUSTORS OR SURCHARGES IN THIS APPLICATION?

A. Yes. In this application, we have requested approval of an Environmental Improvement Charge ("EIC"). The purpose of the charge is to provide a funding mechanism for investments that will reduce emissions associated with burning fossil fuels at our power plants. This proposed charge is discussed in detail in the testimony of APS Witness Gregory Delizio.

Q. DOES THIS APPLICATION IMPACT THE PSA THAT WAS APPROVED IN DECISION N0. 67744?

A. Yes. The calculations found in the PSA were based on a Base Rate Power Supply Cost of $0.020743 per kWh, as approved in Decision No. 67744. The proposed new Base Rate Power Supply Cost is $0.031904 per kWh, as discussed in detail in the testimony of APS Witness Peter Ewen. A description of other requested PSA changes is found in the testimony of APS Witness Don Robinson.

Q. DOES THIS APPLICATION IMPACT ANY OF THE OTHER ADJUSTERS THAT WERE APPROVED IN DECISION N0. 67744?

A. Yes. We are proposing a change in the Demand Side Management Adjustment Charge. The current methodology does not provide for interest earnings on the account balance. Since recovery of DSM expenditures is in arrears, it is appropriate to include an interest charge. We propose the unrecovered DSM cost accrue interest using the one-year Nominal Treasury Constant Maturities rate that is contained in the Federal Reserve Statistical Release H-15 or its successor publication. This is the same rate that is used in the PSA and for customer deposits. A revised Plan of Administration is attached and marked Attachment DJR-8.

IX. RESIDENTIAL RATE SCHEDULES

Q. WOULD YOU PLEASE GIVE A GENERAL DESCRIPTION OF THE EXISTING RESIDENTIAL RETAIL RATE SCHEDULES?

A. Currently, APS has seven active residential rate schedules. In addition, two new schedules were filed with the Commission prior to this application and are pending Commission action. Two of the rate schedules are for special programs that APS actively supports. Schedule E-3 provides discounts for qualifying low-income customers. Schedule E-4 provides a discounted rate to customers who must use electricity for medical care equipment. These discounts were increased by Decision No. 67744.

We currently have three non time-of-use ("TOU") differentiated Rate Schedules (E-10, E-12, and EC-1). Rate Schedules E-10 and EC-1 were frozen by the Commission in previous proceedings and have not been available to new customers for over 10 years. In accordance with Decision No. 67744, these frozen schedules will be eliminated. We also have two active TOU Rate Schedules. Schedule ET-1 is a time differentiated energy rate schedule. Schedule ECT-1R is time differentiated and also includes a metered demand charge. In September 2005, we filed an application with the Commission to introduce two new TOU rate schedules, designated Rate Schedule ET-2 and Rate Schedule ECT-2. These schedules offer alternative on-peak pricing time periods and have been filed as experimental rate schedules to allow for examination of both customer interest and customer demand response.

Q. WOULD YOU PLEASE DESCRIBE THE PROVISIONS OF DECISION NO. 67744 THAT WERE APPLICABLE TO RESIDENTIAL RETAIL RATE SCHEDULES?

A. Decision No. 67744 had several provisions of importance to residential customers. As I noted earlier, we unbundled the Standard Offer rate schedules in our last rate case to comply with the Competition Rules. Decision No. 67744 impacted residential customers as follows: 1) Frozen Schedules EC-1 and E-10 were continued but are to be eliminated in APS' next rate case, 2) APS was required to study rate designs that encourage energy efficiency, discourage wasteful and uneconomic use of energy and reduce peak demand, 3) APS was ordered to file additional TOU rate schedules with different peak schedules, 4) APS was ordered to evaluate the break points and tier pricing in Schedule E-12 in the next rate, and 5) APS was directed to evaluate SurePay and examine the possibility of providing discounts to customers who participate in SurePay.

Q. WOULD YOU PLEASE DESCRIBE APS' COMPLIANCE WITH THE REQUIREMENTS OF DECISION NO. 67744 AS APPLICABLE TO RESIDENTIAL CUSTOMERS.

A. In this Application, we are implementing the elimination of Schedules EC-1 and E-10. We have prepared a report (Attachment DJR-9) that: 1) examines rate design alternatives that encourage energy efficiency; and 2) evaluates the breakpoints and rate in Schedule E-12. On October 7, 2005, we filed two other reports with Commission Staff in accordance with Decision No. 67744. The reports examined: 1) the issue of TOU rate schedules and rate designs that encourage rate flexibility; and 2) the possibility of providing discounts to customers who participate in SurePay. These reports and the October 7, 2005 transmittal letter are Attachment DJR-10 to my testimony. As noted previously, we recently filed an application for approval of two additional residential TOU rate schedules. These rate schedules are based on on-peak pricing time periods of 12:00 P.M. to 7:00 P.M. on weekdays, weekends are off-peak, and the holidays recognized by the National Electric Reliability Council ("NERC") are off-peak.

Q. PLEASE SUMMARIZE THE RESULTS OF THE REPORT THAT YOU FILED AND HOW IT IMPACTS THE RATE SCHEDULES FOUND IN THIS RATE SCHEDULE APPLICATION.

A. On the topic of rate designs that encourage energy efficiency, we have concluded that we are leaders in the industry in many aspects. For example, our non-TOU residential rates are inclining block rates that have the effect of charging more for higher consumption levels. We have the greatest percentage of residential customers on TOU rates than almost any other utility nationally and we are one of the few utilities that offer residential rates with an explicit demand charge. The rate designs for general service customers that were implemented in our last case provide strong demand conservation price signals because of cost-based pricing. Because of the nature of our customer base and metering limitations, we do not believe it is appropriate to mandate TOU pricing for general service customers. The rate designs that we are proposing in this application provide strong price signals. This case is being driven chiefly by the rapid increase in fuel and energy costs. Because of this, our proposed rate designs appropriately recover these increased energy costs through the energy charges.

Our analysis also concludes that our current blocks in Schedule E-12 are appropriate. This conclusion is based on a review of bill frequency analyses and the pricing implications of alternative block sizes. Lowering the initial block in the rate would have the effect of shifting consumption to higher priced blocks and shift revenue recovery to the second tier. The net benefits of lowering the block size of the first tier and lowering the price for the first tier would be limited to customers whose marginal usage is at or near the block limit. Also, some customers served on Rate Schedule E-12 also receive discounts under Schedule E-3. Shifting the cost recovery to the second rate tier would adversely impact those customers since many of the customers receiving the discount purchase significant energy in the second tier of the rate.

Q. PLEASE SUMMARIZE THE RESULTS OF THE REPORTS THAT YOU FILED IN OCTOBER REGARDING TOU RATE FLEXIBILITY AND THE APS SUREPAY PROGRAM.

A. The study regarding the potential of providing additional flexibility in our TOU programs concluded that we have significant obstacles to overcome before rate flexibility can be offered on a widespread basis. First, we have approximately 400,000 customers on TOU rate schedules. To accommodate changes in TOU rate schedules, meters must be re-programmed or replaced. Current technology does not allow us to reprogram meters in the field with our meter reading equipment. The meters can only be field programmed with laptop computers which is not a practical solution. However, we are investigating new technologies that may allow us to have greater flexibility in the future. For example, we are in the process of rolling out an advanced metering system ("AMS") pilot. This system uses radio frequency and cell phone technology to read meters and gather customer information. Because of software flexibility in the AMS, it will be easier in the future to provide customers rate options as AMS is rolled out. Software limitations also affect the number of rate options that we can offer. A change in rate structures necessitates changes in many computer systems ranging from the meter-reading system, to the software used by the customer call center to provide information to customers, to the bill printing systems, to the APS website. These software changes are expensive to implement and require significant resource commitments for coding and testing software changes. However, as indicated earlier, we have filed an application with the Commission to request approval for two new experimental TOU rate schedules that will provide rate options with alternative TOU time periods. Customer reaction to these new rate offerings will be one indicator whether we will expand the experiment to a broader group of customers.

Our review of the SurePay program leads us to the conclusion that offering discounts to encourage participation is not warranted. We currently offer two automatic payment options to customers. SurePay authorizes a customer's bank to transfer funds to APS. AutoPay is an on-line version of SurePay in which the customer will get an e-mail notification when the fund transfers occur. AutoPay customers can print a paper copy of their bill from APS.COM if the customer so desires. We do not believe that a discount is required to encourage participation since we have a high level of participation in the automatic payment programs even when compared to companies that offer financial inducements. Also, our analysis indicates that many of the inducements offered by other companies are not cost effective and result in cost shifting from customers who participate to customers who do not elect to participate.

Q. **WOULD YOU PLEASE DESCRIBE THE PROPOSED RESIDENTIAL RATE SCHEDULES?**

A. As described earlier in my testimony, the changes proposed for the residential rate schedules are refinements of the changes that were made in the last case. This rate application is being driven primarily by increases in the cost of generation resources including fuel, purchased power expense, and the inclusion of new generation in rate base. Therefore, the proposed rate changes primarily influence the power supply element of our unbundled rate schedules. We have also included the impact of the energy efficiency demand side management programs on expected sales volumes through a slight reduction in billing determinants used to develop the proposed rates.

Q. PLEASE DESCRIBE THE PROPOSED CHANGES TO RESIDENTIAL RATE SCHEDULES ET-1, ECT-1R AND E-12.

A. The only changes we are proposing at this time are increases in the revenue levels produced by the rates, with most of the increase reflected in the generation component. We are also modifying the winter-summer rate differentials to better reflect the higher energy costs APS faces in the summer months. The basic unbundled structure of the rates will not be changed. The proposed base rate increase for the residential customer class is approximately 21.1%. On a rate schedule basis, the proposed increases for Schedules ET-1, ECT-1R, and E-12 are 24.5%, 19.7% and 15.6% respectively, excluding customers who are transferring to these schedules from cancelled schedules. These increases are computed based on total schedule results excluding the EIC. Individual customers may experience changes higher or lower than the schedule averages depending on individual consumption patterns.

Q. WHAT ARE YOUR INTENTIONS FOR FROZEN RATE SCHEDULE EC-1 AND ITS CUSTOMERS?

A. We will eliminate frozen Rate Schedule EC-1 as provided for in Decision No. 67744. Rate Schedule EC-1 customers would be transferred to Rate Schedule ECT-1R unless they choose an alternative rate schedule. Rate Schedule ECT-1R has been selected as the default rate schedule as both rate schedules have explicitly billed demand components, and many customers currently on Rate Schedule EC-1 are managing their demand through load controllers or timers. These customers are familiar with demand-based rates and the potential for saving money by actively managing their peak load. Rate Schedule ECT-1R encourages customers who are actively managing demand to continue to do so with the addition of a TOU element. Therefore, we believe that the transition from Rate Schedule EC-1 to Rate Schedule ECT-1R would provide the best continuity for the Rate Schedule EC-1 customers as the default rate, should the customer not select from the available rate schedules on their own.

In this application, we have also included a revised Rate Schedule EC-1 which will be used during the transition until all customers are transferred to other schedules. A transition period is required because of the potential requirement for meter changes. For example, if an EC-1 customer moves to Rate Schedule ECT-1R, a meter exchange may be required. Although meter exchanges may not be required on all 22,000 customers currently on Rate Schedule EC-1, we anticipate a large number of exchanges will be required.

Q. IS A TRANSITION PERIOD REQUIRED FOR THE ELIMINATION OF RATE SCHEDULE E-10?

A. No, since our basic assumption is that E-10 customers will transition to Rate Schedule E-12, meter exchanges will likely not be necessary in most instances. However, if a Schedule E-10 customer selects another schedule such as Rate Schedule ET-1, it may be necessary to exchange meters and that exchange will be worked in our normal meter exchange process. The customer would be billed on the default rate until the meter exchange occurs.

Q. PLEASE DESCRIBE HOW E-10 AND EC-1 CUSTOMERS WILL BE INFORMED OF THEIR NEW RATE OPTIONS ONCE THESE RATES ARE ELIMINATED.

A. APS would like to explore, with the Commission Staff, various opportunities to proactively inform and educate E-10 and EC-1 customers about their rate options once these rates are eliminated. Our initial thought would be to inform customers of this change through APS.COM and through bill inserts targeted towards the E-10 and EC-1 rate codes. Key components of our message should inform them of the option to choose an alternative residential rate schedule once these rates are eliminated, and describe the actions needed by them to make their rate selection. However, our message will also need to inform them that no action by a certain date will cause them to be placed on the appropriate default rate as I described earlier in my testimony.

Q. WHAT IF A CUSTOMER IS PLACED ON A DEFAULT RATE AND LATER WANTS TO SELECT ANOTHER RATE OPTION?

A. If a customer is placed on a default rate as a result of E-10 or EC-1 being eliminated, they will be able to subsequently select another rate option.

Q. DOES THIS APPLICATION AFFECT THE EXPERIMENTAL TOU RATES THAT APS FILED ON SEPTEMBER 22, 2005?

A. Yes. Schedules ET-2 and ECT-2 that were filed in September were based on costs and revenues that were developed in the Settlement Agreement and Decision No. 67744. We are filing revisions to the new rates in this application that reflect the results of the latest cost-of-service study. At the time of the writing of this testimony, the Commission has not yet acted on the application for approval of the new rates, therefore, revenue impacts cannot be calculated. However, the concepts behind the modifications found in this application are consistent with the original rate design, i.e., if all ET-1 customers moved to ET-2 the move would be revenue neutral.

Q. WOULD YOU PLEASE SUMMARIZE THE PROPOSED RESIDENTIAL RATE SCHEDULE CHANGES?

A. We are proposing the following:

- Each residential rate schedule has been designed to improve cost tracking.
- Rate Schedule EC-1 will be eliminated and customers will select another rate option or be transferred to Rate Schedule ECT-1R by default, as meters are exchanged. The interim rate that will be applied during the transition will be an increase of approximately 26 % compared to EC-1 and is comparable to the increase the customers will experience when moved to Rate Schedule ECT-1R.
- Rate Schedule E-10 will be eliminated. Customers will have the option to choose another rate, or will be transferred to Schedule E-12 by default if no choice is made.
- Rate Schedules E-12, ET-1, ECT-1R, ET-2 and ECT-2 will be increased to reflect increased revenue requirements.
- The discounts available under the low income and medical equipment rates, Rate Schedules E-3 and E-4 respectively, will remain unchanged from the levels found in Decision No. 67744.

X. <u>GENERAL SERVICE RATE SCHEDULES</u>

Q. WOULD YOU PLEASE DESCRIBE APS' GENERAL SERVICE RATE SCHEDULES?

A. APS has eleven general service rate schedules. These are used for serving our commercial and industrial loads as well as specialized applications. There are five TOU schedules, one schedule for unmetered service, one schedule for athletic stadiums and arenas, a seasonal schedule, schedules for partial requirements service and schedules for dusk-to-dawn and street lighting services. There are two demand based, non-TOU differentiated schedules. Approximately 95% of our general service customers are served on Rate Schedule E-32. Rate Schedule E-34 and TOU Rate Schedule E-35 are available for customers whose loads exceed three megawatts.

Q. WOULD YOU PLEASE SUMMARIZE THE ASPECTS OF DECISION NO. 67744 THAT PERTAIN TO APS' GENERAL SERVICE RATE SCHEDULES?

A. Decision No. 67744 provided that Rate Schedules E-21, E-22, E-23 and E-24, would be eliminated in the next APS rate proceeding. These were introduced many years ago as experimental TOU schedules. It is proposed that these customers be transferred to Rate Schedule E-32TOU. Rate Schedule E-20, a TOU schedule that is applicable to houses of worship, was frozen to new customers. New customers would take service on Rate Schedule E-32TOU or another general service rate schedule of their choice. Decision No. 67744 also provided for the elimination of Rate Schedules E-38 and E-38-8T in the next APS rate proceeding. We propose that customers currently on these schedules be transferred to Rate Schedule E-221. Decision No. 67744 also required that we examine rate designs that would encourage energy efficiency and reduce peak demand. These topics have been addressed in the report described earlier in my testimony.

Q. WOULD YOU PLEASE DESCRIBE THE PROPOSED RATE SCHEDULE E-32?

A. Rate Schedule E-32 was extensively modified in the last APS rate proceeding. In this Application, we are proposing the basic rate structure developed in the last case be retained. The charges in the schedule have been increased to reflect increased revenue requirements. The cost emphasis is shifted to high energy use customers to reflect the dramatically increased energy costs that APS is incurring to serve its customers. This will also encourage energy conservation through an energy-driven price signal.

Q. HAVE YOU MODIFIED RATE SCHEDULE E-32R?

A. Rate Schedule E-32R provides for partial requirements customers taking service under Rate Schedule E-32. Therefore, the changes proposed for Rate Schedule E-32 impact customers served under Rate Schedule E-32R.

Q. WOULD YOU PLEASE DESCRIBE THE PROPOSED CHANGES TO THE GENERAL SERVICE TOU SCHEDULES?

A. Yes. Decision No. 67744 directed that Rate Schedules E-21, E-22, E-23 and E-24 be eliminated in the next APS rate proceeding and that customers be transferred to Rate Schedule E-32TOU. Customers have been notified of that change and will be notified in conjunction with this application. The design of Rate Schedule E-32TOU has been modified to replace the existing "excess capacity" charge with an off-peak demand charge. The rate has been designed so that customers who shift demand to off-peak hours can realize significant savings. However, some customers who are on existing general service TOU rates and have not made shifts in consumption patterns may transfer to Rate Schedule E-32. Currently there are approximately 240 customers on Rate Schedules E-21, E-22, E-23 and E-24 combined.

Q. WOULD YOU PLEASE DESCRIBE THE PROPOSED CHANGES TO RATE SCHEDULES E-34 AND E-35?

A. Yes. Rate Schedules E-34 and E-35 are the rate schedules that are applicable to APS' largest customers, i.e., general service customers with loads over 3 MW. We are not proposing changes to the basic rate structure for Schedule E-34. The billing charges have been increased to reflect increased revenue requirements and most of the increase is in the generation component of the unbundled rate to reflect higher generation, purchased power and fuel expenses. Schedule E-35 billing charges have also been increased to reflect increased revenue requirements. The structure of Schedule E-35 has been modified to substitute an off-peak charge for the "excess capacity" charge that currently exists. This change was made to simplify rate calculations and improve rate clarity. We have also modified the metering charge found in these two schedules for new transmission voltage customers. Transmission voltage metering installations for customers served at higher voltages (i.e., greater than 69 kV) are site specific. Rather than attempting to develop an average cost for universal application, we propose that the charge be based on the carrying cost of the investment. A fixed charge rate will be applied to the actual installed cost of the metering system. The charge will be identified in the service contract between APS and the customer.

Q. ARE YOU PROPOSING CHANGES TO THE STREET LIGHTING AND DUSK TO DAWN LIGHTING SCHEDULES?

A. In our last case, we reformatted Rate Schedule E-47 (Dusk to Dawn) and Rate Schedule E-58 (Street Lighting) to improve cost tracking. Because customers on these rate schedules often request different combinations of poles, arms, and fixtures, we developed a menu format for these rate schedules. Subject to certain physical/construction limitations, customers are able to select the lighting system that best fits their needs. The menu system makes it easier to add new poles or fixtures to the schedules, as they become available. In this case, we are continuing the menu structure but increasing the charges to reflect higher revenue requirements.

Q. DOES APS PROVIDE STREET LIGHTING SERVICE ON RATE SCHEDULES OTHER THAN E-58?

A. Yes, Rate Schedule E-59 is used to provide energy service for government-owned street lighting systems. Under Rate Schedule E-59, APS has no responsibility for operations, maintenance, or replacement of street light poles or fixtures. There is also a series of "Share the Light" schedules for street lighting services in Ajo, Camp Verde, and other areas. The charges for these special schedules are based on Rate Schedule E-58.

Q. WHAT ARE THE PROPOSED CHANGES FOR THESE STREET LIGHTING RATE SCHEDULES?

A. APS proposes to increase the overall charges under the street lighting rate schedules at approximately the same level as our overall requested increase.

Q. ARE THERE ANY OTHER LIGHTING RELATED RATE SCHEDULES IN THE APS TARIFF?

A. Rate Schedule E-67 is used to provide energy service to the City of Phoenix for various non-street lighting systems. It was originally based on an old contract that has long since expired. Because the level of this Rate Schedule and its return is substandard, we propose that it be increased by a larger average percent increase than the overall increase that APS is requesting in this rate case. This requested 34% increase will still not bring the rate schedule up to the average rate of return paid by our other retail customers.

Q. WOULD YOU PLEASE DESCRIBE ANY OTHER PROPOSED CHANGES FOR GENERAL SERVICE CUSTOMERS?

A. We propose that charges under Rate Schedule E-40 for service to Agricultural Wind Machines and charges under frozen Rate Schedule E-51 for service to certain cogenerators and small power producers be increased by the same overall percentage as is being requested in this application. Partial Requirements Service Rate Schedules E-52 and E-55 currently have no customers being served on them and no increase is proposed at this time. However, these rate schedules may be replaced in the future as a result of the current proceedings on distributed generation. We have also added language to the general service rate schedules that describes power factor requirements. This language was moved to the rate schedules from Schedule 1. Power factor minimum requirement for customers served at distribution voltage continues to be 90% lagging. For transmission voltage customers, the power factor requirement corresponds to the OATT power factor requirement which is 95% lagging to 95% leading.

Q. ARE YOU PROPOSING ANY CHANGES FOR RATE SCHEDULE E-36?

A. We are proposing a change in the method used to compute the energy consumption portion of the bill for customers on Rate Schedule E-36. Currently, the energy charge is computed based on the system incremental cost of power supplies in the hour that the E-36 customer is consuming energy. At the time that the Rate Schedule E-36 was originally developed, system incremental cost was also used in computing energy imbalance charges for customers who take service under the FERC approved OATT. Earlier this year, the energy imbalance charge in the OATT was modified and accepted by FERC. The charge is now based on the average hourly cost at the three major trading hubs that influence the Arizona market; Palo Verde, Four Corners, and Mead. Therefore, we are proposing to use the trading hub indices to calculate the energy component of the bill for E-36 customers so that the methodology is consistent with the OATT energy imbalance calculation. Currently, we have only four customers on Rate Schedule E-36. The new energy price calculation would result in lower bills to E-36 customers based on a test year analysis.

Q. WOULD YOU PLEASE SUMMARIZE THE PROPOSED CHANGES TO THE GENERAL SERVICE SCHEDULES?

A. Yes, the changes are as follows:

- All rate schedules have increased charges to reflect increased revenue requirements. The majority of the increases is due to increased fuel and purchased power expenses and is reflected in the power supply component of the unbundled rates. Rates were developed with consideration of the impacts on energy sales due to energy efficiency demand side management programs.
- TOU Rate Schedules E-21, E-22, E-23, and E-24 will be eliminated and customers transferred to E-32TOU.
- Rate Schedule E-30 for Unmetered Service will be increased to better reflect costs.
- Rate Schedule E-32 will be increased to reflect increased revenue requirements, especially higher energy costs.
- Rate Schedules E-34 and E-35 will be increased approximately 24.6 % and 24.9% respectively which reflects cost of service and increased fuel and purchased power expenses.
- Rate Schedule E-53 for service to Athletic Fields and Rate Schedule E-54 for Seasonal Service are used in conjunction with other applicable general service rate schedules and no stand alone changes to these rate

schedules are proposed.

- Rate Schedules E-38 and E-38-8T will be eliminated and customers transferred to Rate Schedule E-221 in accordance with Decision No. 67744.
- The basis for computing the energy portion of Rate Schedule E-36 will change from system incremental cost to an index-based cost that is consistent with the computation of energy imbalance charges under the APS OATT.

Q. ARE YOU PROPOSING ANY OTHER RATE SCHEDULE CHANGES?

A. Yes. We are eliminating schedules that are no longer required. Schedule EPR-3 is a frozen purchase rate schedule for qualifying facilities and there are no longer any customers on the schedule. Solar 1 is being cancelled as it is a frozen schedule and there are no longer any customers taking service under the schedule. As discussed in the testimony of APS Witness Ed Fox, we are freezing the Solar Partners program that is described in Schedule SP-1. We are also eliminating the direct access rate schedules that were put in effect as a result of the 1999 Settlement Agreement. Since APS unbundled rates as a result of the 2004 Settlement Agreement (Decision No. 67744), separate direct access rates are no longer necessary and are confusing. No customers are served under the old direct access rates so there is no revenue impact resulting from the rate schedule elimination.

XI. "H" SCHEDULES

Q. WOULD YOU DESCRIBE THE "H" SCHEDULES BEING SPONSORED BY YOU?

A. The "H" Schedules are a series of summaries that present an analysis of the impacts of the proposed rate schedules.

Q. WOULD YOU PLEASE DESCRIBE SCHEDULE H-1?

A. Schedule H-1 provides a summary of the revenue impact on each major customer classification, e.g., Residential, General Service, Irrigation, etc. This schedule compares the revenue generated under the proposed rate schedules with the revenue generated under present rate schedules.

To develop the data found in the column entitled "Present Rate Schedules," we began with actual revenue from the test year, but then made a series of normalization adjustments to that data. The adjustments were made to reflect normal weather, the year-end number of customers, energy conservation and the rate schedule increases that became effective in April, 2005. The purpose of these adjustments was to enable us to compare existing and proposed rate schedules on an "apples-to-apples" basis.

Q. WOULD YOU DESCRIBE THE INFORMATION FOUND IN SCHEDULE H-2?

A. Schedule H-2 presents the information found in Schedule H-1 in a more detailed format. The comparisons of current and proposed revenue are shown by schedule whereas Schedule H-1 data is presented on a class basis. Schedule H-1 is actually a summary of the data found in Schedule H-2.

Q. WOULD YOU PLEASE DESCRIBE SCHEDULE H-3?

A. Schedule H-3 presents comparisons of the specifics of each rate schedule. These specifics include details such as the basic service charge, billing blocks, energy charges, and demand charges. Although our proposed rate schedules have been functionally unbundled, the information shown on Schedule H-3 is presented on a bundled basis to allow for easier comparisons since all customers today effectively purchase a bundled product from APS.

Q. WOULD YOU PLEASE DESCRIBE SCHEDULE H-4?

A. Schedule H-4 presents a typical bill comparison for our major rate schedules under existing and proposed rates. Bill comparisons are presented for varying levels of consumption and for seasons, when applicable. We have included an additional column to show the impact on bills of the proposed Environmental Improvement Charge (EIC). The "add-ons" of sales tax, franchise fees, and Regulatory Assessment have not been included in the bill comparisons.

Q. WOULD YOU PLEASE DESCRIBE SCHEDULE H-5?

A. Schedule H-5 presents a series of bill frequency analyses for major schedules. This information includes the number of bills and energy consumed based on blocks of consumption levels.

XII. <u>SCHEDULE 3 - LINE EXTENSIONS</u>

Q. WHAT IS SCHEDULE 3?

A. Schedule 3 is APS' line extension policy. The current policy includes three main elements that define conditions governing residential line extensions. These elements are: (1) a footage allowance for residential extensions; (2) a revenue test for extensions when the construction cost is under $25,000; and (3) an economic feasibility analysis for extensions when the cost exceeds $25,000 or that are not subject to the footage allowance or revenue test. Also, when I refer to "residential" customers, I mean individual residential premises as opposed to subdivision developers. Line extensions for residential subdivisions being constructed by developers are currently evaluated under the revenue test or an economic feasibility analysis.

Q. PLEASE DESCRIBE THE CHANGES THAT ARE PROPOSED IN THE POLICY.

A. Under the footage allowance portion of the current extension policy, permanent residential customers are provided with a 1,000-foot free construction allowance. If the customer's extension exceeds 1,000 feet but is less than 2,000 feet, or the construction cost exceeds $25,000, the policy requires that the customer sign an extension agreement and provide a refundable advance. Under our proposed new policy, the footage basis is eliminated and permanent residential customers will be given a dollar-based equipment allowance. If the construction cost of the extension exceeds the allowance, the customer will be required to make a refundable advance.

Q. HOW DOES THE CURRENT APS POLICY COMPARE WITH INDUSTRY TRENDS?

A. I am currently the Chairman of the Edison Electric Institute's Economic Regulation and Competition Committee, and the topic of line extension policies is an agenda item at almost every semi-annual meeting. We have extensive discussions regarding the application and administration of line extension policies and, almost universally, utility companies struggle with developing policies that are fair to new customers, existing customers and the companies. Tracking the terms of numerous extension contracts and administering extension policies on a uniform basis are difficult issues that most utilities face. Utilities are moving from footage-based policies to construction-allowance based policies in order to improve extension policy administration and more correctly recover costs. The construction allowance approach recognizes that construction costs for individual customer locations can vary widely. APS believes that our proposed change is more equitable and is consistent with the current trends in the industry. When we compared our current footage based policy with other companies, we found that the 1000-foot allowance is extremely generous to new customers and correspondingly detrimental to existing customers.

Q. YOU DESCRIBE THE CURRENT POLICY AS "GENEROUS." WOULD YOU PLEASE EXPLAIN THAT COMMENT?

A. Yes. The purpose of a line extension policy is to prevent shifting of cost burdens from a customer who requires an extension to other customers. For example, for APS, the average net embedded distribution plant investment, excluding substation plant investment, for residential customers is approximately $1,500. Since our rates are based on a rate of return on rate and operating costs, the distribution component of retail rates is designed to recover costs associated with that average distribution plant investment. Our rates are not geographic based nor are they based on the costs of serving a specific customer. They are based on average costs. Thus, if the investment to serve a specific customer exceeds the average cost, and the specific customer pays average rates and does not make a contribution to offset the higher investment, all other customers must subsidize the higher cost customer.

Q. ARE THERE OTHER REASONS SUPPORTING A CHANGE TO A CONSTRUCTION ALLOWANCE?

A. The primary reason to convert to a construction allowance approach is to recognize that construction costs can vary significantly for each individual extension. The Company's service territory is very diverse. There are densely populated areas, rural areas, desert areas and mountainous areas. Because of this diversity, and to also recognize that some extensions are overhead while others are underground, an allowance based on a fixed investment amount is more fair. Under a footage allowance-based approach, the cost of a short, very expensive extension results in an unfair burden on the rest of the Company's customers.

Q. WHAT IS THE PROPOSED CONSTRUCTION ALLOWANCE UNDER APS' REVISED LINE EXTENSION POLICY?

A. APS is proposing a residential extension allowance of $5,000 per permanent residential customer in a single family home.

Q. HOW WAS THIS AMOUNT DETERMINED?

A. APS examined several approaches. In other states that have adopted the construction allowance approach, the allowance is based on the average net embedded distribution investment per customer based on a cost-of-service study. The underlying theory is that this average is the investment on which retail rates are designed. For APS, the average net embedded investment, excluding substation plant investment, for residential customers is approximately $1,500. We also analyzed the average plant investment from a reproduction cost basis and determined that value to be approximately $2,700. We elected to apply a much higher ($5,000) allowance for several reasons. First, this allowance equates to the cost of a typical 500-feet underground extension, which is comparable to the allowance provided by other Arizona utilities. Second, we wanted to ease the transition from the current 1000-foott allowance. Today, the construction costs for a 1000-foot overhead extension is in excess of $10,000. Thus, simply converting the existing footage allowance to an equivalent construction allowance would not solve the problem of excessive investment needed to serve one customer and would not accurately capture average embedded costs.

Q. UNDER YOUR PROPOSED POLICY, WILL CUSTOMER ADVANCES BE ELIGIBLE FOR REFUNDS?

A. Yes. For example, let us assume that the cost of an extension is $22,000. The customer receives a $5,000 equipment allowance and will advance APS $17,000. Let us now assume a second customer requests service from the same extension and the cost to add that second customer is $2,000. Since the second customer used only $2,000 of his $5,000 allowance, the original customer will receive a refund of $3,000. Refunds will be made up to five years from the date the original extension is energized and in no case will the refunds exceed the original advance. Customers will be provided an "Advance Certificate" which can be presented to the Company to request a refund when other customers connect to the original extension.

Q. ARE YOU PROPOSING ANY OTHER CHANGES FOR INDIVIDUAL RESIDENTIAL LINE EXTENSIONS?

A. Yes. As I noted previously, our existing policy changes when the estimated cost of an extension exceeds $25,000. If the threshold is exceeded, the extension is made based on an economic feasibility study, and the customer contribution can be significantly more than if the extension was less than $25,000 since the customer does not have the benefit of the 1000 foot. extension. In our proposed policy, the $25,000 threshold is eliminated for residential extensions. Thus, all residential customers will be entitled to the same equipment allowance.

Q. HOW WILL THE LINE EXTENSION POLICY BE APPLIED TO RESIDENTIAL REAL ESTATE SUBDIVISIONS?

A. Currently, we perform an economic study for residential subdivisions that compares expected revenue levels with investment and determines how many homes must be constructed for the investment to be economic. For most developers that have a track record of successfully developing projects, no customer advances are required. We propose that we will continue to evaluate subdivisions in this manner but incorporate our residential equipment allowance concept in lieu of performing studies. For example, if a subdivision has 200 lots, the developer will be credited with $5,000 per lot or $1,000,000 to cover the investment in local and back-bone facilities. Should the estimated cost for the subdivision exceed that allowance, a non-refundable contribution in aid of construction will be required. Developers without a proven track record in the APS service territory will be required to advance the estimated costs to serve the subdivision and will receive refunds based on the $5,000 equipment allowance as permanent customers establish service with APS. The $5,000 allowance is applicable to developments with single family housing. Developers will be provided a $500 allowance per unit for developments comprised of owner occupied multifamily units such as condominiums and townhouses.

Q. HOW WILL THE EXTENSION POLICY BE APPLIED TO NON-RESIDENTIAL APPLICATIONS?

A. We will continue to use a revenue test for non-residential extensions where the construction cost does not exceed $25,000 and an economic feasibility based analysis for extensions when the cost exceeds $25,000. The revenue test is based on a simple relationship between expected revenue from a customer and the extension cost. Currently, if six times the customer's expected annual distribution revenue is more than the cost of the extension less nonrefundable contributions, the extension is provided for free. If expected revenue does not meet the revenue test, an advance is received from the customer. The economic feasibility-based analysis is a more exhaustive approach that entails examining the return on investment for a particular extension.

Q. ARE THERE ANY OTHER CHANGES PROPOSED FOR THE LINE EXTENSION POLICY?

A. Yes, we have made minor clarifying changes to the schedule. For example, language was added that corresponds to changes in Schedule 1 regarding master metering applications.

XIII. CONCLUSION

Q. WOULD YOU STATE YOUR GENERAL CONCLUSIONS AS TO PRICING MATTERS IN THIS PROCEEDING?

A. The cost-of-service study indicates that APS' current rate schedules produce rates of return that vary greatly from each other and from the overall average and required rate of return. In addition, the rate designs stray greatly from the unit Demand, Energy, and Customer costs of providing service to our customers. The rate schedules being proposed in this proceeding will meet APS' revenue requirement, better track costs, and have been simplified for better customer understanding and administration.

Q. DOES THAT CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes it does.

Appendix A

Statement of Qualifications

David J. Rumolo

David J. Rumolo is Arizona Public Service Company's Manager of State Pricing. He has over 32 years experience in the electric utility business as a consultant and utility professional. Mr. Rumolo holds Bachelor of Science Degrees in Electrical Engineering and Business (Finance as an area of emphasis) from the University of Colorado. He is a registered professional engineer in the states of Arizona, California, and New Mexico.

Mr. Rumolo's areas of expertise include utility Rate Schedule design; embedded and marginal cost analysis; formulation of utility service policies; contract development and negotiation; utility valuation analyses; and evaluation of utility revenue requirements. Mr. Rumolo has testified on utility matters before state regulatory bodies in the states of Arizona, Colorado, Florida, and Wyoming and before judicial bodies in the states of Arizona and California. Mr. Rumolo is also experienced in the many aspects of electric utility planning and design including preparation of long range resource plans; transmission and distribution system long range planning; system protection analyses; and reliability assessments.

Mr. Rumolo has held his current position at Arizona Public Service Company for approximately three years. Prior to assuming that position, he served as the Manager of Transmission and Market Structure Assessment for Pinnacle West Energy Corporation ("PWEC"). Before joining PWEC, Mr. Rumolo had a 15-year career as a consultant with Resource Management International, Inc., where he provided utility Rate Schedule and engineering consulting services to utility clients across the United

States and overseas. He began his career providing consulting services to utility clients when he joined the firm of Miner and Miner Consulting Engineers in Greeley, Colorado where he became the Manager of Planning and Rate Schedules. He later became a partner in Electrical Systems Consultants where he focused on cost of service and Rate Schedule analyses, as well as transmission and distribution planning.

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($)

		<—— GJ ——>		
Line No.	Description	ELECTRIC TOTAL (1)	ACC JURISDICTION (2)	ALL OTHER (3)
	SUMMARY OF RESULTS			
1	**DEVELOPMENT OF RATE BASE**			
2	ELECTRIC PLANT IN SERVICE	$10,096,271,000	$8,556,179,618	$1,540,091,382
3	GENERAL & INTANGIBLE PLANT	$722,630,705	$666,173,004	$56,457,701
4	LESS: RESERVE FOR DEPRECIATION	($4,170,525,134)	($3,548,546,146)	($621,978,988)
5	OTHER DEFERRED CREDITS	($448,168,000)	($438,604,344)	($9,563,656)
6	WORKING CASH	($29,138,598)	($25,220,726)	($3,917,872)
7	MATERIALS, SUPPLIES & PREPAYMENTS	$197,285,248	$177,653,628	$19,631,620
8	ACCUM. DEFERRED TAXES	($1,203,998,000)	($1,062,992,832)	($141,005,168)
9	REGULATORY ASSETS	($80,002,029)	($93,364,564)	$13,362,535
10	DECOMMISSIONING FUND	$290,537,000	$285,856,167	$4,680,833
11	GAIN FROM DISP. OF PLANT	($46,901,000)	($46,360,307)	($540,693)
12	*MISCELLANEOUS DEFERRED DEBITS*	$42,522,000	$39,464,108	$3,057,892
13	CUSTOMER ADVANCES	($59,807,000)	($59,807,000)	$0
14	CUSTOMER DEPOSITS	($54,860,000)	($54,860,000)	$0
15	PROFORMA ADJUSTMENTS	$71,987,000	$71,125,898	$861,102
16	**TOTAL RATE BASE**	**$5,327,833,192**	**$4,466,696,503**	**$861,136,689**
17				
18	**DEVELOPMENT OF RETURN**			
19	REVENUES FROM RATES	$2,103,857,729	$2,066,144,726	$37,713,003
20	PROFORMA TO REVENUES FROM RATES	$60,953,295	$61,177,173	($223,878)
21	OTHER ELECTRIC REVENUE	$1,344,909,371	$1,313,268,572	$31,640,799
22	**TOTAL OPERATING REVENUES**	**$3,509,720,395**	**$3,440,590,471**	**$69,129,924**
23				
24	**OPERATING EXPENSES**			
25	*OPERATION & MAINTENANCE*	$2,246,012,697	$2,302,448,767	($56,436,070)
26	ADMINISTRATIVE & GENERAL	$141,768,183	$132,687,128	$9,081,055
27	DEPRECIATION & AMORT EXPENSE	$321,526,000	$285,758,990	$35,767,010
28	AMORTIZATION ON GAIN	($6,613,638)	($6,528,055)	($85,583)
29	REGULATORY ASSETS	($2,203,510)	($2,203,510)	$0
30	PROFORMA ADJUSTMENTS	$504,561,367	$495,794,531	$8,766,836
31	TAXES OTHER THAN INCOME	$139,970,767	$116,332,654	$23,638,113
32	INCOME TAX	$9,951,628	$395,489	$9,556,139
33	**TOTAL OPERATING EXPENSES**	**$3,354,973,494**	**$3,324,685,995**	**$30,287,499**
34				
35	**OPERATING INCOME**	**$154,746,901**	**$115,904,477**	**$38,842,425**
36				
37	**RETURN**	**$154,746,901**	**$115,904,477**	**$38,842,425**
38				
39	**RATE OF RETURN (PRESENT)**	**2.90%**	**2.59%**	**4.51%**
40				
41	**INDEX RATE OF RETURN (PRESENT)**	**1.00**	**0.89**	**1.55**

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Line No.	Description	GE-1 TOTAL RETAIL (4)	RESIDENTIAL (5)	GENERAL SERVICE (6)	E-38,221 (Water Pumping) (7)	STREET LIGHTING (8)	DUSK TO DAWN (9)
	SUMMARY OF RESULTS						
1	DEVELOPMENT OF RATE BASE						
2	ELECTRIC PLANT IN SERVICE	$8,556,179,618	$4,681,780,206	$3,708,391,092	$48,573,070	$80,454,414	$36,980,837
3	GENERAL & INTANGIBLE PLANT	$666,173,004	$413,695,677	$240,421,594	$3,598,464	$5,898,943	$2,558,325
4	LESS: RESERVE FOR DEPRECIATION	($3,548,546,146)	($1,928,646,656)	($1,556,766,586)	($21,905,575)	($28,552,296)	($12,674,834)
5	OTHER DEFERRED CREDITS	($438,604,344)	($230,684,114)	($204,189,689)	($2,582,154)	($844,471)	($303,917)
6	WORKING CASH	($25,220,726)	($12,831,079)	($11,971,511)	($114,802)	($208,823)	($94,713)
7	MATERIALS, SUPPLIES & PREPAYMENTS	$177,853,628	$91,914,861	$82,459,091	$1,381,406	$1,358,190	$540,061
8	ACCUM. DEFERRED TAXES	($1,062,992,832)	($577,093,568)	($470,076,111)	($4,073,726)	($8,024,201)	($3,725,226)
9	REGULATORY ASSETS	($93,364,564)	($49,127,146)	($44,234,787)	($193,572)	$145,136	$45,605
10	DECOMMISSIONING FUND	$285,856,167	$135,532,339	$145,260,236	$3,481,853	$1,280,428	$301,312
11	GAIN FROM DISP. OF PLANT	($46,360,307)	($24,074,114)	($22,075,210)	($210,983)	$0	$0
12	MISCELLANEOUS DEFERRED DEBITS	$39,464,108	$24,492,979	$14,258,861	$213,053	$348,203	$151,013
13	CUSTOMER ADVANCES	($59,807,000)	($43,338,952)	($13,858,832)	($2,407,716)	($201,500)	$0
14	CUSTOMER DEPOSITS	($54,860,000)	($29,075,800)	($24,737,362)	($584,674)	($330,038)	($152,126)
15	PROFORMA ADJUSTMENTS	$71,125,898	$37,195,208	$33,683,008	$279,633	($25,865)	($6,087)
16	TOTAL RATE BASE	$4,466,698,503	$2,489,739,662	$1,876,563,796	$25,474,477	$51,298,118	$23,620,450
17							
18	DEVELOPMENT OF RETURN						
19	REVENUES FROM RATES	$2,066,144,726	$1,058,729,739	$987,398,538	$20,966,540	$12,913,053	$6,136,856
20	PROFORMA TO REVENUES FROM RATES	$61,177,173	$30,821,291	$29,741,269	($102,439)	$431,212	$285,840
21	OTHER ELECTRIC REVENUE	$1,313,268,572	$624,903,158	$662,981,779	$15,739,104	$8,074,267	$1,570,264
22	TOTAL OPERATING REVENUES	$3,440,590,471	$1,714,454,188	$1,680,121,586	$36,603,205	$21,418,532	$7,992,960
23							
24	OPERATING EXPENSES						
25	OPERATION & MAINTENANCE	$2,302,448,787	$1,142,667,874	$1,118,136,205	$25,236,754	$13,153,614	$3,254,320
26	ADMINISTRATIVE & GENERAL	$132,687,128	$81,444,413	$48,467,580	$880,883	$1,303,165	$571,087
27	DEPRECIATION & AMORT EXPENSE	$285,758,990	$159,732,184	$119,779,814	$1,842,301	$3,034,821	$1,369,871
28	AMORTIZATION ON GAIN	($6,528,055)	($3,299,367)	($3,172,586)	($45,007)	($8,981)	($2,113)
29	REGULATORY ASSETS	($2,203,510)	($1,144,245)	($1,049,237)	($10,028)	$0	$0
30	PROFORMA ADJUSTMENTS	$495,794,531	$245,906,575	$243,317,050	$4,654,889	$1,563,573	$352,444
31	TAXES OTHER THAN INCOME	$116,332,654	$65,666,581	$47,839,518	$739,434	$1,432,424	$654,697
32	INCOME TAX	$395,489	($14,265,270)	$13,414,661	$933,679	($114,020)	$426,438
33	TOTAL OPERATING EXPENSES	$3,324,685,995	$1,676,708,745	$1,586,753,008	$34,232,906	$20,364,595	$6,626,743
34							
35	OPERATING INCOME	$115,904,477	$37,745,444	$73,368,581	$2,370,299	$1,053,936	$1,366,217
36							
37	RETURN	$115,904,477	$37,745,444	$73,368,581	$2,370,299	$1,053,936	$1,366,217
38							
39	RATE OF RETURN (PRESENT)	2.59%	1.52%	3.91%	9.30%	2.05%	5.78%
40							
41	INDEX RATE OF RETURN (PRESENT)	0.89	0.52	1.35	3.20	0.71	1.99

