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BEFORE THE ARIZONA CORPORATION

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IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND TO AMEND DECISION NO. 67744.	DOCKET NO. E-01345A-05-0816
IN THE MATTER OF THE INQUIRY INTO THE FREQUENCY OF UNPLANNED OUTAGES DURING 2005 AT PALO VERDE NUCLEAR GENERATING STATION, THE CAUSES OF THE OUTAGES, THE PROCUREMENT OF REPLACEMENT POWER AND THE IMPACT OF THE OUTAGES ON ARIZONA PUBLIC SERVICE COMPANY'S CUSTOMERS.	DOCKET NO. E-01345A-05-0826
IN THE MATTER OF THE AUDIT OF THE FUEL AND PURCHASED POWER PRACTICES AND COSTS OF THE ARIZONA PUBLIC SERVICE COMPANY.	DOCKET NO. E-01345A-05-0827

Arizona Corporation Commission
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EXCEPTIONS
OF
ARIZONA PUBLIC SERVICE COMPANY

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I. INTRODUCTION

Arizona Public Service Company (hereinafter "APS" or "Company") hereby submits the following Exceptions to the Recommended Opinion and Order ("Recommended Order") filed in the above consolidated dockets on April 27, 2007. Although the Recommended Order improves the timing of recovery for fuel and purchased power costs and shows innovation in its endorsement of an acceptable variant of the Company's requested Environmental Improvement Charge ("EIC"), it fails to alleviate the bulk of the financial strains that caused the Company to file this rate case in the first place. In fact, the Recommended Order: (1) does virtually nothing to address the increasingly large under-recovery of non-fuel costs; (2) recommends an allowed ROE that is insufficient and below market expectations; (3) rejects the Company's earnings-neutral proposals to improve cash flow; and (4) rejects the Company's request for an attrition allowance without adequately addressing the undisputed fact that the costs of rapid growth will prevent the Company from earning its allowed rate in coming years. APS has also identified certain inconsistencies and mathematical errors in the Recommended Order that should be corrected irrespective of the Company's substantive objections.

Finally, the Recommended Order proposes disallowances of 2005 Palo Verde outage costs that are both incorrectly calculated and that do not reflect the evidence presented by APS demonstrating that the outages in question were not imprudent and that the financial impacts of the outages were more than offset by the overall superior performance of the Company's base load generation taken as a whole.

As the following chart demonstrates, the Recommended Order rejects 95 percent of the Company's non-fuel costs included in the Company's final rate request.

Adjustments Made by the Recommended Order to the Company's Request

	APS Rejoinder Request (millions)	Recommended Order Adjustments and Disallowances (millions)	Recommended Order Increase (millions)	Recommended Order if Corrected ** (millions)
Fuel	$ 314.4	$ (31.2)	$ 283.2	$ 283.2
Non Fuel	$ 111.4	(108.5)*	2.9	7.0
Base Increase	**$ 425.8**	**$ (139.7)**	**$ 286.1**	**$ 290.2**

***Detail of Non Fuel Adjustments**
Disallowances per the Recommended Order

****Corrections**	
Interest Synchronization	$ (4.0)
Bark Beetle	(0.1)
Total Corrections	**$ (4.1)**
Contested Items:	
Pension	$ (41.2)
Reduction in ROE	(28.8)
Rate Base (Working Capital)	(7.3)
PWEC A&G	(6.3)
PWEC Maintenance	(5.7)
DSM – Conservation Adjustment	(4.9)
Stock Based Incentive	(4.5)
SERP	(3.4)
Sundance O&M	(1.1)
Lobbying Costs	(0.8)
Business Meals Expenses	(0.4)
Total Contested Items	**$ (104.4)**
***Total Non Fuel Disallowances**	**$ (108.5)**

Although individually some adjustments made by the Recommended Order may appear relatively minor, their collective impact is significant to the Company's financial well-being.

By focusing almost exclusively on more timely recovery of fuel costs to the exclusion of non-fuel costs, an adequate ROE, and the alleviation of cash flow shortfalls and earnings attrition, the Recommended Order gives the appearance of substantial financial improvement for the Company because fuel costs, by themselves, require a double-digit rate increase. But recovery of fuel costs alone is not enough to address the financial woes that have beset the

Company in recent years. Nor is it enough for the Company to be allowed a rate of return on invested equity that is below market expectations and that is insufficient to provide a just and reasonable return to the Company's investors.

Of equal or greater significance is the fact that the Recommended Order fails to acknowledge the ongoing problems of cash flow shortfalls and earnings attrition that stem largely from rapid growth. On the contrary, the Recommended Order dismisses these growth-related financial impacts on the Company by suggesting -- incorrectly -- that the Company can deal with these issues in future rate cases. In actuality, as explained in depth below, the Company can never fully recover the lost revenue and reduced earnings resulting from this growth phenomenon, and the Recommended Order's failure to provide even a partial solution to that problem is a glaring deficiency that the Commission should address.

The rate levels proposed in the Recommended Order virtually guarantee that the Company's precarious credit rating and weak financial metrics will not improve, and may even deteriorate. Although acknowledging the dire financial consequences to the Company and its customers if the Company is downgraded to "junk" credit status, the Recommended Order rejects **all** proposals to increase cash flow and address earnings attrition and suggests that credit rating issues and the overall financial health of the Company are not the Commission's concern. In this regard, the Recommended Order is in error, is out of step with sound regulatory policy, runs counter to the actions of other regulatory commissions in recent years, and perpetuates the considerable risk that the Company and its customers will be saddled with the huge financial burden of increased borrowing costs and limited access to financial markets stemming from a downgrade to "junk" credit status.

The Company respectfully urges the Commission to address these issues, adopt the Company's exceptions, and thereby help the Company meet the needs of a rapidly growing customer base under rates that are just and reasonable. In Attachment A, APS has provided the Commission with a series of proposed amendments to the Recommended Order.

II. COST OF CAPITAL AND REVENUE ENHANCEMENT

1. An Allowed ROE of 10.75%, as Proposed in the Recommended Order, is Insufficient and Will Not Result in a Just and Reasonable Return on the Company's Invested Equity.

The Recommended Order's proposal of an allowed ROE of 10.75 percent -- without any additional revenue enhancements -- will not allow APS to receive a just and reasonable return on its invested equity. Although the Recommended Order's adoption of the forward-looking PSA addresses in significant part the timely recovery of fuel and purchased power costs (Recommended Order at 63), the PSA produces no earnings for APS, thus, no refinements to the PSA can be sufficient *by themselves* to address the non-fuel cost recovery or the ROE issues that APS raised in this proceeding. It is these issues that have largely led to chronic under-earning by APS, contributed to its cash flow deterioration, and driven the Company and its customers to the very brink of "junk" credit status, with the attendant problems of even higher costs and limited access to critically needed capital to meet the growing demands of energy service in this State. The evidence in this proceeding was undisputed -- indeed, conceded by Staff and RUCO witnesses -- that APS would not actually earn its allowed ROE because of the huge capital expenditures required in coming years and the time lag associated with the eventual recovery of those expenditures in future rate proceedings. Thus, the Recommended Order consigns APS to a ROE at least 300 basis points less than even 10.75 percent – one that, if accepted by the Commission, would ensure that the Company's under-earnings and cash flow shortfalls continue for years to come.

Although fuel and purchased power costs are about 70 percent of the revenue requirements of the Company's current rate request, they account for only about 32 percent of APS's total revenue requirements. (APS Exhibit No. 80.) The balance of the increase is composed of increased non-fuel costs over 2002 levels, both operating and capital, that like fuel, are driven both by price increases in components ranging from copper wire to steel to concrete to equity capital and, perhaps to a greater extent, by the continued rapid growth of the Company's customers -- a growth that demonstrably does not "pay for itself." (*Id.* at 2, 4; APS Exhibit No. 5 at 9-10 [Brandt]; *id.* at Attachment DEB-1RB; Tr. Vol. IV at 782-85; APS

Exhibit No. 59.) APS's need in recent years to fund a huge capital expenditure program coupled with the regulatory lag in recovering those expenses as part of rate base, has prevented APS from maintaining a level of earnings commensurate with its allowed ROE. (APS Exhibit No. 4 at 29-31 [Brandt].) Even Staff and RUCO witnesses agreed that the "attrition" of earnings resulting from the lag in recovering capital expenditures is causing APS to under-earn its allowed rate of return. (Tr. Vol. XVII at 3267 [Parcell]; Tr. Vol. X at 2090-91[Hill].)

Just as important, no party presented any evidence that APS could earn the ROE recommended by that party when rates become effective in this case.