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Line No.	Description	GE-2 TOTAL GENERAL SVC (10)	E-20 (Church Rate) (11)	E-30, E-32 (0 - 20 kW) (12)	E-32 (21 - 100 kW) (13)	E-32 (101 - 400 kW) (14)	E-32 (401 - 999 kW) (15)	E-32 (1,000 + kW) (16)	E-34 (17)	E-35 (18)
	SUMMARY OF RESULTS									
1	DEVELOPMENT OF RATE BASE									
2	ELECTRIC PLANT IN SERVICE	$3,708,391,092	$13,156,897	$713,155,581	$919,510,111	$826,034,200	$457,251,885	$358,405,105	$234,275,856	$186,601,479
3	GENERAL & INTANGIBLE PLANT	$240,421,594	$800,809	$52,580,861	$57,265,737	$49,297,753	$28,539,066	$22,452,629	$15,147,299	$14,337,418
4	LESS: RESERVE FOR DEPRECIATION	($1,556,766,586)	($4,998,590)	($279,217,143)	($374,393,106)	($351,525,773)	($200,022,369)	($153,844,888)	($102,825,889)	($89,838,828)
5	OTHER DEFERRED CREDITS	($204,189,689)	($504,986)	($33,881,944)	($46,623,347)	($45,546,063)	($26,468,874)	($21,907,125)	($14,852,010)	($14,405,339)
6	WORKING CASH	($11,971,511)	($41,526)	($2,053,804)	($2,885,084)	($2,721,723)	($1,551,419)	($1,227,267)	($811,036)	($679,652)
7	MATERIALS, SUPPLIES & PREPAYMENTS	$82,459,091	$266,994	$12,148,857	$18,052,533	$18,725,412	$11,772,505	$8,953,712	$6,220,412	$6,318,665
8	ACCUM. DEFERRED TAXES	($470,076,111)	($1,567,481)	($80,308,700)	($116,045,895)	($103,935,236)	($57,118,420)	($46,381,008)	($30,261,289)	($24,456,083)
9	REGULATORY ASSETS	($44,234,787)	($87,353)	($8,279,471)	($10,756,114)	($9,709,906)	($5,095,187)	($4,641,924)	($3,022,635)	($2,641,997)
10	DECOMMISSIONING FUND	$145,260,236	$398,517	$14,406,781	$27,667,366	$34,001,927	$23,592,112	$17,516,133	$12,742,045	$14,937,355
11	GAIN FROM DISP. OF PLANT	($22,075,210)	($50,436)	($3,849,143)	($5,211,280)	($4,923,522)	($2,721,500)	($2,342,339)	($1,557,044)	($1,419,946)
12	MISCELLANEOUS DEFERRED DEBITS	$14,258,861	$47,424	$3,115,471	$3,396,159	$2,924,948	$1,692,897	$1,332,470	$898,856	$650,635
13	CUSTOMER ADVANCES	($13,858,832)	($47,917)	($2,036,227)	($3,125,023)	($3,289,801)	($2,093,348)	($1,348,634)	($955,473)	($960,209)
14	CUSTOMER DEPOSITS	($24,737,362)	($85,530)	($3,638,139)	($5,578,020)	($5,872,139)	($3,736,527)	($2,407,606)	($1,705,476)	($1,713,927)
15	PROFORMA ADJUSTMENTS	$33,683,008	$75,650	$6,093,756	$8,085,335	$7,480,055	$4,037,726	$3,531,529	$2,325,358	$2,053,598
16	TOTAL RATE BASE	$1,876,583,796	$7,360,473	$378,234,737	$469,359,373	$410,940,132	$228,078,548	$177,990,687	$115,618,777	$88,981,168
17										
18	DEVELOPMENT OF RETURN									
19	REVENUES FROM RATES	$967,398,538	$3,344,799	$142,275,889	$218,138,380	$229,640,445	$146,123,538	$94,153,699	$66,695,822	$67,026,166
20	PROFORMA TO REVENUES FROM RATES	$29,741,269	$241,901	$9,060,700	$3,862,319	$13,851,012	$1,053,159	$1,013,448	$23,659	$635,071
21	OTHER ELECTRIC REVENUE	$662,981,779	$1,836,772	$67,075,107	$127,027,116	$155,000,606	$107,242,574	$79,566,919	$57,813,697	$67,418,789
22	TOTAL OPERATING REVENUES	$1,660,121,586	$5,423,472	$218,411,696	$349,027,816	$398,492,063	$254,419,271	$174,734,066	$124,533,178	$135,080,026
23										
24	OPERATING EXPENSES									
25	OPERATION & MAINTENANCE	$1,118,136,205	$3,103,839	$129,308,205	$220,897,730	$258,190,478	$174,469,857	$130,869,186	$94,134,754	$107,362,156
26	ADMINISTRATIVE & GENERAL	$48,487,580	$166,558	$10,453,288	$11,676,787	$10,128,362	$5,827,742	$4,474,610	$3,006,658	$2,751,578
27	DEPRECIATION & AMORT EXPENSE	$119,779,814	$441,855	$23,085,668	$29,369,824	$26,524,854	$15,018,891	$11,487,621	$7,583,550	$8,267,552
28	AMORTIZATION ON GAIN	($3,172,586)	($7,702)	($476,581)	($702,487)	($718,845)	($430,995)	($351,385)	($241,284)	($243,307)
29	REGULATORY ASSETS	($1,049,237)	($2,397)	($182,950)	($247,693)	($234,016)	($129,353)	($111,332)	($74,006)	($87,490)
30	PROFORMA ADJUSTMENTS	$243,317,050	$668,036	$31,104,069	$47,266,911	$60,972,779	$35,437,484	$27,211,782	$18,743,874	$21,912,115
31	TAXES OTHER THAN INCOME	$47,839,518	$190,638	$9,622,639	$12,021,204	$10,585,525	$5,888,989	$4,435,255	$2,889,635	$2,205,634
32	INCOME TAX	$13,414,661	$237,240	$2,028,353	$5,848,284	$7,877,179	$4,370,160	($2,721,834)	($1,596,586)	($2,628,135)
33	TOTAL OPERATING EXPENSES	$1,586,753,006	$4,800,066	$204,942,692	$326,130,561	$373,326,316	$240,452,774	$175,093,904	$124,446,694	$137,860,101
34										
35	OPERATING INCOME	$73,368,581	$623,406	$13,469,005	$22,897,254	$25,165,747	$13,966,498	($359,838)	$86,584	($2,480,075)
36										
37	RETURN	$73,368,581	$623,406	$13,469,005	$22,897,254	$25,165,747	$13,966,498	($359,838)	$86,584	($2,480,075)
38										
39	RATE OF RETURN (PRESENT)	3.91%	8.47%	3.56%	4.88%	6.12%	6.12%	-0.20%	0.07%	-2.79%
40										
41	INDEX RATE OF RETURN (PRESENT)	1.35	2.92	1.23	1.68	2.11	2.11	-0.07	0.03	-0.98

ARIZONA PUBLIC SERVICE COMPANY
ADJUSTED ELECTRIC COST OF SERVICE STUDY
FOR THE 12 MONTHS ENDING SEPTEMBER 30, 2005
($)

Line No.	Description	TOTAL RESIDENTIAL (19)	GE-3 RESIDENTIAL E-10 (20)	RESIDENTIAL E-12 (21)	RESIDENTIAL EC-1 (22)	RESIDENTIAL ET-1 (23)	RESIDENTIAL ECT-1 (24)
	SUMMARY OF RESULTS						
1	DEVELOPMENT OF RATE BASE						
2	ELECTRIC PLANT IN SERVICE	$4,681,780,206	$281,733,273	$1,463,863,508	$155,716,852	$2,319,963,476	$460,503,097
3	GENERAL & INTANGIBLE PLANT	$413,695,677	$27,609,575	$148,850,621	$12,375,982	$190,265,394	$34,594,106
4	LESS: RESERVE FOR DEPRECIATION	($1,928,646,856)	($121,994,885)	($606,016,515)	($66,501,787)	($945,187,421)	($188,944,248)
5	OTHER DEFERRED CREDITS	($230,684,114)	($13,825,950)	($71,463,902)	($7,843,378)	($113,766,401)	($23,784,463)
6	WORKING CASH	($12,831,079)	($723,129)	($3,720,280)	($447,338)	($6,554,955)	($1,385,377)
7	MATERIALS, SUPPLIES & PREPAYMENTS	$91,914,881	$5,685,919	$28,611,532	$3,209,242	$44,893,772	$9,514,416
8	ACCUM. DEFERRED TAXES	($577,093,568)	($33,820,196)	($178,907,141)	($19,024,386)	($287,506,651)	($57,835,194)
9	REGULATORY ASSETS	($49,127,146)	($2,735,750)	($14,707,336)	($1,630,247)	($24,868,511)	($5,185,302)
10	DECOMMISSIONING FUND	$135,532,339	$8,749,151	$41,051,666	$5,176,484	$65,386,973	$15,168,064
11	GAIN FROM DISP. OF PLANT	($24,074,114)	($1,381,773)	($7,212,965)	($820,405)	($12,112,000)	($2,546,971)
12	MISCELLANEOUS DEFERRED DEBITS	$24,492,979	$1,633,948	$8,808,332	$733,029	$11,267,889	$2,049,781
13	CUSTOMER ADVANCES	($43,338,952)	($2,879,259)	($14,760,504)	($1,501,737)	($20,077,388)	($4,120,063)
14	CUSTOMER DEPOSITS	($29,075,800)	($1,831,675)	($9,902,719)	($1,007,505)	($13,469,779)	($2,764,122)
15	PROFORMA ADJUSTMENTS	$37,195,208	$2,115,285	$11,135,269	$1,256,282	$18,769,977	$3,918,396
16	TOTAL RATE BASE	$2,489,739,662	$148,234,534	$795,627,567	$79,691,088	$1,227,004,374	$239,182,098
17							
18	DEVELOPMENT OF RETURN						
19	REVENUES FROM RATES	$1,058,729,739	$70,337,587	$360,585,198	$36,686,029	$490,471,664	$100,849,261
20	PROFORMA TO REVENUES FROM RATES	$30,821,291	($2,224,915)	$11,853,176	($1,254,829)	$20,328,518	$2,119,341
21	OTHER ELECTRIC REVENUE	$624,903,158	$40,280,141	$189,690,778	$23,754,957	$301,576,795	$69,600,487
22	TOTAL OPERATING REVENUES	$1,714,454,188	$108,392,813	$562,129,152	$59,186,157	$812,376,977	$172,369,089
23							
24	OPERATING EXPENSES						
25	OPERATION & MAINTENANCE	$1,142,667,874	$73,964,084	$357,077,451	$41,906,267	$547,808,416	$121,913,655
26	ADMINISTRATIVE & GENERAL	$81,444,413	$5,435,590	$28,926,720	$2,483,640	$37,721,841	$8,876,622
27	DEPRECIATION & AMORT EXPENSE	$159,732,184	$9,911,645	$51,449,950	$5,249,433	$77,904,622	$15,216,534
28	AMORTIZATION ON GAIN	($3,299,367)	($196,177)	($991,655)	($116,349)	($1,840,307)	($354,879)
29	REGULATORY ASSETS	($1,144,245)	($65,676)	($342,833)	($38,994)	($575,685)	($121,058)
30	PROFORMA ADJUSTMENTS	$245,906,575	$14,092,176	$76,874,215	$8,130,951	$120,576,974	$26,232,260
31	TAXES OTHER THAN INCOME	$65,666,581	$4,071,767	$21,173,025	$2,145,953	$32,090,164	$6,185,673
32	INCOME TAX	($14,265,270)	($924,514)	$2,664,602	($925,760)	($11,644,819)	($3,434,778)
33	TOTAL OPERATING EXPENSES	$1,676,708,745	$106,288,896	$536,831,474	$58,835,140	$802,239,206	$172,514,029
34							
35	OPERATING INCOME	$37,745,444	$2,103,917	$25,297,678	$351,017	$10,137,772	($144,940)
36							
37	RETURN	$37,745,444	$2,103,917	$25,297,678	$351,017	$10,137,772	($144,940)
38							
39	RATE OF RETURN (PRESENT)	1.52%	1.42%	3.18%	0.44%	0.83%	-0.06%
40							
41	INDEX RATE OF RETURN (PRESENT)	0.52	0.49	1.09	0.15	0.28	-0.02

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

PRO FORMA ADJUSTMENT: **ANNUALIZE 4/1/05 ACC RATE LEVELS**
Adjustment to Test Year operations to reflect the annualization of ACC rate levels for the 4/1/05 rate increase authorized in Decision No. 67744.

Line No.	Description		Amount
1.	**REVENUES:**		
2.	Operating Revenue		
3.	Residential (less Dusk-to-Dawn)	$ 9,584	
4.	E-32 and E-30 Classes (less Dusk-to-Dawn)	3,891	
5.	Extra Large General Service	2,273	
6.	Other G.S. Classes (less Dusk-to-Dawn)	438	
7.	Irrigation	315	
8.	Other (Dusk-to-Dawn and Lighting)	635	
9.	Total Pro Forma Adjustment to Revenues		$ 17,136
10.	**OPERATING INCOME (before income tax)**		**$ 17,136**
11.	Income Tax at 39.17%		6,712
12.	**OPERATING INCOME AFTER TAX**		**$ 10,424**

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

PRO FORMA ADJUSTMENT: **E-3/E-4 PROMOTIONAL EXPENSE**
Adjustment to Test Year operations to reflect increased promotional expense for low income rate options as required in Decision No. 67744.

Line No.	Description	Amount
1.	**REVENUES:**	
2.	Operating Revenue	$ -
3.		
4.	**EXPENSES:**	
5.	Other Operating Expenses	
6.	Operations Excluding Fuel Expenses	62
7.	Total Pro Forma Adjustment to Expenses	62
8.		
9.	**OPERATING INCOME (before income tax)**	**(62)**
10.	Income Tax at 39.05%	(24)
11.	**OPERATING INCOME AFTER TAX**	**$ (38)**

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

PRO FORMA ADJUSTMENT:

SCHEDULE 1 CHANGES
Adjustment to Test Year operations to reflect revenue related changes to Schedule 1 as authorized in Decision No. 67744.

Line No.	Description	Amount
1.	**REVENUES:**	
2.	Operating Revenue	$ 127
3.		
4.	**EXPENSES:**	
5.	Other Operating Expenses	
6.	Operations Excluding Fuel Expenses	(19)
7.	Total Pro Forma Adjustment to Expenses	(19)
8.		
9.	**OPERATING INCOME (before income tax)**	**146**
10.	Income Tax at 39.05%	57
11.	**OPERATING INCOME AFTER TAX**	**$ 89**

Demand Side Management Adjustment Charge Plan for Administration

Demand Side Management Adjustment Charge Plan for Administration

General Description

Section VII of the Settlement Agreement approved by the Arizona Corporation Commission ("Commission") Decision No. 67744 provides for the establishment of a Demand-Side Management Adjustment Charge ("DSMAC"). The Arizona Public Service Company ("Company") is obligated under the Settlement Agreement to spend \$30 million (\$10 million annually) in base rates and at least another \$18 million (an average of \$6 million annually) during calendar years 2005 - 2007, with the latter amounts to be recovered by the DSMAC, on approved eligible Demand Side Management ("DSM") related items.

For purposes of implementing the Settlement Agreement, eligible DSM-related items include energy-efficiency DSM programs; a performance incentive; and low income bill assistance. These terms are defined in the Settlement Agreement. Energy-efficiency DSM is defined as the planning, implementation, and evaluation of programs that reduce the use of electricity by means of energy-efficiency products, services, or practices. The DSMAC charge is applied to Standard Offer or Direct Access customer's bills as a monthly kilowatthour or kilowatt demand charge. The charge is initially set at zero and will be reset annually, on March 1st, beginning in 2006. The change to the charge will be effective in billing cycle 1 of the March revenue month and will not be prorated.

All DSM programs must be approved before the Company may include their costs in any determination of the total DSM costs incurred. The Company may apply the program costs incurred after December 31, 2004 but prior to the effective date of Decision No. 67744 to the annual \$10 million base rate DSM allowance and to the additional spending on eligible DSM-related items provided for in the Settlement Agreement. These costs must be from programs already approved by Staff, or the Commission.

The Company may request Commission approval for DSM program costs and performance incentives that exceed the \$16 million (\$48 million over three years) level. Such additional DSM programs may include demand-side response and additional energy efficiency programs and the costs and incentives that will be recovered through the DSMAC.

Base Rate DSM Description

The Company may phase in its DSM spending from the base rate allowance funding. However, the Company is required to expend at least \$30 million on approved energy-efficiency DSM programs over the initial three years after a Commission order authorizing this program. After the initial three-year period, the Company is required to spend at least \$10 million of the base rate DSM funds annually on approved energy-efficiency DSM programs. If the Company does not expend during calendar years 2005 through 2007 at least $30 million (in total) of the base rate allowance for approved and eligible DSM-related items, the unspent amount of the $30 million will be credited to the balance for the DSMAC. The Company is obligated to spend at least $13 million on approved and eligible DSM-related items during 2005 with the spending obligation to be pro-rated to the date that the Commission approves the Final 2005 DSM Plan. In no event will such pro-ration reduce the Company's 2005 obligation below the annual $10 million base rate DSM allowance.

Performance Incentives

The Company will be permitted to earn, and recover, performance incentives based on a share of the net economic benefits (benefits minus costs) from the energy-efficiency DSM programs approved in accordance with the Settlement Agreement. Such performance incentives will be capped at 10% of the total amount of DSM spending, inclusive of the program incentives, provided for in the Settlement Agreement (e.g., $1.6 million out of the $16 million average annual spending or $4.8 million over the initial three-year period). Any such performance incentive collected by the Company during a test year will be considered as a credit against the Company's test year base revenue requirement.

DSMAC Billing

For residential billing purposes, the DSMAC and the EPS Surcharge adjustor are combined and will appear on customer bills as the "Environmental Benefits Surcharge." For the billing of general service and other non-residential customers, the Company may, but is not required to, provide for such combined billing of the EPS and DSM adjustment mechanisms. In any event, each such adjustor shall have separate rate schedules and will be kept separate in the Company's books, records, and reports to the Commission.

Allowable Costs

The DSMAC will recover: (1) all costs (whether capitalized or expensed) associated with pre-approved energy-efficient DSM programs in excess of the $10 million built into base rates; and (2) performance incentives as described above. The DSMAC may also recover approved DSM program costs and performance incentives that exceed $16 million annually ($48 million over three years). Such additional DSM programs may include demand-side response and additional energy-efficiency programs. The types of allowable costs are as follows:

A. Program Costs — Allowable expenses will include: program development, implementation, promotion, administrative and general, monitoring/metering costs, advertising, educational expenditures, incentives, research and development, data collection (such as end-use), tracking systems, demonstration facilities and all other activities required to design and implement cost effective energy efficient DSM for DSM Programs that are pre-approved and are not in base rates. For those DSM programs that generate revenue, the revenue will be credited back to the DSMAC.

B. Performance Incentives — Represents a share of the net economic benefits (benefits minus costs). Performance Incentives cannot exceed 10% of the total amount of DSM spending inclusive of the program incentive.

Customer Participation

Direct access customers shall be eligible to participate in the Company DSM programs. Any customer who can demonstrate an active DSM program and whose single site usage is twenty MW or greater may file a petition with the Commission for exemption from the DSM adjustor. The public shall have 20 days to comment on such petition. In considering any petition pursuant to this paragraph, the Commission may consider the comments received and any other information that is relevant to the customer's request.

DSMAC Calculations

Before March 1st, beginning in 2006, the Company will file a request with supporting documentation to revise its DSMAC. The DSMAC will be recomputed annually.

All required and approved spending on eligible DSM-related items above the annual $10 million base rate allowance will be recovered by the Company only on an "after-the-fact" basis through the DSM adjustment mechanism. DSMAC Schedules 1 through 4 shall be used to document DSMAC calculations.

The per-kWh charge for the year will be calculated by dividing the DSMAC recoverable costs by the number of kWh used by customers in the previous calendar year. General Service customers that are demand billed will pay a per kW charge instead of a per kWh charge. General Service customers that are not demand billed shall pay the DSMAC on a per kWh basis. To calculate the per kW charge, the recoverable costs shall first be allocated to the General Service class based upon the number of kWh consumed by that class. The remainder of the recoverable costs allocated to the General Service class shall then be divided by the kW billing determinants for the demand billed customers in that class to determine the per kW DSM adjustor charge. The DSM adjustor will be applied to both Standard Offer and Direct Access customers with the exception of solar rates Solar-1, Solar-2 and SP-1.

DSMAC Schedules

The recoverable annual costs and incentives from approved programs above the base rate cost allowance will be listed on Schedule 1. Schedule 2 lists actual revenues received by the Company through imposition of the DSMAC on customer bills. The Balancing Account computation (Schedule 3) contains the development of the recoverable costs for each year's DSMAC. Each year, the Un-Recovered DSM Cost accrues interest using the one-year Nominal Treasury Constant Maturities rate that is contained in the Federal Reserve Statistical Release H-15 or its successor publication. Schedule 4 is an example of the DSMAC demand and energy charge calculations.

ARIZONA PUBLIC SERVICE COMPANY
DSMAC Schedule 1
Example DSM Adjustment
Recoverable Costs
Charge Period XXXXXXX 1, XXXX through XXXXXXX 31, XXXX

Line No.		2005	2006	2007
1	Recoverable Program and Incentive Costs above the Base Rate allowance	$ 100,000	$ 5,000,000	$ 11,000,000

ARIZONA PUBLIC SERVICE COMPANY
DSMAC Schedule 2
Example DSM Adjustment
ACTUAL DSM Adjustment Charge Revenues
Charge Period XXXXXXX 1, XXXX through XXXXXXX 31, XXXX

Line No.	Mths	Actual Retail Energy Sales (kwh)	Effective DSM Adj. Energy Charge $ per kWh	Revenue From DSM Adj. Energy Charge	Actual Retail G.S. Monthly Demand (kW)	Effective DSM Adj. Monthly Demand Charge $ per kW	Revenue From DSM Adj. Demand Charge	Revenue From DSM Adj. Charges
1	Jan - Feb 05	3,048,197,000	$ -	$ -	4,166,667	$ -	$ -	$ -
2	Mar - Dec 05	19,305,074,000	$ -	$ -	20,833,333	$ -	$ -	$ -
		22,353,271,000		$ -	25,000,000		$ -	$ -
3	Jan - Feb 06	3,109,160,940	$ -	$ -	4,250,000	$ -	$ -	$ -
4	Mar - Dec 06	19,691,175,480	$ 0.000005	$ 98,456	21,250,000	$ 0.002000	$ 42,500	$ 140,956
		22,800,336,420		$ 98,456	25,500,000		$ 42,500	$ 140,956
5	Jan - Feb 07	3,171,344,159	$ 0.000005	$ 15,857	2,167,500	$ 0.002000	$ 4,335	$ 20,192
6	Mar - Dec 07	20,084,998,990	$ 0.000220	$ 4,418,700	23,842,500	$ 0.088000	$ 2,098,140	$ 6,516,840
		23,256,343,148		$ 4,434,556	26,010,000		$ 2,102,475	$ 6,537,031

ARIZONA PUBLIC SERVICE COMPANY
DSMAC Schedule 3
Example DSM Adjustment
Balancing Account Computation
Charge Period XXXXXXX 1, XXXX through XXXXXXX 31, XXXX

Line No.		2005	2006	2007
1	Recoverable Program and Incentive Costs above the Base Rate allowance (Sch. 1)	$ 100,000	$ 5,000,000	$ 11,000,000
2	Less DSM Revenue recovered from effective DSMAC (Sch. 2)	$ -	$ 140,956	$ 6,537,031
3	Un-Recovered DSM Costs (Line 1 - Line 2)	$ 100,000	$ 4,859,044	$ 4,462,969
4	Annual Interest @ 3.33%	$ 3,330	$ 161,806	$ 148,617
5	Total DSMAC Recoverable Costs (Forward to Sch. 4)	$ 103,330	$ 5,020,850	$ 4,611,585

ARIZONA PUBLIC SERVICE COMPANY
DSMAC Schedule 4
Example Calculation of the DSM Adjustment Charge
Charge Period XXXXXXX 1, YYYY through XXXXXXX 31, YYYY

Line No.		2005	2006	2007
1	Total DSMAC Recoverable Costs (Sch. 3, Line 5)	$103,330	$5,020,850	$4,611,585
2	Retail kWh Sales in Period (Sch. 2)	22,353,271,000	22,800,336,420	23,256,343,148
3	DSM Adjustment Charge per kWh to be Applied in Following Year (Line 1/Line 2)	**$ 0.000005**	**$ 0.000220**	**$ 0.000198**
4	kWh Sales for General Service Customers with Demand-Based Bills	10,000,000,000	10,200,000,000	10,404,000,000
5	kW Billing Determinants for General Service Customers with Demand-Based Bills	25,000,000	25,500,000	26,010,000
6	Revenue for G.S. Customers with Demand-Based Bills (Line 3*Line4)	$50,000	$2,244,000	$2,059,992
7	Monthly DSM Adj. Charge per kW to be Applied in Following Year (Line 6/Line 5)	**$ 0.002000**	**$ 0.088000**	**$ 0.079200**

APS Investigation into Rate Designs Conducive to Conservation and DSM

November, 2005

TABLE OF CONTENTS

APS Investigation into Rate Designs
Conducive to Conservation and DSM

Executive Summary

Arizona Public Service ("APS" or "Company") conducted an assessment of various retail pricing concepts that could be conducive to encouraging conservation and peak demand reduction while meeting other key rate design criteria. This study was performed in accordance with Decision No. 67744[1] of the Arizona Corporation Commission ("ACC").

The study assessed the Company's situation concerning the customers and electric loads that we are committed to serve, both now and in the future, and the generation resources and costs necessary to serve our customers. This evaluation outlined key issues concerning our system loads and resources and provided direction and focus for the types of pricing designs that could potentially help address those issues. The key issues include the following:

A. APS System Needs

1. The Company is facing high load growth, especially during peak times. APS' load growth is nearly three times the national average.

2. The summer daily peak is broad, lasting from late morning to well into the evening. Peak day hourly loads in the early to mid evening are still within 90% of the peak hour.

3. The winter peak is low relative to the summer. Winter peaks are typically 40% to 50% lower than the summer.

4. Annual system load factor is relatively low. This is driven by low energy usage in the winter relative to the summer as well as a low daily off-peak usage relative to peak usage, for both the winter and summer seasons. Low load factors are generally considered to be more expensive to serve, in terms of average cost per kilowatthour (kWh), since generation, transmission and distribution capacity fixed costs necessary to serve the peak load are spread over fewer kWhs compared with high load factor cases.

5. While the APS system load remains high over a number of hours during the peak day, the number of critical days or hours with extremely high loads or high short-term energy costs is moderate.

B. Pricing Concepts Evaluated

The pricing study focused on evaluating pricing concepts that could (1) help manage peak growth by reducing summer peak usage, (2) improve the system load factor by

[1] APS Rate Settlement Section VII, Paragraph 57.

reducing summer peak use or shifting load from on-peak to off-peak during the summer season, (3) encourage energy efficiency or (4) focus the intended customer load response to critical days and hours. As a result, the study investigated the following pricing concepts:

- Residential inclining block rates
- Residential time-of-use rates
- General Service time-of-use rates
- Mandatory vs. Voluntary Rates
- Other Demand Response Programs such as critical peak pricing and demand bidding programs

Each pricing concept was evaluated based on the following criteria; industry experience, potential customer acceptance and participation, potential impacts on the system peak and overall annual load shape, and program implementation costs.

C. Conclusions

Inclining Block Rates – Residential

Inclining block rates establish prices for blocks of monthly energy consumption and increase the price for the higher blocks. The objective is to encourage energy conservation by placing a higher price on the highest marginal usage, which is presumed to be for some discretionary purpose. The Company currently has over 479,000 or 56% of total residential customers on inclining block rates, which are the standard residential rates. The conclusions reached are:

1. APS should maintain the defined usage levels for the pricing blocks at their current levels, which are 0-400 kWh per month for Tier 1 prices, 401-800 for Tier 2 prices, and greater than 800 kWh per month or Tier 3 prices. A reduction in the block usage structure to 0-350 kWh per month for Tier 1 and 351-750 kWh per month for Tier 2 would likely provide only limited impacts on energy conservation, could limit the benefits of the pricing change for some low and moderate-use customers, and would create an inconsistency with the blocks for the low income and medical discount programs.

2. Changing the pricing structure for Rate Schedule E-12 by shifting cost emphasis from the price of the lowest usage block (Tier 1) and raising the price of the highest usage block (Tier 3) should be done with moderation because the Tier 3 price is already high in relation to the Tier 1 price.

Time-of-Use Rates – Residential

Time-of-use rates (TOU) determine daily and seasonal time periods for pricing electricity, which include peak, off-peak and sometimes shoulder periods. Energy and/or demand charges are determined for each of these time periods. Currently APS offers two residential TOU rates: Time Advantage (ET-1), which includes peak and off-peak energy charges; and Combined Advantage (ECT-1R) which includes both time differentiated demand and energy charges. Over 357,000 APS residential customers, or 40% of total, are currently participating in a TOU rate. On September 22, 2005, APS filed an Application with the Commission to obtain approval for two new experimental residential TOU rates. Schedule ET-2 parallels the exiting TOU schedule ET-1 and ECT-2 parallels the features of ECT-1R. These new schedules provide for longer off-peak periods than the existing TOU rates and also incorporate holidays in the off-peak periods. Both new rates have time-differentiated charges. ECT-2 will also have a demand charge applied to the peak period. Customer reaction to these new rate offerings will be one indicator whether the experiment will be expanded to a broader group of customers.

Time-of-Use Rates – General Service

Time-of-use rates have been used widely by numerous utilities for general service customers. For the purposes of this report, general service refers to commercial and industrial customers with demands typically less than 3,000 kW. TOU rates encompass a variety of pricing designs which use a combination of demand and energy charges for peak and off-peak periods. TOU rates are referred to as static demand response rates because both the peak and off peak prices and time periods are established in the tariff and cannot be varied to react to temporary changes in hourly energy costs or loads. The Company's, new general service TOU rate, E32TOU, was implemented in April, 2005. Thus, it is too soon to assess the potential customer acceptance and load impacts. However, the rate is consistent with other general service TOU rates offered by other utilities in terms of the rate structure, price ratios for on- and off-peak periods, and on-peak hours. The Company will undertake the following:

1. Continue to implement the current general service time-of-use rate as designed with the potential for minor design adjustments to make the rate more customer friendly. As discussed below, the rate structure, charges, and peak time period is consistent with current TOU pricing concepts and tariffs offered by many other utilities.

2. Monitor customer participation in Schedule E-32 TOU. Examine the load patterns of customers who opt for the new rate to determine if the desired goals of reduction in on-peak demand and on-peak energy conservation are being realized.

Mandatory vs. Voluntary Rates

Voluntary demand rates are generally considered to be favorable because; they avoid the negative image of mandatory rates, they avoid adverse impacts on inelastic customers, they maintain market discipline for providing better programs, and they can result in better target marketing of programs to specific customer groups.

After considering the various issues, it is not recommended that APS move to mandatory general service TOU rates largely due to the negative image of forcing customers to participate in a rate or program. Some of this is a general concern that many customers may not be able to respond to time-differentiated prices. Therefore, forcing all customers on a demand response rate would have adverse and, in some cases, unintended consequences for particular customers or customer groups.

Other Demand Response Programs

1. Critical Peak Pricing

   Critical Peak Pricing (CPP) options are fairly new and are typically targeted to commercial and industrial (C&I) customers. However, there have been a few residential programs or experiments. CPP combines time-of-use pricing with an additional on-peak higher price period, which is selectively applied by the utility during periods of high energy costs or reliability issues.

2. Demand Bidding Programs

   Demand bidding programs are being tested by some utilities for commercial and industrial customers. These programs allow a customer to bid potential load reduction, typically the day before a critical event, for an incentive based on a predetermined price. For some programs, participants are not required to bid into any particular critical event or even reduce their load as bid. Other programs require customers to "deliver" their load reductions as bid or face penalties. These demand response programs are fairly new and there are still many uncertainties concerning customer acceptance, potential load impacts and implementation costs.

   Based on the uncertainty at this time of the potential participation and implementation issues including costs, the Company will undertake the following:

   - The Company will continue to monitor critical peak pricing and demand bidding programs to assess pricing designs, program best practices, and customer participation and load impacts.

   - The Company will further assess program implementation costs, especially communication infrastructure, data handling and billing systems to better assess the cost/benefit.

Implementation of New Pricing Concepts

Section I of this report discusses metering, meter reading and billing system limitations that must be addressed in order to implement new pricing concepts. For example, because of the market penetration of residential TOU pricing, even a modest change to the existing rate structure such as altering off-peak pricing hours could be a significant undertaking because of the need to reprogram meters that are currently installed. APS is investigating new technologies, including a pilot Advance Metering System (AMS), that, if proven successful, will provide for greater rate option flexibility in the future.

APS Investigation into Rate Designs Conducive to Conservation and DSM

SECTION I

Company Peak, Load Shape and Load Factor

Overview

APS serves more than 1,000,000 customers in 11 of Arizona's 15 counties, including the Phoenix Metro area. In August 2005, the APS system load demand peaked at 7,000 MW with associated annual energy of approximately 30,000 GWh.

Historically, growth in APS' service territory has been about three times the national average. In 2004, the APS customer base increased by 3.7% or approximately 35,000 customers and retail energy sales increased by 3.2%. Currently the Company is projecting an average annual growth rate of approximately 3.9% for peak demand through 2009, and 4.6% for energy sales over this period.

Annual system load factor, which is the relationship between peak demand and overall energy usage, was 52% in 2004. This means that for every 100 MW of consumption during the annual peak hour, APS customers used only 52 MW per hour on average in all of the other hours of the year.

The summer peak load is typically 40% to 50% or 2,000 MW higher than the winter peak. In addition the Company's high loads are concentrated into a relatively small number of hours on an annual basis. For example, in 2004 there were only 25 hours in which loads were within 5% of the system peak, 87 hours within 10% of system peak.

APS owns a portfolio of generation technologies that include steam turbines and combustion turbine engines fueled by nuclear, coal, gas and oil. The mix of generation comprises of 71% baseload capacity and 29% peaking capacity.

Peak Day Load Shape

Summer Peak

Figure 1 displays the APS system peak day load for 2004. In addition, Table 1 shows hourly information for the highest 10 peak days in 2004. As shown, the summer peak for APS' retail load typically occurs between 3:00 and 6:00 p.m. The load begins to ramp up at 9:00 am. By 12:00 p.m. the load is within 10% or 500 MWs of the daily peak. The load remains high, within10% of the daily peak, though 8:00 p.m. and falls off after 9:00 p.m. The load from 6:00 to 7:00 is typically 95% of the daily peak; the load from 7:00 to 8:00 is 91% of the daily peak.

Winter Peak

The winter peak for APS' retail load typically occurs at 7:00 to 8:00 a.m. in one of the cold months (December – February). The daily load ramps up at 6:00 a.m. and falls off after 9:00 a.m. Afternoon usage picks up at 6:00 p.m., reaching 90% of the daily peak, and falls off after 9:00 p.m.

In some years, hot temperatures in March or April can cause daily loads to rival some of the cold days in December and January. In 2004, for example, 5 of the top 10 "winter" days were in March and April. However, the usage patterns for these days resemble the summer peak days. In any case, winter loads are significantly lower than summer loads. Typically, the winter peak is 40% or 2,000 MW lower than the summer peak.

Figure 1. APS System Peak Day 2004

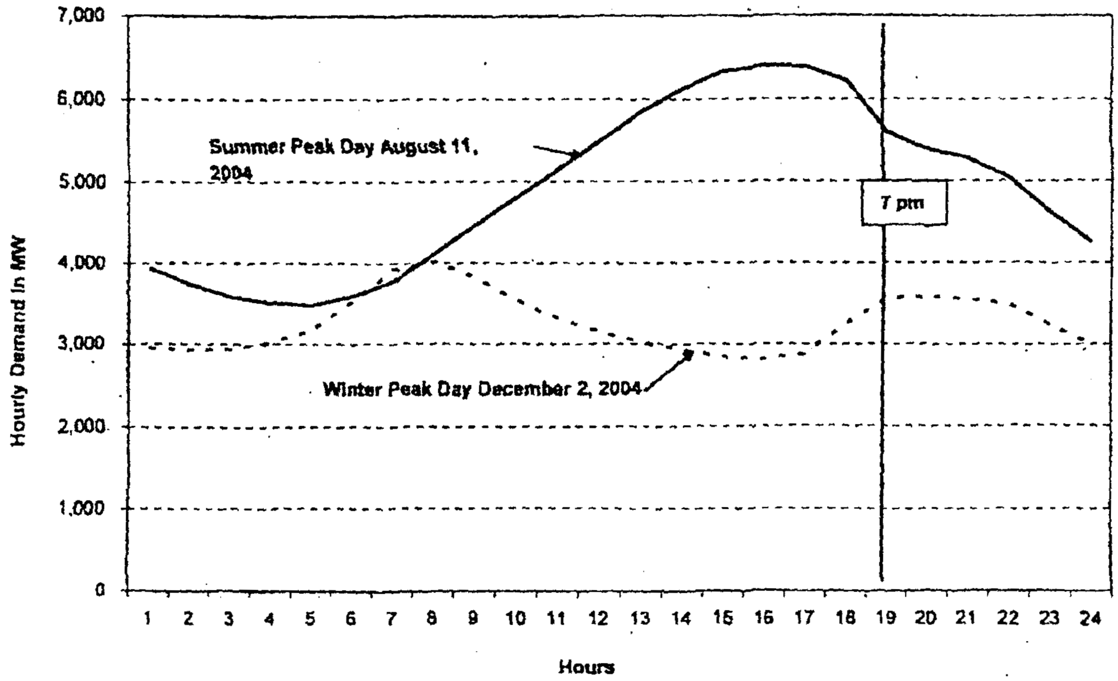


Table 1 Summer 2004 Top 10 Peak Days (hour ending)

Hour	1am	6am	9am	noon	1pm	2 pm	3 pm	4pm	5pm	6pm	7pm	8pm	9pm	10pm	12pm
Average	4014	3595	4378	5324	5609	5870	6054	6104	6117	6086	5816	5585	5446	5170	4334
Delta Peak	-2103	-2522	-1739	-794	-508	-248	-63	-13	0	-31	-301	-532	-671	-948	-1783
% Peak	66%	59%	72%	87%	92%	96%	99%	99%	100%	99%	95%	91%	89%	84%	70%

System Load Factor

Table 2 compares the annual system load factors for APS and other regional utilities for 2000-2003. The system load factor represents the relationship between usage during the system annual peak hour and the usage during all other hours of the year. A low load factor means that customers demand a lot of load during the peak hour, but don't use very much energy on average during other times of the year. Due to our high summer peak, APS' annual system load factor has been relatively low as compared to load factors of other electric systems in other western states.

Table 2 Historical System Load Factors for WECC Utilities (in %)

	2003	2002	2001	2000
APS	50.9	52.6	53.2	52.3
EPE	61.4	61.5	64.8	65.4
LDWP	55.0	55.2	59.5	55.7
NPC	47.6	47.5	47.2	47.2
PAC	68.1	68.8	73.7	72.2
PG&E	56.8	56.6	57.5	55.6
PGE	67.3	67.0	65.8	65.3
PNM	64.8	68.4	69.5	67.0
PSC	59.0	62.0	61.6	61.1
PSE	61.5	64.0	61.7	61.6
SCE	55.1	57.6	60.2	57.8
SDGE	57.8	60.9	66.6	64.8
SMUD	43.0	41.5	45.0	43.5
SPP	66.9	67.8	71.0	69.7
SRP	49.4	50.8	51.8	52.4
TEP	50.4	53.1	56.7	55.6

Another perspective of the APS system load factor is presented in Table 3, which shows the number of hours that the system hourly demand reached a certain percentage of the annual system peak demand. For example, in 2004, there were only 87 hours during which time the system hourly load was equal to, or higher than, 90% of the annual peak. The implication is that peaking capacity is always required to meet the customer demand for energy for a short period of time.

Table 3 APS Historical Hourly Own Load Analysis

YEAR	ANNUAL PEAK LOAD IN MW	NUMBER OF HOURS WHEN SYSTEM HOURLY DEMAND IS EQUAL TO OR GREATER THAN				
		95% of Peak	90% of Peak	85% of Peak	80% of Peak	75% of Peak
2000	5,186	45	153	374	719	1092
2001	5,372	16	69	267	625	1030
2002	5,494	28	150	382	686	1008
2003	5,973	34	119	299	542	859
2004	6,018	25	87	269	520	825

Customer Load Diversity

The APS system load shape is the result of various diversified usage patterns generated by customers' end uses of electricity in different climate zones. An end use is met by an appliance (residential usage) or equipment (commercial/industrial applications). For example, an air conditioner is used to supply space cooling (an end use) in a residential home. Each electric appliance or equipment imposes a pattern of varying hourly demand on the system, that is, it has its own load shape.

Individual end use (or appliance) load shapes are vastly diversified that the sum of their individual hourly consumptions results in a total load shape that is significantly different from the end-use load shapes. Most important is the peak hourly demand on the utility's total system. The peak hourly demand of the total load shape is significantly lower than the sum of the individual peak hourly demands.

An example of the diversity of customers' end-use loads is demonstrated in Table 4, using load research data from August, 2004.

Table 4 APS Customer Load Diversity

	Residential	General Service*
Sum of individual customer maximum demands	5841 MW	3478 MW
Non-coincident peak demand	3127 MW	2748 MW
Coincident peak demand (Peak day July 14,2003)	2571 MW	2252 MW
Average customer maximum demand	6.83 kW	33.40 kW
Average customer coincident demand	3.01 kW	21.63 kW

August 2004 data.
* *Customers on rate schedules E-30 and E-32.*

The APS service territory covers the high-country area (Flagstaff), the Phoenix Valley and the low-desert area (Yuma) which contribute to the system diversity due to the natural diversity in weather patterns among the various locales.

Diversity can also be viewed on a much larger system perspective, that is, diversity among different utilities. Utilities in the Desert Southwest area typically peak in the summer whereas those in the Northwest area typically peak in the winter. This diversity in system peaks allows opportunities for seasonal energy exchanges. An example of this opportunity is the contract between APS and PacifiCorp, which was consummated in 1990 to take advantage of the diversity between APS (summer peaking) and PacifiCorp (winter peaking).

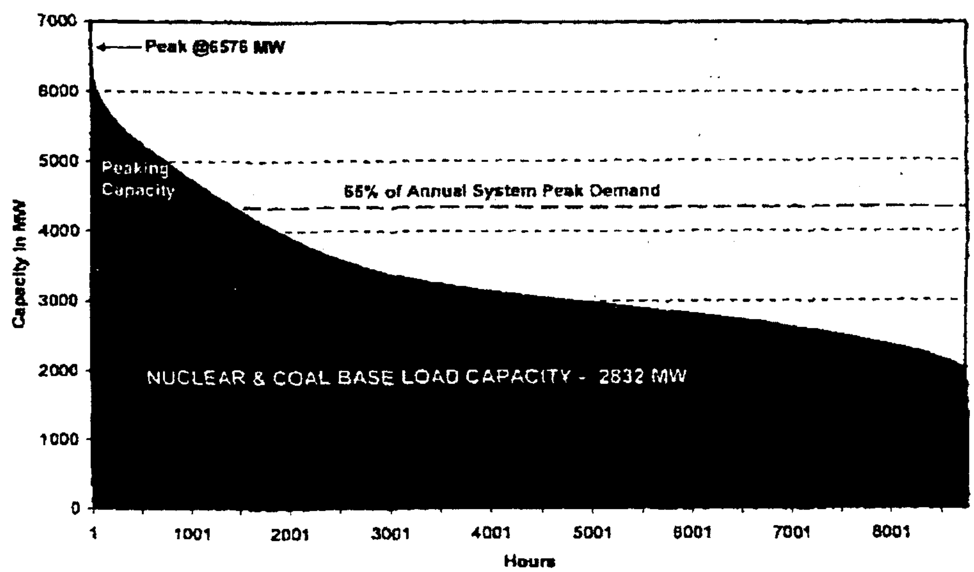
Generation Resources

Peaking Capacity Requirements

Figure 2 shows the projected Load Duration Curve (LDC) for the year 2005. Plotted against the 2005 LDC is the expected energy to be dispatched from APS' current mix of generation capacity including baseload nuclear/coal, gas-fired combined cycle and peaking plants. It can be seen that the system was designed for optimal efficiency with peaking capacity being dispatched when system hourly demand is higher than 65% of annual peak demand. This also depicts the requirements for peaking capacity to meet the peak demand of the system. Figure 2 shows the need of about 2,200 MW of peaking capacity in 2005. Currently, APS has about 1,800 MW of gas-fired peaking capacity installed. Reserve requirements are not included in the peaking capacity estimate.