The Recommended Order errs by stating that "it is not the rate of return or the level of revenues received that must be just and reasonable, but the rates and charges." (Recommended Order at 65.) In fact, the two concepts (just and reasonable rates and **earning** a reasonable return) are inseparable. Under applicable constitutional and regulatory principles, "rates cannot be considered just and reasonable if they fail to produce a reasonable rate of return." *Scates v. Arizona Corporation Comm'n*, 118 Ariz. 531, 533-34, 578 P.2d 612, 614-15 (Ariz. App. 1978); *see also Bluefield*, 262 U.S. at 692 ("A public utility is entitled to such rates as will permit it to earn a return on the value of property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties").

APS has demonstrated that it substantially under-earned its allowed ROE for the last several years. (APS Initial Brief Exhibit 4; APS Exhibit No 5, Attachment DEB-10RB [Brandt].) The evidence showed that, over the more than three-year period from March 31, 2003 to June 30, 2006, APS consistently under-earned its allowed rate of return by as much as half, resulting in a $134,000,000 annual earnings shortfall as of June 30, 2006, relative to APS's current allowed rate of return of 10.25 percent. (*Id.*) Over this period, APS's actual ROE eroded from 8.4 percent for the twelve months ending March 31, 2003, to 5.7 percent for the twelve months ending June 30, 2006. (*Id.*) Nothing in the record suggests that this trend will be reversed by the rate changes in the Recommended Order. On the contrary, **all** the evidence supports the proposition that attrition will continue.

APS presented strong and compelling evidence that its proposed ROE of 11.5 percent was both consistent with market expectations and necessary to address, at least in part, consistent earnings shortfalls. (APS' Initial Brief at 20-25.) Although the proposed 10.75 percent ROE in the Recommended Order is an improvement over the status quo, it does not go nearly far enough. At best, the ROE proposed in the Recommended Order is a compromise between the extremely low ROE proposed by RUCO (9.25 percent), the no-increase-from-current-ROE proposed by Staff (10.25 percent), and the realistic, market-based ROE proposed by the Company (11.50 percent). The Commission should not allow an apparent compromise to substitute for the hard evidence presented by the Company and the reality of the capital marketplace in which the Company currently operates.

Knowing that the regulatory process in Arizona can entail at least a year or two before a new rate order is implemented, it is not enough to suggest, as the Recommended Order does, that APS need only file another rate case in order to timely recover capital expenditures and thereby avoid the effects of earnings attrition and related cash flow pressure. (Recommended Order at 66.) The "catch-up" concept premised in the Recommended Order is completely illusory because the Company never recovers an earnings shortfall; it is lost forever. In the wake of compelling evidence in this proceeding that APS has consistently under-earned its allowed ROE and will continue to do so for the foreseeable future because of the attrition of earnings resulting from huge capital expenditures and consistently rising non-fuel costs, the Company submits that the Commission should take appropriate measures to limit the impact of such earnings attrition and thereby afford the Company a reasonable opportunity to earn its allowed ROE. The starting point for doing so is to authorize the more realistic and fair ROE of 11.5 percent as proposed by the Company. Even that authorized ROE will only produce an earned ROE in the mid-7 percent range in 2008 – the first full year rates in this case will be effective. (APS Exhibit 5 at 28 [Brandt].) (APS Proposed Amendment No. 1 attached hereto.)

2. <u>The Recommended Order's Failure to Implement any of the Revenue Enhancement Proposals Made by the Company Will Cause Continued Cash Flow Problems, Will Depress the Company's Already Weak Financial Metrics, and Will Result in Continued Earnings Attrition</u>.

A. The Company's Cash Flow Needs and Weak Financial Metrics Will Not Materially Improve if the Rates Proposed in the Recommended Order Are Approved by the Commission.

By essentially accepting, with minor modification, the rate proposal put forth by Staff, (*i.e.*, recovery of fuel costs but virtually no recovery of non-fuel-related expenses), the Recommended Order implicitly rejects the unrefuted testimony of Mr. Brandt and Mr. Fetter that the Staff proposal carries with it a very high risk that the Company's financial metrics and overall credit outlook will remain below or precariously close to non-investment ("junk") grade and will present a substantial risk of a downgrade of the Company's credit rating to "junk" status. Mr. Brandt (with 25 years of experience in the electric utility industry and extensive experience dealing with rating agencies) and Mr. Fetter (a former rating agency official and a former Chairman of the Michigan Public Utility Commission) were the two most knowledgeable witnesses on this subject. Although the Recommended Order acknowledges Mr. Brandt's testimony that the Staff proposal would produce FFO/Debt ratios in 2007 and 2008 that **remain below** S&P's investment grade category (Recommended Order at 52), the Recommended Order contains no discussion or analysis as to why that is an acceptable result for the Company and its customers.

Instead, the Recommended Order concludes that the Commission must rigidly adhere to the "historical test year cost-of-service analysis" in setting rates and that "it would not be constitutional for us to set rates based upon the achievement of certain targeted financial credit metrics or return on equity." (Recommended Order at 67.) On that basis, the Recommended Order concludes "that no additional adjustments or modifications to our traditional ratemaking method are necessary or appropriate to set just and reasonable rates." (Recommended Order at 68.)

The Recommended Order's findings and conclusion in this regard are neither analytically sound nor legally correct, and should be rejected outright. By implicitly accepting the notion that rates resulting in cash flow problems that produce non-investment grade financial metrics and potentially a "junk" credit rating for the Company are somehow "just and reasonable" (as the Constitution requires they be), the Recommended Order turns the rate-making process on its head and ignores the fundamental principle that the Commission can and should exercise its broad discretion to ensure that rates are just and reasonable **under all the facts and circumstances,** which necessarily includes consideration of the Company's ROE, its credit status, and its overall financial integrity. The United States Supreme Court has made this point abundantly clear:

> The rate-making process . . . *i.e.*, the fixing of "just and reasonable" rates, involves a balancing of the investor and consumer interests. . . . By that standard, the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risk. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and attract capital.

Federal Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591, 603 (1942).[1]

Contrary to what the Recommended Order states, a Company's financial metrics and credit rating are often considered by regulatory agencies engaged in ratemaking and even this Commission has done so in the past. (*See* case citations and discussion in APS Initial Brief at 8-11.) In fact, the Company is **required** by Commission rules and regulations to submit such information in a rate case and in monthly filings with the Commission. Taking such credit-rating and related financial factors into consideration is especially warranted in the current

[1] The Recommended Order (at page 60) purports to distinguish the *Hope* case and suggests that the *Hope* case does not apply in Arizona, citing to an argument made by Staff. But the *Hope* case -- a constitutional pronouncement of the United States Supreme Court -- certainly does apply in Arizona, as it does in every other state. The language of the Arizona Supreme Court in the *Simms* case (cited in the Recommended Order) that *Hope* could not be used by the Commission to support the kind of fair value determination at issue in the *Simms* case is of no relevance here. There are two aspects to the *Hope* decision: (1) a statement of the constitutional principles that must be followed to ensure that ratemaking comports with due process, and (2) a discussion of the application of those constitutional principles to the particular statute at issue in *Hope* where the statute did not prescribe the methodology for ascertaining a reasonable rate. The *Hope* court made clear that the manner in which a regulatory agency arrives at "just and reasonable rates" is not constitutionally significant as long as the "end result" is consistent with constitutional requirements. (320 U.S. at 603.) In *Simms*, the Arizona Supreme Court did not purport to disavow the substantive constitutional principles set forth in *Hope* (nor could it). Rather, the *Simms* court merely held that where, as in Arizona, a specific method (*i.e.*, fair value of a company's property) is prescribed, that portion of *Hope* that states that any method is permissible (as long as it produces constitutionally mandated results) did not apply in Arizona. That is a far cry from saying that *Hope's* constitutional requirements do not apply in Arizona. Both Staff witness Parcell and RUCO witness Hill relied on the *Hope* case (and the similarly pertinent *Bluefield* case) in their written testimony. Thus, in assessing the fair value of the Company's property, it is both appropriate and constitutionally required for the Commission to determine whether the proposed rates provide a reasonable return on equity, allow the Company to maintain its credit, and otherwise allow the Company to maintain its financial integrity. Those are elements of the constitutional due process analysis, not optional elements of a chosen methodology for arriving at "just and reasonable" rates.

credit-rating climate where, as described by Mr. Fetter, recent instability in the financial markets and increased importance of a utility's financial profile make it much more likely that a company's credit rating will be downgraded if satisfactory financial metrics are not maintained. As Mr. Fetter explained, the current credit-rating climate requires a regulatory commission to engage in "proactive regulatory behavior" to ensure that the closer scrutiny now being given to a regulated utility's financial metrics does not result in a credit downgrade that produces dire financial consequences for both the utility and its customers -- the kind of dire financial consequences that Nevada Power and its customers have had to endure as a result of that company's downgrade to "junk" status a few years ago. (APS Exhibit No. 23 at 16-19 [Fetter].)

If accepted by the Commission, the rates proposed by the Recommended Order would produce an FFO/Debt ratio at year end 2007 near non-investment grade territory, likely falling below 18%, into non-investment grade territory near the end of 2008. Such financial metrics present the very real possibility, as Mr. Brandt and Mr. Fetter both testified, that APS will not be able to maintain its investment grade credit rating (currently at BBB-minus -- just one step away from "junk" status). At a minimum, such financial metrics leave APS on the precipice of "junk" credit status, which Mr. Fetter described as "a very dangerous place to be." (Tr. Vol. VI at 1278.) The Company's return on equity would at best hit 7% in 2007, and then continue its downward trend into the 6% range in 2008, as earnings attrition continues due to the cost of serving new and existing customers rising faster than revenue growth from new and existing customers.

After discussing the demonstrable lag between the Company's growth expenditures and the recovery of those expenditures, the Recommended Order erroneously states that "APS failed to demonstrate that the near-term costs of customer growth are greater than the increased revenues generated by that growth." (Recommended Order at 65.) That statement simply cannot be squared with the evidence in the record. As Don Brandt explained, the Company's expected customer growth requires the Company to make "massive capital expenditures" in order to enable APS to increase its load capacity to meet the rapidly growing demand, averaging $900 million a year for the next five years (comparable to the growth in the last several years). (Tr. Vol. IV at 783.) The increased revenue generated by serving a larger customer base decidedly does not provide sufficient revenue to offset the increased costs associated with serving that customer base in the short term. To the contrary, over a three-year period, the growth in expenses and capital investment exceeds the growth in revenues by a factor of approximately one-third. (*Id.* at 783-84.) APS Exhibits 27, 59 and 77, and the testimony of the various APS witnesses relating to those exhibits provide ample and unrefuted evidence that there is a significant lag between the costs of growth and the recovery of those costs in rates, and that such lag has a substantial adverse impact on the Company's available cash flow and is the major cause of the large gap between its earned return on equity and its allowed return on equity. (APS Exhibit No. 5 at Attachment DEB-10RB [Brandt].) Moreover, the resultant loss in earnings is irretrievable. Thus, this "regulatory lag" not only results in earnings attrition (which will be addressed in more detail below) but also depresses the Company's financial metrics because of the negative impact on cash flow. (*Id.*)

The Recommended Order further errs by suggesting that the financial impact of growth on the Company's cash flow and earnings requires "a breakdown comparing the cost of providing service to a specific class of customer now and at some future point." (Recommended Order at 64.) There is no need to conduct such an analysis because the distinction between increased costs to serve existing customers is irrelevant to the issue of attrition. What can be determined, however, and what was amply demonstrated by APS during the hearing, is that current and anticipated expenditures to meet the requirements of APS customers have a significant adverse effect on APS's cash flow and earnings. Moreover, APS was able to quantify that adverse effect with more than sufficient and reasonable precision. (Tr. Vol. IV at 783-84 [Brandt].) As Mr. Brandt explained:

> By the time those [new] rates are in effect [for two years], the additional $2 billion or so of capital investment, plus the increase in operating expenses over that period of time, it's virtually impossible to implement those rates a year or a year and a half down the road and have the company earn a reasonable return on investment because of the fact that over the ensuing year to year and a half period of time, the rate of

growth of expenses, including the costs associated with capital expenditures, has outstripped the rate of growth of revenues.

Finally, the Recommended Order incorrectly asserts that "APS's cash flow problems will be sufficiently addressed through our adoption of Staff's forward looking PSA and the higher base cost of fuel and purchased power." (Recommended Order at 63.) While it is true that the forward looking PSA and the higher base cost of fuel are significant improvements that will somewhat increase the Company's available cash flow, they do nothing to deal with the lag in recovering the huge current capital and O&M expenditures necessary to be ready for future growth of the Company's customer base. Indeed, the above-quoted statement in the Recommended Order is directly contrary to the only testimony on point at the hearing. (Tr. Vol. IV at 783-84 [Brandt].)

In short, the Recommended Order fails to recognize, and certainly fails to adequately address, that the rates proposed in that Order will not materially improve the Company's financial metrics (particularly the highly important FFO/Debt ratio and return on equity) and will cause continued cash flow and earnings problems for the Company. With at least one Commissioner having specifically asked the Company to address ways to improve the Company's cash flow and financial metrics,[2] it is even more important for the Commission to take a second look at the financial impact and financial consequences of the proposed rates in the Recommended Order and make adjustments to ensure that the Company's precarious credit rating and other financial indicators are not just maintained but rather are improved under the Commission's rate order. Anything less is contrary to sound regulatory ratemaking policy and raises serious due process questions if the rates fall short of those sufficient to allow the Company "to maintain its credit and attract capital." *Hope*, 320 U.S. at 603.

B. The Company's Precarious BBB-Minus Credit Rating is Not Likely to Improve, and Could Result in a Downgrade, if the Rates Proposed in the Recommended Order Are Approved by the Commission.

With financial metrics at or below the minimum required for an investment grade credit rating, there can be no doubt that, if the rates proposed in the Recommended Order are

[2] *See* letter dated July 21, 2006 from then Chairman Hatch-Miller (APS Exhibit No. 5 at Attachment DEB-11RB.).

accepted by the Commission, the Company's ability to maintain an investment grade credit rating -- already standing at S&P's lowest possible level and carrying a negative outlook by Moody's -- will not improve. In a short release dated April 30, 2007, S&P indicated that the rates proposed in the Recommended Order, if adopted, "would be modestly beneficial for cash flow, but unlikely to result in an improvement in the current [credit] ratings." (Attachment B.) Similarly, Moody's stated in a release dated May 7, 2006, that it was continuing its negative outlook for the Company and that the Recommended Order "would likely result in limited 'headroom' or financial flexibility for APS and Pinnacle to address any unanticipated adverse developments such as increased expenses due to significant operational difficulties, material cost overruns on capital expenditure programs or prolonged rate case outcomes." (Attachment C.)

The only question is whether those rates, which only "modestly" improve the Company's cash flow, will result in a further downgrade of the Company's credit rating to "junk" status. Mr. Brandt testified that acceptance of Staff's rate proposal -- which is very close to what the Recommended Order proposes -- would carry a very substantial risk (perhaps as high as 80 or 85%) that the Company would be downgraded to "junk" status by one or both of the two major credit rating agencies. (APS Initial Brief at 13.) Mr. Fetter agreed with this assessment. (*Id.* at 14-15.) And, of course, such a downgrade would limit the Company's access to capital markets and increase the Company's borrowing costs by as much as $1.3 billion over the next ten years. (APS Initial Brief at 17.)

The Commission should not turn a blind eye to this downgrade possibility and the dire financial consequences that it would produce for the Company and its customers. The Recommended Order seems to take the position, as one of RUCO's witnesses put it, that a downgrade of the Company's credit rating to "junk" is just "a situation we will deal with when we get there." (Tr. Vol. X at 2130 [Hill].) But such a downgrade has real and dire consequences that cannot be so cavalierly dismissed and from which it would be extremely difficult for the Company and its customers to recover.[3]

C. *CWIP in Rate Base and Accelerated Depreciation Recovery Are Sensible and Sound Steps to Improving the Company's Cash Flow without Any Resulting Increase in the Company's Earnings.*

Given the obvious detrimental impact of the rates proposed in the Recommended Order on the Company's financial metrics and credit standing, the Recommended Order's complete rejection of the revenue enhancements suggested by the Company -- particularly the earnings-neutral suggestions of CWIP in rate base and accelerated depreciation -- is unwarranted. Although recognizing that the Company's cash flow would improve (without any increase in the Company's earnings) and the Company's FFO/Debt ratio would increase if the Commission included in its rate order the suggested enhancements of CWIP in rate base and accelerated depreciation, the Recommended Order rejects these suggestions on the flawed premise that "it would not be constitutional for [the Commission] to set rates based upon the achievement of certain targeted financial credit metrics or return on equity." (Recommended Order at 67.) That statement misapplies the law and fundamentally mischaracterizes the nature and purpose of CWIP in rate base and accelerated depreciation.