Figure 2

2005 LOAD & RESOURCE BALANCE



Key Findings

1. The Company is facing high growth, especially during peak times.

2. The summer daily peak is broad, lasting from late morning to well into the evening.

3. The winter peak is low relative to the summer. Winter peaks are typically 40% lower than the summer.

4. System load factor is relatively low. This is driven by low energy usage in the winter relative to the summer as well as a low daily off-peak usage relative to peak usage, for both the winter and summer seasons. Low load factors are generally considered to be more expensive to serve, in terms of average cost, as generation, transmission and distribution capacity costs necessary to serve the peak are spread over fewer megawatt hours (MWH) of overall energy use.

5. While the system load remains high over a number of hours during the peak day, the number of critical days or hours with extremely high loads or high short-term energy costs is moderate.

Implications for Pricing Design

Reflecting the characteristics of the APS system, this study focuses on evaluating pricing concepts that could potentially:

- Help manage peak growth by reducing summer peak usage.
- Improve the system load factor by reducing summer peak use or shifting load from the peak to off peak during the summer season.
- Focus the intended load response to critical days and hours.

Pricing Design Reviewed

To encourage or enable customers to change their usage patterns in order to lower overall costs, pricing should be designed to send price signals that are more reflective of costs or capacity constraints in specific periods of time or in specific situations. Typically this means lowering consumption during peak periods, especially during times of very high costs or system constraints. However, it can also mean increasing consumption in off-peak periods with relatively low energy costs, especially by shifting load from peak to off-peak periods.[2] The latter can improve system load factor and thereby potentially lower average costs. It can also increase consumer welfare by providing customers with the derived benefits of electricity when costs are low.

Rates may be static or dynamic. Static prices, such as time-of-use (TOU) rates, have peak and off-peak prices that are pre-determined and set in rate tariffs. Dynamic prices by contrast can change contemporaneously with changing cost or reliability conditions. Examples of dynamic pricing include critical peak pricing, real-time pricing (RTP), or various demand-bidding programs. Critical peak pricing is a TOU rate with a critical period price that is only applied during select days of the year with high costs or low reliability. Dynamic prices typically involve on-going interaction between the utility or control area operator and the customer such as the communication of prices, notification of critical periods, submission of load bids, and in some cases direct control of customers' loads by the utility.

Inclining block rates establish prices for blocks of monthly energy consumption and increase the price for the higher blocks. The objective is to encourage energy conservation by placing a higher price on the marginal usage, which is presumed to be for some discretionary purpose. These rates also attempt to protect customers by setting a lower price on the lowest consumption block, which is presumed to for necessities. Inclining block rates are generally considered to be conservation rates, but have been considered by some to be a type of demand response pricing as will be discussed later.

[2] This issue is often overlooked [Christensen 2003]

The pricing study includes an assessment of:

- Residential inclining block rates
- Residential time-of-use rates
- General service time-of-use
- Mandatory vs. Voluntary Rates
- Demand response Programs
  - Real time pricing and
  - Demand bidding programs

Each rate was evaluated in terms of how it helped to address the Company's load and resource issues, industry experience, potential participation, impacts on system peak and energy, and program implementation costs. Industry assessments of these pricing concepts also address issues of mandatory versus voluntary rates and potential revenue erosion from new rates.

Implementation of New Pricing Concepts

Implementing new pricing concepts requires changes to metering, the customer information and billing system, the metering information system and related programs. These systems and numerous subsystems interrelate to capture metered data, ensure that the customer is on the correct rate with the correct meter, calculate the bill, present the bill, allow for re-bills and corrections, schedule meter and service changes, provide customer service information and screens to advise customers about rate options, allow customers to assess rate options through the internet, post the revenue to the general ledger, and many other functions. Most importantly, any new rates that are structurally different from current rates require significant systems testing to ensure that the data is correctly captured, billing is accurate and that the programming changes do not adversely impact any other part of the systems.

Several of the key systems that require modifications for implementing new rate schedules are metering, the customer information and billing system, the customer service software interface, APS.COM and the meter information system. Two of the key systems are described below. Additional discussion on this topic can be found in the report on TOU flexibility that was provided to the Commission in October, 2005.

<u>Metering technology</u>
APS' current meter reading system does not support the capability of reprogramming meters in the field with the hand held "probe" device that is used to read the meters. While software support that enabled field programming was once available, it is no longer supported by the current vendor. Therefore, meter programming must be performed at the manufacturer, at the utility's meter shop, or in the field using a computer loaded with each meter vendor's software. The latter option is not practical for handling a significant number of customers due to the time required to reprogram each meter.

Because of the limitation of our current meter reading system, changing time-of-use characteristics, such as the on-peak hours for an existing rate schedule would require replacing the meters of all of the current customers on the rate schedule. In addition to being very costly, such a massive meter change out could only occur over a long period of time. During the transition period, meter record keeping would be very challenging since the links between the meter which is currently in use at a customer's residence and the appropriate rate schedule must be maintained. For example, if the customer has already migrated to the rate schedule with new TOU periods and experiences a meter failure, the APS meter service personnel must have the correct replacement meter available in inventory.

Another issue concerns the potential need for a meter change when a customer switches between standard and TOU rate schedules. Many customers require a meter change to accommodate a switch in rate schedules. Some customers have meters that are pre-programmed to be able to bill both standard and TOU rate schedules. In this case, the customer would not typically require a meter replacement if the customer switched between a standard rate schedule and one of APS' current TOU rate schedules.

However, this flexibility erodes as new TOU rates with different on-peak hours and other characteristics are introduced. For example, while a meter can be pre-programmed to be able to bill both a standard rate and a TOU rate, it cannot be pre-programmed to be able to bill both a TOU rate schedule with a 9A.M. to 9 P.M. on-peak period and one with a noon-7 P.M. on-peak period. This is because the billing determinants for the standard rate are nested in (or captured by) the TOU billing information. However, the billing determinants for the two TOU rate schedules, namely the on-peak and off-peak kWh, are distinct and cannot be simultaneously captured by the same meter. Rate switches between the alternative TOU rate schedules would require the meter to be re-programmed with the new rate schedule.

APS is reviewing several metering alternatives that may add flexibility for changing TOU rates in the future. These included implementing an alternate meter reading system, implementing an advanced metering system (AMS) and using interval data recording meters (IDR). These alternatives are not mutually exclusive and a combination of the new technologies will likely be implemented.

Customer Information System (CIS)

CIS is the mainframe software application that handles all billing, customer data, and customer information processing. In order to implement new rate offerings, CIS requires programming changes to ensure that the customer account is maintained properly with the current rate schedule, meter and other relevant information, and that the bill is calculated and presented accurately. This requires changes to various tables, service plans, screens, reference tables, bill calculation, bill statements, rate comparison features, order processing, E-bill, service account maintenance, new business cases, new reports, and related subsystems.

If a new rate schedule involves changing the basic structure of the rate calculation, it requires extensive programming of the basic CIS data base and related tables and code. New rate schedules and meter types have to be tested to ensure that the billing information is correctly extracted from the meter and uploaded to the CIS system. Also, old data structures and relations must be maintained so that rebilling of customers, if ever needed, can occur. In summary, rate structure changes such as new pricing concepts cannot be handled by CIS without considerable investment in programming and testing.

SECTION II

Inclining Block Pricing - Residential

Overview

Inclining block rates establish prices for blocks of monthly energy consumption and increase the price for the higher blocks of consumption.

Variations include baseline pricing and inverted pricing for peak time energy usage or demand. For peak-period inverted-block rates, prices increase with energy usage or demand during peak periods, but are constant or decline with usage during off-peak periods. Under baseline pricing, prices increase for usage above a baseline level for basic and necessary services.

Currently the Company offers inclining block rates as the standard, non-time-of-use rate for residential customers. The inclining block rates are Rate Schedule E-10, which is frozen to new customers, and Rate Schedule E-12, which is the standard, non-TOU option for residential customers. As shown in Table 5, over 479,000 customers or 56% of total customers are participating in inclining-block rates. Both rates divide the monthly energy consumption into three blocks: 0 to 400 kWh, 401 to 800 kW, and above 800 kWh. The current energy charges for each block for the summer season are shown in Table 6.

Table 5 Residential Inclining Block Rates (2004)

	AVERAGE CUSTOMERS	ENERGY SALES (MWH)
E-10	83,504	814,452
E-12	396,024	3,420,566
Total Inclining Block	479,528	4,235,018
Total Residential	859,069	11,497,367
Percent	56%	37%

Table 6 Residential Inclining Block Rates
Summer Energy Charges by Block (Cents per kWh)
Rates Effective April 1, 2005

	0 to 400 kWh	401 to 800 kWh	Above 800 kW
E-10	6.929	9.490	9.760
E-12	7.570	10.556	12.314

Industry Experience

A review of standard residential rates for select utilities showed a mix of flat (energy charges do not vary with usage), declining block or inclining block prices. The review included major utilities in the South, West, and Midwest which were likely to have substantial summer loads. Utilities in the Northeast were not reviewed because they were presumed to be more winter peaking and because many states in the region have active retail competition and have required utilities to divest generation assets. California utilities generally have an inclining block structure for standard residential rates, which were instituted a few years ago and modified as a response to the energy crisis. The California rates will be discussed separately.

Table 7 compares APS' standard residential rate E-12 with other standard residential rates. Out of the 25 utilities reviewed, 10 have inclining block rates for standard residential service, 15 have either flat or declining block rates. The inclining block rates generally have two or three tiers, with the upper limit of the first tier ranging from 200 to 1,000 kWh per month. By comparison, the first tier of APS' E-12 rate ends at 400 kWh per month. For rates with three tiers, the upper limit of the second tier ranges from 800 to 1300 kWh per month. APS' second tier limit is 800 kWh per month. APS generally has a more aggressive tiered pricing structure compared with other utilities. As shown, the comparative price ratio of the highest to lowest tiers for the APS E-12 rate is 1.63, meaning that the last tier price is 63% higher than the first tier. This is second only to Georgia Power with a 1.70 ratio, and they have a much higher starting point for the last tier – 1,100 kWh versus 800 kWh for APS. The remaining 23 utilities have high-to-low tier price ratios ranging from 1.04 to 1.34.

Table 7 Standard Residential Rates for Select Utilities

UTILITY, STATE	RATE STRUCTURE	TIERS, KWH/MONTH	LAST TIER/FIRST TIER CHARGE
APS – AZ	Inclining Block	0-400, 401-800, >800	1.63
PNM – NM	Inclining Block	0-200, >200	1.17
PacifiCorp –Wash	Inclining Block	0-600, >600	1.58
Detroit Edison – MI	Inclining Block	0-17 kWh per day	1.18
FPL	Inclining Block	0-750, >750	1.12
Utah Power Light – UT	Inclining Block	0-400, 601-1000, >1000	1.34
Georgia Power – GA	Inclining Block	0-650, 651-1100, >1100	1.70
Duke – NC, SC	Inclining Block	0-350, 351-1300, >1300	1.13
Progress Energy – FLA	Inclining Block	0-1000, >1000	1.14
Alabama Power – AB	Inclining Block	0-1000, >1000	1.04
Aquilla – KA, MO	Flat		
Nevada Power – NV	Flat		
SRP- AZ	Flat		
TEP – AZ	Flat		
Progress Energy – NC	Flat		
MidAmerican – IOWA	Flat, winter DB		
LGE – KY	Flat		
Entergy – Ark	Flat		
Entergy – LA	Flat		
Commonwealth Ed – IL	Flat		
PSC – CO	Flat		
Cinergy – Ohio	Flat		
OGE – OK	Declining Block		
Entergy - Miss	Declining Block		
Dominion – VA	Declining Block		

California Baseline Inclining Block Rates

California utilities implemented inclining block rates several years ago with a first energy usage tier designed to provide customers a baseline level of service. The baseline allowance was calculated according to geographical/climate regions. Additional baseline allowance was typically added for all-electric homes and for qualified medical needs. For example, the baseline usage For SCE customers varies from 10.0 to 47.6 kWh per day, which is an average of 300 to 1400 kWh per month, for the summer season, depending on the region. Usage above the baseline amount is charged according to three additional tiered prices with the tiers defined as 101% to 130% of baseline usage, 131% to 200% of baseline and over 200% of baseline. As a response to the energy crisis of 2000-2002, pricing of the inclining block rates became more aggressive. Tiered energy prices range from approximately 11.75 cents per kWh for summer baseline usage and 17.34 cents per kWh for the highest tier (exclusive of other charges). These prices can vary somewhat depending on the proportion of generation that comes from the utilities retained generation versus the amount that was procured for SCE customers by California during the energy crisis. The ratio of the price of the highest tier to the lowest tier is 1.48 for the summer season, which is less than APS' ratio of 1.63 for Rate Schedule E-12.

Analysis and Issues

Pursuant to Decision No. 67744, APS investigated potential changes to the tier usage levels and prices for Rate Schedule E-12. Specifically we evaluated the potential implications of (1) lowering the first tier usage limit from 400 to 350 kWh per month, (2) lowering the second tier usage limit from 800 to 750 kWh per month, (3) lowering the energy price for the first tier usage and (4) raising the price for the highest tier usage. The potential benefits of these proposed changes are presumably to encourage additional energy conservation by shifting the average customer's marginal monthly usage into the highest tier and to raising the price of the highest tier. The rate modification could also potentially provide bill savings for the lower-usage customers. Each of these changes is assessed below.

Assessment of Proposal to Lower the Usage Limit and Price for Tier 1

Lowering the usage limit of Tier 1 from 400 to 350 kWh per month can help to reduce the potential revenue loss from lowering the Tier 1 price. However, the change could cause unintended consequences for some customers. Specifically, while this proposed change would lower the price for usage in the 0-350 kWh block, it would significantly raise the price for the 350 to 400 kWh block by shifting this usage to the Tier 2 price. Therefore, customers at the 350 to 400 kWh usage level could be harmed from this change.

Table 8 Rate E-12 Summer Customers and Consumption by Block

Block (kWh/month)	Bills (per Summer)	kWH (per summer)	Average Customers (per month)	kWh (per month)	Current Charge ($/kWh)	Proposed Change in Block Price
0-350	703,761	113,808,000	117,294	18,968,000	0.07570	Decrease
350-400	102,797	38,605,990	17,133	6,434,332	0.07570	Increase
400-750	670,095	380,885,072	111,683	63,480,845	0.10556	No Change
750-800	77,784	60,302,304	12,964	10,050,384	0.10556	Increase
above 800	947,269	1,325,185,565	157,878	220,864,261	0.12314	Increase
Total	2,501,706	1,918,786,931	416,951	319,797,822		
Average	767	kWh/month				
Median	0	kWh/month				

*2004 Data

As shown in Table 8, there are over 17,000 customers on average with summer monthly usage between 350 and 400 kWh per month. Currently their summer energy cost is $0.07570 per kWh for all of their consumption. Under the change, the energy price for the first 350 kWh of consumption would be reduced somewhat, but the 350 to 400 consumption would be increased significantly from $0.07570 to $0.10556 /kWh shifting it to Tier 2 pricing. For example, under the current rate E-12 a customer consuming 400 kWh per month would pay $30.28 for base energy charges (excluding the basic service charge and other taxes and fees). If the first block is changed to 0-350 and the Tier 1 price is reduced by 5%, then on net this customer's bill would actually increase.

Table 9 Impact from Tier 1 Changes

Impact of the 0-350 Tier 1 Block and a 5% reduction in Tier 1 Price Base energy charges for customer consuming 400 kWh per month

	Usage kWh per month	Energy Price $/kWh	Base energy Cost $/month*
Current E-12 Rate			
Tier 1	350	0.07570	26.50
Tier 1	50	0.07570	3.79
Total	400		30.28
Tier 1: 0-350 kWh, 5% Price Reduction			
Tier 1	350	0.07192	25.17
Tier 2	50	0.10556	5.28
Total	400		30.45
% change			0.6%

* excludes basic service charge, CRCC and other taxes and fees

The decrease in the Tier 1 price could be structured to be large enough to avoid a bill increase for this group of customers. For example, a 7% decrease in the Tier 1 price would result in a reduction in monthly base energy charges of 1.2% for the customer consuming 400 kWh per month. But even so, their savings is far lower than the 7% reduction for customers consuming below 350 kWh per month. The point of the example is that lowering the Tier 1 block from 0-400 to 0-350 kWh per month can unintentionally harm or greatly reduce the benefits for customers consuming at or slightly above the block limit.

Furthermore, as shown in Table 10, many of APS' E-12 customers receiving E-3 low income discounts could fall into his category. In fact, over 38% of low income customers are typically billed at the second pricing tier, 401-800 kWh per month, and could be affected by the lower block limit. The low income information points to another benefit of keeping the lower block limit at 400 kWh per month, which is to maintain consistency with the block levels for the E-3 low income discounts.

Table 10 E-12 Customers with Low Income Discount

Pricing Tier	Bills per Summer	Average Customers	
0-400	24,333	4,056	25.3%
401-800	36,738	6,123	38.2%
801-1200	19,510	3,252	20.3%
>1200	15,498	2,583	16.1%
	96,079	16,013	100%

* E-3 discount, 2004 Data

Additionally, it is difficult to target the benefits of a Tier 1 price reduction to lower use customers because larger use customers would also receive a price reduction for their Tier 1 consumption. As shown in Table 11, 43% of all summer consumption for rate E-12 was billed under the first pricing tier. However, lower usage customers with monthly consumption of 0-400 kWh, who were billed solely under Tier 1 pricing, comprised only 8% of total consumption. The implication is that in order to grant a price discount for the 8% lower-usage consumption, a price discount must also be given to 43% of total consumption. This would include the 19.6% Tier 1 usage for the largest customers with monthly consumption greater than 800 kWh per month.

Table 11 E-12 Percent Total Summer Usage Pricing Tiers

Monthly Usage Blocks	Tier 1	Tier 2	Tier 3	Total
0-400	7.9%	0.0%	0.0%	8.0%
401-800	15.6%	7.4%	0.0%	23.0%
>800	19.7%	19.7%	29.5%	69.0%
Total	43.2%	27.1%	29.5%	100.0%

2004 data

In addition, some of the low-usage customers may not necessarily be low income. While APS has not studied this issue in depth, some of the data suggests that some of the low-usage accounts could be second homes that have limited consumption during the summer. Table 12 shows that roughly 806,000 summer bills or 134,000 average customers consume at or below 400 kWh per month (numbers derived by adding the 0-350 kWh and 350-400 kWh blocks). However, over 12,800 of these customers consumed 0 kWh and roughly 69,000 consumed less than 200 kWh per month during the summer season. This 0-200 kWh group could include some low income customers, but it could also represent some other type of account, such as a second home. As shown in the Rate Schedule E-3 discount data in Table 9, low income customers are more likely to use above 400 kWh per month.

Table 12 E-12 Rate, Bills and kWh for Summer Season*

	Tier (kWh per month)	Charge	Bills per Summer	kWh per Summer
First Tier	0-400	0.07570	806,558	152,413,990
Second Tier	401-800	0.10556	747,879	441,187,376
Third Tier	Above 800	0.12314	947,269	1,325,185,565
Total			2,501,706	1,918,786,931

*2004 data

The implications are that lowering the Tier 1 price could help some low income customers, but it is difficult to target the help to those customers. The price change would also reduce the Tier 1 usage for all Rate Schedule E-12 customers and could provide the largest benefit to customers with second homes or other types of accounts that would not warrant a subsidy from other customers. In addition some low income customers use more than 800 kWh per month and could in fact be hurt by this proposed change.

Assessment of Lowering the Usage Limit for Tier 2 and Raising the Price for Tier 3

Lowering the usage limit on the second block from 800 to 750 kWh per month, would not likely have a meaningful impact on energy conservation. Again, the apparent motivation of the proposed change was to move the average summer consumption of 770 kWh per month to the upper tier, subjecting it to the higher block pricing and, therefore, maximizing the encouragement of energy conservation. However, in this case, the average consumption across all customers for the summer season is not very relevant because the tiered pricing is applied to the tiered usage of each customer in each month. Average consumption is effected by low-usage customers, high-usage customers, and even variations in monthly usage for a given customer, none of which would be impacted by this proposed change.

In other words, lowering the second tier usage limit would only change the marginal price signal for customers using between 750 and 800 kWh in a given month, and only for their last increment of usage above 750 kWh. Referring back to Table 12, this group comprises roughly 12,964 average customers and 60,302 MWH for the summer season, which is approximately 3% of both total customers and total energy for E-12. Furthermore, a large percent of E-12 customers and consumption are already being billed at the highest tier (over 800 kWh). In fact, over 157,000 customers, or 38% of total E-12 customers and 1,325,185 MWH, or 30% of total, are billed in the highest priced tier over the summer period.

Raising the price of the highest tier could encourage energy conservation, but this potential impact is not well understood in the industry. As discussed later in this report, most of the studies have concluded that residential customers on average respond to higher price signals. However, the analysis has largely been in the context of customers reducing or shifting peak-period consumption in response to time-of-use rates, real time pricing or, more recently, critical peak pricing.

Furthermore, one of the well understood short-comings of inclining block rates is that while they are presumed to encourage some conservation, they do not necessarily encourage conservation at the right time. They do not send time-differentiated price signals to ensure that the energy reduction is taking place during peak periods, when it is needed. So while they may be useful for pricing storable commodities such as water, they have limited benefits for managing electricity loads, especially the high peak growth that the Company is facing.

Conclusions

1. Any pricing change for rate E-12 should be moderate because the tier 3 price is already high in relation to the Tier 1 price.

2. The defined usage levels for the pricing blocks at their current levels, which are 0-400 kWh per month for Tier 1 prices, 401-800 kWh for Tier 2 prices, and greater than 800 kWh or Tier 3 prices should be maintained. A reduction in the block

usage structure to 0-350 kWh for Tier 1 and 301-750 kWh for Tier 2 would likely provide only limited impacts on energy conservation, could limit the benefits of the pricing change for some low and moderate-use customers, and would create an inconsistency with the blocks for the low income and medical discount programs.

SECTION III

Time of Use Pricing – Residential

Overview

Time of use rates have energy and/or demand charges which vary by time periods, both by time of day and season. Typically, these rates are static, that is, the charges and designated hours for peak and off-peak periods are determined and set in the tariff and cannot be flexibly changed to respond to changes in system costs or reliability.

Industry Experience

Time-of-use rate programs were reviewed for major utilities in the South, West and Midwest, which have significant summer peaks. States with active deregulation were generally not included in the analysis because many have divested generation and are changing the structure of standard offer service prices based on competitive issues. The results are summarized in Table 13. Of the 25 programs reviewed, 20 rates had time-differentiated energy charges, 4 had time differentiated demand and energy charges, and 1 rate had a time differentiated demand charge and a flat energy charge.

For the TOU energy rates, most (85%) were structured as a two-part rate, which includes a peak and off-peak energy charge for each season. Three-part rates include charges for a peak period, shoulder period and off-peak period. The on-peak hours vary considerably by utility, ranging from 5 hrs to 14 hrs. For the two-part rates, 41% had a summer peak period of 8 hours or less, 50% were between 9 and 12 hours; and 9% were greater than 12 hours. Three-part rates had summer peak periods ranging from 5 to 7 hours and combined peak and shoulder hours of 7 to 11 hours. By comparison, APS' current TOU rates fall into the middle group with a 12 hour summer peak period.

Table 13 Residential TOU Rates for Select Utilities

UTILITY, STATE	RATE STRUCTURE	SUMMER PEAK HOURS	PEAK/OFF PEAK ENERGY CHARGE
APS – AZ	2 part energy	9 am – 9 pm	3.1
PNM – NM	2 part energy	8 am – 8 pm	2.3
AEP – Indiana	2 part energy	7 am – 9 pm	4.2
FPL – FLA	2 part energy	12 noon - 9 pm	1.9
Utah Power Light – UT	2 part energy	1 pm – 8 pm	NA
Progress – NC	2 part energy	10 am – 9 pm	4.3
TECO – FLA	2 part energy	12 noon – 9 pm	1.2
Georgia Power – GA	2 part energy	2 pm – 7 pm	3.2
Progress Energy – FLA	2 part energy	12 noon – 9 pm	3.5
Nevada Power – NV	2 part energy	1 pm – 7 pm	2.4
SRP- AZ	2 part energy	1 pm – 8 pm	3.8
Entergy – Ark	2 part energy	1 pm – 8 pm	5.1
OGE – OK	2 part energy	1 pm – 7 pm	6.4
SMUD – CA	2 part energy	2 pm – 8 pm	2.2
Commonwealth Ed – IL	2 part energy, declining block off peak	9 am – 6 pm	3.5 – 4.2
PGE – CA	2 part energy tiered to usage	12 noon – 6 pm	2.2 – 3.4

Table 13 Residential TOU Rates for Select Utilities (cont)

UTILITY, STATE	RATE STRUCTURE	SUMMER PEAK HOURS	PEAK/OFF PEAK ENERGY CHARGE
SDGE – CA	2 part energy tiered to usage	12 noon – 6 pm	1.1
SMUD – CA	3 part energy	2 pm – 8 pm peak; 12-2, 8-10 shoulder	2.5 peak/off 1.7 shoulder/off
Alabama Power – AB	3 part energy	12-7 peak; 10-12, 7-9 shoulder	9.3 peak/off 2.9 shoulder/off
TEP – AZ	3 part energy	1-6 peak; 6-8 shoulder	3.2 peak/off 2.0 shoulder/off
APS – AZ	Demand and energy	9 am – 9 pm	1.78 energy, plus demand charge
Ameren CIPs	2 part demand and energy	10 am - 10 pm	1.4 energy, plus demand charge
MidAmerican – IOWA	2 part demand and energy	10am to 10pm	1.7 energy, plus demand charge
Dominion – VA	2 part demand and energy	10 am – 10 pm	2.7 energy, plus demand charge
PSC – CO	2 part demand	8 am to 10 pm	Demand differential only

The levels of charges for various pricing periods also vary considerably by utility. As shown, the ratio of peak to off-peak energy charges for various TOU rates ranges from 1.1 to 6.4 for two-part energy rates, most of which are below 3.5. Again, a 3.5 ratio means that the peak period price is 3.5 times the off-peak price. For the two-part energy rates, 44% had peak/off-peak ratios below 3.0, 31% had ratios between 3.0 and 3.9, and 25% were 4.0 and above. By comparison APS' two-part energy rate has a ratio of 3.1.

Peak to off-peak price ratios for three-part rates ranged from 2.5 to 9.3, while ratios of shoulder to off-peak prices ranged from 1.7 to 2.9. The 9.3 ratio for Alabama Power is likely to be an outlier driven by an extremely low off-peak energy charge of 1.8 cents per kWh.

TOU rates which include both time-differentiated demand and energy charges generally have lower peak/off-peak energy price ratios, because on-peak revenue is also collected through a demand charge. Energy price ratios for this rate structure ranged from 1.4 to 2.7. APS' comparative rate has a ratio of 1.78. Note that the on-peak time periods are typically fairly long for these rates - 12 hours or above.

Participation in residential TOU rates has generally been low. As shown in Table 14, APS by far ranks high in terms of participation compared with other utility TOU programs. A recent survey of TOU and demand response programs confirmed this result, finding that participation in TOU rates and other types of residential demand response programs is generally low, usually ranging from almost zero to 3% of eligible customers. The survey also reported that TOU programs are not generally expanding, due to lack of customer interest or changing regulatory circumstances.[3]

[3] *See Summit Blue Utility Survey Draft Report 2005 pg 6-7.*

Table 14 Participation in Select TOU Programs*

UTILITY, STATE	RESIDENTIAL TOU CUSTOMERS*
APS – AZ	357,372
PNM – NM	142
AEP Indiana	5,303
Utah Power Light – UT	176
Georgia Power – GA	93
SRP- AZ	145,000
Entergy – Ark	38
OGE – OK	383
Commonwealth Ed – IL	47
PGE – CA	86,672
TEP – AZ	4,883
Ameren CIPs	1,105
MidAmerican – IOWA	30

* 2004 data. Numbers reflect rates reviewed above

Assessment of Potential New TOU Pricing Options

Pursuant to Decision No. 67744, the Company investigated the potential for offering two new time-of-use rates, one with time-differentiated energy charges, and one with demand and energy charges, both of which have shorter on-peak hours and a higher ratio of summer peak to off-peak prices compared with current rates. Proposed rates were filed with the Commission on September 22, 2005. The Company also performed a TOU Flexibility Study that was submitted to the Commission on October 7, 2005. These reports addressed the metering and billing system limitations that must be addressed before new TOU pricing options can be implemented.

Potential Peak and Energy Impacts

Load impact studies have generally found that residential customers are responsive to TOU prices although the results varied considerably depending on the utility, customer characteristics, rate structure, and, most importantly, the methodology used.

The results of impact studies are generally reported as either direct percentage reductions in energy usage over a specified peak period or by elasticity values, which measure the percentage change in energy usage in response to a percentage change in prices.

Elasticities for these purposes are generally expressed as either own-price elasticity or the elasticity of substitution. Own-price elasticity measures the percent change in consumption caused by a percentage change in price. In this context, it measures the percentage reduction in peak-period energy usage for a percentage increase in peak-period price. For example, if the own-price elasticity was 0.15, then a 100% increase in the peak period price would result in a 15% reduction in energy usage during the peak period. The elasticity value is actually -0.15, but the negative is typically dropped because it is generally understood that an increase in price will lead to a decrease in usage.

The elasticity of substitution measures how much energy is shifted to the off-peak period in response to a change in the ratio of peak to off-peak prices. It calculates the percent change in the ratio of peak to off-peak energy usage relative to a percentage change of the ratio of on, to off-peak prices. For example, an elasticity of substitution of 0.15 means that if the ratio of on, to off-peak prices increased by 100%, then the ratio of peak to off-peak energy consumption would decrease by 15%. The peak period load impacts can then be derived from the elasticity information.

The impact of residential time-of-use pricing has been estimated in numerous studies over the last 30 years. Elasticities of substitution have ranged from almost zero to 0.37 from these various experiments. Some of the studies date back to the 1970's and 1980's using data from a series of TOU experiments sponsored by the (now) Department of Energy at a number of utilities. One review of these experiments found that the elasticity of substitution was fairly consistent across the utilities with typical values in the range of 0.14. Elasticity estimates for TOU rates which also incorporate critical peak pricing are typically higher as reviewed and will be discussed below. A summary of several of the more prominent findings for TOU rates (without critical peak pricing) is provided in Table 15. Estimated reductions in peak period energy usage derived from these elasticities ranged from very low to over 7%.

Table 15 Elasticity Findings from Other Studies Residential Time-of-Use

Utility	Year	Elasticity of Substitution	Study
California IOUs	2003; 2004	Sub 0.122 Daily 0.038	CRA California Statewide Pricing Pilot, CPP-F Zone 4 normal weekdays
California IOUs	2003	Sub 0.109 Daily 0.118	CRA California Statewide Pricing Pilot, TOU, Zone 4, 2003
Five States	1977 – 1980	0.12	Caves 1984
PG&E – CA		0.37	Caves 1989
Midwest Power		0.15-0.39	Balidi 1998
Oklahoma Muni	1977 – 1978	0.12	Huettner 1982

<u>The California Statewide Pricing Pilot</u>
Recently, the California Energy Commission (CEC) conducted a study of demand response rates, including residential TOU rates. In the experiment, nearly 1,600 residential and small commercial customers were placed on one of several TOU and critical peak pricing plans. In addition a control group of over 800 customers remained on their standard baseline rate, which was typically an inclining block rate. Treatment groups for each rate were also placed on several different price levels to be able to derive the relationship between usage and price (demand curves) for each rate. Furthermore, the sample was structured for four different climate zones, with zone 4 being the hottest and most comparable to much of the APS service territory.

The California experiment found that residential customers were somewhat responsive to demand response rates. The substitution elasticities are shown in Table 15. Notice that the customer responsive to TOU rates varied considerably from 2003 to 2004. In 2003 the estimated reduction in peak period usage for TOU customers for zone 4 during the hottest months of the summer was 6.73%. In 2004, the measured response for the same group of customers was only 0.4%. The study offers several issues with the sample size and estimation methodology as potential explanations for this dramatic difference.

The study suggests that an alternative estimate of TOU response can be made by using the response results for the critical peak price during normal weekdays. The critical peak price (CPP-F) had a high price during declared critical days, but had a normal TOU structure during normal weekdays. Both the response to the critical price as well as the normal TOU price were estimated for this customer group. And because the sample sizes were relatively large, the study recommends that it may provide a better estimate of response to TOU rates.

Table 16 California Statewide Pricing Pilot – Residential Results

Rate	Elasticity	Reduction in peak period usage
Time of Use		
CPP-F, Zone 4, normal weekdays, 2003, 2004, inner summer	Sub -0.122 Daily -0.038	7.35%
TOU Zone 4, 2003, inner summer	Sub -0.109 Daily -0.118	6.73%
TOU Zone 4, 2004, inner summer	Sub 0.018 Daily -0.127	0.4%
Critical Peak Pricing		
CPP-F, Zone 4, critical days 200	Sub -.127 Daily -.033	17.4%
CPP-V, critical days	Sub -.111 Daily -.027	15.7%

Estimating the Load Impacts of New TOU Rates Using Data from the California Study
Impact estimates using response results from other studies can potentially be inaccurate for several reasons. First, elasticities are point estimates – they measure responses of new prices in relation to the existing baseline rates. If baseline prices or new prices differ from those used in the borrowed data, the results may not be comparable. Also, the customer response depends on a number of factors that can vary across utilities including weather, and saturations of appliances such as air conditioning, electric water heating and pool pumps.

The California SPP study provides several advantages that allow reasonable estimates using their borrowed data. First, the California study not only estimated the load impact from the various experimental rates, but they also estimated demand functions for each of these pricing structures. Demand functions specify the relationship of peak usage to price over a range of prices, which better allow applying the data to rate levels not considered in the study. Also as discussed, the California study performed the analysis for four different climate zones. Zone 4 is most comparable to APS with higher summer temperatures and higher saturations of air conditioning.

The prime target for new TOU rates are customers who are currently participating in one of the current TOU rates or new customers who would have chosen one of the existing TOU rates. These customers already have a propensity for time-of-use and the proposed new rates considered in the study are similar in structure to the existing rates, but with shorter peak hours and a higher ratio of peak to off-peak prices. The current APS TOU energy rate (ET-1), has a peak/off-peak price ratio of approximately 3:1. So the price response for the new TOU (ET-2) energy rate will be the incremental shifting from going to a higher price ratio and from reducing the peak period from 12 hours to 7 hours.

To the extent that the baseline rate for some participants would be one of the inclining block rates such as Rate Schedule E-12, the impacts would measure the total shifting of energy use from the peak to off-peak period relative to their baseline usage pattern.

The Model

The California study estimated demand functions for the various rates using the constant elasticity of substitution model, which is well developed and widely used in demand response studies. This method first models the ratio of peak to off-peak usage as a function of the ratio of peak to off-peak prices and other terms. Next, the system models daily electricity usage as a function of the daily price of electricity and other variables. Many studies omit the second element and thus assume that TOU rates have no impact on overall energy consumption, only the allocation of usage to peak and off-peak periods.

Impact Estimate Results

The California estimates and APS estimates based their adapted model to include both the hourly-shifting and daily usage equations. APS data was substituted and the California substitution elasticities were used to estimate a reasonable range of potential peak period energy reductions from the time periods in the new energy based TOU rate recently developed by APS.

The results reflect the incremental impact of current TOU (ET-1) customers moving to the new TOU energy rate. This was performed with two cases: case 1 used the elasticity estimates from the California critical peak price for normal days; case 2 used the TOU elasticity estimate from 2003. The results, provided in Table 17, show potential reductions in summer peak-period energy consumption of 1.3 to 1.8 percent.

Table 17 Impact Estimates - Reduction in Summer Peak Period Usage*

	Elasticity	Estimated Peak Period Energy Reduction(Summer)	Reasonable range of summer impacts
Case 1 CA, SPP, 2003-04, CPP-F Zone 4, normal weekdays	Sub -0.122 Daily -0.038	1.8 %	2% to 5%
Case 2 CA, CEC, 2003, CRA '03 Zone 4, summer	Sub -0.109 Daily -0.118	1.3%	2% to 5%

* Resulting from customers switching from ET-1 to the new TOU energy rate.

Although the TOU peak hours were included in the analysis, the model probably does not fully account for the peak impact due to the change in the peak period from 12 hours to 7 hours. In addition some of the participants could be customers currently on an inclining block rate, such as E-12, rather than a TOU rate. In this case the potential impacts, while not specifically estimated, would be higher, perhaps more in line with the California findings of 6% to 7% peak period impact. Therefore, a reasonable overall range of expected reductions in peak-period energy usage would be from 2% to 5%.

SECTION IV

General Service Time-of-Use

Overview

Time-of-use rates have been used widely by numerous utilities for general service customers. For our purposes, general service refers to commercial and industrial customers with demands typically less than 3,000 kW. As summarized below, TOU rates encompass a variety of pricing designs which use a combination of demand and energy charges for peak and off-peak periods. TOU rates are referred to as static demand response rates because both the peak and off-peak prices and time periods are established in a tariff and cannot be varied to react to temporary changes in hourly energy costs or loads.

Advantages

1. Time-of-use rates have been around for a number of years, are typically not very complicated and, therefore, should require less customer education compared with dynamic demand response rates.

2. Time-of-use rates can support a number of rate designs including both demand and energy charges.

3. Time-of-use rates are less costly to implement than dynamic demand response rates such as critical peak pricing and demand bidding programs, which require customer communications, remote metering, and more complicated data handling, billing, and settlement systems.

Disadvantages

1. The potential load response of commercial and industrial customers to time-of-use rates is not well understood and can vary considerably across utility studies depending on the customer mix. Time-of-use rates also suffer from the same sort of customer reaction to the critical peak pricing, which is that many customers report having a hard time consistently responding to peak price signals due to the nature or their business and end-use loads.

2. General service customers are very diverse in their overall usage patterns, their end-uses, operating hours, and ultimately their potential responsiveness to TOU rates.

3. TOU rates are static, they cannot be changed on a daily basis as costs and loads fluctuate. Therefore, it is more difficult to fine tune the price signals sent to customers and match them with actual Company needs at any point in time.

Conclusions

1. Continue to implement the current general service time-of-use rate as designed. The rate is newly implemented in April 2004, so it is too soon to tell whether the current rate design will be successful in attracting customers and providing beneficial load shifting or reduction. Furthermore, as discussed below, the rate structure, charges, and peak time period is consistent with current TOU pricing concepts and tariffs offered by many other utilities.

2. Keep the current summer on-peak time period, which is weekdays 11 am to 9 pm. This keeps a level of diversity compared to the proposed shortened time periods of the new residential TOU rates. The concern is that system load is still within 10% of the system peak hour of 7 to 8 p.m. As a result, if too much load is shifted to this hour, it could create in a system peak in the later hour, rather than reducing the peak.

3. Monitor participation and load patterns for customers obtaining service under Rate Schedule E-32TOU.

APS General Service Customers

Currently, APS has over 105,000 general service customers taking service under Rate Schedules E-32 and E-30. These customers have demands under 3,000 kW and as a group consume nearly 11 million MWH per year, which is approximately 43% of total retail energy sales. Most of our general service customers are commercial customers. As shown in Tables 18a and 18b, only 3% of general service customers and 7.4% of revenue are categorized as industrial customers. Of the commercial customers, office and retail loads are the most significant, comprising over 42% of total general service annual energy consumption.

Table 18a APS General Service Customers

	Customers		MWH per year	
Commercial	102,359	97%	10,177,440	92.6%
Industrial	3,356	3%	807,775	7.4%
Total	105,715	100%	10,985,215	100.0%

2004 Data, Customers < 3,000 kW demand

Table 18b APS General Service Customers
MWH by Customer

	2004 MWH Share	Growth 2001 - 2004	Growth 2003 - 2004
Other	24.6%	10.2%	3.6%
Office	23.6%	7.1%	2.6%
Retail	18.5%	9.0%	4.1%
Industrial	7.8%	-5.0%	4.0%
Grocery	4.9%	0.4%	-0.4%
School	5.7%	9.7%	6.4%
Restaurant	5.3%	3.4%	2.9%
Hotel	3.6%	6.7%	0.6%
Warehouse	3.4%	1.9%	1.3%
Hospital	2.5%	7.1%	0.5%
All	100.0%	6.5%	3.1%

C&I A Class Weather Adjusted Sales (MWh)

The majority of general service customers have demands below 100 kW. However, customers with demands greater than 100 kW consume most of the energy. For example, as shown in Table 19 for the 2004 peak month, 98,000 out of the 104,000 general service customers were below 100 kW demand. However, nearly 65% of the monthly energy was consumed by customers with demands greater than 100 kW. In addition the customer's load factor, which is the relationship between usage during the peak hour and usage in other hours, increases with size. Load factors can be expressed on a monthly or annual basis and can be based on a customer's individual peak or their usage during the hour coincident with the system peak. A higher monthly load factor means that usage is more consistent across the different hours in the period. As shown, load factors for the peak month, based on the customer's individual peak usage, range from 21% for customers with demands less than 20 kW to 63% for customers with demands between 1,000 and 3,000 kW. Similarly, the load factors based on the coincident peak usage range from 40.5% to 75.3% respectively.

Table 19 E-32, E-30 General Service Customers and Usage – 2004 Peak Month
E32, E30 August 2004 data

kW demand	Customers	Monthly Energy	Demand Customer Peak	Demand Coincident Peak	Monthly Load Factor Customer Peak	Monthly Load Factor Coincident Peak
0 - 20	80,914	116,695	731	395	21.2%	40.5%
21 - 100	18,074	236,623	945	594	33.1%	54.6%
101 - 400	4,118	295,786	952	654	41.9%	62.0%
401 - 999	821	202,674	447	409	61.7%	83.2%
1000 - 3000	205	151,663	324	276	63.3%	75.3%
	104,132	1,003,441	3,399	2,252	39.5%	61.0%

Comparison of TOU Rates

Historically, the Company offered TOU rates for various general service customer segments on an experimental basis. However, in April 2005 the Company implemented a new TOU rate available to all general service customers. The new rate, E32-TOU, combines demand and energy charges for on-peak and off-peak periods. The tariff is split for customers from 0 to 20 kW demand and customers above 20 kW. For the latter group, the summer on-peak demand charge for secondary service is $15.112 per kW for the first 100 kW and $10.887 for each additional kW. Summer base energy charges are 4.815 cents per kWh on-peak and 3.815 cents per kWh off-peak. The rate also has a residual demand charge if the customer creates a new peak in the off-peak period. There are currently only a few customers enrolled on the rate. The on-peak hours are weekdays from 11 a.m. to 9 p.m. year round. APS also offers a TOU rate, designated E-35, for large general service customers (over 3 MW).

A comparison of general service time-of-use rates for select utilities is summarized in Table 20. The comparison includes major utilities in the South, West, and Midwest with substantial summer loads; states with predominately cold climates and active retail competition were excluded. As shown, utilities generally use several rate designs for general service time-of-use. The majority of the utilities included in the comparison, including APS, use a combination of demand and energy charges for the peak and off-peak periods. Some utilities use 2-part or 3-part energy rates, without demand charges.

The APS E32-TOU rate uses a combination of on-peak and off-peak demand and energy charges. Under this rate design, the ratio of peak to off-peak energy charges is typically much lower than all-energy TOU rates. So a key incentive for customers to reduce or shift their usage during peak periods is to avoid the peak demand charge. As shown, the ratio of peak to off-peak energy prices for the demand and 2-part energy rates range from 1.0 to 2.2 for the utilities compared. APS' ratio of 1.3 is fairly typical for this group. Also notice that the daily on-peak hours are fairly long for this group of rates, ranging from 8 to 16 hours.

Table 20 General Service Time-of-Use Summer Rates for Select Utilities

Utility	Rate	Demand Charge (1) $/kW	Energy Charge (2) - On/Off ratio	Peak Hours	Peak and Shoulder Hours
Demand and 2-part energy rates					
APS	E32TOU	11.73	1.3	11-9	
SCEG	21	18.86	1.4	1-9	
LGE	LC-TOD	14.20	1.0	10-9	
KU	LI-TOD	6.87	1.0	10-9	
FPL	GSDT-1	8.32	1.6	12-9	
FPL	GSLTD-1	8.34	1.4	12-9	
Duke	OPT (NC)	12.98	1.9	1-9	
Dominion	GS-2T	9.64	2.2	10-10	
PNM	3B	3.84	1.9	8-8	
Entergy-ARK	GST	11.74	1.2	7-6	
Pacific Power	48T	5.05	1.0	6-10	

(1) Combines peak, NCP, and shoulder demand charges.
(2) Includes base energy charges and fuel adjustor.