First, it is worth re-emphasizing that CWIP in rate base and accelerated depreciation produce **no increased earnings** for the Company; they merely increase cash flow by accelerating cost recovery. Indeed, both of these revenue enhancement tools address the timing of cost recovery, not the entitlement to that cost recovery. Thus, they are recognized methods for a regulatory commission to address cash flow shortfalls or regulatory lag in the

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[3] As Mr. Fetter explained (citing to the recent downgrades of Nevada Power and Central Vermont Public Service to "junk" credit status):

> [O]nce a company goes below investment grade, it is not like turning on a dime, and the Commission by itself cannot divine decisions that return investment grade immediately. Even if all the parties in this room are in agreement, it could not bring APS back from the fall off the cliff within a day or a month or a week. It's a long process. And Nevada Power is now about three or four years into being below investment grade. Central Vermont accepts that even with a positive regulatory agreement, if approved by the commission, that they are looking at a two to three year time period to get back. And so it . . . cannot be underemphasized the danger of going below investment grade.

(Tr. Vol. VI at 1288-89; *see also* APS Exhibit No. 23 at 24 [Fetter].)

recovery of capital expenditures, and even this Commission has used these tools in the past. As Mr. Wheeler stated at the hearing regarding this Commission, he was aware of "at least three [Arizona] examples where construction work in progress was allowed for the company when it was facing challenges to its financial health and where it was at risk for ratings downgrade." (Tr. Vol. I at 106 [Wheeler]; *see also* APS Exhibit No. 5 at 25 [Brandt]; Decision No. 54204, October 11, 1984.) Just in the last two years, both the Colorado Public Utility Commission and the Missouri Commission used combinations of CWIP in rate base and accelerated depreciation to deal with recurring cash flow problems of the utilities in question and the adverse impact that such cash flow problems was having on the credit metrics and credit ratings of those utilities. (APS Initial Brief at 28-29; APS Exhibit No. 23 at 25-28 [Fetter].)[4]

Even Staff's own witness, Mr. Dittmer, recognized the benefits of an allowance for accelerated depreciation (and the same can be said for CWIP in rate base):

> Because there would be an increase in the recording of depreciation expense that would be equivalent to the increase in revenues being collected, the Company would not experience any reduction in earnings attrition. However, depreciation is a "non-cash" expense. Accordingly, the recovery of depreciation expense on an accelerated basis would improve the Company's cash flow metrics.

(Staff Exhibit No. 37 at 16 [Dittmer].)

Moreover, there is absolutely no discussion in the Recommended Order of the fact that then Chairman Hatch-Miller requested the Company to propose methods for improvement of the Company's cash flow and related financial metrics such as its FFO/Debt ratio. To dismiss these proposed revenue enhancements of CWIP in rate base and accelerated depreciation on the theory that they are not needed or allegedly would be contrary to law, as the

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[4] Commenting on the inclusion of CWIP in rate base by the Colorado Commission , S&P stated:

> This is a major step forward in eliminating the tug-of-war over cost recovery that, in the past, has plagued the credit of so many utilities when the time comes to build again.

(APS Exhibit No. 23 at 28 [Fetter], citing *S&P Research: PS Colorado Garners Support for Credit Quality Up-Front; a Viable Model for the Electric Industry*, March 29, 2005.)

Recommended Order does, is to suggest -- erroneously -- that the Commission has no power to use them and that it was improvident for the Chairman to ask that they be proposed and considered.

Simply put, CWIP in rate base and an allowance for accelerated depreciation are sensible, earnings-neutral mechanisms for the Commission to address the recurring cash flow problems and related adverse credit impacts that APS has experienced in recent years and will surely experience in coming years as a result of its large capital expenditure obligations. The forward-looking PSA and the increased base cost for fuel will not be enough to deal with the Company's expected cash flow needs. Thus, the Commission should not adopt that portion of the Recommended Order that rejects these revenue enhancement mechanisms and should instead adopt one or more of the attached amendments proposed by APS.

(APS Proposed Amendment Nos. 2, 3 and 4 attached hereto.)

D. The Recommended Order Erroneously Rejects an Attrition Allowance on the Flawed Theory that an Earnings Shortfall Can Be Remedied by Filing Future Rate Cases.

Like CWIP in rate base and accelerated depreciation, an attrition allowance is a regulatory tool that allows the Commission to address the very real fact that the Company will be unable to earn its allowed rate of return because of the lag between the Company's current need to expend huge sums for expansion of plant and equipment to meet the needs of a rapidly growing customer base and the eventual recovery of those sums in future rate base adjustments approved by the Commission. (APS Exhibit No. 5 at 28 [Brandt].) This Commission has previously granted the Company an attrition adjustment for just such reasons. *See* Decision No. 51009, (May 29, 1980). But notwithstanding undisputed evidence in this proceeding that the Company had substantially under-earned its allowed ROE of 11.25 percent prior to 2005 and its allowed ROE of 10.25 percent in 2005 and 2006, and that the Company would continue to under-earn its allowed ROE in coming years (APS Exhibit No. 5 at 28 [Brandt]), the Recommended Order rejects the Company's proposed attrition allowance on the theory that the Company can deal with such earnings shortfalls in a future rate case.

The fundamental problem with the Recommended Order's logic in this regard is that it fails to recognize that what the Recommended Order suggests the Company do in the future is precisely what the Company is attempting to do **in this rate case** -- *i.e.*, deal with chronic under-earning of its allowed ROE due to the lag associated with recovery of large capital expenditures. Nowhere in the Recommended Order is there any explanation as to how, in reality, the Company is supposed to rectify even prospectively years of demonstrated under-earning of its allowed ROE. As a practical matter, the Company cannot do so because the ratemaking process in Arizona absent a specific provision generally does not allow, absent a specific provision, for recoupment of past earnings shortfalls. As Mr. Brandt explained:

> As a matter of fact, it is growth itself and the capital, the massive capital expenditure program and the regulatory lag that impacts that capital expenditure program that is the source of the cash flow problem and the earnings erosion. I mean the way it works under traditional historic test year, we virtually are guaranteed there is no possible whatsoever of earning our allowed rate of return or even coming very close ... Unless the Commission addresses it in some way, that earnings erosion is going to continue in the future.

Tr. Vol. XXIV at 4581. No witness testified to the contrary, and no witness provided any support for the assertion in the Recommended Order that APS can somehow address this issue of earnings attrition in a future rate case.

The Recommended Order compounds its incomplete analysis of this issue by stating that "attrition in and of itself, is not especially significant. It is a normal, expected, and to some degree, necessary, component of the rate setting process." (Recommended Order at 66.) Attrition is not "normal" or "necessary" but rather a red flag that the rate-setting process has not functioned properly. Setting inadequate rates that will not produce the allowed return is a regulatory failure, not a desired result. Moreover, even assuming the Recommended Order's assertion has some validity in the ordinary rate-setting circumstance -- one in which a company is **not** chronically experiencing significant earnings attrition due to huge capital expenditures the Company is required to make in order to meet the demand of a customer base that is growing at unprecedented levels -- the statement in this instance ignores the reality that this is not the "normal" case where "some degree" of earnings attrition might be expected to occur. The undisputed evidence here is that the Company has consistently under-earned its allowed ROE over the last 3 to 4 years by thirty to fifty percent, and can be expected to do so in coming years because of the growth phenomenon with which its is faced.

From a pure constitutional-requirement standpoint (*i.e.*, the requirement that an allowed return on invested equity must be just and reasonable), serious questions are raised when there is acknowledgement by Commission Staff's own witness that he has "no reason to believe that APS would necessarily earn its authorized rate of return" (Tr. Vol. XVII at 3267 [Parcell]) and yet the Commission fails to address that very issue in the ratemaking process. By describing an attrition allowance in this case as an "artificial increase in [the Company's] rate of return" (Recommended Order at 66), the Recommended Order begs the very question that prompted the Company to seek an attrition allowance in the first place -- *i.e.*, will the Company truly have a reasonable opportunity to earn the allowed ROE of 10.75 percent proposed in the Recommended Order or some other ROE set by the Commission given the unquestioned earnings impact that will result from the lag associated with the future recovery of huge current capital expenditures? If the answer to that question is "no" (and it surely must be under the evidence presented in this proceeding), then a just and reasonable rate level has not been set.

E. The Recommended Order's Other Arguments Against the Need for an Attrition Adjustment are Not Valid.

The Recommended Order makes several assertions why it does not believe the Company's projections of earned returns under the various rate proposals herein are not "reliable." None of these assertions is supported by the record.

<u>Recommended Order Assertion No. 1</u>: "APS' projected financial information failed to properly account for this effect [of changes to the PSA] . . ." *Id.* at 63.