Table 20 General Service Time-of-Use Summer Rates for Select Utilities (cont)

Utility	Rate	Demand Charge (1) $/kW	Energy Charge (2) - On/Off ratio	Peak Hours	Peak and Shoulder Hours
Utah Power	6B	12.76	1.0	7-11	
Demand and 3-part energy rates					
PGE	E-19	16.76	1.9	12-6	8:30-9:30
SDGE	AL-TOU	17.27	1.3	11-6	6-10
SRP	E32	5.24	2.7	2-7	11-11
Georgia Power	GSD-2	12.03	5.6	2-7	12-9
Energy rates					
OGE	GS-TOU		6.9	2-8	
Utah Power	6A		3.3	7-11	
Tucson Electric	GS-76		3.3	1-6	1-8
Alabama Power	LPTM		6.5	12-7	10-9
SMUD	GSTOU1		1.4	2-8	12-10

(1) Combines peak, NCP, and shoulder demand charges.
(2) Includes base energy charges and fuel adjustor.

The demand and 3-part energy rates typically have a higher ration of on/off-peak energy prices, ranging here from 1.3 to 5.6. These rates have a shorter "super peak" period lasting 5 to 7 hours, but a long overall peak and shoulder period of 9 to 16 hours. The energy only rates have the highest on/off-peak price ratios ranging from 3.3 to 6.9. The high price ratio for Alabama Power is driven by a very low off-peak energy price, which is probably impacted by the glut of new wholesale power plants in the region.

As can be seen, APS' new TOU rate for general service customers is consistent with those of comparative utilities in terms of rate structure, price ratios and peak hours. In particular, APS' general approach of using on-peak demand charges as a primary driver for customers to shift load to off-peak periods is similar to the approach taken by most of the comparative general service rates.

SECTION V

Voluntary versus Mandatory Rates

In various jurisdictions, analysts and policy makers have debated whether the new rates should be mandatory, voluntary, or established as the default rate. The latter option would automatically place customers on the rate, but allow them to opt-out to another rate option.

Aside from a few large general service (LGS) time-of-use rates and some provider of last resort rates for large customers, TOU rates have generally been offered on a voluntary basis. Major new initiatives today such as the California Statewide Pricing Pilot (SPP) and the New England Demand Response Initiative (NEDRI) follow in that trend. A recent survey of rate offerings nationally confirmed this result and found that all of the rates in their survey were provided on a voluntary basis.[4] A report on TOU pricing commissioned by the Idaho PUC concluded that TOU rates have generally not been mandated or established as the default rate for residential customers.[5]

Arguments in Favor of Mandatory or Default Rates

Mandatory or default demand response rates, including TOU, have been considered because of the potential for increasing participation, reducing revenue erosion, improving cost causality, and lowering marketing costs.

One concern is that customer inertia, or the propensity to stay put and not change rates, and risk avoidance is likely to keep participation low for voluntary demand response rates. In addition, many of the customers that should be on the rate due to their low load factors or high coincident peak usage are the very customers that are least likely to participate. This is due to the fact that these customers may have to shift a lot of load to off-peak periods in order to save money or at least avoid losing money on the rate.

Mandatory rates would obviously maximize participation by forcing all relevant customers on the program. Proponents assert that this in turn would promote optimal capacity investment decisions. Default rates would increase participation initially as customers are placed on the rate, but not necessarily increase participation over time as customers can switch to another rate. Inertia would help to preserve participation over time in a default rate. However, customer's general level risk avoidance would tend to propel customers back to their old rate, before being placed on the default demand response rate.

Revenue erosion, which is discussed more fully below, occurs from free riders – customers that save money on the rate without changing their usage patterns; and from load shifting – saving money by changing usage patterns as a response to the rate. The former is also referred to as the self-selection problem as customers that can best take advantage of the rate while doing the least will be most apt to participate in the rate. One of the advantages of a mandatory demand response rate is that it would reduce or eliminate the revenue erosion due to free riders, if it was designed to be revenue neutral for the mandatory customer group. Revenue erosion would still

[4] Summit Blue 2003
[5] Christensen and Associates 2003

occur between rate cases from customers saving on their bill by conserving usage or shifting usage to lower cost periods.

Proponents also argue that mandatory rates can better allocate costs to those customers who cause them. Lower load factor customers, who are more costly to serve, may currently be receiving an intra-class subsidy from customers with higher load factors. To the extent that this occurs with standard rates, mandatory demand response rates could better match rates with cost causality.

Finally, mandatory rates could lower some of the program costs such as the costs of initially acquiring the customers or the costs of certain incentives for participation.

Arguments for Voluntary Rates

Voluntary demand rates are generally considered to be favorable because, they avoid the negative image of mandatory rates, they avoid adverse impacts on inelastic customers, they maintain market discipline for providing better programs, and they can result in better target marketing of programs to specific customer groups.

After considering the various issues, a general aversion to mandatory rates appears to persist, largely due to the negative image of forcing customers to participate in a rate or program. Some, of this is a general concern that many customers may not be able to respond to time-differentiated prices. Therefore, forcing all customers on a demand response rate would have adverse and, in some cases, unintended consequences for particular customers or customer groups.

In addition, some demand response rates or programs are not appropriate for all customers. For example, some rates involve load control or demand bidding approaches which require particular metering and communication equipment or customer equipment such as energy management systems. In a recent demand response pilot, the Sacramento Municipal Utility District (SMUD) found that 88% of interested, prospective participants had electrical or phone equipment that was incompatible with the program.[6] Voluntary programs can effectively target potential participants to better manage program effectiveness and avoid the one-size-fits-all approach, which would probably be inherent in mandatory programs.

Furthermore, voluntary programs have the discipline of the market as a check for program quality and effectiveness. Demand response programs must be effective and deliver value to customers in order to gain acceptance.

Finally, while voluntary rates may increase some program costs such as customer acquisition costs and incentives, they may lower others. For example, many demand response rates involve metering, communication, education and training costs that increase with the level of participation. Mandatory rates would require an investment in these costs for all customers, not just the targeted participants. In addition, default rates could result in many customers switching back to their original rate, which would further increase the implementation costs.

[6] See SMUD presentation on CPP Pilot 2004.

In the final equation, stakeholders from a variety of perspectives appear to continue to recommend that TOU and demand response rates should be provided on a voluntary basis, even for larger general service customers. For example, the working group in the California CPP responsible for developing rates for general service customers reached a general consensus that the demand response tariffs should be voluntary. In fact, they reported that no participant appeared to favor a mandatory requirement.[7]

Considering all of these issues, the Company concludes that any of the new rates considered from the results of this study should be piloted or implemented on a voluntary basis.

Revenue Erosion

As discussed above, revenue erosion from TOU rates can be caused by either free riders – customers who save money by migrating to a rate without changing usage; or customers conserving energy, clipping peak demand, or switching usage to lower price time periods. So demand response rates can result in short-term net revenue loss for utilities, even if they lead to lower system costs over time.

There are several approaches to help mitigate the potential revenue erosion between rate cases. These include rate design, multiple-part rates, recovery of net lost revenues, and mandatory rates.

Mandatory rates can reduce or perhaps eliminate revenue erosion from free riders, but would not necessarily address the loss in revenue from customers conserving energy or shifting energy to lower price time periods.

Revenue erosion can occur from a new demand response rate if the rate is designed to be revenue neutral on a class basis – that is, the rate is designed to collect the same total revenue if the entire customer class moved on to the rate. In reality the entire class will not move on to the new rate, but only a subset of the customers who are more likely to benefit from the rate. Customers who would likely lose (pay more) will not move to the new rate or stay on it for very long. Because there are no revenue increases from losers to make up for the customer savings from winners, the new rate will result in revenue erosion between rate cases. One approach to mitigate revenue erosion is to design the rate to be revenue neutral anticipating the subgroup that is likely to participate. In the context of a rate case, the expected revenue reduction from the new rate would be made up by customers on standard rates, which are presumably more costly to serve. This approach also helps to reduce, but does not eliminate, free-riders.

If a new demand response rate is introduced outside of a general rate case revenue erosion is more difficult to mitigate because standard rates cannot be increased to compensate for customer savings on the new rate. And as asserted above, the customer savings cannot be made up solely by the participants in the new rate, because there would not likely be any losers on the rate to compensate the winners. However, in this situation this approach can still be used to reduce free riders by designing the new rate so that most of the expected participants would have to change their usage patterns to be able to save money on the rate.

[7] California Energy Commission Working Group 2 Report, November 2002.

Multiple part rates are another potential solution for reducing potential revenue erosion. This approach uses a rate design that combines elements of both standard and demand response rates. The rate would price basic monthly usage according to a standard rate, but price the desired "responsive usage" according to a demand response rate. The responsive usage could be usage during critical hours in the month, in the case of two-part critical peak pricing, or a marginal usage above an allowed baseline usage in any hour, in the case of two-part real time pricing.

For example, Pacific Gas and Electric (PG&E)'s proposed critical peak prices for residential and small commercial customers layer on a high price during critical hours and a discount in other hours to the customer's otherwise applicable standard tariff, which could be an inverted block or time-of-use rate. Furthermore, the critical peak surcharges and commensurate discounts for other periods only apply to their four month summer season. While the PG&E approach does not eliminate revenue erosion, it restricts the revenue in question to the critical usage and avoids any revenue erosion in the non-summer period when demand response is presumably not needed.

Two-part real time prices typically establish a baseline hourly usage level which is purchased at embedded rates. Deviations in usage above or below this level are charged or credited according to a real-time hourly rate, which is reflective of real-time energy prices plus adjustments. This approach preserves revenue for most of the customer's monthly usage, but sends a temporal price signal for marginal consumption which is more reflective of the marginal prices at that time.

The Company concludes that any pricing concept considered as a result of this study be designed and implemented in a manner that addresses potential revenue erosion and that implementation costs be thoroughly addressed. For example, a mandatory TOU program for general service customers would require that APS replace over 100,000 meters, a costly and lengthy proposition.

SECTION VI

Other Demand Response Programs

Overview

Critical Peak Pricing (CPP) combines time-of-use with an additional high price period, which is selectively applied by the utility during periods of high energy costs or reliability issues. Typically the customer is notified the day before, or in some cases the hour before, a critical period will be called. The critical hours in a critical day can be either variable or a fixed time period, e.g. 2 p.m. to 6 p.m. Energy rates for critical periods can reach as high as 50 to 75 cents per kWh. The maximum critical days or hours allowed each year are usually limited by the tariff. Critical hours are typically capped at 100 critical hours or less per year.

CPP programs are fairly new and are typically targeted to C&I customers. However, there have been a few residential programs or experiments including the California Statewide Pricing Pilot, a pilot by the Sacramento Municipal Utility District (SMUD) and a program offered by Gulf Power, which combines CPP with automatic appliance control. These two programs will be reviewed here along with a CPP program proposed by PG&E as a result of the statewide pilot.

While the residential pilot programs have indicated that targeted customers can respond to critical peak pricing, several important questions concerning the ultimate viability and value of critical peak pricing remain.

First of all, customers need to be informed before critical peak events occur, and their usage during critical periods needs to be measured to properly apply the critical-peak charges. This can require substantial upgrades to communication and metering equipment, infrastructure and related data handling and billing systems, which can be extremely expensive. For example, PG&E is proposing investments in advanced metering, communication, and billing system upgrades necessary to support critical peak pricing programs of over $1.46 billion. In addition several of the pilot programs indicate that residential critical peak pricing is most effective when combined with an appliance control program, which would require additional equipment and infrastructure costs.

The potential participation and customer acceptance is also uncertain, especially for residential customers. A key unresolved issue is whether the monthly bill savings from critical peak pricing programs is meaningful to the customer. Unlike time-of-use programs, which have on and off-peak prices which apply each day, critical peak prices only occur for a limited number of days each year. As a result, the bill savings to the customer can be limited, especially for residential customers. In addition, some residential customers may not have electrical service equipment that is compatible with program requirements. This was an important issue for the SMUD pilot program described below.

The ultimate question is whether critical peak pricing programs can provide enough additional benefits compared with time-of-use programs to justify their high implementation costs and program complexities. This question appears to be unresolved at this point

Advantages

- CPP pricing can offer customers more refined price signals compared with inclining block or time-of-use pricing, especially during the periods of high load or costs.

- The preliminary experience of CPP pilot programs have shown that residential customers generally respond to high critical peak prices by reducing usage during critical periods.

- Some commercial customers in California (20-200 kW demand) were also found to respond to critical peak pricing, especially with programmable air conditioning controls.

- CPP prices can be layered onto existing baseline rates in order to make the option available to a wider group of customers and to help address concerns over potential revenue erosion.

Disadvantages

- Preliminary results of the California pilot program suggest that many small and medium commercial customers may not be able to effectively respond to critical peak pricing. For those that did respond, much of the usage reduction during critical periods was due to air conditioning reductions through thermostat controls. This result may not be applicable to Arizona commercial customers during the extreme summer heat.

- While initial market research has reported interest in the programs, actual experience and participation for residential and small commercial customers has been modest to date, so long-run customer acceptance is somewhat uncertain at this time.

- The costs of implementing demand response programs can be very high due to the required advanced metering and communication systems as well as changes to billing, data handling, and customer information systems.

Company Loads and Resource Impact

Critical peak pricing could potentially provide advantages from a Company load perspective by sending more refined price signals to customers during periods of very high load or energy costs. As discussed in the Company Loads and Resource section of this report, APS' loads are typically at or above 90% of the peak hour for only a small number of hours per year. For example, as shown in Table 21, in 2004 only 87 hours were within this range. Critical peak prices are designed to send relatively high price signals during the limited number of critical hours.

Table 21 APS Hourly Loads - Percent of Annual Peak Hour*

Year	Number of Hours When System Hourly Demand Is Equal To or Greater Than				
	95% of Peak	90% of Peak	85% of Peak	80% of Peak	75% of Peak
2000	45	153	374	719	1092
2001	16	69	267	625	1030
2002	28	150	382	686	1008
2003	34	119	299	542	859
2004	25	87	269	520	825

*For "Own Load" hourly energy profile

Load Impacts

While the CPP programs and experiments are relatively new and limited, impact studies have generally found that residential customers respond to the critical prices as well as the time-of-use prices in the non-critical periods. Small and medium general service customers also respond to critical prices, but have a limited response during non-critical TOU peak periods. For example, the California Statewide Pricing Pilot estimated the reduction in usage by residential customers during critical hours to be 13% to 16%, and 8% to 11% during non-critical TOU peak hours. For small and medium general service customers the pilot estimated critical period reductions to be 6% to 9% and 1.5% to 2.4% for normal TOU peak hours. The customer response from the SMUD Pilot was similar to the California pilot for residential customers. The Gulf Power program, which also included appliance control, estimated a 45% reduction in usage during critical hours in the summer.

Table 22 Estimated Peak-Period Impacts from Critical Peak Pricing

	Energy Reduction Critical Hours	Energy Reduction TOU Peak Hours
Residential		
California SWPP	13% to 16%	6.5%
SMUD experiment	16%	8% to 11%
Gulf Power	45%	NA
General Service		
California SWPP 0-20 kW	6%	1.5%
California SWPP 20-200 kW	9.1%	2.4%

Customer Acceptance

Critical peak pricing programs and experiments are relatively new and participation to date is limited. For example, Gulf Power's residential CPP program, which is three years old, currently has 7,500 participants. At this time it is too early to be able to predict the potential market acceptance and participation for these programs. Marketing research for the California Statewide Pricing Pilot indicated interest in demand responsive rates for residential customers, less so for small general service. However, actual participation may vary significantly from self-reported customer interest or intentions from surveys.

One of the challenges for CPP programs is to make the bill savings meaningful, especially if customers have to install equipment or incur other costs in order to effectively respond to the price. Typically the programs charge customers a high price for consumption during critical periods in exchange for price discounts during other off-peak periods. But because the critical hours are limited, the compensating discounts in other hours are also limited. As discussed below, the PG&E proposed residential program provides additional off-peak discounts in order to make the bill savings meaningful to targeted customers.

Some customers, especially general service customers may perceive the CPP programs as new, unknown, and risky. The critical price looks very high, and the potential bill savings are uncertain. To address this, some programs offer a limited guarantee of savings.

Some of the lessons learned from marketing research of program participants and non-participants in the California Statewide Pricing Pilot are summarized below for residential and general service customers below 200 kW of demand.[8]

Residential customers

- Overall program satisfaction was high.

- Customers like demand response rates because of bill savings and ability to manage loads.

- While savings levels have a significant effect on customer response, non-price rate features can also have a meaningful impact on customer willingness to participate in demand response rates.

- Estimates of potential customer participation into new demand response rates, based on customer reported interest and likely awareness levels, could be in the 15% to 20% of total customers in an opt-in program. However, actual experience could vary significantly from survey results of self-reported customer interest and intentions.

- 85% of residential participants in the pilot program report making a change in their energy use in response to high energy prices. Of these, 17-43% shifted laundry use (depending on the specific rate option), 9-15% either turned off or used their electricity less, and 2-14% shifted their pool pump usage.

- Potential participants are likely to be high energy users.

- If residential customers were placed on a demand response rate as their default rate, on an opt-out basis, a high percent would be expected to remain on the rate and not switch back to the standard rate or to another new rate option.

[8] A Market Assessment of Time-Differentiated Rates among Residential Customers in California. Momentum Market Intelligence, December 2003.
Customer Preferences Market Research – C&I, A Market Assessment of Time-Differentiated Rates among Small /Medium Commercial & Industrial Customers in California July 2004.

General Service Customers (0-200 kW)

- Overall program satisfaction was high, although lower for commercial and industrial customers compared with residential.

- Similar to residential customers, commercial customers like demand response rates because of bill savings and ability to manage loads.

- Customers appear to worry more about having to make adjustments to electricity usage than they care about the savings they might experience. The information below shows the trade-off between the level of bill savings and the amount of effort (e.g. load shifting) necessary to achieve those savings. As shown, customers prefer low moderate savings coupled with low to moderate shifting required. The highest preferred scenario is 5% savings with no effort required.

Table 23 Trade Off Between Customer Savings and Load Shifting
Small and Medium C&I customers - California

Level of Customer Effort (e.g. load Shifting required to achieve savings)	Bill Savings Level	Preference Index
High	20%	.66
High	15%	.21
High	10%	-.23
Moderate	10%	.75
Moderate	5%	.24
None	5%	1.41
None	0%	.67

- Many commercial customers reported that they would not be able to shift or reduce energy usage during peak periods. They reported that the nature of the business does not allow them to change usage patterns, they cannot reduce air conditioning usage, or they don't have sufficient end-uses to shift load.

- Some of the difficulties cited by higher use customers included: limited control over guest tenant electricity usage; their greatest demand occurs during the weekday afternoons; certain end-uses need to be kept running at all times; usage is based on demand of manufacturing process; cannot compromise comfort of customers, patients, students, or employees.

- The design of the on-peak periods and critical peak days are important drivers of the customer preference for a given pricing option, more important for many customers than the savings potential.

- Those currently on a TOU rate tend to be more receptive to a new demand response rate, regardless of the specific details of that rate.

- Likely participants in demand response rates tend to be larger customers with a higher electricity costs as % of total operating costs (greater than 10% of total operating costs).

- Among building types, hospitals, lodging and education customers appeared to be more inclined to accept critical peak pricing than other building types, with hospitals as the most likely target.

- Appliance control packages have the potential to enhance customer participation if the packages offered focus on basic or moderate controls (rather than extensive controls), and if they offer customers the ability to program the system to their own specifications and override any utility control.

- Overall, there was little interest in signing up for a real time pricing plan. Only 3% of respondents indicated a strong interest and 73% gave the concept a low rating

Implementation Costs

One of the major drawbacks of dynamic demand response pricing, such as critical peak pricing, is that it can require an extensive investment in data handling, metering, billing, and communication systems. The rates typically require some type of advanced metering capable of recording the customers' usage during dynamic critical periods. The programs also require a communication system to automatically acquire the interval load data for billing purposes. For critical peak pricing programs that include appliance control, the communication network must be two-way in order to notify the customer of a critical period and signal a load controller. Dynamic demand response rates can also require upgrades to data handling, billing systems due to the increased data processing and storage requirements from the interval data.

Large deployments of advanced metering are typically justified based on savings in operating cost and other benefits not related to dynamic pricing. However, such an investment is nevertheless necessary to implement dynamic pricing programs, such as critical peak pricing, for other than small pilot programs.

For example, PG&E is proposing to implement over $1.46 billion in equipment and systems necessary for their proposed demand response rates for residential and commercial customers. This includes the cost of purchasing and installing advanced metering equipment for 2.5 million customers to be installed over a 15 year period. It also includes over $80 million for significant upgrades to customer care and billing systems. PG&E justifies 90% of the project costs based on operating cost savings for meter reading, customer service, billing and other costs. The savings in energy and generation capacity costs from the dynamic rates are expected to cover the other 10%.

California Statewide Pricing Pilot – Critical Peak Pricing

Residential Customers
The California pilot tested several different time-of-use and critical peak-pricing structures on 2,500 residential customers in 2003 and 2004. The primary objectives of the pilot were to estimate the load impacts from the prices, and understand customer preferences for the rates and various program features. The pilot offered two types of critical peak-prices where the peak price during critical hours was approximately five times the standard tariff and six times the off-peak price. The CPP-F rate had a fixed time period for critical hours in critical "event" days, which was 2-7 pm weekdays. Critical days were restricted to 15 per year, and no more than 3 consecutive days. Notification of a critical day was made the day before. For the CPP-V rate the critical time period could vary on each critical day and notification could be made the day of the event. The experiment estimated a load reduction during critical hours of 13 to 16%.

CPP-V customers also had the option of receiving a programmable thermostat/appliance control device or other enabling equipment installed free of charge to help facilitate demand response to the rate. The critical period price ranged from 50 to 75 cents per kWh tiered to total monthly usage level. This compares to normal peak prices of 23 cents to32 cents and off-peak prices of 8 cents to 16 cents per kWh.

General Service (under 200 kW)
The general service pilot was separated into two groups, 0-20 kW demand and 20-200 kW demand. All of the customers were in the SCE service territory. The CPP-V rate was tested for two groups (1) the general population and (2) customers with central air conditioning, who had participated in a utility smart thermostat program. Most of the general population had air conditioning and about half had "smart thermostat" technology.

Critical periods could be called on weekdays from 12 noon to 6 p.m., although the duration of any critical event could vary within this time period. Total critical hours are capped at 90 hours per year. Events could be triggered by system emergencies (ISO stage 1 or higher), extreme temperature conditions, utility procurement requirements, or discretionary events for testing purposes. Customers are notified at least 4 hours before an event by land-line telephone, pager, e-mail or cell phone.

The 0-20 kW group had a relatively small reduction in peak period usage which was 6% during critical days and 1.5% on normal weekdays. The load reduction for the 20-200 group was somewhat larger – 9.1% for critical days, 2.4% for normal weekdays. The experiment also concluded that much of the response was due to the air conditioning thermostat/control equipment. Findings from the marketing research from the experiment are summarized above.

PG&E Proposed Critical Peak Pricing

PG&E has proposed to offer new critical peak pricing for residential and small and medium commercial customers, less than 200 kW demand, as they implement advanced metering between 2006 and 2010. They are also proposing other dynamic rates for larger C&I customers. PG&E' CPP rates will be offered on a voluntary, opt-in basis, and are designed as overlays to customers' current rates. In other words, a participating customer would pay all charges on their standard tariff, but they would receive additional charges for consumption during critical periods and credits for charges during non-critical periods.

PG&E believes that this approach provides several key advantages. First, it offers flexibility to change charges and credits as needed for a variety of rates without having to completely redesign each tariff. This is especially valuable since the potential customer acceptance is somewhat uncertain. Second, the approach allows the preservation of the existing inclining block and TOU rates. In fact, customers can choose either basic tariff and still be able to participate in critical peak pricing. Third, the overlay approach will help to preserve class-level revenue neutrality, although it will not eliminate potential revenue erosion. In other words, it does not create incentives for customers to switch rate schedules and thereby result in revenue erosion. There could still be free riders who would naturally use less during critical peak periods and more during other non-critical times, who would automatically save from the CPP rate overlay, without changing their consumption patterns. Nevertheless, PG&E intends to match the revenues from charges and the credits for each rate group using load research information. Furthermore, the charges and credits would be subject to annual updates based on the actual load shapes for the groups of customers who participate over time. After the first two years of the program revenue-neutral adjustments to the standard rates are proposed to be made annually, to avoid under of over collections (mismatches between the CPP charges and credits) on a forecast basis.

PG&E designed the program to provide many customers with bill savings of 10% or more if they reduce their usage by 25% during critical periods. Although average savings are expected to be more in the range of 5%. In addition, PGE is offering customers bill protection during the first summer of enrollment, where they are compensated if their actual critical period charges exceed their credits.

Residential Rate

Again, the CPP rate overlays a critical period price and compensating credits during non-critical hours over the customers existing baseline rate. Fifteen critical days can be called on a day-ahead basis each summer for a maximum of 75 hours. The critical period of 1-7 pm is fixed for event days. The critical peak price was derived by first assigning $45 per kW-year of summer season revenue responsibility for the CPP charge. The $45 divided by the 75 hours resulted in a recommended CPP charge of 60 cents per kWh. The credit for non-critical hours is 3 cents per kWh. An additional credit of 1.0 cent per kWh was also applied to all usage in the upper tiers (tier 3 and above) of the customer's baseline rate in the summer billing season to enhance customer savings and participation.

Small and Medium Commercial (under 200 kW demand)

The small and medium commercial critical peak price program operates similar to the residential program, except the critical hours are 2-6 p.m. for this group. The 15 day maximum number of critical days translates into a cap of 60 critical hours per year. The $45 capacity cost responsibility was spread across 60 critical hours each summer for a 75 cent per kWh charge and an offsetting credit for non-critical hours of 2.7 cents per kWh. The proposed additional promotional credit is 0.5 cents per kWh for these customers.

Implementation Costs

PG&E is implementing the Advanced Metering Infrastructure (AMI) project – $1.46 billion including $1.35 billion capital costs and $13 million in expense. It is projected that 90% of the costs will be recovered by savings in meter reading costs, other employee-related expenses, avoided meter maintenance cost, improved outage restoration, avoided interval metering costs, call center savings, improved cash flow, and other benefits such as reduced energy theft. The project cost estimate includes the AMI system, meters and data handling systems, communication infrastructure, and significant refurbishment of the CIS /billing system.

SMUD Critical Peak Pricing Experiment

In 2003 the Sacramento Municipal Utility District (SMUD) conducted a pilot program for residential critical peak pricing. They installed advanced metering and appliance control equipment for a sample of 78 customers. The pilot, which operated during the summer of 2003, combined critical peak pricing with automatic control of air conditioning, electric water heating and pool pump motors. The metering, communication and control equipment included advanced metering, communication gateway, load control relay and a thermostat controller. While the customer could program end-uses to automatically respond during critical periods, they could also override the control system and continue to consume energy during those times.

The program included a four part critical peak price effective for the summer billing season. Energy prices ranged from 7.03 cents per kWh during "low load" periods in the summer to 27 cents per kWh during critical periods. Critical periods were triggered by a combination of high temperature (above 95 degrees F) and high system load (above 2,100 MW). Critical periods could also be called if wholesale prices exceeded $90/MWh or in case of a system emergency.

Required utility systems included a head end information processing system, an on-line system for providing customer load information, and billing infrastructure and software, communication system to and from the home, an online critical peak event scheduling, and load profiling.

The program required the customer to have compatible electric service and specific end-uses. For example, the program required central air conditioning, but zoned and variable speed systems were not compatible with the control system and therefore didn't qualify.

SMUD conducted customer training on how to program the thermostat and control system and how to access the on-line energy usage data.

<u>Findings</u>
In a presentation made in June of 2004, SMUD reported the following information regarding their pilot program:

- All of the critical periods during the 2003 summer pilot were triggered by temperature and load.
- The customer acquisition process for the pilot appeared to be challenging. The results reported that 88% of responding customer's service panels were

incompatible with the program equipment. Other customers had ineligible end-uses or an inaccessible phone line. All-in-all the utility sent 30,000 direct mail solicitations, called over 4,000 customers, received initial agreements with 570 customers, screened out all but 177 eligible customers and installed 78 systems.

- Customers did respond by reducing consumption in both the critical period by 0.54 kW per customer per hour, which is 16% on average. They also reduced load during some of the other higher non-critical periods of the four-part rate. For example, SMUD reports that participants reduced usage in the highest non-critical time-of-use period by 11%. Customers increased usage slightly during the low-load period, but overall reduced peak load rather than shift load to off-peak periods. Overall energy savings was 4% over the summer season.

- Many customers made investments in energy efficient equipment after enrolling in the program. Many of the changes were low cost items, such as purchasing compact fluorescent bulbs, but 40% of the customers reported to make higher price equipment changes such as replacing windows, repairing ducts, replacing refrigerators or replacing air conditioners.

- Customers reported that they responded to critical and high periods by reducing the use of major appliances such as air conditioners, washers and dryers, and cooking. However, 60% of participants reported that they temporarily over-rode the control settings. In addition, despite training, 44% of customers reported having difficulty programming or operating the thermostat.

- Participants tended to be higher energy users (1565 kWh per month), living in larger homes (2300 Sqft) and had someone home during the summer peak hours.

- The pilot infrastructure, administration and maintenance were expensive. Equipment installation was complicated.

Gulf Power Critical Peak Pricing Program

In Florida, Gulf Power offers residential critical peak pricing combined with control of major appliances through a communications gateway and programmable thermostat/controller. The program is called the Advanced Energy Management Good Cents Select (AEM) program. The four-part rate combines a three-part TOU rate with a critical period price which is callable by the utility. The program enables customers to respond automatically to high and critical price periods by controlling their air conditioning, heating, water heating, and pool pumps.

The TOU summer hours are 1 p.m. to 6-p.m. peak (high price period), 6 a.m. to1 p.m. and 6 p.m. to 11 p.m. shoulder (medium cost periods), and 11 p.m. to 6 a.m. off-peak (low cost hours). The medium price also applies from 6 a.m. to 11 p.m. on weekends. The critical hours are determined by the utility and are capped at 1% of total annual hours. Participants are notified by electronic signal at least one half hour before a critical hour is called. Prices for the various periods are shown below (effective 4/1/05) compared with the standard residential energy charge. The tariff also requires an additional monthly charge of $4.95 for the thermostat and communications equipment.

Table 24 GPU CPP Energy Prices by Time Period

Period	Price cents/kWh	% of Annual Hours
Low (off-peak)	5.4	28%
Medium (shoulder)	6.7	59%
High (peak)	11.2	12%
Critical	32.1	1% max
Standard Residential Rate	7.6	

Equipment Requirements

The program requires an electronic control module to program the operations of the end-uses and a communications gateway module which is added to the meter. It enables communication between the utility and the control module to alert of critical periods and the system components to interrupt demand. It also records energy usage for transmittal to the utility. The utility communicates with the gateway through use of a paging signal. Billing information is later retrieved via the land-line public switched telephone network Signals are passed from the gateway to the controlled end-uses over the house's internal wiring and to and from the controller over the existing thermostat wiring.

In addition the customer has certain requirements including touch-tone phone service, HVAC compatible with the energy management equipment, electric wiring conducive to power line carrier, located in area with certain paging strength, compatible existing metering equipment.

Load Impact

Gulf Power estimated the reduction in load during critical hours to be 2.1 kW per home on average, which is a 45% reduction in critical hour usage.

Implementation Costs

Gulf Power reports that the average equipment and installation cost for the metering, communication and control equipment on the customer site is approximately $600 per home.

Other costs included the communication infrastructure and the required changes to the CIS/Billing system. The latter was not extensive in Gulf Power' case. As a part of Southern Company, they use Southern's billing platform, which had been recently refurbished before the CPP program was implemented. The updated CIS system was able to accommodate the billing of the CPP program with moderate changes.

Participation

The program has been in operation for 3 years and the current participation (2005) is 7,500 customers. They plan to expand the program offering to the multi-family segment later this year.

Medium and Large General Service Demand Response -RTP

Demand response programs reviewed for medium and large size general service customers include critical peak pricing and demand bidding programs. Again, critical peak pricing is basically a hybrid of a time-of-use rate with a critical price added, which can be called at the discretional of the utility for a limited number of hours each year. Demand bidding programs offer incentives for customers to bid load reductions typically a day in advance. A customer's overall usage is billed according to their otherwise applicable tariff along with the incentives. Some utilities also offer real time pricing programs which bill part of the customer's load based on short-run marginal production costs. Real time pricing (RTP) is not formally considered as an option in this study primarily because, from APS perspective, critical peak pricing can provide many of the same benefits as real time pricing, with less costly program administration, and without subjecting customers to the risks of facing hourly marginal energy prices. In addition, many real time pricing programs have been focused on industrial load growth, rather than peak demand and energy reduction, which is the focus of this study. However, this study does consider some of the lessons learned from real-time pricing programs as they apply to the other demand response programs considered.

Advantages

1. Dynamic demand response programs can help match customer load reductions to periods when it is most needed by the utility to respond to high system loads or costs.

2. Demand response can also send price signals to customers that are more reflective of short-term energy costs, as they vary across days and hours.

3. Demand bidding programs have the advantage of allowing the utility to adjust both the hourly prices and the critical hours as needed.

4. Communication methods between the utility and the customer have improved including new software to better facilitate notification and confirmation processes, web-based interfaces, and more use of wireless communications including 2-way paging and email.

5. Some C&I customers have been shown to reduce their usage in response to critical peak pricing and demand bidding programs.

6. Critical peak pricing programs are reasonably straight forward to operate, they do not require any customer confirmation or complicated settlement process. The tariffs are similar to TOU prices and can be overlaid over standard baseline tariffs.

7. Customers could interface demand response rates with energy management systems, which are used fairly widely in certain C&I segments, to better automate response. However, actual automated response to these programs appears to be limited.

Disadvantages

1. Demand bidding and critical peak pricing programs are relatively new, so there is limited experience to access customer acceptance, load impacts, or other key program issues.

2. The overall customer savings from these programs could potentially be relatively low, especially if the number of critical events is limited due to stable prices or program constraints. This potential low savings could limit customer interest and active participation.

3. Inactivity caused by stable prices and a low number of critical events could create complacency among participants and loss of a dependable customer response when a critical event is actually called. Some programs provide system tests and other readiness activities to address this issue.

4. Demand bidding programs require a higher level of program administration compared with TOU or CPP rates including notification, receipt and acceptance of bids; forecasting and posting day ahead hourly energy prices; estimating customer baseline loads and settling actual load reductions for each customer.

5. Implementation costs can be high and can include metering costs, communication and data handling systems, and potential changes to CIS and billing systems.

6. Typically the customer is not obligated to reduce load during critical events, which could make the expected load reduction less certain. None of the CPP programs reviewed require the participating customer to actually reduce load during critical events; the only penalty is the high critical period price. A few demand bidding programs require customers to honor bids that have been accepted, but others do not.

Lessons Learned from Real-Time Pricing

There are currently about 70 RTP programs offered by utilities. Some are legacy programs that have been operating since the 80's and early 90's, others are new programs which are largely part of electric restructuring and the revamping of standard offer prices. Lessons learned from the non-restructuring programs include the following results.

Program participation, in general is low. A survey of 43 RTP programs in 2004 found that a total of 2,700 non-residential customers, representing more than 11,000 MW of peak demand, were enrolled in the RTP programs. However, most of these participants were associated with a couple of large programs. Only three programs had more than 100 non-residential participants or more than 500 MW enrolled, one-third of the programs had no participants. Another third had fewer than 25 participants, less than 50 MW, and less than 1% of the utility's system load enrolled.

In addition, participation has been declining for most programs. Over the last several years 50% of all RTP programs lost 25% or more of their customers. Only two programs had increased participation.

RTP programs can face somewhat of a "catch 22" in terms of program participation. When wholesale energy prices become high and volatile, customers face substantial price risk which can limit participation. When prices are stable, opportunities for savings are lower, so customers can lose interest in the program. Utilities attempted to address the risk issue by designing two part tariffs, where a customer's baseline usage was billed according to the otherwise applicable tariff and only incremental changes in usage were subjected to market prices. Some utilities also offered risk management products such as caps, collars, and contracts for differences to address the price risk issue.

Some customers respond dramatically to real-time prices. However, this appears to be limited to certain types of customers including industrial customers with flexible manufacturing schedules and customers with flexible use of on-site generation. A substantial number of participants are not price responsive. Some RTP program mangers believe that many program participants expected to realize bill savings solely by purchasing load at marginal cost based prices, without responding to these prices on an hourly or daily basis. Overall peak impacts reported by program managers range from 12-33% reduction in participants' aggregate peak demand.

Critical Peak Pricing - Large General Service

California CPP Programs

The critical peak prices for larger general service customers offered by PG&E and SCE, and San Diego Gas and Electric (SDG&E) include increased prices during critical periods compensated by reduced prices at other times. Eligible customers had to have demands above 200 kW for SCE and PG&E, above 100 kW for SDG&E.

For SCE, critical events could occur during the summer season between 12 noon and 6 p.m., weekdays. The critical days were limited to 12 days per year. Events could be triggered by a number of factors including high system demand, low generation supply, high market prices, high temperature or system emergency testing. Customers are notified one day prior to an event starting at 3:00 p.m. Notification is made by telephone, email, or pager. There is no obligation to reduce load during an event and no penalties, other than the high critical price, for non-response.

The PG&E program is similar to SCE except that their program operates year round and notification is made by 5:00 p.m. the day prior to an event. The SCE program also operates year round, notification is given by 4:00 p.m. the prior day and the critical period begins at 11:00 a.m.

For SCE, the critical period for each event is split into two high-price periods: from 12 noon to 3:00 p.m. where prices are approximately 2 times the normal on-peak rate of the customers otherwise applicable tariff and from 3:00 to 6:00 p.m. where prices are 6.7 times the normal on-peak rate. For compensation the rate during non-critical periods is 9.5% less than the normal rate.

For PG&E, the energy rate during high period is 5 times the otherwise applicable rate, the moderate price period is 3 times the normal rate. For compensation, normal on-peak rates are reduced by 22%, shoulder rates by 3%.

SDG&E's energy rates are 10.0 times the normal rate from 11 a.m. to 3 p.m. and 3.8 times the normal rate for CPP Period 2. For compensation, the CPP rates are about 9.5 percent lower than the normal energy rates during non-critical times in the summer.

Potential Customer Bill Savings

The California utilities conducted rate analyses to determine whether eligible customers would pay more or less on the CPP rate than on their normal rate, assuming their previous year's pattern of energy usage with load shifting ranging from 0 to 20 percent. For PG&E and SCE about 50% of eligible customers would save under the CPP rates without making any changes to their usage patterns. However, of these, 75% would save less than 1% per year. At the other end of the spectrum about 99% of customers would save, assuming a 20% load reduction during critical periods. But again, of these, 75% would save less than 1.6% per year. For SDG&E, about 75 percent would save assuming a 10% reduction; 3.8% of these customers would save less than 2% per year.

Participation

Program penetration levels for the 2004 California critical peak pricing and demand bidding programs are summarized in Table 24. The participating customers represent 4.7% of eligible customers, 8% of non-coincident demand and 11% of energy from eligible customers.

Participation in the California critical peak pricing programs was relatively low. Only 1.1% of eligible customers participated from the three utilities. Participation was somewhat higher (3.1%) for customers with demands between 1,000 and 2,000 kW demand. Participation was highest for institutional commercial customers and some industrial and transportation customers.

Table 24 Participation in California Demand Response Pilot Programs

	Critical Peak Pricing	Demand Bidding	Total Demand Response
Office	11	52	63
Retail/Grocery	3	167	170
Institutional	36	63	99
Other Commercial	28	105	133
Total Commercial	78	387	465
Petroleum, Plastic, Chemicals	7	57	64
Mining, Metals, Glass, Concrete	4	50	54
Electronic, Machinery, Fabricated Metals	32	74	106
Other Industrial and Agricultural	30	78	108
Total Industrial	73	259	332
Transportation/ Communication/ Utility	28	72	100
Unclassified	27	45	72

Total		206 (1.1%)	763 (3.8%)	969 (4.7%)

PG&E, SDGE, SCE 2004

Load Impacts

The California pilot did not estimate demand models or elasticities for medium and large general service customers. Instead the pilot measured actual hourly consumption during critical days for each participant and compared it with estimated hourly consumption that might have occurred without the critical peak prices. This was accomplished using a variety of "representative day" techniques for estimating load using hourly consumption information prior to the critical event. The results varied significantly by customer type and utility and are, therefore, difficult to translate to an estimate of total potential reduction for general service customers. For example, impacts for PG&E customers ranged from 2% to 16% load reduction across the various critical periods. Impacts for SDG&E customers were 10% to 19%. While impacts for SCE ranged from 42% to 66% across the events. The latter result is primarily driven by the high response of one large customer. The three utilities are currently using an impact estimate of 15% during critical periods.

Demand Bidding Programs

Demand bidding programs allow a customer to bid potential load reduction, typically the day before a critical event, for an incentive based on a predetermined price. For some programs participants are not required to bid into any particular critical event or even reduce their load as bid. Other programs require customers to "deliver" their load reductions as bid or face penalties.

California Demand Bidding Program Pilot

As part of the pricing pilot, California experimented with a demand bidding program for general service with loads greater than 200 kW demand. The utilities had already installed interval metering for all customers in this targeted group so implementation costs were not a significant factor.

In the program, customers submit bids to curtail usage during critical periods, which last for no more than 4 hours between 12 noon and 8 p.m. on critical days. A bid must be for at least 100 kW of load reduction for at least two consecutive hours. The customer's compensation equals the estimated load reduction times a pre-determined price, equal to the utility's projected hourly energy costs.

The program tested two types of events. Day-ahead events were called by the utility when its projected hourly energy costs exceed $0.15/kWh. Day-Of events could be called for reliability issues. There is no limit to the number of critical events that can be called by the utility.

Each customer's estimated load reduction during critical events is calculated by subtracting their actual metered usage from as estimate of what the load would have been without the curtailment. Several "typical day" estimation methods were tested in the program evaluation. While there was no penalty for non-compliance, the customer is only paid for 50 to 150% of their bid curtailment.

Since the pilot, SCE implemented a new demand bidding tariff, with some changes based on lessons learned from the pilot. They dropped the day-of events for lack of participation – many customers reported that it did not allow enough time to respond.

Critical events under the new program are triggered when the California ISO forecasted a reliability problem or when the ISO load exceeds 43,000 MW for the next day. The incentive was increased to equal the forecasted hourly market price plus 10 cents per kWh.

Participation

Customer participation in the California demand bidding pilot is summarized in Table 24. Overall, 763 customers participated from the three utilities, which represented 3.8% of eligible customers. However, this includes 286 small to medium size customers who were erroneously enrolled in the SCE program without having the ability to meet the 100 kW bid minimum. Participating customers included retail and grocery stores, industrial customers and some institutional customers, which was primarily municipal water pumping accounts.

The program evaluation suggested that participation may have been small because of the modest level of potential bill savings, which was typically in the order of 1 percent, for participating customers relative to any perceived risks or customer implementation costs.[9]

For example, the utilities estimated that customer savings from 1 MW of load reduction over 4 events would be about $2,400 for day ahead events and $8,000 for day-of events. Based on 12 events, the savings would increase to $7,200 for day ahead events and $24,000 for day-of events. At the lower end of the spectrum, for a 100 kW reduction over 4 day ahead events the customer's bill savings would be $240, savings would increase to $800 for 4 day-of events, $720 for 12 day ahead events, and $2,400 for 12 day-of events.

Potential Load Impacts

Estimates of peak reduction from a demand bidding program can be obtained through the bid settlement process for each customer. This settlement process compares each customer's actual metered load during the critical event to an estimate of what the load would have been absent the program. The latter is performed using a function of the customer's hourly metered load profile in the days prior to the critical event.

The average estimated load impacts varied across the three utilities. The average customer load reduction during PG&E' single day ahead was estimated to be 17 percent. The load impacts for SCE customers who submitted bids ranged from 12 to 50 percent. Estimated peak-load reductions for SDG&E customers were 19 to 28 percent. The utilities report that they are currently using an estimate of 15 percent load impact for the demand bidding program for planning and reporting purposes.

However, as with the CPP impacts, because of the limited events, the dominance of a few large customers, and the low level of actual customer bidding, the California demand bidding pilots did not produce a reliable overall impact estimate that could be used for future program planning.