All of the Company's financial projections fully accounted for the proposed changes to the PSA. Moreover, none of these changes could or did impact the Company's projected ROE, and thus the need for an attrition adjustment. In addition, Mr. Brandt testified that the financial forecast and other projected financial information presented by the Company in this proceeding were prepared using the same forecasting methodology that the Company uses in the ordinary course of business, in its regular dealings with rating agencies and financial analysts, and in its filings with the SEC and other government agencies (Tr. Vol. IV at 769-72 [Brandt].) (APS Reply Brief at 4.)

<u>Recommended Order Assertion No. 2</u>: "APS has not provided such a breakdown comparing the cost of providing service to a particular class of customer now and at some future point." *Id.* at 64.

As APS understands the above statement, the Recommended Order criticizes the Company for not distinguishing between increasing costs attributable to new customers and increased costs to serve existing customers. This criticism is repeated at the bottom of page 64 and the top of page 65. However, the Recommended Order misses the point. If cost of service, *i.e.,* revenue requirements, is increasing faster than revenues, attrition to earned return must necessarily occur. In fact, that is the very definition of attrition. The reasons for these increases in revenue requirements, whether they be growth, inflation, or simply the replacement of old depreciated plant with new plant, is irrelevant to the existence and measurement of attrition.

<u>Recommended Order Assertion No. 3</u>: "The exhibits presented by APS in support of its argument are very general and do not include an analysis of offsetting economies of scale or other efficiencies that will occur as fixed costs are spread over more customers." *Id.*

This statement is invalid for at least two reasons. First, the APS projections of financial results in 2007 and 2008 **do** reflect whatever "economies of scale and other efficiencies" as are anticipated to exist during those periods. Second, if plant costs per customer are increasing (APS Exhibit Nos. 59 and 77), there are, by definition, no economies of scale. If such economies did exist and could offset the cost of future plant additions, one would see **declining** plant, and hence fixed costs, per customer.

<u>Recommended Order Assertion No. 4</u>: "including demand charges in the PSA significantly addresses any attrition costs…"

Including demand costs in the PSA cannot to **anything** to address attrition. The PSA produces no earnings and cannot affect ROE. In fact, the mechanics of the PSA insure that any reduction in per kWh costs attributable to spreading fixed demand charges over an expanding base of customers and sales is flowed through to APS customers rather than create a potential partial offset to attrition.

<u>Recommended Order Assertion No. 5</u>: "...the [APS] projections were prepared on a total company basis, not on the ACC Jurisdictional basis used to set [retail] rates." *Id.* at 61.

In his Supplemental Testimony, Staff witness Dittmer calculated a revenue deficiency for the Company's non-jurisdictional activities during the historical test period of some $50,000,000. (Staff Exhibit No. 39 at 8 [Dittmer]; Staff Exhibit No. 40, Supplemental Schedule JRD-1 [Dittmer]). Aside from the fact that this assertion at best identifies $50,000,000 of what is a more than $120,000,000 problem, the forecasted data used by APS for 2007-2008 does **not** reflect such a level of revenue deficiency from non-jurisdictional operations.

There was a loss in unregulated trading activities of some $15,000,000 that was originally included by accident in APS's jurisdictional test period operations. Yet, Mr. Brandt testified that on a going-forward basis, these non-jurisdictional activities would be profitable and that is what is reflected in the forecasts for 2007-2008. (Tr. Vol. III at 44-45 [Brandt]).

Staff witness Dittmer further agreed that in addition to transmission, the Company had non-jurisdictional sales to small "full-requirements" wholesale customers – the so-called "Majority Districts" and the Town of Wickenburg. (Tr. Vol. XXII at 4237-39 [Dittmer]). These wholesale power agreements were amended subsequent to the historical test period, thus eliminating from the forecasts for 2007-2008 some $19,000,000 of the historical under-recovery in non-jurisdictional costs identified by Mr. Dittmer. (Tr. Vol. XXIV at 4602-04 [Brandt]). Thus, the portion of Mr. Dittmer's estimated historical under-collection of non-jurisdictional costs that could remain in 2007-2008 for alleged transmission service revenue deficiency is no more than $14,000,000 to $18,000,000. (Tr. Vol. XXIV at 4604 [Brandt]).

Nearly half of this potential transmission revenue shortfall is tied to the PacifiCorp seasonal exchange agreement – an agreement previously approved by this Commission as providing net benefits to APS's retail customers. *See* Decision No. 57459 (July 11, 1991). In sum, the contention that it is insufficient non-jurisdictional revenues that are at the heart of the Company's financial difficulties, or are even a significant element of those difficulties, simply does not withstand scrutiny and is not a basis for ignoring the dire consequences of inadequate rate relief in this proceeding.

In short, there is no reason to believe that the Company's financial forecasts and other projected financial information presented to the Commission in this proceeding are unreliable or do not accurately reflect the financial impact on the Company of each of the various rate proposals that have been made in this proceeding.

Thus, the Commission should reject the analysis in the Recommended Order regarding the Company's request for an attrition allowance in this case, and the Commission should take appropriate measures to ensure that the Company actually has a reasonable opportunity to earn the allowed ROE that the Commission finds to be just and reasonable. Under the present facts and circumstances, that can best (and perhaps only) be accomplished through the inclusion in the Commission's rate order of the attrition allowance discussed in the testimony and in APS' Initial Brief.

(APS Proposed Amendments Nos. 2 and 5 attached hereto.)

III. OPERATING INCOME ADJUSTMENTS

1. <u>Administrative and General Expense Associated with the Generating Units Acquired by APS from Pinnacle West Energy Corporation</u>.

The Recommended Order disallows nearly $6.3 million in administrative and general ("A&G") expense allocated to the five generating units acquired by APS from Pinnacle West Energy Corporation ("PWEC") pursuant to Decision No. 67744. (Recommended Order at 19.) Because this acquisition took place during the test year, it was necessary to annualize the two months of actual A&G expense included in the test year to reflect a full year's A&G expense related to these five generating units. As explained by APS witness Rockenberger and acknowledged by the Recommended Order, this A&G expense was incurred in support of the generating units and should be charged to the affiliate that owns the generating units. Prior to the APS asset acquisition, the A&G incurred in support of these units was being charged to PWEC. Accordingly, when APS acquired the generating units, the A&G incurred to support these generating units was appropriately charged to APS. Neither Staff nor RUCO took any exception to the Company's proposed adjustment for A&G expense.

The Recommended Order's only argument in support of this significant disallowance of actual APS costs is that APS testimony in the prior rate case indicated a smaller amount of A&G associated with the PWEC units. However, the Recommended Order ignores the fact that the A&G figures cited in the Company's previous testimony were for a 2002 test period – some three years prior to the present test year and now more than four and a half year's ago.[5] That 2002 test year was also well prior to the transfer of the PWEC units to APS (or even, in some instances, their completion) and thus reflected a period when more A&G expense was allocated to PWEC and less to APS for the reasons explained below.

It is important to understand that A&G is an allocated expense for costs incurred by **both** APS and its parent corporation, Pinnacle West Capital Corporation ("Pinnacle West") for overall corporate governance and shared services such as accounting, tax, legal, HR, etc. The allocation of these costs to any particular affiliate depends on the direct activities performed in support of the affiliate and an indirect cost allocation based on the relative debt and equity investment by Pinnacle West in each subsidiary, and complies with the Policy and Procedure No. 1 to the APS Code of Conduct, which was approved by the Commission in Decision No. 68741. The transfer of the PWEC generation to APS, along with the associated increase in APS equity and employees and corresponding decrease in Pinnacle West's equity investment in PWEC (as well as the decline in PWEC employees) appropriately allocates a greater percentage of overall A&G to be allocated to APS. In other words, the shrinking

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[5] The Recommended Order contends this represented the Company's position in "late 2004." However, by that time, APS had entered into a settlement of its previous rate case, and any attempt to update the adjustments proposed in its original June 2003 filing in that proceeding would have been both inappropriate and pointless.

scope of PWEC's activities (which have now ceased altogether) and the expanding scope of APS's, as reflected in the transfer of all but one of PWEC's assets to APS during the test year, would increase APS A&G expense even if the total APS/Pinnacle West A&G had remained constant.

A simple example should help to illustrate this point. Assume there is total A&G of $1 million, half of which is allocated based on investment and half on employees. Prior to the transfer of the PWEC generation, Pinnacle West had, say, $1 billion invested in APS, $400 million in PWEC, and $100 million in other affiliates. APS had, for illustrative purposes, 1000 employees, PWEC 200, and 100 in all other affiliates.