Key findings from California Critical Peak Pricing and Demand Bidding Pilot Programs

- Participation was relatively low for both the CPP and demand bidding programs, especially if you eliminate the smaller customers who enrolled in the SCE demand bidding program. Participation was highest for certain industrial customers and institutional water pumping customers.

- The monetary incentive to customers to reduce load in both programs was relatively small, which was typically in the range of 0.4 to 2 percent of the customer's annual bill. Marketing research indicated that most customers were typically unwilling to make load reductions for savings in this range, especially if the program is perceived to involve financial risks or implementation costs.

- Some program participants (26%) reported that they experienced negative impacts on their employee comfort or productivity and experienced complaints from staff.

- Overall, most of the participants in both pilot programs reported that they intended to participate in the programs the following summer.

- Some larger general service customers did respond to critical peak pricing, however, the impact is uncertain and varied widely by customer type. Few critical events occurred during the pilot so real impact of CPP and DB programs is difficult to determine. Although many participants report that they would respond by reducing load during another critical event, some customers report difficulty in being able to respond to critical events.

- Follow-up marketing research indicated that 80 percent of participants in the critical peak pricing programs reported that they took at least one action to reduce load during a critical event. 84 percent reported that they were either somewhat or very likely to take responsive actions during future critical events.

- The day of notification did not allow many customers enough time to react to a critical event. As a result, PG&E cancelled this program option.

- The utilities reported low levels of bidding for critical events. Only 27 percent of program participants reported placing at least one bid. However, 75% reported being somewhat or very likely to place bids for future critical events.

- Despite multiple channels for notifying customers of critical events, utilities experienced difficulty in reaching the appropriate contact for some customers. Similarly, some customers who did not place bids during a critical event reported that the responsible person was not available to place the bid in time. In fact, half of customers surveyed in follow-up marketing research said that the notification timeframe, which allows an hour to place a bid after being notified of an event, makes it less likely that they would place a bid.

Conclusions

1. The Company will continue to monitor critical peak pricing and demand bidding programs to assess pricing designs, program best practices, and customer participation and load impacts.

2. Further assess program implementation costs, especially communication infrastructure, data handling and billing systems to better assess the cost/benefit.

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APS

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October 7, 2005

Mr. Ernest Johnson
Director, Utilities Division
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

RE: Flexibility Study for Time-of-use Rates, Cost Benefit Analysis of SurePay

Dear Mr. Johnson:

Pursuant to Decision 67744 (Page 31, line 23) Arizona Public Service submits the attached documents: (1) a study which examines flexibility in changing APS' on- and off-peak time periods and other characteristics for its time-of-use rates and (2) a cost-benefit analysis of SurePay, APS' automatic payment program, which explores the possibility of offering a discount to participating customers.

If you have any questions please feel free to call me at 602-250-3933.

Sincerely,

David J. Rumolo
Manager
Regulation and Pricing

Attachment

DJR/bec

cc: Brian Bozzo, Compliance Enforcement

ARIZONA PUBLIC SERVICE COMPANY

Time-of-Use Flexibility Study

INTRODUCTION

Decision No. 67744 (Page 31, line 23) required Arizona Public Service (APS) to examine flexibility in changing APS' on- and off-peak time periods and other characteristics for its time-of-use (TOU) rates. One of the greatest challenges to providing flexibility in the APS residential TOU program is a result of the success of the current program. APS' residential TOU program is one the largest in the country in both absolute numbers and expressed as a percentage of residential customer base. Changing any of the rate characteristics, such as modifying the on-peak hours or adding holidays to the off-peak period for all existing customers requires a time extensive effort and significant expense to implement the necessary metering and system changes

This study discusses the technology and system challenges that must be addressed to increase flexibility by introducing rate options with differing time periods. The study also discusses the TOU rate options that were filed with the Commission on September 22, 2005 to provide customers with additional options and that will allow the Company to assess customer reactions to differing TOU periods and on and off peak pricing differentials. These proposed rate schedules address many of the flexibility issues that have been raised. Additionally, the study discusses projects that are currently under way that examine alternate metering technologies that should provide more flexibility in the future long term implementation of TOU rates.

APS SYSTEM PEAK DAY PROFILE

Since the purpose of TOU pricing is to provide customers with proper price signals to encourage electricity use during times when production costs are lower (i.e. off-peak periods), it is important to understand the nature of APS' load shape.

Due to air conditioning load, the APS system has a dominant summer peak which drives the need for generation capacity additions. The summer peak for APS' retail load typically occurs between 3:00 and 6:00 P.M., and high load levels continue well into the night which is atypical compared with most utilities. The load begins to ramp up at 9:00 A.M. By noon, the load is within 10% or 500 MW of the daily retail peak. The load remains high, within 10% of the daily peak, through 8:00 P.M. and falls off significantly only after 9:00 P.M. More specifically, the load from 6:00 to 7:00 P.M. is typically 95% of the daily peak; the load from 7:00 to 8:00 P.M. is 91% of the daily peak. Therefore, a significant shift in load to the 7:00 P.M. to 9:00 P.M. period could have the potential to merely shift the system peak to this later period, rather than reduce the peak as intended.

The APS winter load shape is significantly different compared to summer. In addition to being approximately 35-40 % lower in magnitude, the winter season peak exhibits two peak periods with the morning peak being dominant. The winter peak for APS' retail load typically occurs at 7:00 to 8:00 A.M. in one of the colder months (December – February). The daily load ramps up at 6:00 A.M. and falls off after 9:00 A.M. Afternoon usage picks up at 6:00 P.M, reaching 90% of the daily peak, and falls off after 9:00 P.M. However, in some years, hot temperatures in March or April can cause daily loads to rival some of the cold days in December and January. For example, in 2004, 5 of the top 10 "winter" peak days were in March and April. The usage patterns for these days resemble the summer peak days, not the winter. In any case, winter peak demands are significantly lower than summer peak demands. Typically, the winter peak is 35% or 2,000 MW lower than the summer peak. Because the APS resource fleet has been designed to meet maximum summer loads, winter peak loads can be generally met with lower cost resources. The benefit of encouraging customers to shift load to off peak periods during the winter is much lower than in the summer.

CURRENT RESIDENTIAL TOU RATES

Currently APS offers two residential time-of-use ("TOU") rate schedules; Time Advantage (ET-1), which includes peak and off-peak energy charges, and Combined Advantage (ECT-1R) which includes both time differentiated demand and energy charges. The peak period for both rate schedules is weekdays 9:00 A.M. to 9:00 P.M. in both the summer and winter seasons. These rates were introduced in 1982 and 1988 respectively.

As shown in Table 1, over 357,000 APS residential customers are currently participating in a TOU rate, which represents over 40% of total residential customers. As discussed below, APS has recently proposed to implement two new experimental residential TOU rate schedules, ET-2 and ECT-2 that will offer rate alternatives to customers. At this point, it can not be determined whether the new TOU rates will attract customers from non-time differentiated rates or customers on existing rates will transfer to the new rates.

Table 1. Current Residential TOU Customers

Rate Schedule	Customers (2004 Avg.)	% of Total
ET-1	312,327	36.4 %
ECT-1R	45,045	5.2%
Total Residential TOU	357,372	41.6%
Total Residential	859,069	100.0%

TOU RATE ALTERNATIVES

On September 22, 2005, APS filed an application to obtain approval for two new experimental residential TOU rates. Schedule ET-2 parallels most of the features of existing Schedule ET-1 and Schedule ECT-2 parallels most of the features of existing Schedule ECT-1R. These new schedules provide for longer off-peak periods than the existing TOU rates and also incorporate holidays in the off-peak periods. Both new rate schedules have time-differentiated energy charges. ECT-2 will also have a demand charge applied to the peak period. The new rate schedules will have on-peak hours of noon to 7 P.M. for both the summer and winter seasons. The relative on and off peak prices have changed compared to the existing schedules so that stronger price signals are provided. Implementing these rates will require approximately seven months for system programming and testing once regulatory approval has been received. The implementation of these new experimental rates will provide customer behavior learning opportunities as information is developed on changes in consumption patterns and customer reaction to price signals. This will provide some indicators of the benefits of offering flexibility through alternative TOU hours.

TECHNOLOGY AND SYSTEM CHALLENGES

Challenges regarding TOU program flexibility are not unique to APS. For example, the recently enacted Federal energy act requires changes to daylight savings time (DST) for states that utilize DST. Utilities that have TOU programs are now trying to sort through issues related to TOU metering since existing meters are programmed to recognize the current DST calendar.

Implementing new rate schedules requires changes to metering, the customer information and billing system, the metering information system and related programs. These systems and numerous subsystems interrelate to capture metered data, ensure that the customer is on the correct rate with the correct meter, calculate the bill, present the bill, allow for re-bills and corrections, schedule meter and service changes, provide customer service information and screens to advise customers about rate options, allow customers to assess rate options through the internet, post the revenue to the general ledger, and many other functions. Most importantly, any new rates that are structurally different from current rates require significant system testing to ensure that the data is correctly captured, billing is accurate and that the programming changes do not adversely impact any other part of the system.

Several of the key systems that require modifications for implementing new rate schedules are metering, the customer information and billing system, the customer service software interface, APS.COM and the meter information system. These systems are described below.

METERING TECHNOLOGY

APS' current meter reading system does not support the capability of reprogramming meters in the field with the hand held "probe" device that is used to read the meters. While software support that enabled field programming was once available, it is no longer supported by the current vendor. Therefore, meter programming must be performed at the manufacturer, at the utility's meter shop, or in the field using a computer loaded with each meter vendor's software. The latter option is not practical for handling a significant number of TOU customers due to the time required to reprogram each meter.

Because of the limitation of our current meter reading system, changing time-of-use characteristics, such as the on-peak hours or holidays for an existing rate schedule would require replacing the meters of all of the current customers on the rate schedule. In addition to being very costly, such a massive meter change out could only occur over a long period of time. During the transition period, meter record keeping would be very challenging since the links between the meter which is currently in use at a customer's residence and the appropriate rate schedule must be maintained. For example, if the customer has already migrated to the rate schedule with new TOU periods and experiences a meter failure, the APS meter service personnel must have the correct replacement meter available in inventory.

Another issue concerns the potential need for a meter change when a customer switches between standard and TOU rate schedules. Many customers require a meter change to accommodate a switch in rate schedules. Some customers have meters that are pre-programmed to be able to bill both standard and TOU rate schedules. In this case, the customer would not typically require a meter replacement if the customer switched between a standard rate schedule and one of APS' current TOU rate schedules.

However, this flexibility erodes as new TOU rates with different on-peak hours and other characteristics are introduced. For example, while a meter can be pre-programmed to be able to bill both a standard rate and a TOU rate, it cannot be pre-programmed to be able to bill both a TOU rate schedule with a 9 A.M. to 9 P.M. on-peak period and one with a noon-7 P.M. on-peak period. This is because the billing determinants for the standard rate are nested in (or captured by) the TOU billing information. However, the billing determinants for the two TOU rate schedules, namely the on-peak and off-peak kWh, are distinct and cannot be simultaneously captured by the same meter. Rate switches between the alternative TOU rate schedules would require the meter to be re-programmed with the new rate schedule.

APS is reviewing several metering alternatives that may add flexibility for changing TOU rates in the future. These included implementing an alternate meter reading system, implementing an advanced metering system (AMS) and using interval data recording meters (IDR). These alternatives are not mutually exclusive and a combination of the new technologies will likely be implemented.

New Meter Reading System

APS is performing an assessment of implementing a new meter reading system that may be capable of reprogramming meters with a hand held device at meter reading time. This would lower the cost and time required to re-program meters, which would enhance the ability to implement new TOU rate schedules, enhance the ability to change existing TOU rate schedules, and lower the cost of customers switching between rate schedules. The assessment is in its initial phases and the technology must be examined in greater detail to determine the technical feasibility and cost/benefits.

Implementation of a new meter reading system will entail replacing all meter reading equipment including handheld devices and related software. An alternate meter reading system will require customer information system programming to coordinate and track meter programming changes. Extensive testing of all systems is required to ensure data accuracy with the reprogrammed meters. It will also require some changes to the meter information (MIS) system, orders processing, and systems that upload and download meter reads.

Implement an Automated or Advanced Metering System (AMS)

APS is assessing the benefits of AMS including the ability to provide flexibility for changing time-of-use on-peak time periods and other characteristics. The communication capabilities of the AMS provide remote meter programming, which would eliminate the need for meter changes or re-programming in the field in order to implement new TOU rate schedules, change current TOU rate schedules or accommodate customer switching between rate schedules. AMS will also facilitate the development of innovative pricing mechanisms such as real time pricing (RTP).

The AMS that APS is currently assessing consists of "spoke" meters on each home which communicate via radio frequency technology to a "hub" meter on a home in the neighborhood, which in turn communicates with the central system via cellular modem. The system features two-way communications and data recording capability. The rate schedules are controlled by a database server. APS is piloting AMS with 500 meters in the Metro Center area with plans to roll out the system to other areas next year. Implementation of AMS for the entire customer base will require a several year phase-in and will be capital intensive.

Expand the use of IDR meters with communication capability
Interval data recording meters (IDR) such as those used by APS for load research were evaluated as a potential solution for implementing new TOU rate schedules. However, most of the meters do not have communication capabilities nor is the data captured through the IDR generally used for billing purposes. In most cases, interval data are captured by meter readers using a probe device. Alternatively, cellular communication capabilities can be used to allow for remote meter reading. APS uses MV90 translation software to process the interval data.

If suitable interval data could be used to bill customers on TOU rate schedules, the need for a meter change for implementing new TOU rate schedules or when customers switch between TOU and standard rate schedules would be eliminated. While APS currently has the meters and systems to support IDR meter data, expanding this capability to implement TOU rates would require extensive upgrades in systems, data handling capabilities and communication capabilities. The use of IDR offers limited benefits compared to other solutions and, therefore, is not being further explored at this time.

Customer Information System (CIS)
CIS is the mainframe software application that handles all billing, customer data, and customer information processing. In order to implement new rate offerings, CIS requires programming changes to ensure that the customer account is maintained properly with the current rate schedule, meter and other relevant information, and that the bill is calculated and presented accurately. This requires changes to various tables, service plans, screens, reference tables, bill calculation, bill statements, rate comparison features, order processing, E-bill, service account maintenance, new business cases, new reports, and related subsystems.

If a new rate schedule involves changing the basic structure of the rate calculation, it requires extensive programming of the basic CIS data base and related tables and code. New rate schedules and meter types have to be tested to ensure that the billing information is correctly extracted from the meter and uploaded to the CIS system. Also, old data structures and relations must be maintained so that rebilling of customers, if ever needed, can occur.

Even seasonal changes in TOU on-peak hours (e.g. different on-peak hours in summer and winter) are significant challenges for the CIS structure and the meter interface. Currently, the system is programmed to transition between summer and winter seasons on the first billing cycle of the transition month in accordance with the APS rate schedules. Creating winter on-peak hours different from the summer would require extensive re-programming and testing of CIS and creates meter interface problems. Meter calendars are hard programmed while meter read cycles have some limited flexibility. If winter and summer TOU periods are different, the meter calendar must be programmed with a hard date for the seasonal switch. For example, a meter would be programmed so that on April 30 the winter time periods are in effect but on May 1 the summer TOU periods become effective. However, meter reading occurs on a cycle basis so that the last day or so of a customer's "winter" consumption can actually occur in the first days of May. Thus the meter programming and billing cycles would not be synchronized. Alternatively, if the seasonal transition for a TOU rate would occur on a firm date to coordinate with meter programming a massive re-write of the existing CIS program applications would be required including a system for prorating the bills during the seasonal transitions. In either case, implementing different winter and summer peak periods requires comprehensive billing component changes as well as database changes in some key areas of the system, which could impact thousands of lines of programming and entail significant testing. These significant base design changes to the system would require not only considerable impact analysis and design time, but very involved and lengthy testing as well to ensure the changes work properly. In addition to the systems impacts, there would be business impacts, meter equipment impacts, etc. with additional costs that would have to be considered.

Customer Care Environment Software (CCE):

Changes in the CCE software, which is the interface used by customer service personnel to advise customers on rate options, switch customers to new rates, and maintaining customer accounts, are required each time new rate schedules are offered. When new rates are implemented, the rate comparison function must be modified for the new schedules. Programming changes need to be made to the relevant screens, windows, prompts and related information, to ensure that the calculations are accurate and the windows and prompts are functioning correctly.

The service account maintenance function of the CCE performs numerous tasks such as determining whether a customer is eligible for a rate schedule. For example, in the case of the proposed experimental TOU rate schedules recently filed with the Arizona Corporation Commission, which is limited to certain cities in the Phoenix metro area, the CCE will determine customer eligibility based on location. Because the total participation for the proposed rates is capped, the CCE will also need the ability to easily discontinue the availability of the rate schedule once the cap is reached.

APS.COM

APS.COM is the web-based tool for customers to be able to view rate schedule options and compare their monthly bill under various options. Implementing new rate schedules requires this system to be updated with new screens, reference tables, information, orders and sample rate calculation functions.

Meter Information System (MIS)

MIS provides the logistics for linking meters/meter types to customer accounts and ensuring that the meter programs are consistent with the rate schedule. For example, when a new customer establishes service and is on a rate schedule such as ECT-1R, MIS tracks the fact that the customer requires a TOU meter with demand registers and the CIS/MIS linkage looks to ensure that demand data is being retrieved. Data in MIS also is used to be sure that if a meter exchange occurs, the correct meter is installed at the customer's premise is installed. When rate schedules are added that require metering with alternative TOU schedules, MIS must be modified so that the new meter types will be recognized.

SUMMARY

Because of the success of its residential TOU programs, APS faces challenges in changing certain characteristics of the rate schedules, such as the on-peak periods for summer and winter seasons. Some of the resulting requirements for reprogramming our billing, customer service and meter information systems are difficult to avoid or short cut. These are large, integrated systems with a significant amount of functionality. Furthermore, any changes to the systems must be thoroughly tested to ensure that customer accounts are billed and maintained accurately.

Metering issues are also a significant challenge for changing TOU rate schedules or for implementing new TOU rates. APS is exploring several solutions to add flexibility to this part of the challenge. Two potential solutions identified are to (1) implement a new meter reading system which would allow for the meters to be reprogrammed in the field by meter readers with the same probe device that they use to read meters and (2) further pursue automatic meter reading which would allow for remote meter reading and programming. It is likely that a combination of these solutions will be implemented. APS believes that APS proposed experimental TOU rate options pending approval before the Commission will help the Company assess customers' reactions and assist in evaluating the future expanded options that would benefit customers and the APS system.

ARIZONA PUBLIC SERVICE COMPANY

Analysis of SurePay Program

INTRODUCTION

Pursuant to Decision 67744 (Page 31, Line 28) APS has examined the cost effectiveness of the SurePay program as well as the possibility of offering a discount to those customers that participate in SurePay. SurePay is the payment option that authorizes a customer's bank to transfer the amount of the customer's monthly bill from the customer's bank account to the customer's APS account. In undertaking the SurePay analysis, APS also took into consideration AutoPay, the on-line version of SurePay. AutoPay is another APS automatic payment program option available to aps.com registered users with email access. AutoPay customers receive an e-mail notification telling the customer the amount of the bill and when payment will occur. AutoPay customers can view their written bill on line in lieu of receiving a mailed copy.

ANALYSIS

After examining APS' automatic payment programs – SurePay and AutoPay, APS does not feel it is advantageous or cost effective to offer customers a discount for participating in these programs for several reasons.

Currently, there are 105,165 Residential SurePay customers and 9,447 Commercial and Industrial (C&I) SurePay customers. Total participation in the SurePay program is 114,612 customers for an 11.9% market share. In addition, there are 27,131 Residential customers and 973 C&I AutoPay customers. Total participation in the AutoPay program is 28,104 for a 2.9% market share. APS has a total of 143,689 customers or 14.8% market share participating in APS' automatic payment programs. Given APS' current robust market share, offering a discount to entice customers to enroll is not needed.

Chartwell, a national market research group, recently published the research findings from the *Chartwell's Guide to Bill Presentment and Payment 2005* report. The report includes exclusive surveys of 90 utilities. The report findings indicate 60 out of the 90 utilities surveyed offer an automatic payment program. The average participation rate is 8.1% overall customer participation. This is far lower than APS' participation rate of 14.8%. Offering any type of incentive to enroll in the program, whether it is a one-time enrollment incentive or an on-going incentive, such as a recurring 1% discount, has not been needed to generate interest in APS' automatic payment programs. These programs have been successfully sold on the benefits of participating in the programs. These benefits include convenience, peace of mind, time savings and cost savings. Salt River Project (SRP), which offers a 1% discount to participants in automatic payment, did not participate in the Chartwell study. However, its percentage of customers choosing automatic payments is believed to be in the 15-16% range – not significantly higher than APS' 14.8%.

The cost savings associated with the Company's automatic payment programs are significantly below the 1% discount that is currently being offered by SRP. SurePay and

AutoPay are APS' least expensive payment processing options. APS currently experiences operating and cost of money savings of $.48 per month, or $5.76 annually from each SurePay or AutoPay customer as shown in Attachment 1. The annual savings associated with these programs is approximately $820,000 per year. Whereas, a 1% discount to our 132,296 Residential SurePay and AutoPay customers, i.e. customers who are already participating without financial inducement, would cost $1,512,143 per year (assuming an average Residential bill of $95.25/month). A similar discount to our 10,420 C&I SurePay and AutoPay customers would be $784,451 per year (assumes average C&I bill of $627.36/month). The total cost of offering a 1% discount to existing SurePay and AutoPay customers is estimated to be $2,296,594 per year. Therefore, the cost of such a discount is significantly more than the savings. Currently, the cost savings generated by customers participating in APS' automatic payment programs are passed along to all APS ratepayers.

In addition, considerable efforts by APS Information Services (IS) and Customer Service would be required to implement a discount for SurePay customers. Changes to APS Customer Information System (CIS) would need to be implemented in order to provide the discount. Such changes are estimated to be at minimum $50,000. Ongoing monitoring and management would also be required to ensure that SurePay and AutoPay customers are receiving the discount.

Based on current participation and the experience of SRP and others, it is unlikely that a discount will provide an incentive to the majority of non-automatic payment program users to enroll in the program. Non-users have very definite reasons for not doing so. These customers raise security and privacy issues as reasons for not participating in the program. They do not like the fact that APS would have access to their personal banking information. Another explanation customers give for not to participating in an APS automatic payment program is account reconciliation. Some non-users are afraid if they sign-up for SurePay or AutoPay they will forget to record the payment withdrawal. Fear of potential errors such as incorrect amounts being debited or multiple unauthorized debits occurring also prevents customers from participating in an APS automatic payment program. Finally, many customers choose not participate in APS' automatic payment programs because they do not want to relinquish control. These customers do not want to have someone control when their bill is paid or the amount that is paid. Offering a discount for participation in SurePay or AutoPay as an incentive will not entice the majority of these customers to enroll in the program. Moreover, since every additional customer on automatic payment would produce $0.48 per month in savings at (conservatively) between $0.95 (residential) and $6.27 (general service) per month in additional costs, a discount would not be cost effective even if it did produce significant customer participation.

Finally, an assessment of the market reveals that very few utilities offer a discount or incentive for participation in an automatic payment program. When Chartwell asked respondents about incentives, only six out of the 90 utilities interviewed offered some type of incentive for participation in an automatic payment program.

SUMMARY

Customer participation in APS' automatic payment programs exceeds the average participation of other utilities without the need to offer a discount. These convenient payment options also achieve cost reductions for all customers. The APS review of the SurePay/AutoPay programs indicates that offering a 1% discount to those customers who participate is not cost effective and cannot be supported by savings realized for these programs. Based on these factors APS concludes that a discount offer is not needed.

Attachment 1
SurePay Analysis

Key inputs & assumptions:			
Payment Option Mix of SurePay Enrollees	% of Mix	Cost/Transaction	
Business Office	15%	$ 2.54	
Mail	65%	$ 0.22	
aps.com/ivr/EDI	17%	$ 0.11	
Bill matrix/NCO	2%	$ 0.09	
Surepay cost/payment		$ 0.11	
Avg Residential Monthly Bill		$ 95.25	
Avg C&I Monthly Bill		$ 627.36	
Cost of Money		2%	
Days of float (Difference between SurePay debit at *day 10 and day 18, the avg day on which non-SurePay customers pay)*		8	

Cost/Benefit Analysis of 1% Surepay Discount			
Savings			
Cost of Money			
# of customers	10000		
Interest Rate	2%		
Days of float	8		
Daily Int Rate	0.04384%		
Avg Residential Monthly Bill	$ 95.25		
Monthly Residential Savings for 10K customers	$ 417.53		
Avg C&I Monthly Bill	$ 627.36		
Monthly C&I Savings for 10K customers	$ 2,750.07		
Operating Cost	Pmt Cost	% of Mix	Wtd Cost
Business Office	$ 2.54	15%	$ 0.39
Mail	$ 0.22	65%	$ 0.14
aps.com/ivr/edi	$ 0.11	17%	$ 0.02
bill matrix/nco	$ 0.09	2%	$ 0.00
Surepay	$ 0.11		$ -
Wdt Avg Cost			$ 0.55
Surepay Cost			$ 0.11
Net Operating Cost Savings			$ 0.44
Total Net Operating Cost Savings			$ 4,430.30
Total Monthly Savings for 10K customers			$ 4,847.83
Avg Savings per Enrollment			$ 0.48
Costs			
Key Assumptions			
Amount of discount	1%		
Current Residential Surepay accts	105,165		
Impact-10K New Additions			
Monthly cost of discount to 10,000 new **residential accounts**	$ 9,525.00		
Net **Monthly** Savings to add 10,000 new accts	$ (4,677.17)		
Avg cost per new addition	$ 0.95		
Impact - Existing Customers			
Monthly cost of discount to existing accounts	$ 100,169.66		
Avg cost per existing customer	$ 0.95		
Impact - New and Existing Customers			
Total monthly discount costs (existing & new accts)	$ 109,694.66		
Monthly savings minus costs to APS (existing & new customers)	$ 104,846.83		
Net Annual Cost to APS	**$ 1,258,161.94**		

Above analysis reflects operating savings for new additions only. No operating savings were applied to customers on the program from previous years.

EXHIBIT
APS-70
admitted

REBUTTAL TESTIMONY OF DAVID J. RUMOLO

On Behalf of Arizona Public Service Company

Docket No. E-01345A-05-0816

September 15, 2006

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REBUTTAL TESTIMONY OF DAVID J. RUMOLO
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-05-0816)

I. <u>INTRODUCTION</u>

Q. PLEASE STATE YOUR NAME.

A. David J. Rumolo.

Q. ARE YOU THE SAME DAVID J. RUMOLO WHO SUBMITTED DIRECT TESTIMONY IN THIS CASE?

A. Yes I am.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. My rebuttal testimony addresses several areas. First, I comment on the non-rate design elements of the direct testimony filed by the Arizona Corporation Commission Staff ("Staff") and the Residential Utility Consumer Office ("RUCO") regarding cost of service allocations, pro forma adjustments, and the Demand Side Management ("DSM") Adjustment Mechanism. I sponsor an operating income adjustment to the Company's Service Schedule 1. Second, I provide comments on the rate design recommendations of Staff, RUCO, Arizonans for Electric Choice and Competition ("AECC"), Kroger, Federal Executive Agencies ("FEA"), the Distributed Energy Alliance of Arizona ("DEAA") and the Arizona Interfaith Coalition on Energy ("AICE"). Third, I am providing testimony regarding the phase out of frozen rates as provided for in Decision No. 67744. Fourth, my testimony discusses the concept of hook-up fees as a tool to finance system growth and includes a discussion of marginal costs. Fifth, I sponsor two alternative Plans of Administration for the Power Supply Adjustor ("PSA") mechanism. These plans implement the modifications to the

PSA that are discussed in the testimony of APS witnesses Don Robinson, Pete Ewen, and also Staff Witness John Antonuk. Finally, I sponsor calculations that include determining the jurisdictional splits of revenue requirements that are discussed in the Rebuttal Testimony of APS witnesses Froggatt, and Rockenberger.

II. SUMMARY

Q. WOULD YOU PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY?

A. Yes. My rebuttal testimony compares production cost allocations proposed by Staff and energy allocation methods proposed by AECC with the methods used in the APS rate case filing. I conclude that the alternative methods shift cost responsibility between customer classes but when the alternatives are combined, the class revenue responsibilities are not that different from those proposed by APS. The alternative methods can shift cost responsibility within a class. My testimony notes that alternative rate designs proposed by intervenors can result in higher rate increases for lower load factor customers. My testimony rebuts rate design arguments of DEAA and note that some of DEAA's arguments simply cannot be factually supported. I also discuss the concept of hook-up fees and conclude that not only are such fees an expensive way to finance plant additions, but that this is a complicated issue and that such a policy decision should involve other parties who may not be participating in this rate case but who will be impacted by the policy. Therefore, I agree with Staff and RUCO that the hook-up fee discussion should occur in the context of generic workshops for all utilities.

III. NON- RATE DESIGN TESTIMONY OF STAFF, RUCO AND INTERVENORS

Q. HAVE YOUR REVIEWED THE DIRECT TESTIMONY FILED BY ACC STAFF, RUCO AND INTERVENORS IN THIS CASE?

A. Yes, I have.

Q. DO YOU HAVE ANY COMMENTS TO OFFER ON THE DIRECT TESTIMONY?

A. Yes, I do. First, I will address the testimony of Staff Witness Brosch regarding demand allocation methods.

Q. DOES STAFF WITNESS BROSCH PROPOSE UTILIZING A DEMAND ALLOCATION METHOD THAT ALLOCATES PRODUCTION COSTS AMONG THE RETAIL CLASSES THAT IS DIFFERENT THAN PROPOSED BY APS IN ITS FILING?

A. Yes. In our filing, APS allocated production demand based on a coincident peak method, specifically, the 4CP method that allocates capacity costs to each jurisdiction and to each customer class within the ACC jurisdiction based on the class contribution to the APS peak during the summer months. Staff Witness Brosch proposes the use of a "peak and average" method that allocates a portion of production capacity costs based on contribution to peak demand and a portion based on average demand.

Q. WHY DID APS ELECT TO USE THE 4CP METHOD?

A. The use of the 4CP method in this case is consistent with its use in previous APS retail rate cases and is consistent with the method that we were directed to use by the Federal Energy Regulatory Commission ("FERC") in previous federal rate case litigation. Because of the magnitude of the requested revenue increase in this case, I was concerned that adopting an alternative demand allocation method for customer class allocations could introduce a higher degree of rate shock to some customers.

Q. HAVE YOU PERFORMED ANY ANALYSIS OF THE CUSTOMER CLASS ALLOCATION METHOD PROPOSED BY MR. BROSCH?

A. Yes. We compared the results of the cost of service study that was the basis of our filing with the results of a cost of study that utilized the 4CP method for the jurisdictional allocation, i.e. the allocation of costs between retail and "all other" and then used the Peak and Average method for the allocation of production demand costs to the retail customer classes.

Q. WHAT WERE THE RESULTS OF YOUR COMPARISON OF THE TWO METHODS?

A. The retail cost allocations shifted between customer classes when the Peak and Average method was used with more costs shifted to general service customers and reduced cost allocation to residential customers. More costs were also shifted to irrigation and lighting service customers. The results of the studies are presented in Attachment DJR-1RB.

Q. WOULD YOU PLEASE EXPLAIN ATTACHMENT DJR-1RB?

A. Yes. The exhibit compares the relative rates of return, based on the revenue requirements requested in APS filing for each customer class under a 4CP allocation method and the method proposed by Staff Witness Brosch. Required rate increases, again based on the APS requested overall increase (less the RES surcharge) of 21.1 %, if each customer class contributed allocated costs of service and earned the same rate of return, under the 4CP and 4CP/Peak and Average methods are also displayed. For example, to achieve a levelized rate of return of 8.73%, which is the requested jurisdiction rate of return on original cost rate base, the residential customer class would experience a 27.1% increase and the general service class would experience a 14.9% increase under the 4CP method. Under the 4CP/Peak and Average method, the residential class would experience a 25.2 % increase while the general service class would experience a 16.3 % increase.

Q. WHAT DID YOU CONCLUDE AS A RESULT OF YOUR COMPARISON?

A. I concluded that, in this rate case, the two methods yield very similar results for the two largest customer classes, i.e. residential and general service. Within the general service class and for the irrigation and lighting classes, the 4CP/Peak and Average method for production demand allocation results in higher revenue requirements than the 4CP method.

Q. IN HIS TESTIMONY, STAFF WITNESS DITTMER PROPOSES A $19,000 ADJUSTMENT TO APS REVENUES RELATED TO A CHANGE IN SERVICE SCHEDULE 1 RELATED TO PAPERLESS BILLS. DO YOU AGREE WITH THAT ADJUSTMENT?

A. Yes, I do.

Q. DO YOU HAVE ANY COMMENTS ON THE DIRECT TESTIMONY OF RUCO'S WITNESSES?

A. Yes. RUCO Witness Diaz Cortez (Direct testimony at pages 38-40) proposed to disallow the APS modification to the Demand Side Management ("DSM") mechanism that would provide for interest accrual on the DSM spending in excess of the $10 million included in base rates. APS has requested the interest accrual for future recovery because the recovery of DSM expenditures in excess of the base amount occurs in years following the expenditures, thus APS incurs carrying costs until the recovery occurs. Therefore, the recovery of interest on the un-recovered DSM costs is appropriate. While RUCO Witness Diaz Cortez is correct that interest accrual was not explicitly addressed by the parties to the settlement agreement approved in Decision No. 67744 ("Settlement Agreement"), the APS proposal is consistent with other adjustment mechanisms such as the PSA that were part of the Settlement Agreement. I believe that not including the interest component for this adjustment mechanism to be merely a drafting oversight. In any event, it is only reasonable for APS to collect interest associated with DSM costs since APS is <u>required</u> to make DSM investments and then file for approval to collect the funds on an after-the-fact basis in the following year.

IV. RATE DESIGN TESTIMONY

Q. HAVE YOU REVIEWED THE RATE DESIGN TESTIMONY FILED BY STAFF AND INTERVENORS ON SEPTEMBER 1, 2006?

A. Yes, I have.

Q. PLEASE PROVIDE A SUMMARY OF YOUR UNDERSTANDING OF THE TESTIMONY THAT WAS PROVIDED.

A. My comments focus on the overall rate designs and general rate levels. Obviously, Staff, RUCO and others offer rate designs based on revenue levels that are lower than the revenue level that was requested by APS. In general, the testimony filed on September 1 focused on how the increased revenue requirement should be allocated to the customer classes. For example, AECC offers demand rate alternatives that recover additional revenue requirements thorough demand charges as compared to the APS proposed rate designs. AECC also recommends that APS adopt an energy allocation method that recognizes the hourly variations in energy costs. The witnesses for Kroger and the FEA suggest demand rate alternatives similar to the alternatives recommended by AECC. These demand alternative proposals will produce relative rate increases for low load factor customers that will be higher than high load factor customers. Additionally, these witnesses that represent general service customers recommend that residential rates be increased more than the increases for the general service customers.

Staff does not offer specific rate designs for all schedules but provide recommendations regarding rate modifications, service schedule modifications, and the phase-out of frozen rates.

Q. DOES APS OBJECT TO STAFF'S RECOMMENDATIONS REGARDING THE PHASE OUT OF FROZEN RATE SCHEDULES?

A. Staff's recommendations provide for a longer phase out period, one year for residential customers and six months for general service customers, than in the APS phase out plan. APS accepts Staff's recommendation for the longer time frame provided that the interim rates are revenue neutral compared to the rates to which the customer will be transferred.

Q. DO YOU HAVE ANY OTHER COMMENTS ON STAFF'S PROPOSED RATE DESIGNS?

A. Yes, Staff has recommended that the rate designs for the new residential time of use rates (Schedules ET-2 and ECT-2R) that were approved earlier this year be revenue neutral compared to Schedules ET-1 and ECT-1R. Any rate design alternatives proposed in this case should also be revenue neutral. We are gathering information on customers' usage patterns as customers opt for these new rates but during the interim period, revenue neutrality should be maintained.

Q. DID STAFF HAVE ANY SPECIFIC RECOMMENDATIONS FOR THE GENERAL SERVICE RATE SCHEDULES?

A. Yes, Staff suggested that the demand component of Schedule E-32 not be increased significantly. Staff also suggested that APS examine breaking up Schedule E-32 into usage divisions in its next rate case. I agree with these suggestions.

Q. STAFF HAS ALSO RECOMMENDED SOME CHANGES TO PROPOSED SCHEDULE 3. PLEASE COMMENT ON THOSE CHANGES.

A. We agree with Staff's changes, except for the recommendation regarding the timing of field audits, and have incorporated changes into a revised schedule.

Field audits are required at the end of 18 months in the case of Residential Homebuilder Subdivision extensions since that time period determines if additional advances are required. For other types of extensions, advances are made at the time the extension agreement is executed. Therefore, the field audits are not needed. We have also increased the construction allowance for multifamily housing projects from $500 to $1000 per unit and modified the provisions for refunds in Residential Custom Home "Lot Sale" Development extensions to allow for refunds. The revised Schedule 3 is attached and marked Attachment DJR–2RB. The revised schedule also corrects formatting and typographic errors in the original document. A redlined version that compares the final document with the version found in the testimony of Staff Witness Erin Andreasen is attached as Attachment DJR-3RB.

Q. PLEASE COMMENT ON RUCO'S PROPOSED RATE DESIGNS.

A. RUCO's designs follow the rate designs that were a result of the Settlement Agreement and are generally an "across the board" approach. I believe that, because of the high energy costs that comprise a significant part of the increase requested in this case, an across the board approach will induce rate inequities that we attempted to eliminate in the process of rate unbundling.

Q. HAVE YOU PERFORMED AN ANALYSIS OF AECC'S RECOMMENDATION REGARDING THE USE OF AN HOURLY ALLOCATION FACTOR FOR THE FUEL AND PURCHASED POWER ELEMENT OF BASE RATES?

A. Yes, we have. The results of that analysis are summarized in Attachment DJR – 1RB. If retail rates were designed strictly based on cost of service and all customer classes earned the same rate of return, residential rates would increase by approximately 27.1% based on the assumptions in the APS cost of service study that utilized the 4CP production cost allocator. General Service rates would increase by approximately 14.9%. If the only change to the APS cost of service model was adoption of the AECC proposed energy allocator, residential rates would increase by 28.8% and general service rates would increase by 13.1%.

Q. HAVE YOU MODELED THE IMPACT OF COST OF SERVICE STUDY MODIFICATIONS RECOMMENDED BY STAFF AND AECC?

A. Yes, we combined the change in the production demand allocation method recommended by Staff Witness Brosch with the AECC energy allocation method. The impact on the results of the cost of service model for the combined recommendations is also found on Attachment DJR-1RB. It can be seen that, on a class basis, the two recommendations tend to offset each other and produce results similar to the APS original filing. Within the classes, the combined method tends to favor high load factor customers but the impact is less favorable than adopting the AECC energy allocation method alone. For example, in the APS base case, the required rate increase for large industrial customers served under Rate Schedule E-34 was 24.6 %. Adopting the Staff production plant method, the increase would be 31.9 %. The AECC modification to the study results in a required increase of 21.4 %. Under the combined modification study, the required rate increase would be 28.8% for Schedule E-34. APS' proposed rate increase for customers served under Schedule E-34 was 24.6% excluding the EIC.

Q. YOU MENTIONED THAT SOME OF THE RATE ALTERNATIVES PROPOSED BY INTERVENORS IN THIS CASE RESULT IN LOWER INCREASES FOR HIGH LOAD FACTOR CUSTOMERS. WHAT DO YOU MEAN BY LOAD FACTOR?

A. Load factor is a measurement of peak demand to average hourly demand. For example, if a customer had a demand of 10 kW and used that demand level for 24 hours per day for the entire month, the customer's monthly load factor would be

100%. If the customer's average demand was 5 kW, the monthly load factor would be 50%.

Q. HOW DOES LOAD FACTOR INFLUENCE A CUSTOMER'S BILL?

A. If a customer is billed on a rate with an explicit demand charge such as Schedule E-32 for loads over 20 kW, higher load factors tend to result in a bill with lower average cents per kWh since the demand component of the bill gets spread over more kWh. For example, a customer with a 50 kW load and a 50 per cent load factor would consume 18,250 kWh. A customer with a 50 kW load and a 30 per cent load factor would consume approximately 10,950 kWh. The demand charge for these two customers would be the same. But, as a percentage of the total bill, the demand component is higher for the low load factor customer. Therefore, in designing rates, the balance of revenue recovery between the demand and energy components of the rate can impact similarly sized customers differently.

Q. IN THE LAST APS RATE CASE THAT RESULTED IN THE SETTLEMENT AGREEMENT APPROVED IN DECISION NO. 67744, WAS THE RATE DESIGN EMPHASIS ON THE DEMAND OR ENERGY CHARGE COMPONENTS OF MOST RATES?

A. The last case included generation additions that require recovery of capacity costs. These costs are recovered through increased demand charges. Also, in unbundling our retail rates, we modified the rates to better reflect cost of service including segregating capacity, energy, and customer components. This also tended to increase demand charges. As a result, customers with low load factors tended to experience greater percentage bill increases than customers with high load factors. In fact, some high load factor customers actually saw a bill reduction as a result of Decision No. 67744. The current rate case is largely driven by higher fuel costs which impacts the energy portion of rates. Therefore, the increase tends to have greater impact on higher load factor customers.

Q. DO YOU HAVE ANY COMMENTS ON THE RATE DESIGN TESTIMONY OF KROGER WITNESS STEPHEN BARON?

A. Kroger Witness Baron recommends acceptance of the APS 4CP allocation method for production plant. His testimony recommends that revenue increases for the generation and delivery components of Rate Schedule E-32 be split equally across the demand blocks for the delivery component and across demand and energy equally for the generation component. I disagree with these recommendations, especially on the generation component. Additionally, Mr. Baron claims that the cost of service study does not support the proposed APS change. I disagree with this statement. The cost of service study is based on increased fuel charges. Our base fuel charge has increased from slightly more than 2 cents per kWh to over 3 cents per kWh. The increased fuel and purchased power expense account for approximately 16% of the total 21% increase requested by APS in this case. Recovery of these increased energy costs through increased energy charges is appropriate and consistent with cost of service principles.

Q. FEA WITNESS GOINS RECOMMENDS INCREASING THE DISCOUNTS FOR PRIMARY AND TRANSMISSION VOLTAGE LEVEL CUSTOMERS. DO YOU AGREE WITH THIS RECOMMENDATION?

A. Dr. Goins recommendation is consistent with the results of the APS cost of service if that is the only consideration, and rates for all classes are set at equal rates of return. I do not disagree with the recommendation but it must be recognized that this recommendation results in slightly higher bills to customers who are not eligible for the discount.

Q. DO YOU HAVE ANY COMMENTS ON THE RATE DESIGN TESTIMONY OF DEAA WITNESS MURPHY?

A. Yes. Generally, Mr. Murphy's arguments are the same he made in the last APS rate case regarding his dislike for demand rates and cost-based rate making because his perception is that cost-based rates are a disincentive to distributed generation. He also is very selective in discussing the "Bonbright" principles on rate-making. I will agree with Mr. Murphy on one point. The APS rate designs for large partial requirements service customers are complex. APS Witness Greg DeLizio's testimony provides a discussion regarding new, less complex partial requirements rates that APS is proposing to offer customers with Commission approval in this rate case.

Q. MR. MURPHY DISCUSSES APS GENERAL SERVICE RATES AND COMPARES THE RATES TO THE RATES OF SALT RIVER PROJECT ("SRP"). WOULD YOU LIKE TO COMMENT ON HIS DISCUSSION?

A. Yes. Mr. Murphy's testimony excludes some important facts. APS has approximately 108,000 general service customers. Approximately 86,000 of those customers have loads under 20 kW. Rate Schedule E-32, as approved in the Settlement Agreement, provides that customers under 20 kW are billed on the basis of energy with capacity costs recovered in the energy charges. This is the exact concept that Mr. Murphy espouses and we apply it to 80% of our general service customers. We also offer a time of use companion rate that has a similar rate design, i.e. no explicit demand charge for customers under 20 kW. Mr. Murphy discusses the SRP Time of Use ("TOU") rates in detail but he neglects to inform the Commission that the majority of SRP's general service customers are served under SRP Schedule E-36, which is a demand/energy rate for all customers. In fact, the SRP E-36 rate design is very similar to the APS rate design prior to Decision No. 67744.

Q. IN HIS TESTIMONY, MR. MURPHY ASSERTS THAT 96% OF NON-RESIDENTIAL CUSTOMERS HAVE PRICING THAT IS BASED ON DEMAND AND ENERGY BILLING UNITS. (TESTIMONY AT PG 6 LINES 12-14). IS THAT CORRECT?