Prior to the transfer, 2/3 of the $500,000 allocated on the basis of investment would go to APS (approximately $334,000), with the balance going to PWEC and other affiliates. Of the $500,000 allocated on the basis of employees, 10/13 (approximately $385,000) would go to APS, with the balance going to PWEC and the other affiliates. The total A&G expense for APS would be $619,000.

Subsequent to the transfer (which for simplicity will assume that it encompassed all of PWEC's investment and employees), APS would now comprise 14/15 of total investment, or roughly 93%, and have 12/13 (also about 93%) of the employees and would therefore be allocated approximately 93% of the A&G, or $930,000. Thus, A&G expense would increase for APS even if total A&G had remained constant since the 2002 test period used in the prior APS rate case.

It is also significant that the Recommended Order lists APS A&G expense among the "uncontested adjustments." (Recommended Order at 40.) If, with the exception of the adjustments made by APS and discussed at that section of the Recommended Order, total APS A&G expense is "uncontested," then any amount of that expense not specifically attributed to the acquisition of the PWEC generation units would nonetheless be allocable to APS using the allocation procedures described above and not challenged by **any** party. Therefore, they should be permitted as a test period expense, as proposed by the Company and agreed to by Staff and RUCO.

APS Proposed Amendment No. 6 would amend the Recommended Order to permit recovery of this $6.3 million in legitimate A&G costs. These prudently-incurred costs (and no party has alleged otherwise) do not simply disappear and to effectively attempt to allocate them back to a now non-existent PWEC results in their disallowance, plain and simple.

2. Underfunded Pension.

APS continues to believe that addressing the underfunded pension liability issue today and in the manner proposed by the Company is both prudent and in the best interests of customers. APS recognizes this is a policy issue for the Commission and one that has only marginal impact on the earnings and other financial metrics of the Company that must necessarily be the primary focus of its Exceptions. Correspondingly, APS will propose no amendment to this portion of the Recommended Order.

3. SERP.

The Recommended Order disallows some $4.7 million in Supplemental Executive Retirement Plan ("SERP") expense. (Recommended Order at 26-27.) The adjustment is based on a RUCO recommendation that cites the following rationales: (1) the APS employees participating in this plan are "already generously compensated for their work;" (2) the expense "is not a necessary cost of doing business;" and (3) the Commission rejected the inclusion of SERP expenses in Decision No. 68487 for Southwest Gas Corporation ("Southwest").

APS presumes that neither RUCO nor the Recommended Order is contending that the affected APS employees are themselves not a "necessary cost of doing business," since neither has suggested that these employees' cash compensation be eliminated from cost of service. Therefore, one must examine whether this particular component of their non-cash compensation (retirement benefits) is itself excessive or whether, in combination with the remainder of their compensation, results in total compensation for such employees being excessive.

SERPs are routinely made available by all companies, including utilities, that otherwise offer "qualified" benefit programs. (APS Exhibit No. 5 at 62-63 [Brandt]). There has been no allegation that APS's program is out of line with these other retirement programs. Neither has there been any evidence that overall management compensation is excessive (and indeed, in APS Exhibit No. 51 [Gordon], an expert executive compensation witness testified to precisely the opposite). Thus, the only remaining rationale is the Southwest Gas decision cited by RUCO and the Recommended Order.

In Southwest Gas, the Commission stated that: "Without SERP, the Company's officers still enjoy the **same** retirement benefits available to other SWG employees" and "allowing a **greater** percentage of retirement benefits does not meet the test of reasonableness." *Id.* at 18 (*emphasis supplied*) and Recommended Order at 27. However, there are critical differences between the facts in the Southwest Gas case, and those that exist here. (Tr. Vol. III at 496-502 [Brandt].) First, the APS program is **not** limited to officers, as was apparently the case in Southwest Gas. Second, APS employees covered by the SERP would **not** enjoy the same retirement benefits as all other APS employees in the absence of this plan. (*Id.*) Finally, the Company's SERP only places all APS employees, including management, on the **same** level with regard to retirement benefits, and **not** on a higher level as was apparently true in the Southwest Gas decision. In short, SERP is not some management "perk," but an important tool in retaining qualified professionals over the long term. (*Id.*)

Even if the Commission does not wish to acknowledge the critical differences between the considerations cited in the Southwest Gas decision and the facts in this case, the Recommended Order is inconsistent in that it does not adopt the corresponding rate base adjustments proposed by RUCO. (Recommended Order at 27.) This inconsistency is addressed in the Rate Base section of the Company's Exceptions.

APS Proposed Amendment Nos. 7 and 17 address SERP. It provides alternative resolutions that either approve SERP expenses in cost of service or remove them but also make the rate base adjustments recommended by RUCO.

4. <u>Stock Incentive Compensation.</u>

APS is seeking approval of $4.8 million in operating expenses related to its employee stock incentive program, which is also part of the compensation package for eligible APS employees. The stock incentive plan is an integral component of employee compensation. It is consistent with similar programs of other companies. (APS Exhibit No. 51 at 19-20 [Gordon] at 22.) The Recommended Order proposes to eliminate this amount in its entirety. (Recommended Order at 36.)

APS's stock incentive component, or "long-term" incentive, is integral in attracting and retaining high quality management personnel. The program 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.
- Long-term financial health provides 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.

(APS Exhibit No. 51 at 19-20 [Gordon] at 21-22.)

The Recommended Order does not dispute these points. Neither does it contend that APS employee compensation, including stock incentives, is unreasonable in amount. And, not only has there been no evidence presented in this case that suggests that overall APS compensation is unreasonable, the evidence presented is to the contrary. (*Id.* at 21-22.) On cross-examination, when asked whether he made any determination as to the reasonableness of the compensation received by the Company's officers and senior management, the Staff witness responded "no" and that the basis for his recommendation was "conceptual." (Tr. Vol. XXII at 4229 [Dittmer].) Staff did not find the stock incentive plan unreasonable or imprudent – indeed, Staff did not even allege as much.

Staff's, and apparently the Recommended Order's, "conceptual" problem with stock compensation is the belief that it is "a program where an employee has an incentive to perform in a manner that could negatively affect the Company's provision of safe, reliable utility service at a reasonable rate." (Recommended Order at 36.) Not only is such a concern entirely speculative and without a shred of evidentiary support, it is illogical. Stock compensation necessarily requires the recipients to take a long-run view toward APS performance. As noted by APS witness Gordon, it encourages the executive and management team to develop and implement effective business strategies that span multiple year periods. It also focuses on the sort of long-term financial health that encourages investment to improve operating efficiencies, all of which directly benefit APS customers. APS Proposed Amendment No. 8 would restore APS stock compensation as part of cost of service in this proceeding.

5. <u>Lobbying</u>.

The Recommended Order essentially adopts the RUCO position that lobbying costs directly relating to APS's regulated utility business be split evenly between the Company and customers (with the exclusion of a specific outside services expense). (Recommended Order at 34-35.) APS has demonstrated direct customer benefits that far exceed the combined costs of its Federal Affairs and Public Affairs Departments (APS Initial Brief at 70.) Nevertheless, APS can accept the Recommended Order's position as a reasonable compromise <u>if</u> indeed it is actually permitted to meaningfully apply this position in future proceedings.

APS must qualify its acquiescence to the RUCO adjustment because the second part of the Recommended Order's discussion on this point completely vitiates the above compromise. By requiring APS to present "the itemized lobbying costs associated with each benefit it alleges resulted from the specific lobbying activity" in future rate cases in order to justify even the 50% of such costs found reasonable in the Recommended Order, the Recommended Order establishes an impossible hurdle to the recognition of these costs. The efforts of entities such as APS in the legislative process cannot be broken down by task like an expense account and assigned specific costs. APS may contact key legislators dozens of times on a variety of issues important either to APS or the legislators in question before seeing positive results for its customers on even a single issue. Was it the last visit that persuaded a legislator -- the first -- or was it all of them? That is unknown and unknowable.

APS is satisfied with the 50/50 resolution of the issue in the Recommended Order. There is no purpose served by starting up this controversy anew in future rate proceedings. APS Proposed Amendment No. 9 would remove the problematic language from the Recommended Order.

6. Demand Side Management Conservation Adjustment.

The Recommended Order rejects APS's request for a pro forma revenue adjustment of $4,907,000 for conservation related to its Commission-approved DSM programs. As addressed herein with respect to the PSA and Base Fuel Cost recommendations, this position is entirely inconsistent with the Recommended Order's recognition of the fuel cost savings associated with the Company's DSM programming.