A. No, that is not correct. I believe that Mr. Murphy is suggesting that all general service customers served under Schedule E-32 are billed on demand. That is simply wrong. As I noted earlier in my testimony, 80% of our general service customers are under 20 kW and are not billed based on demand. In the same testimony cite, Mr. Murphy states that over 8% of residential customers are billed on demand/energy billing determinants. While the correct number is under 8%, I will not argue the point. However, Mr. Murphy neglects to note an important fact. The 67,000 residential customers who are served on demand/energy rates have opted for those rates <u>voluntarily.</u> These customers understand capacity charges and are likely adopting measures to reduce demand.

Q. PLEASE COMMENT ON MR. MURPHY'S DISCUSSION OF THE "BONBRIGHT" PRINCIPLES.

A. First, I wish to clarify a misconception that may be drawn from Mr. Murphy's testimony. Therein, Mr. Murphy implies that the "Bonbright principles" are in order of importance (testimony at pg. 9 lines 6-7). The Bonbright text states, "The sequence of the eight items is not meant to suggest any order of relative importance." (Principles of Public Utility Rates, James C. Bonbright, pg. 291). I will agree with Mr. Murphy that revenue stability is important to utilities. It is also important to customers because a financially stable and healthy utility has better access to capital markets. Mr. Murphy also cites "freedom from controversy" as one of the Bonbright principles, but he does not include the entire cite, which reads: "Freedom from controversies <u>as to proper interpretation</u>." (Emphasis added.) I believe this to mean that rates are designed so they can be applied consistently across the customer base of similar customers.

I also must point out that the Bonbright text recognizes that the "principles" can be somewhat ambiguous and overlapping and the text acknowledges there are three primary objectives. The three primary objectives are: 1) the revenue requirement objective; 2) a fair-cost apportionment objective; and 3) the optimum use objective under which rates are designed to discourage wasteful use while "promoting use that is economically justifiable in view of the relationships between costs incurred and benefits received."

I believe that the primary objectives yield rate designs as proposed by APS in which capacity costs are generally recovered through demand charges, energy costs through energy charges and customer-based costs through customer or basic service charges. I disagree with Mr. Murphy's allegations that APS' customers do not understand capacity charges. As I noted earlier, we have a significant number of residential customers who voluntarily participate in demand based rates, we work with our general service customers so that they understand demand charges and how they can proactively work to reduce demand, and in fact, the intervenors in this case who represent general service customers are endorsing demand charges that are higher than those proposed by APS.

Q. MR. MURPHY AND MR. TANNER OF AICE CLAIM THE APS IS ELIMINATING A SERIES OF RATES THAT COULD BE BENEFICIAL TO CERTAIN CUSTOMERS IN THIS CASE. IS THAT CLAIM CORRECT?

A. No, it is not. First, we are not eliminating Schedule E-20 which is available only to houses of worship. That rate schedule was frozen as part of the Settlement Agreement in Decision No. 67744. The Settlement Agreement provided for the elimination of a series of already frozen, experimental, time of use rate Schedules

E-21, E-22, E-23 and E-24. This case implements the actions of the Commission in the last case. These rates were limited participation rates that were established on an experimental basis several years ago. We now offer Schedule E-32 TOU which is open to all customers who can take advantage of lower off peak prices. New houses of worship whose primary hours of operation are evenings or weekends can likely save relative to our standard general service rate schedule.

Q. DO YOU HAVE ANY FINAL COMMENTS REGARDING THE RATE DESIGN TESTIMONY SUBMITTED BY STAFF AND INTEVENORS IN THIS CASE?

A. Disregarding the issue of overall revenue levels, I believe that the testimony is generally supportive of the rate designs currently used by APS and adjusted in this case. The testimony provides recommendations that "fine tune" the APS rate designs generally to the benefit of a targeted customer group. I believe that the testimony is supportive of the concept that rate design has as much "art" as science as long as the "art" is supported by reasonable cost of service principles. While adjusting the balance between demand and energy charges can be supported by cost of service analyses, I think the customer impact aspect of rate changes is also important. In that regard, I could support modifying Schedules E-34 and E-35 as suggested by AECC, i.e., converting the transmission revenues to a capacity charge in lieu of the current energy charge but recovering the same revenue level, and adjusting the unbundled generation charge balance between capacity and energy. I do not support changing the E-32 rate design as proposed by AECC et al. As mentioned above, our rate unbundling and moving rates closer to cost of service increased demand charges for E-32 customers and low load factor customers experienced larger than average increases. The E-32 customer class is very non-homogeneous, and customers on the rate schedule range from small users such as railroad crossing signals to very large commercial establishments and industrial users. The average load factor is under 40% and only 4% of customers have load factors greater than 70%. On the other hand, customers served under our industrial rate schedules, E-34 and E-35, have average load factors of approximately 70% and tend to have much less load factor disparity than E-32 customers. Therefore, rate design changes tend to impact customers on a more equal basis. The E-32 rate design proposed by APS in this case tends to spread the increase on a more even basis across a broad customer group than then the revisions suggested by intervenors.

V. FROZEN RATE ELIMINATION PLAN

Q. WOULD YOU PLEASE SUMMARIZE THE PROPOSED RESIDENTIAL RATE SCHEDULE CHANGES REGARDING ELIMINATION OF FROZEN RATE SCHEDULES?

A. Decision No. 67744 provided for the elimination of frozen rate schedules in the next APS rate case and we are doing so in this case. APS has and will continue to communicate the proposed rate schedule changes to customers on frozen rates. Communications include bill notices and direct contact with affected customers. In my Direct Testimony, I described our plan for the frozen rate elimination. We proposed that customers on Schedule E-10 be transferred to Schedule E-12 if the customer does not opt for an alternative rate option. The default rate for Rate Schedule EC-1 customers will be Schedule ECT-1R. However, because most meters installed for Schedule EC-1 customers cannot provide the time of use billing determinants required by Schedule ECT-1R, we proposed an interim Schedule EC-1 that would continue until meter exchanges take place. As I stated in my Direct Testimony in these proceedings, APS proposed transferring E-10 customers to the E-12 rate schedule and transferring EC-1 customer to ECT-1R if the customer does not select an alternate rate within a six month period after the frozen rate schedules are eliminated.

Q. DO YOU PROPOSE ANY CHANGES OR UPDATES TO THE TRANSITION PLAN DESCRIBED IN YOUR DIRECT TESTIMONY?

A. Yes. After in-house discussion with APS Customer Service personnel, it was agreed that the original plan could be more 'customer friendly' with the goal of easing or transitioning E-10 and EC-1 customers to new rates. This revised plan includes requesting approval of an interim rate for customers on Schedule E-10.

Q. HAS APS DESIGNED AN INTERIM RATE FOR CUSTOMERS ON THE FROZEN E-10 RATE?

A. Yes. An interim rate for E-10 customers is attached as Attachment DJR-4RB. The interim rate was designed to collect the same revenue level as would be collected if the Schedule E-10 customers were transferred to Schedule E-12.

Q. PLEASE DESCRIBE ANY ADDITIONAL DETAILS REGARDING THE E-10 AND EC-1 TRANSITION PLAN.

A. Upon further examination of bill frequency and bill impact data, we believe that some Schedule E-10 customers might prefer to transfer to a TOU rate option. To aid E-10 customers in the selection process and provide some guidance to customers that haven't selected a rate during the transition period, APS proposes customers using more than 1,000 kWh/month (calculated annual average) be placed on Schedule ET-1 as the default rate. ET-1, also known as the Time Advantage Rate, is our most commonly used residential TOU rate. For the Schedule EC-1 customers that haven't selected a new rate, APS proposes that customers consuming more than 1,000 kWh/month (annual average) be placed on Schedule ECT-1R. For E-10 and EC-1 customers using less than 1,000 kWh/month (annual average), the default rate will be Schedule E-12. These rate selections should result in the lowest rate impact due to elimination of the frozen rates.

Q. ARE THERE METERING IMPLICATIONS TO ELIMINATION OF FROZEN RATE SCHEDULES?

A. Yes. A customer's rate selection may require a meter exchange. For example, a meter exchange will likely be required if an E-10 customer requests to be transferred to a TOU rate schedule. Similarly, a new meter will be required for Schedule EC-1 customers who select a TOU schedule. The need of meter exchanges is another factor in the need for a transition time period.

Q. ARE THERE TRANSITION PLANS FOR GENERAL SERVICE CUSTOMERS ON FROZEN TIME OF USE RATES?

A. Yes. Customers on frozen experimental TOU rates E-21, E-22, E-23 and E-24 will receive a direct mail letter communicating the results of a rate comparison between E-32 and E-32 TOU. Customers will receive the letter within one month after the approval of the rate case.

At least three times during the transition period following the approval of the rate case, APS will conduct an outbound phone call campaign to convey the results of the rate comparison and discuss features of each rate. At the end of the transition period, APS will again call to inform customers they have been defaulted to E-32 TOU if the customer has not selected a new rate.

Q. APS IS ALSO ELIMINATING RATE SCHEDULE E-38. TO WHICH RATE WILL THOSE CUSTOMERS BE TRANSFERRED?

A. At the time frozen rates are eliminated, customers on agricultural irrigation rates E-38 and the TOU option E-38-8T will be transferred to rate schedule E-221. E-221 is a Water Pumping Service TOU rate. E-38 and E-38-8T customers will be given a bill comparison if requested. They will also be provided information on

E-32, E-32 TOU and E-221 at the aps.com website.

Q. EARLIER IN YOUR TESTIMONY YOU DESCRIBED CERTAIN MODIFICATIONS THAT STAFF HAS PROPOSED TO THE TRANSITION PLAN. DO YOU AGREE THAT STAFF'S PROPOSED MODIFICATIONS ARE BASED LARGELY ON THE PLAN PROPOSED BY APS?

A. Yes, Staff proposed modifications consist of time extensions to the APS plan and APS is supportive of those modifications.

VI. HOOK-UP FEES

Q. SEVERAL COMMISSIONERS REQUESTED THAT APS EXAMINE THE CONCEPT OF USING HOOK-UP FEES AS A METHOD OF RAISING CAPITAL TO MEET GROWTH. HAVE YOU DONE SO?

A. Yes, we have looked at the concept. However, hook-up fees have wide ranging ramifications, and we believe that if the Commission is considering the use of hook-up fees by utilities, the examination should be done in the context of a generic workshop as suggested by RUCO Witness Diaz Cortez and Staff Witness Andreasen. This is an industry-wide issue that should involve at least gas, electric, telephone and water companies as well as those who would be impacted by such a significant change.

Q. HAVE YOU IDENTIFIED ISSUES THAT SHOULD BE ADDRESSED IN THE GENERIC WORKSHOPS?

A. Yes. Among the significant policy issues that should be examined are: 1) what would be the impact on growth in the service territories of regulated entities vis-à-vis non-regulated utilities, and correspondingly the impact on government entities that rely on tax revenues from growth; 2) what would be the impact on housing affordability; 3) which capital expenditures (e.g., all distribution plant or only local facilities, generation plant, general plant) should be included in the hook-up fee computation; 4) what are the long term impacts on the financial health of regulated companies; 5) what are the short and long term rate impacts to customers; 6) should the amount of the hook-up fee include tax effects (i.e. gross-up vs. self pay); 7) could existing customers be responsible for hook-up fees; and 8) what would be the impact on homebuilders and the construction industry. The generic workshops should include all utilities, not just APS.

Q. WOULD YOU PLEASE DESCRIBE WHAT IS MEANT BY A HOOK-UP FEE?

A. It is important to understand the use of the term "hook-up fee." It is used in several different contexts. In some instances, the term is used to describe a service initiation fee which is primarily an administrative cost. In the context of this testimony and the questions raised by the Commissioners, the term is used in the context of a capital addition funding mechanism. A hook-up fee is a means to provide capital for infrastructure additions. Hook-up fees are also sometimes called "impact fees" or "cost of development fees." Typically, new customers pay a fee designed to recover the incremental or marginal investment required for the utility to provide service. Hook-up fees are often used by municipalities to fund water or wastewater system additions such as pipelines, water supplies or treatment plants. They are rarely used in the electric utility industry as a capital funding tool and to my knowledge, only by municipalities or other public power entities.

Q. PLEASE DESCRIBE THE TAX CONSEQUNCES OF CONTRIBUTED CAPITAL.

A. When an investor-owned utility receives contributed capital, an immediate income tax liability is created because the payment is considered taxable income. So, for example, if hook-up fees generated $820 million over at ten year period (assuming $2,000 per customer, 42,000 customers per year), approximately $320 million would be paid in additional current income taxes leaving $500 million to fund capital projects. If the objective was to have the full $820 million available, the hook-up fee would need to be "grossed-up" to account for the tax liability to $1.34 billion. This would, of course, significantly raise the hook-up fee paid by customers. This $320 million tax impact actually reduces the Funds from Operations ("FFO") which is a key financial indicator used by the investment community to assess the financial health of APS.

Q. WHY WOULD THE $82 MIILLION ANNUAL HOOK-UP FEE REVENUE REDUCE THE COMPANY'S FFO?

A. It is my understanding that under Generally Accepted Accounting Principles (GAAP), funds received from contributions in aid of construction, hook-up fees etc., are booked to reduce capital expenditures. They are not booked as revenues to the Company. So, the $82 million per year would not directly flow into the calculation that determines the Company's FFO. But the $30 million per year of increased current income taxes decreases the Company's FFO.

Q. HAS APS PERFORMED ANY ANALYSIS OF THE LONG TERM RATE IMPACTS OF THE USE OF HOOK-UP FEES?

A. Yes, our financial modeling group performed some preliminary analyses. Assuming hookup fees would generate $82 million annually, incremental rate impacts due to decreased debt and rate base would be very small, totaling an average of 0.3% per year over a ten year period. These rate impacts are more than offset by the cumulative cost of the hook-up fees. In my example, new customers would contribute $820 million to achieve $400 million in rate benefits over the ten-year period. Therefore, it appears that hook-up fees are an expensive vehicle for financing system improvements.

Q. IF HOOK-UP FEES REPRESENT SUCH AN EXPENSIVE WAY TO FINANCE NEW ADDITIONS, WHY ARE HOOK-UP FEES USED BY SMALL WATER UTILITES AND MUNICIPALITIES?

A. Hook-up fees are often used if a utility has limited access to capital markets such as in the case of small privately owned water companies. Customer or developer contributions may be the only readily available capital source for projects such as new water wells or treatment facilities. Municipal utilities, on the other hand, do not face the significant tax consequences of contributed capital that a utility such as APS would face. Also, private water companies often gross-up contributed capital to cover tax consequences. This make the hook-up fee more effective for the utility but even more expensive to consumers.

Q. IF THE COMMISSION WERE TO ORDER APS TO ADOPT A HOOK-UP FEE APPROACH, HOW COULD THE FEE BE DEVELOPED?

A. There are many approaches to hook-up fee development and fee development would be a key element to be explored in workshops. For example, one of the first decisions is to identify the capital expenditures that would be the target of the hook-up fee. APS invests considerable capital each year in distribution facilities to meet customer growth. We also have increasing capital requirements for transmission plant and could have significant capital needs for generation plant additions or improvements as well as general plant additions such as computer systems and facilities. The basic concept behind typical hook-up fee analysis is based on some form of marginal or incremental cost analysis. For example, APS' distribution capital expenditures for new customers are approximately $5,000 per meter set. However, new customers will pay rates that include an imbedded cost element. Therefore, it is reasonable to "credit" the incremental cost with the cost included in base rates. The average book investment is approximately $1,500 per customer. Therefore, the hook-up charge would be $3,500 per customer. Hook-up fees would be developed for each customer class. Residential hook-up fees would likely be a per customer charge. Because the general service customer group is very non-homogeneous, it is more difficult to state hook-up fees in terms of a per customer charge. General Service hook-up fees would likely be expressed in terms of connected kW load. The water system analogy utilizes service or meter size to determine hook-up fees for different types of customers.

Q. COULD HOOK-UP FEES BE APPLICABLE TO EXISTING CUSTOMERS?

A. Typically, hook-up fees are applicable only to new service applications, e.g. a new subdivision or new home or business. I might add that it is not always easy to determine whether a customer is "new," especially in the case of businesses. However, an argument could be made that a form of hook-up fee should be collected from existing customers who request a change of service or who change service locations. For example, if an existing home has a 200 ampere service and the customer is constructing a large addition that will require that the service be upgraded to 400 amperes, an impact fee could be assessed.

Q. YOU HAVE ONLY DISCUSSED THE APPLICATION OF HOOK-UP FEES FOR THE WIRES PART OF THE BUSINESS. HOW COULD YOU CALCULATE HOOK-UP FEES TO FUND GENERATION RESOURCES?

A. Generation marginal costs are typically developed based on the "peaker deferral method" which computes the cost of the next kW of peaking capacity or a generation planning approach. In either case, the marginal cost is developed on a per kilowatt basis. To develop a per customer hook-up, it would be necessary to assume a coincident peak load per customer class and convert the per kW marginal cost to a customer basis. For example, assume the next unit of generation required as a system resource has a cost of $2,200 per kW. The rate base value of the existing generation fleet is approximately $480 per kW. Therefore, a hook-up charge for generation would be valued at approximately $1,720 per kW. The average residential customer's coincident peak demand is approximately 3.5 kW. Therefore, a generation cost hook-up fee would be approximately $6,000 per kW for new resources. When combined with the distribution facilities fee described above, the total hook-up fee for a customer could be $9,500.

Q. HOW COULD YOU DETERMINE A HOOK-UP FEE FOR TRANSMISSION SYSTEM ADDITIONS?

A. Because transmission charges are regulated by FERC, it may not be possible to include transmission system additions in a hook-up fee computation for retail customers. Many transmission system additions are made for reliability reasons, and it may be more appropriate to recover reliability project costs from all customers, not just new customers.

Q. HAVE YOU REVIEWED COMMISSIONER MAYES LETTER DATED AUGUST 31, 2006 REGARDING HOOK-UP FEES?

A. Yes I have. Commissioner Mayes raises some important issues regarding hook-up fees, and the generic workshop suggested by RUCO and Staff would be the best venue to discuss these points to allow for input from all stakeholders including all regulated utilities, homebuilders, and the general public.

Q. IN HER AUGUST 31, 2006 LETTER, COMMISSION MAYES ASKED SPECIFIC QUESTIONS REGARDING HOOK-UP FEES. CAN YOU RESPOND?

A. Yes, the first question asks about the facilities that were included or excluded in the $1,650 per residential customer and $4,900 per commercial customer budgetary estimates that were provided to Staff in a data request response. These estimates are the direct costs for local facilities. Local facilities include the wires, poles, manholes, and switching cabinets within a subdivision or development. The budget estimates exclude backbone facilities such as main feeders, capacitor banks, duct banks, switching cabinets, substations, and engineering, inspection, warehousing and other overhead costs.

The second question raised by Commissioner Mayes requested comments on the benefits and drawbacks of including generation costs in a hook-up fee. The primary benefit is that the hook-up fee is another source of capital available to the utility, albeit an expensive source. The largest drawbacks are the financial impact on the Company because of the tax consequences and the impact on customers due to the potential size of the generation element in the fee. Another drawback is that the generation element of the hook-up fee could vary depending on the resource acquisition cycle. The per kW cost of a base load generation unit is very different than a peaking unit so the period hook-up fee calculations could vary based on the next expected generation source. Staff Data request EAA 4-18 asked for a hook-up fee for full costs of growth. We interpreted full costs to include generation and assumed the next unit of generation is a base load unit. Although retail competition exists in Arizona, utilities are the providers of last resort and therefore have responsibility to plan for and obtain adequate generation resources to meet that responsibility. Therefore, it may be appropriate to include the cost of generation in hook-up fees.

Commissioner Mayes' third question requested the impact of sample hook-up fees on the Company capital budget. As noted above, a $2,000 per customer hook-up fee would generate approximately $500 million after tax over a ten-year period. APS Witness Don Brandt notes in his Rebuttal Testimony that the non-generation capital budget is approximately $8.6 billion over the next ten years. Finally, the letter asked about the issue of rural vs. subdivision development. We make no distinction in our rates or policies between rural and subdivision development, and in our service territory it often becomes difficult to distinguish between the two. Each has unique system planning and construction aspects. I believe it may be possible to distinguish between rural and subdivisions as far as hook-up fees but from a practical perspective, it may difficult to differentiate the two. For example, the local facilities cost for a subdivision in a rural area may be the same as an urban subdivision, but the backbone system improvements may be significantly more expensive.

VII. POWER SUPPLY ADJUSTMENT

Q. APS WITNESSES ROBINSON AND EWEN DISCUSS CHANGES TO THE POWER SUPPLY ADJUSTMENT MECHANISM. IF ADOPTED, WOULD THESE CHANGES NECESSITATE MODIFICATIONS TO THE PLAN OF ADMINISTRATION?

A. Yes. We have modified the currently approved PSA Plan of Administration ("POA") to reflect proposed changes to the PSA. Attachment DJR-5 RB is a POA that encompasses the modifications to the PSA as proposed by APS and described in the testimony of APS Witness Robinson. Attachment DJR–6 RB is a Plan that reflects our understanding of the proposed PSA mechanism as described by Staff Witness John Antonuk and uses the assumptions regarding the proposal described by APS witnesses Don Robinson and Pete Ewen.

VIII. JURISDICTIONAL CALCULATIONS

Q. WERE YOU RESPONSIBLE FOR JURISDICTIONAL ALLOCATIONS THAT ARE FOUND IN ATTACHMENTS TO THE REBUTTAL TESTIMONY OF OTHER APS WITNESSES?

A. Yes. I am sponsoring the ACC jurisdictional columns on the Adjustments to

Schedules C-1 and C-2 which are attached to APS Witness Froggatt's Rebuttal Testimony, as well as the ACC jurisdictional columns on the Adjustments to Schedules B-1, B-2, and B-3 which are attached to APS Witness Rockenberger's Rebuttal Testimony. These jurisdictional allocations have been calculated using the same factors that were used in APS' January 31, 2006 filing and were presented in my Direct Testimony.

IX. CONCLUSIONS

Q. PLEASE SUMMARIZE THE CONCLUSIONS REACHED IN YOUR TESTIMONY.

A. First, I note that the key issue of rate design changes is customer impact. While strictly adhering to cost of service principles for rate design may benefit one group of customers, it may negatively impact a larger group of customers. I do agree that the rate designs proposed by APS could be "fine tuned" by making some of the modifications such as collecting transmission costs through demand charges from the largest customer. Cost of service is a valuable guide in rate design but it not the only factor to consider. Impacts on individual customer's bills should also be a significant consideration. Second, I believe that while hook-up fees have fairly widespread usage by municipalities and small water companies, the tax consequences offset any advantages for taxable entities. This and several other aspects of hook-up fees can and should be addressed in the context of generic workshops involving all utilities

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

ARIZONA PUBLIC SERVICE COMPANY

COMPARISON OF RATES OF RETURN, OPERATING INCOME AND % REVENUE REQUIREMENT INCREASE UNDER ALTERNATIVE ALLOCATION METHODS

	4 CP as Filed			4 CP Juris. & Avg. & Pk.			4 CP With Fuel Allocated on Hourly Energy Costs			4 CP Juris. & Avg. & Pk. With Fuel Allocated on Hourly Energy Costs		
	ROR	$ Return	% Inc.	ROR	$ Return	% Inc.	ROR	$ Return	% Inc.	ROR	$ Return	% Inc.
GE-1												
Total Retail	2.59%	115,904,477	21.1%	2.59%	115,904,477	21.1%	2.59%	115,904,477	21.1%	2.59%	115,904,477	21.1%
Total Residential	1.52%	37,745,444	27.1%	1.87%	45,634,943	25.2%	1.04%	25,878,910	28.8%	1.38%	33,768,410	27.0%
Total General Service	3.91%	73,368,581	14.9%	3.55%	67,766,451	16.3%	4.49%	84,276,708	13.1%	4.12%	78,674,578	14.5%
Water Pumping	9.30%	2,370,299	-1.2%	3.06%	1,032,844	15.0%	10.18%	2,592,733	-2.9%	3.72%	1,255,278	13.3%
Street Lighting	2.05%	1,053,936	42.1%	0.50%	279,931	56.7%	3.27%	1,676,705	34.5%	1.61%	902,700	49.1%
Dusk to Dawn	5.78%	1,366,217	17.8%	4.82%	1,190,307	24.7%	6.26%	1,479,420	14.9%	5.28%	1,303,510	21.8%
GE-2												
Total General Service	3.91%	73,368,581	14.9%	3.55%	67,766,451	16.3%	4.49%	84,276,708	13.1%	4.12%	78,674,578	14.5%
E-20 (Church Rate)	8.47%	623,406	0.9%	6.94%	544,374	6.4%	8.05%	592,380	2.3%	6.54%	513,348	7.9%
E-30, E-32 (0-20 kW)	3.56%	13,469,005	21.2%	5.55%	19,087,411	11.8%	3.76%	14,238,295	20.4%	5.78%	19,856,702	11.0%
E-32 (21-100 kW)	4.88%	22,897,254	13.4%	5.66%	25,610,610	10.3%	5.17%	24,248,930	12.4%	5.96%	26,962,286	9.3%
E-32 (101-400 kW)	6.12%	25,165,747	7.2%	5.42%	23,011,520	9.5%	6.55%	26,903,570	6.1%	5.83%	24,749,344	8.3%
E-32 (401-999 kW)	6.12%	13,966,498	6.6%	3.89%	9,859,517	13.7%	6.84%	15,606,206	4.8%	4.54%	11,499,226	11.8%
E-32 (1,000+ kW)	-0.20%	-359,838	27.4%	-1.18%	-2,244,824	32.4%	0.63%	1,119,832	24.9%	-0.40%	-765,154	29.9%
E-34	0.07%	86,584	24.6%	-1.45%	-1,848,944	31.9%	1.19%	1,380,609	21.4%	-0.44%	-554,919	28.8%
E-35	-2.79%	-2,480,075	24.9%	-5.57%	-6,253,214	38.9%	0.21%	186,885	18.4%	-3.20%	-3,586,254	32.5%
GE-3												
Total Residential	1.52%	37,745,444	27.1%	1.87%	45,634,943	25.2%	1.04%	25,878,910	28.8%	1.38%	33,768,410	27.0%
Residential E-10	1.42%	2,103,917	26.1%	1.28%	1,914,459	26.8%	1.12%	1,653,718	27.2%	0.98%	1,464,260	27.9%
Residential E-12	3.18%	25,297,678	19.5%	3.50%	27,405,534	18.0%	2.80%	22,247,713	20.8%	3.11%	24,355,569	19.4%
Residential EC-1	0.44%	351,017	30.6%	0.35%	277,932	31.1%	-0.02%	-18,326	32.3%	-0.11%	-91,411	32.8%
Residential ET-1	0.83%	10,137,772	31.2%	1.33%	15,863,466	28.3%	0.26%	3,146,087	33.4%	0.74%	8,871,782	30.6%
Residential ECT-1R	-0.06%	-144,940	33.6%	0.07%	173,551	32.8%	-0.48%	-1,150,281	35.2%	-0.35%	-831,790	34.4%

SERVICE SCHEDULE 3
CONDITIONS GOVERNING EXTENSIONS OF ELECTRIC DISTRIBUTION LINES AND SERVICES

Provision of electric service from Arizona Public Service Company (Company) may require construction of new facilities or upgrades to existing facilities. Costs for construction depend on the customer's location, load size, and load characteristics. This schedule establishes the terms and conditions under which Company will extend its facilities to provide new or upgraded facilities.

All extensions are made on the basis of economic feasibility. Construction allowance and revenue basis methodologies are offered for use in circumstances where feasibility is generally accepted because of the number of extensions made within the construction allowance and dollar limits.

All extensions shall be made in accordance with good utility construction practices, as determined by Company, and are subject to the availability of adequate capacity, voltage and Company facilities at the beginning point of an extension as determined by Company.

The following policy governs the extension of overhead and underground electric facilities rated up to 21kV to customers whose requirements are deemed by Company to be usual and reasonable in nature.

DEFINITIONS

a. Backbone Infrastructure means the electrical distribution facilities typically consisting of main three-phase feeder lines and/or cables, conduit, duct banks, manholes, switching cabinets and capacitor banks.

b. Conduit Only Designs mean a line extension request where the developer is only requesting the conduit layout and design to serve the project. Local distribution facilities such as transformers and services will be installed at a later date when lot sales occur.

c. Corporate Business & Industrial Developments means a tract of land which has been divided into contiguous lots in which a developer offers improved lots for sale and the purchaser of the lot is responsible for construction of buildings for commercial and/or industrial use. Separate line extensions and equipment installations may be needed to provide service to each permanent customer.

d. High Rise Residential means residential multi-family developments built with four or more floors, usually using elevators for accessing floors.

e. Irrigation means water pumping service. Agricultural pumping means water pumping for farms and farm-related pumping used to grow commercial crops or crop-related activity. Non-agricultural water pumping is pumping for purposes other than the growing of commercial crops, such as golf course irrigation or municipal water wells.

f. Master Planned Community Developments means developments that consist of a number of separately subdivided parcels for different "Residential Homebuilder Subdivisions". Developments may have a variety of uses including residential, commercial, and public use facilities.

g. Mixed Use Residential Developments means buildings that consist of both residential and commercial use, such as a high-rise building where the first level is for commercial purposes and the upper floors are residential.

h. Residential Custom Home "Lot Sale" Developments means any tract of land that has been divided into four or more contiguous lots in which a developer offers improved lots for sale and the purchaser of the lot is responsible for construction of a residential home. Separate line extensions and equipment installations may be needed to provide service to each permanent customer.

i. Residential Homebuilder Subdivisions means any tract of land which has been divided into four or more contiguous lots with an average size of one acre or less in which the developer is responsible for the construction of residential homes or permanent mobile home sites.

j. Residential Multi-family Developments means developments consisting of apartments, condominiums, or townhouse developments.

k. Residential Single Family means a house, or a mobile home permanently affixed to a lot or site.

l. System Improvement Costs means the costs of system additions over and above what is required to serve the customer, where such additions provide additional capacity for other customers.

1.0 RESIDENTIAL

1.1 SINGLE FAMILY HOMES

1.1.1 Residential extensions will be made to new permanent residential customers or groups of new permanent residential customers. For purposes of this section, a "group" shall be defined as less than four homes. An allowance of $5,000 per home will be credited against the total construction cost, as determined by Company. Any additional cost will be paid by the applicant, as a refundable advance prior to Company extending facilities.

1.1.2 Where an advance is required, Company will issue the applicant an Advance Certificate. If, within five (5) years of issuance, a lateral extension is made off the original line extension, the applicant may present his/her Advance Certificate to Company for a potential refund. Refunds will be issued when the Advance Certificate is presented for payment and the connection of the subsequent applicant has been verified. In no event will refunds exceed the original advance. Refunds will be determined as shown in the example:

EXAMPLE:

First applicant's estimated cost for a line extension	$22,000
First applicant allowance	$ 5,000
First applicant's advance	$17,000
Second applicant's estimated cost for a lateral off the original extension	$ 3,000
Second applicant's allowance	$ 5,000
Refund to first applicant upon presentation of Advance Certificate and verification	$ 2,000

1.2 RESIDENTIAL HOMEBUILDER SUBDIVISIONS

1.2.1 Extensions will be made to residential subdivision developments of four or more homes in advance of application for service by permanent customers provided the applicant(s) signs an extension agreement. If approved by Company, a per lot allowance of $5,000 may be credited against the total construction cost, which may include applicable backbone system costs as determined by Company (minus street light and system improvement costs). Any additional construction cost in excess of the per lot allowance will be paid by applicant as a non-refundable contribution in aid of construction.

1.2.2 Company reserves the right to perform a field audit as to the number of permanently connected customers within the development eighteen (18) months from the extension agreement's execution date and requires the applicant to make a refundable advance of the construction costs less the applicable credit for the number of permanently connected customers to date.

1.2.3 Company reserves the right to disallow the allowance and collect a full advance of the construction costs from the applicant based on the project scope, or location, or financial condition of the applicant, or where organizational structure of the applicant warrants, as determined by Company. Advances are subject to the refund provisions in Section 4.2.

1.2.4 The following provides examples of the application of the policy:

EXAMPLE 1:

The following example illustrates a case in which the allowance is adequate to cover the subdivision's construction costs. It is assumed that the applicant builds all of the homes in the 18 month period.

Estimated Construction Cost	$450,000
Number of Homes	100
Total Allowance	$500,000
Non-Refundable Contribution	$ 0

EXAMPLE 2:
Example #2 illustrates a case in which the construction costs exceed the allowance and the applicant completes all homes in the subdivision. The total construction cost exceeds the allowance by $150,000 and the applicant provides the non-refundable contribution in aid of construction when the extension agreement is executed. If the applicants completes all 100 homes within the 18 month period after the execution date of the extension agreement, no additional funds are advanced by the applicant.

Estimated Construction Cost	$650,000
Number of Homes	100
Total Allowance	$500,000
Non-Refundable Contribution	$150,000

EXAMPLE 3:

The following example illustrates a case in which two events occur. First, the allowance does not adequately cover the required construction. This results in the requirement that the applicant provide a non-refundable contribution in aid of construction. This payment is due at the time the extension agreement is signed by the applicant.

The second event illustrated in this example is the applicant does not sell sufficient homes in the development in the 18 month period following the extension agreement execution date. In the example, at the end of the 18 month period, the applicant has completed 35 homes. Since there are 65 homes left to be completed the applicant must provide a refundable advance of $325,000. This advance will be eligible for refund during the subsequent 42 months as additional homes are completed. Any un-refunded advance remaining at the end of the refund period becomes a non-refundable contribution in aid of construction.

Estimated Construction Cost	$650,000
Number of Homes Planned	100
Potential Allowance Refundable Advance	$500,000
Non Refundable Contribution	$150,000
Assumed Number of Completed Homes	35
Allowance Credited (35 x $5000)	$175,000
Potential Amount Remaining Eligible For Refund	$325,000

1.3 RESIDENTIAL CUSTOM HOME "LOT SALE" DEVELOPMENTS

Extensions will be made to residential "lot sale" custom home developments in advance of application for service by permanent customers, provided the applicant(s) sign an extension agreement and make a refundable advance of the construction cost associated with the installation of "backbone" infrastructure. The payment of the advance is due at the time the extension agreement is executed and subject to refund as specified in Section 4.1.

1.3.1 Line extensions and/or equipment installations will be made for each permanent customer upon request for service, and an allowance of $5,000 will be credited against the construction cost for each installation as determined by Company (minus streetlight and system improvements costs). Any additional construction cost will be paid as a non-refundable contribution in aid of construction.

1.3.2 Company reserves the right to disallow the allowance and collect a full advance of the construction costs from the applicant(s) based on the project scope, or location, or financial condition of the applicant(s), or where organizational structure of the applicant(s) warrants, as determined by Company. Advances are subject to refund as specified in Section 4.2.

1.3.2 The costs for the installed infrastructure and the extensions and equipment installations needed to provide service to each permanent customer less any applicable credits will be used in determining the development's Economic Feasibility.

1.3.3 Company will provide "conduit only" designs provided applicant makes a non-refundable contribution in aid of construction in the amount equal to the estimated cost of preparation, in addition to the costs for any materials, field survey and inspections that may be required.

1.4 MASTER PLANNED COMMUNITY DEVELOPMENTS

Extensions will be made to master planned community developments in advance of application for service by permanent customers, provided the applicant(s) sign an extension agreement and make a refundable advance of the construction cost associated with the installation of "backbone" infrastructure.

1.4.1 Line extensions and equipment installation for backbone infrastructure to serve a Master Planned Development will be made in advance of application for service by permanent customers. A per lot allowance of $1,000 will be credited against the backbone infrastructure cost as determined by Company (minus street light and system improvement costs). Any additional cost will be paid by applicant as a non-refundable contribution at the time the extension agreement is executed.

Line extensions and equipment installations will be made for each residential subdivision within the planned development in advance of application for service by permanent customers. The cost of the extensions and equipment installations needed to provide service will be used in determining the cost for the development. A per lot allowance of $4,000 will be credited against the "subdivision" cost as determined by Company (minus street light and system improvement costs). Any additional cost will be paid as a non-refundable contribution in aid of construction at the time the extension agreement is executed.

1.4.2 Company reserves the right to disallow the credit and collect a full advance of the construction costs from the applicant based on the project scope, or location, or financial condition of the applicant, or where organizational structure of the applicant warrants, as determined by Company. Advances are subject to the refund provisions in Section 4.0.

1.4.3 The residential extension examples provided in 1.2.4 would be applicable to residential developments within a Master Planned Community. Extensions to multi-family developments or commercial developments would be made in accordance with the applicable sections of this Service Schedule. The following example illustrates the policy application for the entire project.

EXAMPLE 4:

Example #4 illustrates a case in which the applicant of the Master Planned Community requests an extension of backbone infrastructure and individual residential developers request extensions for residential subdivisions. The applicant makes a refundable contribution in aid of construction at the time the extension agreement is executed. The individual subdivision will be handled in a manner consistent with the subdivision examples found in Section 1.2.4.

Estimated Backbone Cost	$2,500,000
Number of Homes	1000
Potential Allowance Refundable Advance	$1,000,000
Non Refundable Contribution	$1,500,000
Estimated Subdivision Cost	$600,000
Number of Homes	200
Total Allowance	$800,000
Non-Refundable Contribution	$0

1.5 RESIDENTIAL MULTI-FAMILY DEVELOPMENTS

1.5.1 Extensions will be made to multi-family apartment, condominium or townhouse developments in advance of application for service by permanent customers. If approved by Company, a per completed unit allowance of $1,000 may be credited against the total construction cost, including any applicable backbone infrastructure costs as determined by the company, (minus street light and system improvement costs). Any additional cost will be paid as a non-refundable contribution in aid of construction at the time the extension agreement is executed.

1.5.2 Company reserves the right to perform a field audit as to the number of permanently connected customers within the development eighteen (18) months from the extension agreement's execution date and require the applicant to make a refundable advance of the construction costs less the applicable credit for the number of permanently connected customers to date.

1.5.3 Company reserves the right to disallow the credit and collect a full advance from the applicant based on the project scope, or location, or financial condition, or where organizational structure of the applicant warrants, as determined by Company. Advances are subject to the refund provisions in Section 4.0.

1.6 HIGH RISE AND MIXED USE RESIDENTIAL DEVELOPMENTS

1.6.1 Extensions will be made to high rise and mixed use developments where the residential units are privately owned and either individually metered or master metered in accordance with Section 6.12.3.

1.6.2 In general, APS will provide service to these type of developments at one point of delivery and it is the applicant's responsibility to provide and maintain the electrical distribution facilities within the building.

1.6.3 Extensions will be on the basis of Economic Feasibility. "Economic Feasibility", as used in this policy, shall mean a determination by Company that the estimated annual revenue based on Company's then currently effective rate for distribution service (excluding taxes, regulatory assessment and other adjustments) less the cost of service provides an adequate rate of return on the investment made by Company to serve the customer(s) and development.

1.6.4 Company reserves the right to collect a full advance from the applicant based on the project scope, or location, or financial condition, or where organizational structure of the applicant warrants, as determined by Company. Advances are subject to the refund provisions in Section 4.2.

2.0 NON-RESIDENTIAL

2.1 General service line extensions and equipment installations will be made to all applicants not meeting the definition of Residential or as provided for in Section 2.4, or Section 3.0 of this Schedule. General service line extensions and equipment installations will be made on the basis of Economic Feasibility or on a revenue basis as described in Section 2.2. "Economic Feasibility", as used in this policy, shall mean a determination by Company that the estimated annual revenue based on Company's then currently effective rate for distribution service (excluding taxes, regulatory assessment and other adjustments) less the cost of service provides an adequate rate of return on the investment made by Company to serve the customer. Extensions that are economically feasible as determined by the revenue basis as described in Section 2.2 or by the economic feasibility analysis described in this section are provided free to the customer. Extensions will be provided to customers that do not meet the economic feasibility determination provided the customer signs an extension agreement and advances as much of the construction cost and/or agree to pay a facilities charge to make the extension economically feasible. All costs are to be paid at the time the extension agreement is executed. Advances are subject to the refund provisions of Section 4.0.

2.2 A revenue basis extension will be made to customers or applicants except those specified in Sections 2.4, 3.1, 3.2, or 3.3, when the extension does not exceed a total construction cost of $25,000.

2.2.1 Such extension shall be free to the customer where the estimated annual revenue based on Company's then currently effective rate for distribution service (excluding taxes, regulatory assessment and other adjustments) multiplied by six (6.0) is equal to or greater than the total construction cost less nonrefundable customer contributions.

2.3 Company reserves the right to collect a full advance from the applicant based on the project scope, or location, or financial condition, or where organizational structure of the applicant warrants, as determined by Company. Advances are subject to the refund provisions in Section 4.0.

2.4 CORPORATE BUSINESS & INDUSTRIAL PARK DEVELOPMENTS

2.4.1 Extensions will be made to business and industrial park developments in advance of application for service by permanent customers, provided applicant(s) make a refundable advance of the construction cost associated with the installation of "backbone" infrastructure.

2.4.2 The costs for the installed infrastructure and the cost of the extensions and equipment installations needed to provide service to each permanent customer will be used in determining the development's Economic Feasibility. "Economic Feasibility", as used in this policy, shall mean a determination by Company that the estimated annual revenue based on Company's then currently effective rate for distribution service (excluding taxes, regulatory assessment and other adjustments) less the cost of service, provides an adequate rate of return on the investment made by Company to serve the customer(s) and development.

2.4.3 For extensions and equipment installations which meet the conditions specified in Section 2.4.1, Company, after special study and at its option, may install its facilities to customers who do not satisfy the definition of economic feasibility as specified in Section 2.1. Such customers or applicant(s) must sign an extension agreement and advance as much of the construction cost and/or pay a non-refundable contribution (facilities charge) to make the extension economically feasible. All costs are to be paid at the time the extension agreement is executed. Advances are subject to refund as specified in Section 4.1.

3.0 OTHER CONDITIONS

3.1 IRRIGATION CUSTOMERS

Customers requiring construction of electric facilities for service to agricultural irrigation pumping will advance the total construction cost at the time the extension advance is executed. Advances are subject to refund as specified in Section 4.3. Non-agricultural irrigation pumping service to permanent customers will be extended as specified in Section 2. Non-agricultural irrigation pumping service to temporary or doubtful permanency customers will be extended as specified in Section 3.2 or 3.3 below, as applicable.

3.2 TEMPORARY CUSTOMERS

Where a temporary meter or construction is required to provide service to the customer, the customer ~~shall make a non-refundable contribution~~ in advance of installation or construction equal to the cost of installing and removing the facilities required to furnish service, less the salvage value of such facilities. When the use of service is discontinued or agreement for service is terminated, Company may dismantle its facilities and the materials and equipment provided by Company will be salvaged and remain Company property.

3.3 DOUBTFUL PERMANENCY CUSTOMERS

When, in the opinion of Company, permanency of the customer's residence or operation is doubtful, the customer will be required to advance the total construction cost. Advances are subject to refund as specified in Section 4.4.

4.0 REFUNDS

4.1 ECONOMIC FEASIBILITY BASIS REFUNDS

Customer advances over $50.00 are subject to full or partial refund. At the end of eighteen months from the date Company facilities are energized, Company will obtain actual closing costs and actual first year distribution revenues and determine if the company is receiving the required minimum rate of return. If this results in an advance lower than the amount advanced by customer, Company will refund the difference between the amount advanced and the amount that would have been advanced using actual closing costs and distribution revenues. In no event shall the amount of any refund exceed the amount originally advanced. Subsequent refund studies will be performed at one year intervals for an additional four years using actual distribution revenues for the year. At the end of this total five year refund period, any advance not refunded shall become a nonrefundable contribution in aid of construction.

4.2 RESIDENTIAL HOMEBUILDER SUBDIVISIONS

Customer advances over $50.00 are subject to refund based on the number of permanently connected customers during the five year refund period commencing on the extension agreement's execution date. At the end of this total five year refund period, any advance not refunded shall become a nonrefundable contribution in aid of construction.

4.3 REFUNDS FOR EXTENSIONS TO IRRIGATION CUSTOMERS

Customer advances over $50.00 are subject to refund of twenty-five (25) percent of the annual accumulation of twelve (12) monthly bills based on Company's then currently effective rate for distribution service (excluding taxes, regulatory assessment and other adjustments) in excess of the annual minimum bill, for service to the irrigation pump specified in the agreement for the extension being surveyed, commencing with the date of signing the agreement. In no event shall the amount of any refund exceed the amount originally advanced.

4.4 REFUNDS TO CUSTOMERS OF DOUBTFUL PERMANENCY

Customer advances over $50.00 are subject to full or partial based on the Economic Feasibility Basis as specified in Section 3.3. In no event shall the refund exceed twenty-five (25) percent of the annual accumulation of twelve (12) monthly bills based on Company's then currently effective rate for distribution service (excluding taxes, regulatory assessment and other adjustments) in excess of the annual minimum bill for the customer specified in the extension agreement. In no event shall the amount of any refund exceed the amount originally advanced.

4.5. GENERAL REFUND CONDITIONS

4.5.1 Customer advances of $50.00 or less are not subject to refund.

4.5.2 No refund will be made to any customer for an amount more than the unrefunded balance of the customer's advance.

4.5.3 Any unrefunded advance balance shall become nonrefundable five (5) years from the execution or the effective date of the agreement.

4.5.4 Company reserves the right to withhold refunds to any customer or developer who is delinquent on any account, agreement, or invoice and apply these refund amounts to past due bills.

5.0 UNDERGROUND CONSTRUCTION

5.1 GENERAL UNDERGROUND CONSTRUCTION POLICY - With respect to all underground installations, Company may install underground facilities only if all of the following conditions are met:

5.1.1 The extension meets feasibility requirements as specified in Sections 1.0, 2.0, or 3.0.

5.1.2 The customer or applicant(s) provides all earthwork including, but not limited to, trenching, boring or punching, backfill, compaction, and surface restoration in accordance with Company specifications.

5.1.3 The customer or applicant(s) provides installation of equipment pads, pull-boxes, manholes, and conduits as required in accordance with Company specifications.

5.1.4 In lieu of customer or applicant(s) providing these services and equipment, the company may provide and the customer or applicant(s) will make a non-refundable contribution equal to the cost of such work plus any administrative or inspection fees incurred by Company. Customers or applicants electing this option will be required to sign an agreement indemnifying and holding APS harmless against claims, liabilities, losses or damage (Claims) asserted by a person or entity other than APS' contractors, which Claims arise out of the trenching and conduit placement, provided the claims are not attributable to APS' gross negligence or intentional misconduct.

5.2 Where it is determined that three phase service is required to serve the customer, customer may be required to make a nonrefundable contribution for excess service footage required by the customer equal to the increased estimated cost of installed service lines over what would be required with a maximum 40-foot service at 480 volts and 20-foot service at 120/208 or 240 volts.

6.0 GENERAL CONDITIONS

6.1 VOLTAGE

The extension will be designed and constructed for operation at standard voltages used by Company in the area in which the extension is located. Company may deliver service for special applications of higher voltages with prior approval from Company's Engineering Department and in accordance with this Schedule.

6.2 POINT OF DELIVERY

6.2.1 For overhead service, the point of delivery shall be where Company's service conductors terminate at the customer's weatherhead or bus riser.

6.2.2 For underground service, the point of delivery shall be where Company's service conductors terminate in the customer's or development's service equipment. The customer shall furnish, install and maintain any risers, raceways and/or termination cabinets necessary for the installation of Company's underground service conductors.

6.2.3 For special applications where service is provided at voltages higher than the standard voltages specified in the Electric Service Requirements Manual, APS and customer shall mutually agree upon the designated point of delivery.

6.3 THREE PHASE

Extensions for three phase service can be made under this extension policy where the customer has installed major three phase equipment. Motors with a name-plate rating of 7-1/2 HP or more or single air conditioning units of 6 tons or more or where total horsepower of all connected three phase motors exceeds 12 HP or total load exceeding 100 kVA demand shall qualify for three phase. If the estimated load is less than the above horsepower or connected kVA specifications, Company may, at its option and when requested by the customer, serve three phase and require a nonrefundable contribution equal to the difference in cost between single phase and three phase construction, but in no case less than $100.

6.4 EASEMENTS

All suitable easements or rights-of-way required by Company for any portion of the extension which is either on premises owned, leased or otherwise controlled by the customer or developer, or other property required for the extension, shall be furnished in Company's name by the customer without cost to or condemnation by Company and in reasonable time to meet proposed service requirements. All easements or rights-of-way obtained on behalf of Company shall contain such terms and conditions as are acceptable to Company.

6.5 GRADE MODIFICATIONS

If subsequent to construction of electric distribution lines and services, the final grade established by the customer or developer is changed in such a way as to require relocation of Company facilities or the customer's actions or those of his contractor results in damage to such facilities, the cost of relocation and/or resulting repairs shall be borne by customer or developer.

6.6 OWNERSHIP

Except for customer-owned facilities, all electric facilities, including that for which customers have made advances and/or contributions, will be owned, operated and maintained by Company.

6.7 MEASUREMENT AND LOCATION

6.7.1 Measurement must be along the proposed route of construction.

6.7.2 Construction will be on public streets, roadways, highways, or easements acceptable to Company.

6.7.3 The extension must be a branch from, the continuation of, or an addition to, one of Company's existing distribution lines.

6.8 UNUSUAL CIRCUMSTANCES

In unusual circumstances as determined by Company, when the application and provisions of this policy appear impractical, or in case of extension of lines to be operated on voltages other than specified in the applicable rate schedule, or when customer's estimated load will exceed 3,000 kW, Company will make a special study of the conditions to determine the basis on which service may be provided. Additionally, Company may require special contract arrangements as provided for in Section 1.1 of Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Service.

6.9 NON-STANDARD CONSTRUCTION

Company's construction practices employ contemporary methods and equipment and meet current industry standards. Where extensions of electric facilities require construction that is in any way nonstandard, as determined by Company, or if unusual obstructions are encountered, the customer will make a non-refundable contribution equal to the difference in cost between standard and non-standard construction, in addition to other applicable costs involved.

6.10 ABNORMAL LOADS

Company, at its option, may make extensions to serve certain abnormal loads (such as: transformer-type welders, x-ray machines, wind machines, excess capacity for test purposes and loads of unusual characteristics), provided the customer makes a nonrefundable contribution equal to the total cost of such extension, including transformers.

6.11 RELOCATIONS AND/OR CONVERSIONS

6.11.1 Company will relocate or convert its facilities for the customer's convenience or aesthetics, providing the customer makes a nonrefundable contribution equal to the total cost of relocation or conversion.

6.11.2 When the relocation of Company facilities involve "prior rights" conditions, the customer will be required to make a non-refundable contribution equal to the total cost of relocation.

6.11.3 When the relocation or conversion is in conjunction with added revenue, as determined by Company and is not for the customer's convenience or aesthetics, then the relocation or conversion costs plus the costs to serve will be used to determine the customers advance on the basis specified in Section 2.0 or 3.0.

6.12 MASTER METERING

6.12.1 Mobile Home Parks - Company shall refuse service to all new construction and/or expansion of existing permanent residential mobile home parks unless the construction and/or expansion is individually metered by Company.

6.12.2 Residential Apartment Complexes, Condominiums - Company shall refuse service to all new construction of apartment complexes and condominiums which are master metered unless the builder or developer can demonstrate that the installation meets the provisions of R14-2-205 of the Corporation Commission's Rules and Regulations or the requirements discussed in 6.12.3 below. This section is not applicable to Senior Care/Nursing Centers registered with the State of Arizona with independent living units which provide packaged services such as housing, food, and nursing care.

6.12.3 Multi-Unit Residential Developments – Company will allow master metering for residential units where the residential units are privately owned provided the building will be served by a centralized heating, ventilation and/or air conditioning system, and each residential unit shall be individually sub-metered and responsible for energy consumption of that unit.

6.12.3.1 Sub-metering shall be provided and maintained by the builder or homeowners association.

6.12.3.2 Responsibility and methodology for determining each unit's energy billing shall be clearly specified in the original bylaws of the homeowners association, a copy of which must be provided to Company prior to Company providing the initial extension.

6.12.4 Company will convert its facilities from master metered system to a permanent individually metered system at the customer's request provided the customer makes a nonrefundable contribution equal to the residual value plus the removal costs less salvage of the master meter facilities to be removed. The new facilities to serve the individual meters will be extended on the basis specified in Section 1. Applicant is responsible for all costs related to the installation of new service entrance equipment.

6.13 CHANGE IN CUSTOMER'S SERVICE REQUIREMENTS

Company will rebuild or revamp existing facilities to meet the customer's added load or change in service requirements on the basis specified in Section 2.0 or 3.0.

6.14 STUDY AND DESIGN DEPOSIT

Any applicant requesting Company to prepare special studies or detailed plans, specifications, or cost estimates may be required to deposit with Company an amount equal to the estimated cost of preparation. Where the applicant authorizes Company to proceed with construction of the extension, the deposit shall be credited to the cost of construction, otherwise the deposit shall be nonrefundable. Company will prepare, without charge, a preliminary sketch and rough estimate of the cost to be paid by the customer for a line extension upon request.

6.15 CUSTOMER CONSTRUCTION OF COMPANY DISTRIBUTION FACILITIES

The customer may provide construction related services, e.g. engineering, survey, materials and/or labor, associated with new distribution facilities to serve the customer's new or added load, provided the customer meets all of the requirements set forth by Company. All work and/or materials provided by the customer shall comply with Company standards in effect at the time of construction. The customer shall receive written approval from Company prior to performing any construction related services. Company will perform an Economic Feasibility Analysis prior to the approval of any proposed customer provided construction to ensure the proposed scope of work results in mutual benefits to the customer and Company.

6.16 SETTLEMENT OF DISPUTES

Any dispute between the customer or prospective customer and Company regarding the interpretation of these "Conditions Governing Extensions of Electric Distribution Lines and Services" may, by either party, be referred to the Arizona Corporation Commission or a designated representative or employee thereof for determination.

6.17 INTEREST

All advances made by the customer to Company in aid of construction shall be non-interest bearing.

6.18 EXTENSION AGREEMENTS

All line extensions or equipment upgrades requiring payment by the customer shall be in writing and signed by both the customer and Company.

6.19 ADDITIONAL PRIMARY FEED

When specifically requested by the customer to provide an alternate primary feed (excluding transformation), Company will perform a special study to determine the request's feasibility and the customer may be required to pay a nonrefundable contribution in aid of construction for the added cost as well as the applicable rate for the additional feed requested.

Provision of electric service from Arizona Public Service Company (Company) may require construction of new facilities or upgrades to existing facilities. Costs for construction depend on the customer's location, load size, and load characteristics. This schedule establishes the terms and conditions under which Company will extend its facilities to provide new or upgraded facilities.

All extensions are made on the basis of economic feasibility. Construction allowance and revenue basis methodologies are offered for use in circumstances where feasibility is generally accepted because of the number of extensions made within the construction allowance and dollar limits.

All extensions shall be made in accordance with good utility construction practices, as determined by Company, and are subject to the availability of adequate capacity, voltage and Company facilities at the beginning point of an extension as determined by Company.

The following policy governs the extension of overhead and underground electric facilities rated up to 21kV to customers whose requirements are deemed by Company to be usual and reasonable in nature.

DEFINITIONS

a. Backbone Infrastructure means the electrical distribution facilities typically consisting of main three-phase feeder lines and/or cables, conduit, duct banks, manholes, switching cabinets and capacitor banks.

b. Conduit Only Designs mean a line extension request where the developer is only requesting the conduit layout and design to serve the project. Local distribution facilities such as transformers and services will be installed at a later date when lot sales occur.

c. Corporate Business & Industrial Developments means a tract of land which has been divided into contiguous lots in which a developer offers improved lots for sale and the purchaser of the lot is responsible for construction of buildings for commercial and/or industrial use. Separate line extensions and equipment installations may be needed to provide service to each permanent customer.

d. High Rise Residential means residential multi-family developments built with four or more floors, usually using elevators for accessing floors.

e. Irrigation means water pumping service. Agricultural pumping means water pumping for farms and farm-related pumping used to grow commercial crops or crop-related activity. Non-agricultural water pumping is pumping for purposes other than the growing of commercial crops, such as golf course irrigation or municipal water wells.

f. Master Planned Community Developments means developments that consist of a number of separately subdivided parcels for different "Residential Homebuilder Subdivisions". Developments may have a variety of uses including residential, commercial, and public use facilities.

g. Mixed Use Residential Developments means buildings that consist of both residential and commercial use, such as a high-rise building where the first level is for commercial purposes and the upper floors are residential.

h. Residential Custom Home "Lot Sale" Developments means any tract of land that has been divided into four or more contiguous lots in which a developer offers improved lots for sale and the purchaser of the lot is responsible for construction of a residential home. Separate line extensions and equipment

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installations may be needed to provide service to each permanent customer.

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i. Residential Homebuilder Subdivisions means any tract of land which has been divided into four or more contiguous lots with an average size of one acre or less in which the developer is responsible for the construction of residential homes or permanent mobile home sites.

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j. Residential Multi-family Developments means developments consisting of apartments, condominiums, or townhouse developments.

k. Residential Single Family means a house, or a mobile home permanently affixed to a lot or site.

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l. System Improvement Costs means the costs of system additions over and above what is required to serve the customer, where such additions provide additional capacity for other customers.

1.0 RESIDENTIAL

1.1 SINGLE FAMILY HOMES

1.1.1 Residential extensions will be made to new permanent residential customers or groups of new permanent residential customers. For purposes of this section, a "group" shall be defined as less than four homes. An allowance of $5,000 per home will be credited against the total construction cost, as determined by Company. Any additional cost will be paid by the applicant, as a refundable advance prior to Company extending facilities.

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1.1.2 Where an advance is required, Company will issue the applicant an Advance Certificate. If, within five (5) years of issuance, a lateral extension is made off the original line extension, the applicant may present his/her Advance Certificate to Company for a potential refund. Refunds will be issued when the Advance Certificate is presented for payment and the connection of the subsequent applicant has been verified. In no event will refunds exceed the original advance. Refunds will be determined as shown in the example:

EXAMPLE:

First applicant's estimated cost for a line extension	$22,000
First applicant allowance	$ 5,000
First applicant's advance	$17,000
Second applicant's estimated cost for a lateral off the original extension	$ 3,000
Second applicant's allowance	$ 5,000
Refund to first applicant upon presentation of Advance Certificate and verification	$ 2,000

1.2 RESIDENTIAL HOMEBUILDER SUBDIVISIONS

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Extensions will be made to residential subdivision developments of four or more homes in advance of application for service by permanent customers provided the applicant(s) signs an extension agreement. If approved by Company, a per lot allowance of $5,000 may be credited against the total construction cost, which may include applicable backbone system costs as determined by Company (minus street light and system improvement costs). Any additional construction cost in excess of

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the per lot allowance will be paid by applicant as a non-refundable contribution in aid of construction.

1.2.2 Company reserves the right to perform a field audit as to the number of permanently connected customers within the development eighteen (18) months from the extension agreement's execution date and requires the applicant to make a refundable advance of the construction costs less the applicable credit for the number of permanently connected customers to date.

1.2.3 Company reserves the right to disallow the allowance and collect a full advance of the construction costs from the applicant based on the project scope, or location, or financial condition of the applicant, or where organizational structure of the applicant warrants, as determined by Company. Advances are subject to the refund provisions in Section 4.2.

1.2.4 The following provides examples of the application of the policy:

EXAMPLE 1:

The following example illustrates a case in which the allowance is adequate to cover the subdivision's construction costs. It is assumed that the applicant builds all of the homes in the 18 month period.

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Estimated Construction Cost	$450,000
Number of Homes	100
Total Allowance	$500,000
Non-Refundable Contribution	$ 0

EXAMPLE 2:
Example #2 illustrates a case in which the construction costs exceed the allowance and the applicant completes all homes in the subdivision. The total construction cost exceeds the allowance by $150,000 and the applicant provides the non-refundable contribution in aid of construction when the extension agreement is executed. If the applicants completes all 100 homes within the 18 month period after the execution date of the extension agreement, no additional funds are advanced by the applicant.

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Estimated Construction Cost	$650,000
Number of Homes	100
Total Allowance	$500,000
Non-Refundable Contribution	$150,000

EXAMPLE 3:

The following example illustrates a case in which two events occur. First, the allowance does not adequately cover the required construction. This results in the requirement that the applicant provide a non-refundable contribution in aid of construction. This payment is due at the time the extension agreement is signed by the applicant.

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The second event illustrated in this example is the applicant does not sell sufficient homes in the development in the 18 month period following the extension agreement execution date. In the example, at the end of the 18 month period, the applicant has completed 35 homes. Since there are 65 homes left to be completed the applicant must provide a refundable advance of $325,000. This advance will be eligible for refund during the subsequent 42 months as additional homes are completed. Any un-refunded advance remaining at the end of the refund period becomes a non-refundable contribution in aid of construction.

Estimated Construction Cost	$650,000
Number of Homes Planned	100
Potential Allowance Refundable Advance	$500,000
Non Refundable Contribution	$150,000
Assumed Number of Completed Homes	35
Allowance Credited (35 x $5000)	$175,000
Potential Amount Remaining Eligible For Refund	$325,000

1.3 RESIDENTIAL CUSTOM HOME "LOT SALE" DEVELOPMENTS

Extensions will be made to residential "lot sale" custom home developments in advance of application for service by permanent customers, provided the applicant(s) sign an extension agreement and make a refundable advance of the construction cost associated with the installation of "backbone" infrastructure. The payment of the advance is due at the time the extension agreement is executed and subject to refund as specified in Section 4.1.

1.3.1 Line extensions and/or equipment installations will be made for each permanent customer upon request for service, and an allowance of $5,000 will be credited against the construction cost for each installation as determined by Company (minus streetlight and system improvements costs). Any additional construction cost will be paid as a non-refundable contribution in aid of construction.

1.3.2 Company reserves the right to disallow the allowance and collect a full advance of the construction costs from the applicant(s) based on the project scope, or location, or financial condition of the applicant(s), or where organizational structure of the applicant(s) warrants, as determined by Company. Advances are subject to refund as specified in Section 4.2.

1.3.2 The costs for the installed infrastructure and the extensions and equipment installations needed to provide service to each permanent customer less any applicable credits will be used in determining the development's Economic Feasibility.

Company will provide "conduit only" designs provided applicant makes a non-refundable contribution in aid of construction in the amount equal to the estimated cost of preparation, in addition to the costs for any materials, field survey and inspections that may be required.

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1.3.4 . The examples provided in 1.2.4 would also be applicable to "lot sale" developments.

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1.4 MASTER PLANNED COMMUNITY DEVELOPMENTS

Extensions will be made to master planned community developments in advance of application for service by permanent customers, provided the applicant(s) sign an extension agreement and make a refundable advance of the construction cost associated with the installation of "backbone" infrastructure.

1.4.1 Line extensions and equipment installation for backbone infrastructure to serve a Master Planned Development will be made in advance of application for service by permanent customers. A per lot allowance of $1,000 will be credited against the backbone infrastructure cost as determined by Company (minus street light and system improvement costs). Any additional cost will be paid by applicant as a non-refundable contribution at the time the extension agreement is executed.

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Line extensions and equipment installations will be made for each residential subdivision within the planned development in advance of application for service by permanent customers. The cost of the extensions and equipment installations needed to provide service will be used in determining the cost for the development. A per lot allowance of $4,000 will be credited against the "subdivision" cost as determined by Company (minus street light and system improvement costs). Any additional cost will be paid as a non-refundable contribution in aid of construction at the time the extension agreement is executed.

1.4.2 Company reserves the right to disallow the credit and collect a full advance of the construction costs from the applicant based on the project scope, or location, or financial condition of the applicant, or where organizational structure of the applicant warrants, as determined by Company. Advances are subject to the refund provisions in Section 4.0.

1.4.3 The residential extension examples provided in 1.2.4 would be applicable to residential developments within a Master Planned Community. Extensions to multi-family developments or commercial developments would be made in accordance with the applicable sections of this Service Schedule. The following example illustrates the policy application for the entire project.

EXAMPLE 4:

Example #4 illustrates a case in which the applicant of the Master Planned Community requests an extension of backbone infrastructure and individual residential developers request extensions for residential subdivisions. The applicant makes a refundable contribution in aid of construction at the time the extension agreement is executed. The individual subdivision will be handled in a manner consistent with the subdivision examples found in Section 1.2.4.

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Estimated Backbone Cost	$2,500,000
Number of Homes	1000
Potential Allowance Refundable Advance	$1,000,000
Non Refundable Contribution	$1,500,000

Estimated Subdivision Cost	$600,000
Number of Homes	200
Total Allowance	$800,000
Non-Refundable Contribution	$0

1.5 RESIDENTIAL MULTI-FAMILY DEVELOPMENTS

1.5.1 Extensions will be made to multi-family apartment, condominium or townhouse developments in advance of application for service by permanent customers. If approved by Company, a per completed unit allowance of $1,000 may be credited against the total construction cost, including any applicable backbone infrastructure costs as determined by the company, (minus street light and system improvement costs). Any additional cost will be paid as a non-refundable contribution in aid of construction at the time the extension agreement is executed.

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1.5.2 Company reserves the right to perform a field audit as to the number of permanently connected customers within the development eighteen (18) months from the extension agreement's execution date and require the applicant to make a refundable advance of the construction costs less the applicable credit for the number of permanently connected customers to date.

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1.5.3 Company reserves the right to disallow the credit and collect a full advance from the applicant based on the project scope, or location, or financial condition, or where organizational structure of the applicant warrants, as determined by Company. Advances are subject to the refund provisions in Section 4.0.

1.6 HIGH RISE AND MIXED USE RESIDENTIAL DEVELOPMENTS

1.6.1 Extensions will be made to high rise and mixed use developments where the residential units are privately owned and either individually metered or master metered in accordance with Section 6.12.3.

1.6.2 In general, APS will provide service to these type of developments at one point of delivery and it is the applicant's responsibility to provide and maintain the electrical distribution facilities within the building.

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Extensions will be on the basis of Economic Feasibility. "Economic Feasibility", as used in this policy, shall mean a determination by Company that the estimated annual revenue based on Company's then currently effective rate for distribution service (excluding taxes, regulatory assessment and other adjustments) less the cost of service provides an adequate rate of return on the investment made by Company to serve the customer(s) and development.

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1.6.3 Company reserves the right to collect a full advance from the applicant based on the project scope, or location, or financial condition, or where organizational structure of the applicant warrants, as determined by Company. Advances are subject to the refund provisions in Section 4.2.

2.0 NON-RESIDENTIAL

2.1 General service line extensions and equipment installations will be made to all applicants not meeting the definition of Residential or as provided for in Section 2.4, or Section 3.0 of this Schedule. General service line extensions and equipment installations will be made on the basis of Economic Feasibility or on a revenue basis as described in Section 2.2. "Economic Feasibility", as used in this policy, shall mean a determination by Company that the estimated annual revenue based on Company's then currently effective rate for distribution service (excluding taxes, regulatory assessment and other adjustments) less the cost of service provides an adequate rate of return on the investment made by Company to serve the customer. Extensions that are economically feasible as determined by the revenue basis as described in Section 2.2 or by the economic feasibility analysis described in this section are provided free to the customer. Extensions will be provided to customers that do not meet the economic feasibility determination provided the customer signs an extension agreement and advances as much of the construction cost and/or agree to pay a facilities charge to make the extension economically feasible. All costs are to be paid at the time the extension agreement is executed. Advances are subject to the refund provisions of Section 4.0.

2.2 A revenue basis extension will be made to customers or applicants except those specified in Sections 2.4, 3.1, 3.2, or 3.3, when the extension does not exceed a total construction cost of $25,000.

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2.2.1 Such extension shall be free to the customer where the estimated annual revenue based on Company's then currently effective rate for distribution service (excluding taxes, regulatory assessment and other adjustments) multiplied by six (6.0) is equal to or greater than the total construction cost less nonrefundable customer contributions.

2.3 Company reserves the right to collect a full advance from the applicant based on the project scope, or location, or financial condition, or where organizational structure of the applicant warrants, as determined by Company. Advances are subject to the refund provisions in Section 4.0.

2.4 CORPORATE BUSINESS & INDUSTRIAL PARK DEVELOPMENTS

2.4.1 Extensions will be made to business and industrial park developments in advance of application for service by permanent customers, provided applicant(s) make a refundable advance of the construction cost associated with the installation of "backbone" infrastructure.

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The costs for the installed infrastructure and the cost of the extensions and equipment installations needed to provide service to each permanent customer will be used in determining the development's Economic Feasibility. "Economic Feasibility", as used in this policy, shall mean a determination by Company that the estimated annual revenue based on Company's then currently effective rate for distribution service (excluding taxes, regulatory assessment and other adjustments) less the cost of service, provides an adequate rate of return on the investment made by Company to serve the customer(s) and development.

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2.4.3 For extensions and equipment installations which meet the conditions specified in Section 2.4.1, Company, after special study and at its option, may install its facilities to customers who do not satisfy the definition of economic feasibility as specified in Section 2.1. Such customers or applicant(s) must sign an extension agreement and advance as much of the construction cost and/or pay a non-refundable contribution (facilities charge) to make the extension economically

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feasible. All costs are to be paid at the time the extension agreement is executed. Advances are subject to refund as specified in Section 4.1.

3.0 OTHER CONDITIONS

3.1 IRRIGATION CUSTOMERS

Customers requiring construction of electric facilities for service to agricultural irrigation pumping will advance the total construction cost at the time the extension advance is executed. Advances are subject to refund as specified in Section 4.3. Non-agricultural irrigation pumping service to permanent customers will be extended as specified in Section 2. Non-agricultural irrigation pumping service to temporary or doubtful permanency customers will be extended as specified in Section 3.2 or 3.3 below, as applicable.

3.2 TEMPORARY CUSTOMERS

Where a temporary meter or construction is required to provide service to the customer, the customer, in advance of installation or construction, equal to the cost of installing and removing the facilities required to furnish service, less the salvage value of such facilities. When the use of service is discontinued or agreement for service is terminated, Company may dismantle its facilities and the materials and equipment provided by Company will be salvaged and remain Company property.

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3.3 DOUBTFUL PERMANENCY CUSTOMERS

When, in the opinion of Company, permanency of the customer's residence or operation is doubtful, the customer will be required to advance the total construction cost. Advances are subject to refund as specified in Section 4.4.

4.0 REFUNDS

4.1 ECONOMIC FEASIBILITY BASIS REFUNDS

Customer advances over $50.00 are subject to full or partial refund. At the end of eighteen months from the date Company facilities are energized, Company will obtain actual closing costs and actual first year distribution revenues and determine if the company is receiving the required minimum rate of return. If this results in an advance lower than the amount advanced by customer, Company will refund the difference between the amount advanced and the amount that would have been advanced using actual closing costs and distribution revenues. In no event shall the amount of any refund exceed the amount originally advanced. Subsequent refund studies will be performed at one year intervals for an additional four years using actual distribution revenues for the year. At the end of this total five year refund period, any advance not refunded shall become a nonrefundable contribution in aid of construction.

4.2 RESIDENTIAL HOMEBUILDER SUBDIVISIONS

Customer advances over $50.00 are subject to refund based on the number of permanently connected customers during the five year refund period commencing on the extension agreement's execution date. At the end of this total five year refund period, any advance not refunded shall become a nonrefundable contribution in aid of construction.

4.3 REFUNDS FOR EXTENSIONS TO IRRIGATION CUSTOMERS

Customer advances over $50.00 are subject to refund of twenty-five (25) percent of the annual accumulation of twelve (12) monthly bills based on Company's then currently effective rate for distribution service (excluding taxes, regulatory assessment and other adjustments) in excess of the annual minimum bill, for service to the irrigation pump specified in the agreement for the extension being surveyed, commencing with the date of signing the agreement. In no event shall the amount of any refund exceed the amount originally advanced.

4.4 REFUNDS TO CUSTOMERS OF DOUBTFUL PERMANENCY

Customer advances over $50.00 are subject to full or partial based on the Economic Feasibility Basis as specified in Section 3.3. In no event shall the refund exceed twenty-five (25) percent of the annual accumulation of twelve (12) monthly bills based on Company's then currently effective rate for distribution service (excluding taxes, regulatory assessment and other adjustments) in excess of the annual minimum bill for the customer specified in the extension agreement. In no event shall the amount of any refund exceed the amount originally advanced.

4.5. GENERAL REFUND CONDITIONS

4.5.1 Customer advances of $50.00 or less are not subject to refund.

4.5.2 No refund will be made to any customer for an amount more than the unrefunded balance of the customer's advance.

4.5.3 Any unrefunded advance balance shall become nonrefundable five (5) years from the execution or the effective date of the agreement.

4.5.4 Company reserves the right to withhold refunds to any customer or developer who is delinquent on any account, agreement, or invoice and apply these refund amounts to past due bills.

5.0 UNDERGROUND CONSTRUCTION

5.1 GENERAL UNDERGROUND CONSTRUCTION POLICY - With respect to all underground installations, Company may install underground facilities only if all of the following conditions are met:

5.1.1 The extension meets feasibility requirements as specified in Sections 1.0, 2.0, or 3.0.

5.1.2 The customer or applicant(s) provides all earthwork including, but not limited to, trenching, boring or punching, backfill, compaction, and surface restoration in accordance with Company specifications.

5.1.3 The customer or applicant(s) provides installation of equipment pads, pull-boxes, manholes, and conduits as required in accordance with Company specifications.

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5.1.4 In lieu of customer or applicant(s) providing these services and equipment, the company may provide and the customer or applicant(s) will make a non-refundable contribution equal to the cost of such work plus any administrative or inspection fees incurred by Company. Customers or applicants electing this option will be required to sign an agreement indemnifying and holding APS harmless against claims, liabilities, losses or damage (Claims) asserted by a person or entity other than APS' contractors, which Claims arise out of the trenching and conduit placement, provided the claims are not attributable to APS' gross negligence or intentional misconduct.

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5.2 Where it is determined that three phase service is required to serve the customer, customer may be required to make a nonrefundable contribution for excess service footage required by the customer equal to the increased estimated cost of installed service lines over what would be required with a maximum 40-foot service at 480 volts and 20-foot service at 120/208 or 240 volts.

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6.0 GENERAL CONDITIONS

6.1 VOLTAGE

The extension will be designed and constructed for operation at standard voltages used by Company in the area in which the extension is located. Company may deliver service for special applications of higher voltages with prior approval from Company's Engineering Department and in accordance with this Schedule.

6.2 POINT OF DELIVERY

6.2.1 For overhead service, the point of delivery shall be where Company's service conductors terminate at the customer's weatherhead or bus riser.

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6.2.2 For underground service, the point of delivery shall be where Company's service conductors terminate in the customer's or development's service equipment. The customer shall furnish, install and maintain any risers, raceways and/or termination cabinets necessary for the installation of Company's underground service conductors.

6.2.3 For special applications where service is provided at voltages higher than the standard voltages specified in the Electric Service Requirements Manual, APS and customer shall mutually agree upon the designated point of delivery.

6.3 THREE PHASE

Extensions for three phase service can be made under this extension policy where the customer has installed major three phase equipment. Motors with a name-plate rating of 7-1/2 HP or more or single air conditioning units of 6 tons or more or where total horsepower of all connected three phase motors exceeds 12 HP or total load exceeding 100 kVA demand shall qualify for three phase. If the estimated load is less than the above horsepower or connected kVA specifications, Company may, at its option and when requested by the customer, serve three phase and require a nonrefundable contribution equal to the difference in cost between single phase and three phase construction, but in no case less than $100.

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6.4 EASEMENTS

All suitable easements or rights-of-way required by Company for any portion of the extension which is either on premises owned, leased or otherwise controlled by the customer or developer, or other property required for the extension, shall be furnished in Company's name by the customer without cost to or condemnation by Company and in reasonable time to meet proposed service requirements. All easements or rights-of-way obtained on behalf of Company shall contain such terms and conditions as are acceptable to Company.

6.5 GRADE MODIFICATIONS

If subsequent to construction of electric distribution lines and services, the final grade established by the customer or developer is changed in such a way as to require relocation of Company facilities or the customer's actions or those of his contractor results in damage to such facilities, the cost of relocation and/or resulting repairs shall be borne by customer or developer.

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6.6 OWNERSHIP

Except for customer-owned facilities, all electric facilities, including that for which customers have made advances and/or contributions, will be owned, operated and maintained by Company.

6.7 MEASUREMENT AND LOCATION

6.7.1 Measurement must be along the proposed route of construction.

6.7.2 Construction will be on public streets, roadways, highways, or easements acceptable to Company.

6.7.3 The extension must be a branch from, the continuation of, or an addition to, one of Company's existing distribution lines.

6.8 UNUSUAL CIRCUMSTANCES

In unusual circumstances as determined by Company, when the application and provisions of this policy appear impractical, or in case of extension of lines to be operated on voltages other than specified in the applicable rate schedule, or when customer's estimated load will exceed 3,000 kW, Company will make a special study of the conditions to determine the basis on which service may be provided. Additionally, Company may require special contract arrangements as provided for in Section 1.1 of Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Service.

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6.9 NON-STANDARD CONSTRUCTION

Company's construction practices employ contemporary methods and equipment and meet current industry standards. Where extensions of electric facilities require construction that is in any way nonstandard, as determined by Company, or if unusual obstructions are encountered, the customer will make a non-refundable contribution equal to the difference in cost between standard and non-standard construction, in addition to other applicable costs involved.

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6.10 ABNORMAL LOADS

Company, at its option, may make extensions to serve certain abnormal loads (such as: transformer-type welders, x-ray machines, wind machines, excess capacity for test purposes and loads of unusual characteristics), provided the customer makes a nonrefundable contribution equal to the total cost of such extension, including transformers.

6.11 RELOCATIONS AND/OR CONVERSIONS

6.11.1 Company will relocate or convert its facilities for the customer's convenience or aesthetics, providing the customer makes a nonrefundable contribution equal to the total cost of relocation or conversion.

6.11.2 When the relocation of Company facilities involve "prior rights" conditions, the customer will be required to make a non-refundable contribution equal to the total cost of relocation.

6.11.3 When the relocation or conversion is in conjunction with added revenue, as determined by Company and is not for the customer's convenience or aesthetics, then the relocation or conversion costs plus the costs to serve will be used to determine the customers advance on the basis specified in Section 2.0 or 3.0.

6.12 MASTER METERING

6.12.1 Mobile Home Parks - Company shall refuse service to all new construction and/or expansion of existing permanent residential mobile home parks unless the construction and/or expansion is individually metered by Company.

6.12.2 Residential Apartment Complexes, Condominiums - Company shall refuse service to all new construction of apartment complexes and condominiums which are master metered unless the builder or developer can demonstrate that the installation meets the provisions of R14-2-205 of the Corporation Commission's Rules and Regulations or the requirements discussed in 6.12.3 below. This section is not applicable to Senior Care/Nursing Centers registered with the State of Arizona with independent living units which provide packaged services such as housing, food, and nursing care.

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6.12.3 Multi-Unit Residential Developments – Company will allow master metering for residential units where the residential units are privately owned provided the building will be served by a centralized heating, ventilation and/or air conditioning system, and each residential unit shall be individually sub-metered and responsible for energy consumption of that unit.

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6.12.3.1 Sub-metering shall be provided and maintained by the builder or homeowners association.

6.12.3.2 Responsibility and methodology for determining each unit's energy billing shall be clearly specified in the original bylaws of the homeowners association, a copy of which must be provided to Company prior to Company providing the initial extension.

Company will convert its facilities from master metered system to a permanent individually metered system at the customer's request provided the customer makes a nonrefundable contribution equal to the residual value plus the removal costs less salvage of the master meter facilities to be removed. The new facilities to serve the individual meters will be extended on the basis specified in Section 1. Applicant is responsible for all costs related to the installation of new service entrance equipment.

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6.13 CHANGE IN CUSTOMER'S SERVICE REQUIREMENTS

Company will rebuild or revamp existing facilities to meet the customer's added load or change in service requirements on the basis specified in Section 2.0 or 3.0.

6.14 STUDY AND DESIGN DEPOSIT

Any applicant requesting Company to prepare special studies or detailed plans, specifications, or cost estimates may be required to deposit with Company an amount equal to the estimated cost of preparation. Where the applicant authorizes Company to proceed with construction of the extension, the deposit shall be credited to the cost of construction, otherwise the deposit shall be nonrefundable. Company will prepare, without charge, a preliminary sketch and rough estimate of the cost to be paid by the customer for a line extension upon request.

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6.15 CUSTOMER CONSTRUCTION OF COMPANY DISTRIBUTION FACILITIES

The customer may provide construction related services, e.g. engineering, survey, materials and/or labor, associated with new distribution facilities to serve the customer's new or added load, provided the customer meets all of the requirements set forth by Company. All work and/or materials provided by the customer shall comply with Company standards in effect at the time of construction. The customer shall receive written approval from Company prior to performing any construction related services. Company will perform an Economic Feasibility Analysis prior to the approval of any proposed customer provided construction to ensure the proposed scope of work results in mutual benefits to the customer and Company.

6.16 SETTLEMENT OF DISPUTES

Any dispute between the customer or prospective customer and Company regarding the interpretation of these "Conditions Governing Extensions of Electric Distribution Lines and Services" may, by either party, be referred to the Arizona Corporation Commission or a designated representative or employee thereof for determination.

6.17 INTEREST

All advances made by the customer to Company in aid of construction shall be non-interest bearing.

6.18 EXTENSION AGREEMENTS

All line extensions or equipment upgrades requiring payment by the customer shall be in writing and signed by both the customer and Company.

6.19 ADDITIONAL PRIMARY FEED

When specifically requested by the customer to provide an alternate primary feed (excluding transformation), Company will perform a special study to determine the request's feasibility and the customer may be required to pay a nonrefundable contribution in aid of construction for the added cost as well as the applicable rate for the additional feed requested.

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RATE SCHEDULE E-10
RESIDENTIAL SERVICE
INTERIM CLASSIC RATE

AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

APPLICATION

This rate schedule is applicable to all Standard Offer and Direct Access electric service, except as stated below, required for residential purposes in individual private dwellings and in individually metered apartments when such service is supplied at one site through one point of delivery and measured through one meter. For those dwellings and apartments where electric service has historically been measured through two meters, when one of the meters was installed pursuant to a water heating or space heating rate schedule no longer in effect, the electric service measured by such meters shall be combined for billing purposes.

Additionally, this rate schedule is applicable only to those customers being served on the Company's Rate Schedule E-10 prior to December 6, 1991.

This rate schedule is not applicable to breakdown, standby, supplemental or resale service.

TYPE OF SERVICE

The type of service provided under this schedule will be single phase, 60 Hertz, at a single standard voltage (120/240 or 120/208 as may be selected by customer subject to availability at the customer's site). Three phase service may be furnished under the Company's Schedule 3 (Conditions Governing Extensions of Electric Distribution Lines and Services), and is required for motors of an individual rated capacity of 7-1/2 HP or more.

RATES

The customer's bill shall be computed at the following rates, plus any adjustments incorporated in this schedule:

Bundled Standard Offer Service

Basic Service Charge: $ 0.253 per day

Energy Charge:

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
$0.09205 per kWh for the first 400 kWh, plus $0.12607 per kWh for the next 400 kWh, plus $0.12966 per kWh for all additional kWh	$0.09501 per kWh

Bundled Standard Offer Service consists of the following Unbundled Components:

Unbundled Components

Basic Service Charge: $ 0.056 per day

RATES (cont)

Unbundled Components (cont)

Revenue Cycle Service Charges:		
Metering	$0.080	per day
Meter Reading	$0.055	per day
Billing	$0.062	per day
System Benefits Charge:	$0.001860	per kWh
Transmission Charge:	$0.00476	per kWh
Delivery Charge:	$0.03288	per kWh

Generation Charges:

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
$0.05255 per kWh for the first 400 kWh, plus $0.08657 per kWh for the next 400 kWh, plus $0.09016 per kWh for all additional kWh	$0.05551 per kWh

DIRECT ACCESS

The bill for Direct Access customers will consist of the Unbundled Components Basic Service Charge, the System Benefits Charge, and the Delivery Charge, plus any applicable adjustments incorporated in this schedule. Direct Access customers must acquire and pay for generation, transmission, and revenue cycle services from a competitive third party supplier. If any revenue cycle services are not available from a third party supplier and must be obtained from the Company, the Unbundled Components Revenue Cycle Service Charges will be applied to the customer's bill.

ADJUSTMENTS

1. The Environmental Portfolio Surcharge shall be applied to every retail electric service as set forth in the Company's Rate Schedule EPS-1.

2. The bill is subject to the Power Supply Adjustment factor as set forth in the Company's Rate Schedule PSA-1 pursuant to Arizona Corporation Commission Decision No. 67744.

3. The bill is subject to the Transmission Cost Adjustment factor as set forth in the Company's Rate Schedule TCA-1 pursuant to Arizona Corporation Commission Decision No. 67744.

4. The bill is subject to the Competition Rules Compliance Charge as set forth in the Company's Rate Schedule CRCC-1 pursuant to Arizona Corporation Commission Decision No. 67744.

ADJUSTMENTS (cont)

5. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge as set forth in the Company's Rate Schedule RCDAC-1 pursuant to Arizona Corporation Commission Decision No. 67744.

6. The bill is subject to the Demand Side Management Adjustment charge as set forth in the Company's Rate Schedule DSMAC-1 pursuant to Arizona Corporation Commission Decision No. 67744.

7. The bill is subject to the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of APS and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

CONTRACT PERIOD

Any applicable contract period will be set forth in APS' standard agreement for service.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

APS Proposed Power Supply Adjustment Plan of Administration

APS Proposed Power Supply Adjustment Plan of Administration

General Description

The purpose of the Power Supply Adjustment ("PSA") is to track changes in Arizona Public Service Company's ("APS") cost of obtaining power supplies. This is done by making an annual adjustment to the cost of fuel and purchased power embedded in APS' base rates. The PSA applies to all fuel and purchased power costs incurred on or after April 1, 2005. The costs/savings are shared on a 90 percent customer/10 percent APS basis ("90/10 Sharing"). The PSA currently has five different accounts: 1) an Annual Tracking Account, 2) an Annual Adjustor Account, 3) a Paragraph 19(d) Balancing Account, 4) a Surcharge Account for any surcharge approved by the Arizona Corporation Commission ("Commission") and if applicable 5) a Interim Adjustor Account for any approved Interim Adjustor rate.

Entries are made each month into the Annual Tracking Account. These entries reflect 90 percent of the difference between incurred fuel and purchased power costs and the sum of costs collected through the base cost of fuel and purchased power rate ($0.0XXXXX established in Decision No. XXXXX).

The results of the PSA are applied to customer bills through the Adjustor Rate. The Adjustor Rate is applicable to APS' retail electric rate schedules (with the exception of Solar-1, Solar-2, SP-1, E-3, E-4, E-36, Direct Access service and any other rate that is exempt from the PSA) and is adjusted annually. It is applied to the customer's bill as a monthly kilowatt-hour ("kWh") charge that is the same for all customer classes. The Adjustor Rate must remain within a plus or minus $0.004 per kWh annual bandwidth that limits the amount it can increase or decrease in a year. Examples of applying the two bandwidths are as follows:

1. Assume that the Adjustor Rate was set at *negative* $0.002 per kWh. The following year, the calculation of the new Adjustor Rate would indicate a new rate of *positive* $0.003 per kWh. However, since that rate would constitute a change of $0.005 from the prior year's Adjustor Rate, the new Adjustor Rate would be set at $0.002 per kWh. That new rate would meet the limit of $0.004 from the base level.

2. Assume that the Adjustor Rate was set at $0.003 per kWh. The following year, the calculation of the new Adjustor Rate would indicate a new rate of $0.005 per kWh. The annual change is less than $0.004, so the new Adjustor Rate would be set at $0.005 per kWh.

The Adjustor Rate is reset on February 1 each year and is effective with the first billing cycle in February unless suspended by the Commission. It is not prorated. APS will submit a publicly available report to the Commission that shows the calculation of the new Adjustor Rate. The amount expected to be recovered or refunded through the Adjustor Rate is entered into the Annual Adjustor Account.

Any recoverable or refundable amounts outside of the bandwidth are recorded in the Paragraph 19(d) Balancing Account and will carry over to the subsequent year or years. The carryover amount shall not be subject to further sharing. Surcharges may be approved by the Commission to recover/refund amounts in the Paragraph 19(d) Balancing Account. Amounts approved for collection through surcharges will be removed from the Paragraph 19(d) Balancing Account.

Definitions

Adjustor Rate – A 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 adjust the cost of fuel and purchased power embedded in APS' base rates to reflect the prior calendar year's fuel and purchased power costs. This annual adjustment is limited to a maximum change of plus or minus 4 mills in a year.

Annual Adjustor Account – An annual schedule/account that shows/records the amount that is available to be recovered through the PSA (after the 90/10 Sharing mechanism is applied); the amount that can be collected through the applicable Adjustor Rate; and also tracks/records the collections per month and the monthly ending balance remaining to be collected.

Annual Tracking Account – An annual schedule/account that tracks/records on a monthly basis APS' over/under-recovery of its actual costs of fuel and purchased power as compared to the base cost.

Base Cost of Fuel and Purchased Power – The fuel and purchased power cost embedded in the base rates approved by the Commission in APS' most recent rate case. Decision No. XXXXX set the base cost at $0.0XXXXX per kWh.