That inconsistency notwithstanding, the Recommended Order denies the requested DSM net lost revenue adjustment for three reasons: (1) in contrast to its expressed interest in offering both performance-based incentives and rate/revenue decoupling in order to encourage APS to invest in socially beneficial programs (described in the context of renewables), the Recommended Order contends that, because the Company is already awarded a modest financial incentive for its successful implementation of DSM programs (the amount of which is capped at 10% of its total DSM spending in any given year), APS should not also be permitted to recover the revenue it loses because of those programs; (2) in disregard of the Rebuttal Testimony of APS witness Peter Ewen, the Recommended Order posits that neither the adjustment nor its amount is sufficiently "known and measurable" to affect the Company's cost of service; and (3) in a strained interpretation of the Settlement Agreement ("Agreement") approved by the Commission in Decision No. 67744, the Recommended Order (incorrectly) suggests that the terms of the Agreement somehow prevent APS from recovering net lost revenues related to DSM "in this case on a going forward basis." Each of these contentions is fundamentally flawed.

First, there is simply no basis for the Recommended Order's position that the financial incentive offered to APS in the Agreement (as approved in Decision No. 67744) was intended to be the exclusive means of compensating APS for the net lost revenue related to the Company's DSM-related expenses. Rather, immediately after providing for the DSM performance incentive, the Agreement expressly <u>permits</u> APS to recover or seek to recover net lost revenues "to the extent reflected in a test year used to establish APS rates in future rate proceedings" – in other words, **in this rate case.** (Agreement, ¶¶ 45-46.) Far from rendering the financial incentive and the pro forma adjustment "mutually exclusive," the Agreement expressly contemplated that each can (and should) be used to not only compensate APS for its cost of service related to these Commission-approved programs, but to **incentivize** APS to effectively implement such programs.

The purpose of a DSM program is to reduce energy consumption by implementing programs that encourage customers to control their own energy usage. By its very nature, the success of a DSM program results in a margin of lost revenue to the utility implementing the program. For this reason, as a means to encourage APS to invest in energy-saving resources, Decision No. 67744 both allows APS to be compensated for its lost revenue attributable to DSM programs and gives APS an **added** financial incentive based on the economic benefits to customers that are realized by the programs. The performance incentive was intended to be just that – a mechanism to encourage APS to enthusiastically execute programs in the most cost-effective means possible so as to maximize the net benefits to society. This performance incentive simply was not intended to be a revenue-recovery measure -- a point made plain by the fact that the performance incentive award is based on a sharing of the net benefits of the DSM program and is capped at 10% of the Company's total expenditures on DSM programming. It does not begin to compensate the Company for the lost margins attributable to these programs. (Agreement, ¶ 45; APS Initial Brief at 121-122.)

In contrast to its position here, the Recommended Order expressly acknowledges in another context that using both a performance incentive and a rate/revenue decoupling measure (such as pro forma adjustment for net lost revenues) is an appropriate means of encouraging APS to invest in socially beneficial programs. In its recommendations regarding renewable procurement, the Recommended Order advises interested parties to "discuss and evaluate *how performance-based incentives **and** decoupling of rates from revenues* might encourage APS to procure more renewable energy resources." (Recommended Order at 93 (*emphasis added*).) In so doing, the Recommended Order expressly acknowledges that both a performance-based incentive (like that awarded to APS for successful implementation of its DSM programs) and decoupling of rates from revenues (like the requested pro forma adjustment for net lost revenues related to the DSM programs) can and should be used in tandem as a means to encourage APS to implement socially valuable programs.

The Recommended Order's position that the proposed DSM conservation adjustment is not "sufficiently known and measurable" disregards APS's Rebuttal Testimony and evidence submitted on the subject, and is simply wrong. In his Rejoinder Testimony, Mr. Ewen expressly responded to the argument that "the Company's proposed pro forma adjustment for revenue reductions attributed to DSM measures should be disallowed because they are not known and measurable," noting that, while the Company's initial calculation was based on estimated values, he had since modified that calculation "to reflect the **actual** spending to date [October 2006] and the amounts planned to be spent in the 4th quarter of this year [2006]." (*Emphasis added.*) (APS Exhibit No. 18 at 9 [Ewen].) The revised calculations thus rely on "known program expenditures, and these expenditures have resulted in the implementation of quantifiable energy-saving measures." (*Id.* at 10 [Ewen].) As the hearing testimony made clear, most of the Company's 2005-2006 DSM spending was for programs, such as the compact fluorescent light program, for which the savings can be precisely calculated. (Tr. Vol. VII at 1404 [Orlick].) Thus, APS's DSM conservation adjustment calculation is based, not on estimates, but on "known and measurable" adjustments to expenditures and corresponding revenue losses that need to be reflected in the adjusted test year.

Finally, the Recommended Order incorrectly interprets the Agreement approved in Decision No. 67744 as prohibiting APS from recovering "net lost revenues in this case on a going forward basis." However, at Paragraph 46, the Agreement reads in relevant part as follows:

> This Agreement does not provide for the recovery of net lost revenues. **Except to the extent reflected in a test year used to establish APS rates in future rate proceedings, or unless otherwise authorized by the Commission in a separate non-rate case proceeding.** APS shall not recover or seek to recover net lost revenues on a going-forward basis. In no event will APS recover or seek to recover net lost revenues incurred in periods prior to such test year or prior to the Commission's authorization of net lost revenue recovery in a separate non-rate case proceeding.

This language does three salient things: first, it establishes that the terms of the Agreement alone do not compensate APS for its net lost revenues related to the DSM programming required by the Agreement; second, it establishes that, "on a going-forward basis" (that is, from the time the parties execute the Agreement onward) APS may recover net lost revenues related to its DSM programming to the extent reflected in an adjusted test year used to establish APS rates in future rate proceedings (or in a non-rate proceeding if authorized by the Commission); and third, it prevents APS from recovering net lost revenues incurred **prior** to such test year. There is simply nothing in this language or elsewhere in the Agreement that prevents APS from normalizing its test year based on complete, known data to reflect DSM programming implemented during the test year, as is the case here. The "going forward" language on which the Recommended Order relies was intended simply to convey that the parameters set for APS's net lost revenue recovery were to apply "going-forward" -- it certainly was not meant to prevent APS from using future data to normalize its test year operating costs in this case, nor did Staff, RUCO, or any other intervenor argue otherwise.

Setting rates on conditions that will be present when new rates go into effect is consistent with traditional rate-making. The proposed DSM net lost revenue adjustment simply seeks to make a necessary pro forma adjustment to revenue loss attributable to DSM programming that was reflected in the adjusted test year, predicated on known and measurable conditions. The failure to allow APS to recover its lost revenue attributable to DSM-related conservation in this rate proceeding will prevent the Company from recovering its full cost of service. (APS Proposed Amendment No. 10 attached hereto.)

7. <u>Bark Beetle Regulatory Asset</u>.

With respect to bark beetle remediation costs, the Recommended Order adopted APS's proposed rate base adjustment in the amount of $4,360,000, and agreed conceptually to APS's proposed amortization of that amount. (Recommended Order at 11, 16.) However, the $1,437,983 amortization adjustment recommended by and reflected in the Recommended Order is incorrect, because it reflected an incremental expense adjustment to the wrong base amount of this expense. The $1,437,983 adjustment awarded in the Recommended Order does not include a $110,000 pre-tax adjustment to operating income that the Company provided in rebuttal as an update to its pro forma (an update that was not disputed by any party to the proceeding). (Attachment LLR-4-2RB to Rockenberger Rebuttal Testimony.) That adjustment should be included in the Commission's decision. (APS Proposed Amendment No. 11 attached hereto.)

8. <u>Sundance O&M Adjustment</u>.

The Recommended Order adopts RUCO's proposed adjustment to the Sundance O&M expense, and orders APS to recognize a regulatory liability in the amount of $226,500 per month. (Recommended Order at 17.) Although APS does not take exception to the adjustment itself, it believes that the Recommended Order has incorrectly calculated the amount of regulatory liability accrual that applies to the Sundance non-routine maintenance expense. The $226,500 per month proposed in the Recommended Order is erroneously based on RUCO's entire pro forma adjustment, rather than simply the non-routine maintenance portion of it. The regulatory liability accrual should include only the non-routine expenses at issue – a modification that results in a regulatory liability accrual of $134,100 per month.[6] Amending the Recommended Order in this manner does not affect the Company's operating income, only the amount of regulatory liability the Company is required to accrue. (APS Proposed Amendment No. 12 attached hereto.)