Interim Adjustor Account – A schedule/account that shows/records the revenue collected by the Interim Adjustor rate and the associated fuel and purchased power supply costs that the collected revenue offsets.

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.

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.

Paragraph 19(d) Balancing Account – A schedule/account that shows/records the amount (after the application of the Adjustor Rate) remaining to be refunded or collected through either a Surcharge, or through the next year's Adjustor Rate . This includes any interest accruals on the account's balance.

PSA – The Power Supply Adjustment mechanism used to update the Base Cost of Fuel and Purchased Power each year for fluctuations in APS' actual cost of fuel and purchased power.

Preference Power – Power allocated to APS wholesale customers by federal power agencies such as the Western Area Power Administration.

Surcharge – A per kWh charge that can be applied to customer bills after Commission approval to collect, or refund, an amount for the purpose of reducing the balance in the Paragraph 19(d) Balancing Account. It can be either a positive or negative charge.

Surcharge Account – A schedule/account that shows/records any Surcharge approved, including the amount, timing, rate, and whether interest is applied; and that tracks/records collections per month and the monthly ending balance remaining to be collected.

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, RCDAC-1, ISFSI, and Mark-to-Market Accounting adjustments. Wheeling costs and broker fees are included.

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.

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.

Calculations

Schedule 1. Annual Tracking Account

1. Enter the monthly Retail Energy Sales (MWh) and the monthly Wholesale Native Load Energy Sales. Add these two items together to produce the monthly Total Native Load Energy Sales. Currently, Wholesale Native Load Energy Sales include Traditional Sales-for-Resale and PacifiCorp Supplemental Sales.

2. Enter the monthly System Book Fuel and Purchased Power Costs and the monthly System Book Off-System Sales Revenue. Subtract the System Book Off-System Sales Revenue from the System Book Fuel and Purchased Power Costs to produce the monthly Net Native Load Power Supply Costs. The off-system sales margin is embedded in the Net Native Load Power Supply Cost. The costs associated with the off-system sales are included in the System Book Fuel and Purchased Power Costs. When the System Book Off-System Sales Revenue is subtracted from the System Book Fuel and Purchased Power Costs, the difference between the off-system sales costs and revenue ends up in the Net Native Load Power Supply Cost. That difference is the off-system sales margin. A list of the items included in the PSA sales and costs described above will be included in the PSA reporting schedules filed with the Commission each month.

3. To calculate the Retail Power Supply Costs, divide the Retail Energy Sales by the Total Native Load Energy Sales and then multiply the product by the Net Native Load Power Supply Costs.

Directly-assigned power supply costs and related energy sales from applicable Special Contract customers, Schedule E-36 customers, and customers returning to Standard Offer service from competitive generation subject to Returning Customer Direct Access Charge ("RCDAC") treatment will be deducted prior to the above calculations.

4. The amount recovered by the power supply costs embedded in base rates has to be calculated in order to determine the monthly (over)/under collection. To calculate the monthly Base Rate Power Supply Revenue, multiply the Retail Energy Sales by the Base Cost of Fuel and Purchased Power.

5. Subtract the Base Rate Power Supply Revenue from the Retail Power Supply Costs to get the monthly Pre-90/10 Sharing (Over)/Under Collection amount.

6. Enter the month's 90/10 Sharing Exclusion total. This is the current month's purchased renewable resource cost that is embedded in the System Book Fuel

and Purchased Power Costs which is not covered by the Environmental Portfolio Standard ("EPS") surcharge. Also include the demand costs of Purchased Power Agreements ("PPA") that were acquired through a competitive process.

7. The Post 90/10 Sharing (Over)/Under Collection amount is calculated by multiplying the Pre-90/10 Sharing (Over)/Under Collection amount less the 90/10 Sharing Exclusion by 90 percent. Then the 90/10 Sharing Exclusion amount is added back in to the product of the multiplication to get the Post 90/10 Sharing (Over)/Under Collection.

8. Enter any transfers to the Interim Account Adjustor if such an account is currently active.

9. An interest rate, based on the one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release, H-15, is applied each month to the previous month's Tracking Account Balance. The interest rate is adjusted annually on the first business day of the calendar year in the same manner as the APS customer deposit rate.

10. Add the Post-90/10 Sharing (Over)/Under Collection, Transfer to Interim Adjustor Account and Interest amounts together to get the month's Tracking Account Balance.

<u>Schedule 2. Annual PSA Adjustor Rate Calculation</u>

1. Enter the Tracking Account Balance from Schedule 1.

2. Add the Annual Adjustor Account Balance from Schedule 3, the Paragraph 19(d) Balancing Account Balance from Schedule 4, and the Surcharge Account Balance (if a Surcharge has terminated) from Schedule 5 to determine the Total (Credit)/Charge Amount.

3. The Computed Adjustor Rate is calculated by dividing the Total Credit/Charge Amount by the Projected Energy Sales (kWh) for the next 12 months. The Computed Adjustor Rate is then compared to the plus or minus $0.004 per kWh bandwidth. The Projected Energy Sales amount will exclude E-3, E-4, E-36, Direct Access service and any other rate that is exempt from the PSA.

4. The Adjustor Rate Bandwidth Upper Limit is $0.004 per kWh plus the Current Adjustor Rate. The Adjustor Rate Bandwidth Lower Limit is $(0.004) per kWh plus the Current Adjustor Rate.

5. If the Computed Adjustor Rate is inside the bandwidth, the Computed Adjustor Rate becomes the Applicable Adjustor Rate. It is then applied to customer monthly bills for the next 12 months.

6. If the Computed Adjustor Rate is outside the bandwidth, the Applicable Adjustor Rate can be no higher than the upper limit of the bandwidth and no lower than the lower limit of the bandwidth.

7. The Applicable Adjustor Rate is multiplied by the projected Energy Sales to calculate the amount to be carried forward to the Annual Adjustor Account.

8. If the amount to be carried forward to the Annual Adjustor Account is less than the Total (Credit)/Charge Amount used to calculate the Applicable Adjustor Rate, then the difference is carried forward to the Paragraph 19(d) Balancing Account.

Schedule 3. Annual Adjustor Account

1. The Adjustor Rate from Schedule 2 is entered on Schedule 3 in February. The Amount Carried Forward to Annual Adjustor Account is entered as the Beginning Balance.

2. Each month, the Adjustor Rate is multiplied by the Retail Energy Sales to calculate the revenue received from the Adjustor Rate. The revenue is subtracted from the Beginning Balance.

3. Interest is applied monthly based on the effective one-year Nominal Treasury Constant Maturities rate that is contained in the Federal Reserve Statistical Release, H-15, or its successor publication. The interest rate is adjusted annually on the first business day of the calendar year in the same manner as the APS customer deposit rate.

Schedule 4. Paragraph 19(d) Balancing Account

1. The Amount Carried Forward to Paragraph 19(d) Balancing Account from Schedule 2 is entered as the Beginning Balance.

2. Each month, interest is applied based on the effective one-year Nominal Treasury Constant Maturities rate that is contained in the Federal Reserve Statistical Release, H-15, or its successor publication. The interest rate is adjusted annually on the first business day of the calendar year in the same manner as the APS customer deposit rate.

3. Whenever the Commission approves a Surcharge, the amount to be collected through the surcharge is subtracted from the balance.

APS is required to make a filing for a Surcharge in the following circumstances. If the size of the Paragraph 19(d) Balancing Account, as shown in the monthly reports filed with the Commission, reaches plus or minus $50 million APS has up to 45 days from the end of the month in which this limit was exceeded to either file a request for Commission approval of a Surcharge or an explanation of why such a Surcharge is not necessary. Should APS seek to recover or refund an amount from the Paragraph 19(d) Balancing Account, the timing and manner of recovery, or refund, and whether interest will be allowed to accrue on the Surcharge balance, will be addressed at that time.

Schedule 5. Surcharge Account

1. The approved Surcharge Rate is entered on Schedule 5 in the month it takes effect. The timing of the Surcharge and whether interest is applied are indicated on the schedule. The approved Surcharge amount is entered as the Beginning Balance.

2. Each month, the Surcharge Rate is multiplied by the Retail Energy Sales to calculate the revenue received from the Surcharge Rate. The revenue is subtracted from the Beginning Balance.

3. If interest is authorized, it is applied monthly based on the effective one-year Nominal Treasury Constant Maturities rate that is contained in the Federal Reserve Statistical Release, H-15, or its successor publication. The interest rate is adjusted annually on the first business day of the calendar year in the same manner as the APS customer deposit rate.

Schedule 6. Interim Adjustor Account

1. If applicable, the approved Interim Adjustor Rate is entered on Schedule 6 in the month it takes effect. The revenue from the approved Interim Adjustor Rate is also entered and then the fuel and purchased power costs offset by the Interim Adjustor rate revenue is moved into the account from Schedule 1 where it is shown as a reduction to the balance in the Tracking Account.

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 Officer 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 Annual Tracking Account, Annual Adjustor Account, Paragraph 19(d) Balancing Account, Surcharge Account and if applicable, Interim Adjustor Account calculations, including all input and outputs.
2. Total power and fuel costs.
3. Customer sales in both MWh and thousands of dollars by customer class.
4. Number of customers by customer class.
5. A detailed listing of all items excluded from the PSA calculations.
6. A detailed listing of any adjustments to the adjustor reports.
7. Total off-system sales revenues.
8. System losses in MW and MWh.
9. Monthly maximum retail demand in MW.
10. 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:

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.

Information on economy interchange purchases may be aggregated.

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 therm, total cost, supply basin, and volume by contract.

E. Monthly projections for the next 12-month period showing estimated (Over)/under-collected amounts.

F. A summary of unplanned outage costs by resource type.

G. Provide the data necessary to arrive at the System and Off-System Book Fuel and Purchased Power cost 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.

Allowable Costs

The allowable PSA costs include fuel and purchased power costs incurred to provide service to retail customers. Additionally, the prudent direct costs of contracts used for hedging system fuel and purchased power will be recovered under the PSA. The allowable cost components presently include the following Federal Energy Regulatory Commission ("FERC") accounts:

1. 501 Fuel (Steam)
2. 518 Fuel (Nuclear) less ISFSI regulatory amortization
3. 547 Fuel (Other Production)
4. 555 Purchased Power
5. 557 Broker Fees (Other Expenses)
6. 565 Wheeling (Transmission of Electricity by Others)

These accounts are subject to change if the Federal Energy Regulatory Commission alters its accounting requirements or definitions.

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 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.

ARIZONA PUBLIC SERVICE COMPANY
Schedule 1
XXXX Annual Tracking Account
XXXX XXXX
($ in thousands)

Line No.	Month	(a) PSA Retail [1] Energy Sales (MWh)	(b) Native Load [2] Wholesale Energy Sales (MWh)	(c) Native Load Energy Sales (MWh)	(d) System [3] Book Fuel and Purchased Power Costs	(e) System Book [4] Off-System Sales Revenue	(f) Net Native Load Power Supply Cost	(g) PSA Retail Power Supply Cost	(h) Base Rate Power Supply Cost	(i) Pre 90/10 Sharing (Over)/Under Collections	(j) 90/10 Sharing Exclusions	(k) Post 90/10 Sharing (Over)/Under Collections	(l) Transfer to Interim Adjustor Account	(m) Interest [5]	(n) Tracking Account Balance
				(a + b)			(d - e)	(a/c * f)	(a * 0.0XXXXX)	(g - h)		((i -j)* 0.9) + j)		(n * rate/12)	(k + l + m)
1	January	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	February	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	March	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	April	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	May	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	June	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	July	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	August	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9	September	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	October	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	November	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	December	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12.5	January interest													$ -	
13	Total	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	Interest Rate [5]		4.38%												

[1] PSA Retail Energy Sales are the calendar month's kWh sales. Cumulative Retail Energy Sales of XXXXXX MWhs under rate schedule E-36 were excluded from the PSA Calculations.
[2] Includes traditional sales-for-resale and Pacificorp supplemental sales.
[3] Includes native load and off-system fuel and purchased power costs less those costs associated with E-36 XXXXXX, ISFSI and mark-to-market accounting adjustments.
[4] Includes off-system revenue less mark-to-market accounting adjustments.
[5] Based on one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release, H-15.
Definitions of commonly used terms for this filing are included in the PSA Plan of Administration. Any new terms will be defined on this page.

ARIZONA PUBLIC SERVICE COMPANY
Schedule 2
XXXX Year End PSA Adjustor Rate Calculation
($ in thousands)

Line No.				
	PSA Adjustor Rate Calculation			
1	Annual Tracking Account Balance (From Schedule 1) [1]		$ -	
2	Annual Adjustor Account Balance (from Schedule 3) [1,2]		$ -	
3	Paragraph 19d Balancing Account Balance (from Schedule 4) [1]		$ -	
4	Surcharge Account Balance after surcharge termination (from Schedule 5) [1]		$ -	
5	Total (Credit)/Charge Amount (Line 1 + Line 2 + Line 3 + Line 4)			$ -
6	Projected Energy Sales without E-3, E-4 and E-36 (MWh)	-		
7	Computed Adjustor Rate ($/kWh) (Line 5 / Line 6)		$ -	
8	Current Adjustor Rate ($/kWh)	$ -		
9	Difference between Current Adj. Rate and Computed Adj. Rate (Line 7 - Line 8)	$ -		
	Adjustor Rate Bandwidth			
10	Adjustor Rate Bandwidth Upper Limit ($/kWh) (Line 8 + .004)		$ 0.004000	
11	Adjustor Rate Bandwidth Lower Limit ($/kWh) (Line 8 + .004)		$ (0.004000)	
12	Applicable Adjustor Rate for February 1, 2007($/kWh)			$ -
13	Amount Carried Forward to Annual Adjustor Account (Line 6 * Line 12)			$ -
14	Amount Carried Forward to Paragraph 19d Balancing Account (Line 5 - Line 13)			$ -

[1] Includes interest for January.

[2] Because the actual amount of revenue to be received in January from the adjustor rate is not available at the time of filing this schedule, the Annual Adjustor Account Balance used here contains estimated revenue for January. The difference between estimated and actual revenue for January is included in the February numbers in the new year's Annual Adjustor Account.

ARIZONA PUBLIC SERVICE COMPANY
Schedule 3
XXXX Annual Adjustor Account
XXXX XXXX
($ in thousands)

Line No.		January	February	March	April	May	June	July	August	September	October	November	December	200X January
1	Annual Adjustor Rate ($/kWh)	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
2	Retail Billed Sales Excluding E-3, E-4, E-36 Sales (MWhs) [1]		-	-	-	-	-	-	-	-	-	-	-	-
3	Beginning Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Revenue True-up from January Estimate [2]		$ -											
5	Less Revenue from Applicable Adjustor Rate (Ln. 1 * Ln. 2) [3]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Monthly Interest ([Line 3 + Line 4] * [4.38% / 12]) [4]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	Ending Balance (Ln. 3 + Ln. 4 - Ln. 5 + Ln. 6)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

[1] Sales amounts are for energy billed beginning with the first billing cycle of February 2006.

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

[3] Difference between Line 1 times Line 2 and Line 5 are due to billing adjustments.

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

ARIZONA PUBLIC SERVICE COMPANY
Schedule 4
XXXX Paragraph 19d Balancing Account
XXXX XXXX
($ in thousands)

Line No.		January	February	March	April	May	June	July	August	September	October	November	December
1	Beginning Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	Amounts Removed due to Authorized Surcharge	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	Monthly Interest ([Line 1- Line 2] * [4.38% / 12])[1]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Ending Balance (Ln. 1 - Ln. 2 + Ln. 3)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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

ARIZONA PUBLIC SERVICE COMPANY
Schedule 5
XXXX Surcharge Account
XXXX XXXX
($ in thousands)

Line No.		January	February	March	April	May	June	July	August	September	October	November	December
1	Surcharge Rate ($/kWh)	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
2	Retail Billed Sales Excluding E-3, E-4, E-36 Sales (MWhs)		-	-	-	-	-	-	-	-	-	-	-
3	Beginning Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Less: Revenue from Surcharge Rate (Line 1 * Line 2) [1]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Monthly Interest (Line 3 * [4.38% / 12]) [2]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Ending Balance with Interest (Line 3 - Line 4 + Line 5)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

[1] Difference between Line 1 times Line 2 and Line 5 are due to billing adjustments.

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

ARIZONA PUBLIC SERVICE COMPANY
Schedule 6
XXXX Interim Adjustor Account
XXXX XXXX
($ in thousands)

Line No.		January	February	March	April	May	June	July	August	September	October	November	December
1	Interim Adjustor Rate	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
2	Retail Billed Sales Excluding E-3, E-4, E-36 Sales (MWhs)		-	-	-	-	-	-	-	-	-	-	-
3	Beginning Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Less: Revenue from Interim Adjustor Rate (Line 1 * Line 2)[1]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Transfer from the Annual Tracking Account (Schedule 1)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Ending Balance (Line 3 - Line 4 + Line 5)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

[1] Difference between Line 1 times Line 2 and Line 5 are due to billing adjustments.

Proposed Power Supply Adjustment Plan of Administration using Staff's Approach

Proposed Power Supply Adjustment Plan of Administration using Staff's Approach

General Description

The purpose of the Power Supply Adjustment ("PSA") is to track changes in Arizona Public Service Company's ("APS") cost of obtaining power supplies. This is done by making an annual adjustment to the cost of fuel and purchased power embedded in APS' base rates through the combination of a Prospective Adjustor Rate and Adjustor Rate. The Prospective Adjustor is designed to recover/refund the difference between the base rate fuel and purchased power cost and the actual costs. It is based on the difference between APS' fuel and purchased power costs forecast for the coming year and the base fuel and purchased power rate embedded in APS' effective rates. The Adjustor Rate will recover on an after the fact basis differences between the forecast and actual fuel and purchased power costs in addition to any applicable account balances.

The PSA applies to all fuel and purchased power costs incurred on or after April 1, 2005. This version of the PSA Plan of Administration applies to the fuel and purchased power costs incurred after Decision No. XXXXX was issued on XXXXX XX, XXXX. The costs/savings that are in excess of the forecast balance are shared on a 90 percent customer/10 percent APS basis ("90/10 Sharing"). The PSA has four different accounts: 1) an Annual Tracking Account, 2) an Annual Adjustor Account, 3) a Paragraph 19(d) Balancing Account, and 4) a Surcharge Account for any surcharge approved by the Arizona Corporation Commission ("Commission").

Entries are made each month into the Annual Tracking Account. These entries reflect 90 percent of the difference between incurred fuel and purchased power costs and the sum of costs collected through both the base cost of fuel and purchased power rate ($0.0XXXXX per kWh established in Decision No. XXXXX) and the Prospective Adjustor. The results of the PSA are applied to customer bills through the Adjustor Rate and the Prospective Adjustor Rate. The Adjustor Rate and the Prospective Adjustor are applicable to APS' retail electric rate schedules (with the exception of Solar-1, Solar-2, SP-1, E-3, E-4, E-36, Direct Access service and any other rate that is exempt from the PSA) and are adjusted annually. They are applied to the customer's bill as a monthly kilowatt-hour ("kWh") charge that is the same for all customer classes.

The Adjustor and Prospective rates are reset on February 1 of each year. The new Adjustor and Prospective Adjustor rates are effective with the first billing cycle in February unless suspended by the Commission. They are not prorated.

APS will submit a publicly available report to the Commission that shows the calculation of the new Adjustor Rate. The amount expected to be recovered or refunded through the Adjustor Rate is entered into the Annual Adjustor Account. Any recoverable or refundable amounts over the amount collected by the Adjustor Rate are recorded in the Paragraph 19(d) Balancing Account and will carry over to the subsequent year or years.

The carryover amount shall not be subject to further sharing. Surcharges may be approved by the Commission to recover/refund amounts in the Paragraph 19(d) Balancing Account. Amounts approved for collection through surcharges will be removed from the Paragraph 19(d) Balancing Account and transferred to a Surcharge Account.

The Prospective Adjustor rate calculation will be filed with the Commission by September 30th each year. The Commission Staff will review the forecast on which the rate is based and make a recommendation to the Commission within 45 days. The Commission will determine whether to approve the rate. If the Commission has not acted on the rate by December 31st it will take effect with the first February billing cycle, and it will be subject to refund.

Definitions

Adjustor Rate – A 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 adjust the cost of fuel and purchased power embedded in APS' base rates to reflect the difference between the prior calendar year's actual fuel and purchased power costs and the cost recovery from both the base fuel rate of $0.0XXXXX per kWh and the Prospective Adjustor.

Annual Adjustor Account – An annual schedule/account that shows/records the amount that is available to be recovered through the PSA (after the 90/10 Sharing mechanism is applied); the amount that can be collected through the applicable Adjustor Rate; and that also tracks/records the collections per month and the monthly ending balance remaining to be collected.

Annual Tracking Account – An annual schedule/account that tracks/records on a monthly basis APS' over/under-recovery of its actual costs of fuel and purchased power as compared to the base cost with the Prospective Adjustor.

Base Cost of Fuel and Purchased Power – The fuel and purchased power cost embedded in the base rates approved by the Commission in APS' most recent rate case. Decision No. XXXXX set the base cost at $0.0XXXXX per kWh.

Prospective Adjustor – A 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 adjust the cost of fuel and purchased power embedded in APS' base rates to reflect the difference between the coming year's forecast power supply costs and the base cost of fuel and purchased power of $0.0XXXXX per kWh.

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.

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.

Paragraph 19(d) Balancing Account – A schedule/account that shows/records the amount (after the application of the Adjustor Rate) remaining to be refunded or collected through either a Surcharge or through the next year's Adjustor Rate. This includes any interest accruals on the account's balance.

PSA – The Power Supply Adjustment mechanism used to update the Base Cost of Fuel and Purchased Power each year for fluctuations in APS' actual cost of fuel and purchased power.

Preference Power – Power allocated to APS wholesale customers by federal power agencies such as the Western Area Power Administration.

Surcharge – A per kWh charge that can be applied to customer bills after Commission approval to collect, or refund, an amount for the purpose of reducing the balance in the Paragraph 19(d) Balancing Account. It can be either a positive or negative charge.

Surcharge Account – A schedule/account that shows/records any Surcharge approved, including the amount, timing, rate, and whether interest is applied; and that tracks/records collections per month and the monthly ending balance remaining to be collected.

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, RCDAC-1, ISFSI, and Mark-to-Market Accounting adjustments. Wheeling costs and broker fees are included.

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.

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.

Calculations

Schedule 1. Prospective Adjustor Rate Calculation

1. Enter the Projected Fuel and Purchased Power Costs for the coming year.

2. Enter the Projected Off-System Sales Revenue for the coming year.

3. Enter the PSA Adjustments to Fuel and Purchased Power Costs for the coming year.

4. Add the Projected Fuel and Purchased Power Costs, Projected Off-System Sales Revenue and the PSA Adjustments to Fuel and Purchased Power Costs together to get the Net Fuel and Purchased Power Costs.

5. Enter the Projected Native Load Sales (kWh), excluding the E-3, E-4, E-36 sales for the coming year.

6. Divide the Net Fuel and Purchased Power Costs by the Projected Native Load Sales to get the Projected Average Net Fuel Cost.

7. Enter the Authorized Base Fuel Rate.

8. Subtract the Authorized Base Fuel Rate from the Projected Average Net Fuel Cost to get the Prospective Adjustor Rate for the coming year.

9. Multiply the Prospective Adjustor Rate by the Projected Native Load Sales to get the Projected Prospective Adjustor Collections for the coming year.

10. The Prospective Adjustor Rate will be used on the coming year's Annual Tracking Account as described below.

Schedule 2. Annual Tracking Account

1. Enter the monthly Retail Energy Sales (MWh) and the monthly Wholesale Native Load Energy Sales. Add these two items together to produce the monthly Total Native Load Energy Sales. Currently, Wholesale Native Load Energy Sales include Traditional Sales-for-Resale and PacifiCorp Supplemental Sales.

2. Enter the monthly System Book Fuel and Purchased Power Costs and the monthly System Book Off-System Sales Revenue. Subtract the System Book Off-System Sales Revenue from the System Book Fuel and Purchased Power Costs to produce the monthly Net Native Load Power Supply Costs. The off-system sales margin is embedded in the Net Native Load Power Supply Cost. The costs associated with the off-system sales are included in the System Book Fuel and Purchased Power Costs. When the System Book Off-System Sales Revenue is subtracted from the System Book Fuel and Purchased Power Costs, the difference between the off-system sales costs and revenue ends up in the Net Native Load Power Supply Cost. That difference is the off-system sales margin. A list of the items included in the PSA sales and costs described above will be included in the PSA reporting schedules filed with the Commission each month.

3. To calculate the Retail Power Supply Costs, divide the Retail Energy Sales by the Total Native Load Energy Sales and then multiply the product by the Net Native Load Power Supply Costs.

Directly-assigned power supply costs and related energy sales from applicable Special Contract customers, Schedule E-36 customers, and customers returning to Standard Offer service from competitive generation subject to Returning Customer Direct Access Charge ("RCDAC") treatment will be deducted prior to the above calculations.

4. The amount recovered by the power supply costs embedded in base rates has to be calculated in order to determine the monthly (over)/under collection. To calculate the monthly Base Rate Power Supply Recovery, multiply the Retail Energy Sales by the Base Cost of Fuel and Purchased Power.

5. The Prospective Adjustor Recovery is calculated by multiplying the Retail Energy Sales by the applicable Prospective Adjustor rate.

6. Subtract the Base Rate Power Supply Recovery and the Prospective Adjustor Recovery from the Retail Power Supply Costs to get the monthly Pre-90/10 Sharing (Over)/Under Collection amount.

7. Enter the month's 90/10 Sharing Exclusion total. This is the current month's purchased renewable resource cost that is embedded in the System Book Fuel and Purchased Power Costs and is not covered by the Environmental Portfolio Standard ("EPS") surcharge. Also include the demand costs of Purchased Power Agreements ("PPA") that were acquired through a competitive process.

8. The Post-90/10 Sharing (Over)/Under Collection amount is calculated by multiplying the Pre-90/10 Sharing (Over)/Under Collection amount less the 90/10 Sharing Exclusion by 90 percent. Then the 90/10 Sharing Exclusion

amount is added back in to the product of the multiplication to get the Post 90/10 Sharing (Over)/Under Collection.

9. An interest rate, based on the one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release, H-15, is applied each month to the previous month's Tracking Account Balance. The interest rate is adjusted annually on the first business day of the calendar year in the same manner as the APS customer deposit rate.

10. Sum the Post-90/10 Sharing (Over)/Under Collection, the Interest and the prior months Tracking Account Balance to get the current month's balance.

<u>Schedule 3. Annual PSA Adjustor Rate Calculation</u>

1. Enter the Tracking Account Balance from Schedule 2, the Annual Adjustor Account Balance from Schedule 4, the Paragraph 19(d) Balancing Account Balance from Schedule 5, and the Surcharge Account Balance (if a Surcharge has terminated) from Schedule 6. Add all of these balances together to determine the Total (Credit)/Charge Amount.

2. The Applicable Adjustor Rate is calculated by dividing the Total (Credit)/Charge Amount by the Projected Energy Sales (kWh) for the next 12 months. The Projected Energy Sales amount will exclude E-3, E-4, E-36, Direct Access service and any other rate that is exempt from the PSA.

3. The Applicable Adjustor Rate is then applied to customer monthly bills for the next 12 months.

4. The Applicable Adjustor Rate is multiplied by the projected Energy Sales to calculate the amount to be carried forward to the Annual Adjustor Account.

5. If the amount to be carried forward to the Annual Adjustor Account is less than the Total (Credit)/Charge Amount used to calculate the Applicable Adjustor Rate, then the difference is carried forward to the Paragraph 19(d) Balancing Account.

<u>Schedule 4. Annual Adjustor Account</u>

1. The Adjustor Rate from Schedule 3 is entered on Schedule 4 in February. The Amount Carried Forward to Annual Adjustor Account is entered as the Beginning Balance.

2. Each month, the Adjustor Rate is multiplied by the Retail Energy Sales to calculate the revenue received from the Adjustor Rate. The revenue is subtracted from the Beginning Balance.

3. Interest is applied monthly based on the effective one-year Nominal Treasury Constant Maturities rate that is contained in the Federal Reserve Statistical Release, H-15, or its successor publication. The interest rate is adjusted annually on the first business day of the calendar year in the same manner as the APS customer deposit rate.

Schedule 5. Paragraph 19(d) Balancing Account

1. The Amount Carried Forward to Paragraph 19(d) Balancing Account from Schedule 3 is entered as the Beginning Balance.

2. Each month, interest is applied based on the effective one-year Nominal Treasury Constant Maturities rate that is contained in the Federal Reserve Statistical Release, H-15, or its successor publication. The interest rate is adjusted annually on the first business day of the calendar year in the same manner as the APS customer deposit rate.

3. Whenever the Commission approves a Surcharge, the amount to be collected through the surcharge is subtracted from the balance.

APS is required to make a filing for a Surcharge in the following circumstances. If the size of the Paragraph 19(d) Balancing Account, as shown in the monthly reports filed with the Commission, reaches plus or minus $50 million, APS has up to 45 days from the end of the month in which this limit was exceeded to either file a request for Commission approval of a Surcharge or an explanation of why such a Surcharge is not necessary. Should APS seek to recover or refund an amount from the Paragraph 19(d) Balancing Account, the timing and manner of recovery, or refund, and whether interest will be allowed to accrue on the Surcharge balance, will be addressed at that time.

Schedule 6. Surcharge Account

1. The approved Surcharge Rate is entered on Schedule 6 in the month it takes effect. The timing of the Surcharge and whether interest is applied are indicated on the schedule. The approved Surcharge amount is entered as the Beginning Balance.

2. Each month, the Surcharge Rate is multiplied by the Retail Energy Sales to calculate the revenue received from the Surcharge Rate. The revenue is subtracted from the Beginning Balance.

3. If interest is authorized, it is applied monthly based on the effective one-year Nominal Treasury Constant Maturities rate that is contained in the Federal Reserve Statistical Release, H-15, or its successor publication. The interest

rate is adjusted annually on the first business day of the calendar year in the same manner as the APS customer deposit rate.

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 Officer 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 Annual Tracking Account, Annual Adjustor Account, Paragraph 19(d) Balancing Account, and Surcharge Account calculations, including all input and outputs.
2. Total power and fuel costs.
3. Customer sales in both MWh and thousands of dollars by customer class.
4. Number of customers by customer class.
5. A detailed listing of all items excluded from the PSA calculations.
6. A detailed listing of any adjustments to the adjustor reports.
7. Total off-system sales revenues.
8. System losses in MW and MWh.
9. Monthly maximum retail demand in MW.
10. 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:

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.

Information on economy interchange purchases may be aggregated.

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 therm, total cost, supply basin, and volume by contract.

E. Monthly projections for the next 12-month period showing estimated (Over)/under-collected amounts.

F. A summary of unplanned outage costs by resource type.

G. Provide the data necessary to arrive at the System and Off-System Book Fuel and Purchased Power cost 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.

Allowable Costs

The allowable PSA costs include fuel and purchased power costs incurred to provide service to retail customers. Additionally, the prudent direct costs of contracts used for hedging system fuel and purchased power will be recovered under the PSA. The allowable cost components presently include the following Federal Energy Regulatory Commission ("FERC") accounts:

1. 501 Fuel (Steam)
2. 518 Fuel (Nuclear) less ISFSI regulatory amortization

3. 547 Fuel (Other Production)
4. 555 Purchased Power
5. 557 Broker Fees (Other Expenses)
6. 565 Wheeling (Transmission of Electricity by Others)

These accounts are subject to change if the Federal Energy Regulatory Commission alters its accounting requirements or definitions.

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 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.

ARIZONA PUBLIC SERVICE COMPANY
Schedule 1
XXXX PSA Prospective Adjustor Rate Calculation
($ in thousands)

Line No.	PSA Prospective Adjustor Rate Calculation		
1	XXXX Projected Fuel and Purchased Power Costs	$ -	
2	XXXX Projected Off-System Sales Revenue	$ -	
3	XXXX PSA Adjustments to Fuel and Purchased Power Costs [1]	$ -	
4	Net Fuel and Purchased Power Cost	$ -	
5	XXXX Projected Native Load Sales, excluding E-3, E-4, E-36 (kWhs)	-	
6	XXXX Projected Average Net Fuel Cost		-
7	Authorized Base Fuel Rate		-
8	Prospective Adjustor Rate for XXXX		-
9	XXXX Projected Prospective Adjustor Collections		$ -

[1] Includes costs associated with E-36, ISFSI and mark-to-market accounting adjustments.

ARIZONA PUBLIC SERVICE COMPANY
Schedule 2
XXXX Annual Tracking Account
XXXX XXXX
($ in thousands)

Line No.	Month	(a) PSA Retail [1] Energy Sales (MWh)	(b) Native Load [2] Wholesale Energy Sales (MWh)	(c) Native Load Energy Sales (MWh) (a + b)	(d) System [3] Book Fuel and Purchased Power Costs	(e) System Book [4] Off-System Sales Revenue	(f) Net Native Load Power Supply Cost (d - e)	(g) PSA Retail Power Supply Cost (a/c * f)	(h) Base Rate Power Supply Recovery (a * 0.0XXXX)	(i) Prospective Adjustor Recovery (a * 0.0XXXX)	(j) Pre 90/10 Sharing (Over)/Under Collections (g - h - i)	(k) 90/10 Sharing Exclusions	(l) Post 90/10 Sharing (Over)/Under Collections ((j -k)* 0.9) + k)	(m) Interest [5] (m * rate/12)	(n) Tracking Account Balance (l + m + n)
1	January	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	February	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	March	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	April	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	May	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	June	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	July	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	August	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9	September	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	October	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	November	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	December	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	Total	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	Interest Rate [5]		4.38%												

[1] PSA Retail Energy Sales are the calendar month's kWh sales. Cumulative Retail Energy Sales of XXXXXX MWhs under rate schedule E-36 were excluded from the PSA Calculations.
[2] Includes traditional sales-for-resale and Pacificorp supplemental sales.
[3] Includes native load and off-system fuel and purchased power costs less those costs associated with E-36 XXXXXX, ISFSI and mark-to-market accounting adjustments.
[4] Includes off-system revenue less mark-to-market accounting adjustments.
[5] Based on one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release, H-15.
Definitions of commonly used terms for this filing are included in the PSA Plan of Administration. Any new terms will be defined on this page.

ARIZONA PUBLIC SERVICE COMPANY
Schedule 3
XXXX Year End PSA Adjustor Rate Calculation
($ in thousands)

Line No.	PSA Adjustor Rate Calculation			
1	Annual Tracking Account Balance (From Schedule 2) [1]		$ -	
2	Annual Adjustor Account Balance (from Schedule 4) [1,2]		$ -	
3	Paragraph 19d Balancing Account Balance (from Schedule 5) [1]		$ -	
4	Surcharge Account Balance after surcharge termination (from Schedule 6) [1]		$ -	
5	Total (Credit)/Charge Amount (Line 1 + Line 2 + Line 3 + Line 4)			$ -
6	Projected Energy Sales without E-3, E-4 and E-36 (MWh)	-		
7	Applicable Adjustor Rate for February 1, XXXX ($/kWh)			$ -
8	Amount Carried Forward to Annual Adjustor Account (Line 6 * Line 7)			$ -
9	Amount Carried Forward to Paragraph 19d Balancing Account (Line 5 - Line 8)			$ -

[1] Includes interest for January.

[2] Because the actual amount of revenue to be received in January from the adjustor rate is not available at the time of filing this schedule, the Annual Adjustor Account Balance used here contains estimated revenue for January. The difference between estimated and actual revenue for January is included in the February numbers in the new year's Annual Adjustor Account.

ARIZONA PUBLIC SERVICE COMPANY
Schedule 4
XXXX Annual Adjustor Account
XXXX XXXX
($ in thousands)

Line No.		January	February	March	April	May	June	July	August	September	October	November	December	200X January
1	Annual Adjustor Rate ($/kWh)	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
2	Retail Billed Sales Excluding E-3, E-4, E-36 Sales (MWhs) [1]	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Beginning Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Revenue True-up from January Estimate [2]		$ -											
5	Less Revenue from Applicable Adjustor Rate (Ln. 1 * Ln. 2) [3]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Monthly Interest ([Line 3 + Line 4] * [4.38% / 12]) [4]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	Ending Balance (Ln. 3 + Ln. 4 - Ln. 5 + Ln. 6)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

[1] Sales amounts are for energy billed beginning with the first billing cycle of February 2006.

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

[3] Difference between Line 1 times Line 2 and Line 5 are due to billing adjustments.

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

ARIZONA PUBLIC SERVICE COMPANY
Schedule 5
XXXX Paragraph 19d Balancing Account
XXXX XXXX
($ in thousands)

Line No.		January	February	March	April	May	June	July	August	September	October	November	December
1	Beginning Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	Amounts Removed due to Authorized Surcharge	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	Monthly Interest ([Line 1- Line 2] * [4.38% / 12]) [1]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Ending Balance (Ln. 1 - Ln. 2 + Ln. 3)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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

ARIZONA PUBLIC SERVICE COMPANY
Schedule 6
XXXX Surcharge Account
XXXX XXXX
($ in thousands)

Line No.		January	February	March	April	May	June	July	August	September	October	November	December
1	Surcharge Rate ($/kWh)	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
2	Retail Billed Sales Excluding E-3, E-4, E-36 Sales (MWhs)	-	-	-	-	-	-	-	-	-	-	-	-
3	Beginning Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Less: Revenue from Surcharge Rate (Line 1 * Line 2) [1]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Monthly Interest (Line 3 * [4.38% / 12])[2]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Ending Balance with Interest (Line 3 - Line 4 + Line 5)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

[1] Difference between Line 1 times Line 2 and Line 5 are due to billing adjustments

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

EXHIBIT
APS-71
admitted

REJOINDER TESTIMONY OF DAVID J. RUMOLO

On Behalf of Arizona Public Service Company

Docket No. E-01345A-05-0816
Docket No. E-01345A-05-0826
Docket No. E-01345A-05-0827

October 4, 2006

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REJOINDER TESTIMONY OF DAVID J. RUMOLO
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY

(Docket No. E-01345A-05-0816)
(Docket No. E-01345A-05-0826)
(Docket No. E-01345A-05-0827)

I. <u>Introduction</u>

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. David J. Rumolo, 400 North Fifth Street, Phoenix, Arizona 85004.

Q. DID YOU PREVIOUSLY FILE DIRECT AND REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REJOINDER TESTIMONY?

A. My rejoinder testimony addresses two topics that were discussed in the surrebuttal testimony of Staff Witness Erinn Andreasen. I also discuss the issue of transmission cost allocation that was raised by AECC Witness Kevin Higgins in his surrebuttal testimony.

Q. DOES YOUR SILENCE REGARDING ANY OF THE ISSUES DISCUSSED BY OTHER PARTIES INDICATE AN ACCEPTANCE OF THOSE POSITIONS?

A. No, it does not. An absence on my part of a response to a surrebuttal issue should not be taken as acceptance of any party's testimony; instead it is an indication that I maintain my position, as discussed in previous testimony.

Q. WHAT ARE THE TOPICS DISCUSSED BY STAFF WITNESS ANDREASEN THAT YOU ARE ADDRESSING?

A. I address the Rate Schedule ET-2 design issue and clarifications to Schedule 3.

II. Rate Schedules

Q. PLEASE DISCUSS THE RATE SCHEDULE ET-2 DESIGN ISSUE.

A. Ms. Andreasen notes in her testimony that the winter off-peak charges under Rate Schedule ET-2 are higher than the summer off-peak charges under the APS design proposal. She also comments that generation costs tend to be higher in summer than winter. I agree with her observation to a limited extent. On-peak generation is clearly more expensive for APS in the summer. However, that higher cost has a significant capacity cost element in addition to an energy cost element. Off-peak prices have little or no capacity element. Today, marginal generation resources are gas-fired (either through market purchases or Company-owned generation) for most hours of the year. In the winter, gas prices tend to be higher than during the summer, and off-peak electricity prices at the Palo Verde hub can be higher in winter than during the summer, due to the gas cost impacts. Therefore, it is appropriate that off-peak prices for winter electricity charged to customers be higher than off-peak summer prices. If the Commission adopts Ms. Andreasen's recommendation for lowered winter off-peak prices, it will be necessary to increase some other rate element, e.g. winter on-peak prices, to meet revenue requirements targets and would not be reflective of costs.

Q. STAFF WITNESS ANDREASEN RECOMMENDED CLARIFICATIONS TO SCHEDULE 3 LANGUAGE. DO YOU AGREE WITH HER RECOMMENDATIONS?

A. Yes, I do. Assuming the Commission approves Schedule 3 as modified, we will include Staff's changes in our tariff compliance filing at the conclusion of the case.

Q. DO YOU HAVE CONCERNS REGARDING THE SURREBUTTAL TESTIMONY OF AECC WITNESS HIGGINS AS IT PERTAINS TO THE ALLOCATION OF TRANSMISSION REVENUE REQUIREMENTS?

A. Yes. I would like to clarify a few aspects of the transmission element in our retail rates. First, the current "across the board" energy-based charge is consistent with the rate designs that were part of the Settlement Agreement that was incorporated in Decision No. 67744. We made no changes to that method in this case, i.e. the transmission element costs were allocated based on energy. Second, transmission costs are incurred by APS for retail sales based on charges found in the Open Access Transmission Tariff ("OATT"). The costs are not the result of any allocation method in a retail rate case. Under the OATT, each service schedule has a list of charges that are applicable to retail classes of service based on usage. For example, for residential service, the OATT charges are billed to APS or an energy service provider based on energy. OATT charges for general service customers without demand meters are also based on energy. The OATT charges for customers with demand meters are based on the customers' billing demands each month. Therefore "allocation" of OATT charges by applying a demand allocator, such as the 4CP allocator, does not reflect an accurate representation of how the costs are incurred to provide transmission service and is therefore inappropriate.

Q. **WOULD YOU DESCRIBE THE OATT CHARGES?**

A. Yes. There are six specific charges that are applied each month to the OATT services. The services include network integration transmission service, scheduling service, regulation & frequency service, spinning reserve service, operating reserve service, and energy imbalance service. Each month, a bill is developed based on the service schedule charges and the retail sales volumes as measured by energy sales or billing demand.

Q. **WHAT WOULD BE THE AFFECT ON CUSTOMERS' BILLS IF THE**

APS RETAIL TARIFF WAS MODIFIED SO THAT THE TRANSMISSION CHARGES REFLECTED THE CLASS OATT CHARGES?

A. For residential customers, it would increase bills by an average of approximately $0.50 per month. Bills for general service customers would decrease on average, but the impact would be dependent on each customer's load factor. In our rate case filing, we have proposed that the Settlement Agreement rate of $0.00476 per kWh be continued. However, I have no objection to converting the revenue requirements generated by the $0.00476/kWh charge to a capacity charge equivalent for customers receiving service under Rate Schedule E-34 and Rate Schedule E-35. These are the rate schedules that are applicable to customers with loads over three megawatts. I do not recommend that the demand charge method be used for general service customers with loads under three megawatts.

Q. **PLEASE EXPLAIN WHY YOU DO NOT RECOMMEND CHANGING THE CHARGE FOR GENERAL SERVICE CUSTOMERS UNDER THREE MEGAWATTS.**

A. Almost all general service customers under three megawatts are served under Rate Schedule E-32. As I noted in my Rebuttal Testimony, Rate Schedule E-32 serves a very diverse group of customers with wide load factor disparities. Shifting to a capacity charge would adversely impact lower load factor customers. I propose that the current rate design be continued until a future rate case when separating Rate Schedule E-32 into a group of size-based schedules is evaluated as recommended by Ms. Andreasen.

Q. **WHAT IS YOUR POSITION ABOUT HAVING A DEMAND-BASED CHARGE EXCEPTION FOR PARTIAL REQUIREMENTS CUSTOMERS?**

A. I am opposed to the recommendation that there be a demand-based charge exception for partial requirements customers if the Commission adopted AECC's recommendations regarding transmission cost recovery. Partial requirements customers require adequate "wire" capacity for stand-by and other services and, under the OATT, APS would pay for transmission service based on the partial requirements customer's demand. Therefore, the retail rate should also be demand based, if the transmission service for full requirements customers is demand based.

III. Conclusion

Q. DO YOU HAVE ANY OTHER COMMENTS?

A. Yes. In his rebuttal testimony, Staff Witness Jerry Anderson discusses Demand Side Management ("DSM") Performance Incentives and DSM lost revenue adjustments and describes them as duplicative. I disagree with that statement. DSM Performance Incentives are designed to encourage DSM programs. Lost revenue adjustments are designed to recognize that the utility will have fixed costs that must still be recovered over a reduced sales volume. These are very distinct concepts.

Q. DOES THIS CONCLUDE YOUR REJOINDER TESTIMONY?

A. Yes, it does.