9. Business Lunches.

The Recommended Order recommends reducing APS's operating costs in the amount of $400,000 for Company expenses related to providing employees with a sandwich and a bag of chips from the APS cafeteria, characterizing such an expense as "unreasonable." As the hearing testimony made clear, APS does not cater in expensive meals or provide employees with lunches on a daily basis or whenever an employee opts to work through lunch. (Tr. Vol. XIII, pp. 2687-2689 [Rockenberger]) (describing the type of lunch APS provides.) The issue is not one of inadequate staffing levels, as contended in the Recommended Order. Rather, the Company provides food for its employees on those occasions when business meetings must be held over the noon hour to accommodate the schedules of the required attendees or to take care of time-sensitive matters. (*Id.*).

Significantly, although APS's practice of providing employee meals as described above is a long-standing one, no adjustment to APS's operating expenses related to that cost has ever been proposed by any party to any other APS rate case until now. (*Id.* (citing Tr. Vol. XIII at 2687-89 [Rockenberger]).) Even now, of the many parties to this proceeding (including Staff), only RUCO challenged the Company's meeting meal expense. But, significantly, RUCO did not provide any evidence that the amount claimed by the Company was excessive or that the meals did not serve a valid business purpose. (APS Initial Brief at 58-59; APS Post-Hearing Reply Brief at 20.)

APS's costs in this regard are thus no different than those incurred by businesses in any number of industries, many of which provide food to employees that are required to work

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[6] This is calculated by taking the amount shown on page 10, line 1 of the Schlissel Direct (confidential version) x jurisdictional allocation factor (APS Reply Brief, Exhibit 1, line C-11); divide that amount by 12 months to arrive at $134,100 per month.

during what would otherwise be non-working hours. Such policies are implemented in recognition of the business value of keeping employees productive. Far from being "unreasonable," as the Recommended Order would portray them, these lunches are legitimate operating expenses that provide APS (and its customers) the benefit of additional productive, uninterrupted work time. (APS Initial Brief at 58-59 (citing APS Exhibit No. 57 at 24 [Rockenberger]).)

There is no evidence refuting the Company's legitimate and reasonable business costs; therefore the Commission should reject the Recommended Order's disallowance of the Company's business meal expenditures and permit APS to recover the $400,000 as operating expenses.

(APS Proposed Amendment No. 13 attached hereto.)

10. <u>Income Tax Impacts of Interest Synchronization</u>.

The Recommended Order correctly discusses the Company's interest synchronization adjustment, recognizing that such an adjustment is necessary to align recorded test year interest expense (and therefore, income tax expense) with weighted cost of debt and rate base found appropriate for ratemaking purposes. This is in line with general regulatory practice and an adjustment to which no party objected. Unfortunately, the actual dollar impact of the adjustment shown in the Recommended Order is mathematically incorrect. The $607,000 increase to adjusted test year income tax expense reflected in the Recommended Order only picks up the interest synchronization effect relating to the individual incremental pro forma adjustments to rate base made by the Recommended Order. However, it does **not** reflect the same interest synchronization impact for the remainder of the Company's rate base. That initial Company calculation of interest synchronization had increased adjusted test year income tax expense by $2,429,000 **prior** to any of the Recommended Order's incremental adjustments to rate base (SFR Schedule C-2.) This results in a total increase to adjusted year income tax expense of $3,036,000 ($2,429,000 **plus** $607,000). The $2,429,000 difference, when multiplied by the revenue conversion factor, produces an increase in revenue requirements (and hence, the necessary level of authorized increase) of approximately $4 million over that increase proposed by the Recommended Order. (APS Proposed Amendment No. 14 attached hereto.)

11. Annualized Amortization.

The Recommended Order finds that the Company's proposed adjustment to annual depreciation and amortization is reasonable, and should be adopted (Recommended Order at 30, lines 1-2.) However, the corresponding ordering paragraph (Recommended Order at 150, lines 26-27) only specifies that the Company's depreciation rates are appropriate to use in this case, so the Company is requesting that the ordering paragraph be modified to include amortization. Attached Amendment 15 makes this modification.

IV. RATE BASE ADJUSTMENTS

1. Cash Working Capital.

As noted in the Recommended Order, the issue here is the treatment of balance sheet items that reflect cash outlays in the past but whose recovery takes place over time, including during the test year. The Recommended Order cites the following definition of working capital at page 5:

> Working capital is the average amount of capital provided by investors in the company, over and above the investment in plant and other specifically identified rate base items, to bridge the gap between the time expenditures are required to provide service and the time collections are received for that service.

ROBERT L. HAHNE & GREGORY E. ALIFF, ACCOUNTING FOR PUBLIC UTILITIES 5-2 (1990).

Unlike other rate base elements, which can be taken directly from the Company's balance sheet with or without adjustments, cash working capital is a calculated number that identifies the additional cash investment made by the Company in order to operate and maintain its electric system over and above those items specifically included in rate base such as net utility plant, inventories and prepayments. Simply put, if cash revenues are received after an expense has been incurred and reflected on the Company's income statement or balance sheet, investors have to provide funds to bridge that gap. If cash is received prior to that expense being incurred, the opposite is true, *i.e.*, customers are providing that bridge and should receive credit in the form of an offset to the utility's rate base.

The Recommended Order states that: "[T]he real issue comes down to whether the Commission should allow APS' rate base to be increased to reflect the timing of recording depreciation expense and accumulated depreciation in the Company's financial statements." *Id.* at 8. With all due respect, the real issue is the lag in cash recovery of an expense that affects the rate base upon which the Company is permitted to earn a return.

Both depreciation and deferred taxes generate additional investment needs that must be reflected in rate base as part of the Allowance for Cash Working Capital. (APS Exhibit No. 66 at 2-3 [Balluff].) It is indisputable that the construction of depreciable utility plant, which gives rise to both depreciation and deferred taxes, involves a cash investment. It is equally clear that the utility is entitled to a return on that investment until it has been recovered from customers in the form of cash receipts. When depreciation expense is recorded and deferred income tax charges are recorded, accumulated depreciation and accumulated deferred income tax credits are recorded. The reserve for accumulated depreciation and the accumulated balance of deferred income taxes offset the investment in plant for ratemaking purposes. (*Id.* at 3-4 [Balluff].) Those two reserves, which reduce rate base, are credited (increased) monthly based on the depreciation and deferred tax expense recorded for the month. The corresponding cash receipts will not be received until the following billing month. Because the Company's rate base is reduced by the **recorded** level of accumulated depreciation and deferred taxes (rather than the **received** level of actual cash recovery), there is a gap between when customers are credited (through a rate base deduction) for their payment of depreciation expense and deferred tax expense and the time they actual pay for these items. (APS Exhibit No. 65 at 10-11 [Balluff].) This gap represents additional investment by the Company that must either be reflected in the calculation of cash working capital or recognized as direct adjustments to the depreciation and deferred tax reserves. Exclusion of depreciation expense alone prevents APS from earning a return on over $35,000,000 of unrecovered invested capital. (APS Exhibit No. 66 at 3 [Balluff].) Excluding deferred tax expense leads to another understatement of rate base of $7,872,000. (APS Exhibit No. 65 at Attachment FB-1 [Balluff].)

APS is aware that the Commission has rejected the inclusion of depreciation and deferred taxes in prior decisions. As the arguments on this issue have become focused, an increasing number of jurisdictions have taken a new look and have concluded that one or both of these costs are appropriate elements of cash working capital. A few examples of states that have included depreciation and deferred income taxes in lead lag studies are: South Carolina, where these items must be included in a lead lag to reflect the delay in the collection of these components of revenue;[7] 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;[8] and California, which includes both depreciation expense and deferred taxes at zero lag days because of the reduction of rate base by accumulated depreciation and accumulated deferred income taxes.[9] Each of these jurisdictions likely faced the same contrary precedents as is currently the case in Arizona before finally recognizing the need to reflect **all** the expense elements that lead to the need for working capital.

The same well known utility rate accounting authority, *Accounting for Public Utilities*, which is cited in the Recommended Order and at page 41 of the Company's Initial Brief, addresses the issue of depreciation and deferred taxes as part of cash working capital in some detail:

[2] Depreciation and Deferred Tax Lag

> From figure 5-3 [attached hereto as "APS Reply Brief Exhibit 2"], it can be seen that after having determined the overall lag in operation and

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[7] In re Application of South Carolina Electric & Gas Company for Adjustments in the Company's Electric Rate Schedule and Tariffs, Docket No. 88-681-E – Order No. 89-588 at 37 (July 3, 1989).

[8] DPUC Review of the United Illuminating Company's Rate Filing and Rate Plan Proposal, Docket No. 01-10-10 at 44 (Sept. 26, 2002).

[9] *See, generally,* Water Division, California Public Utilities Commission, Standard Practice U-16-W, Determination of Working Cash Allowance (May 16, 2002).

> maintenance expenses, the next item, depreciation, reflects a zero lag. This zero lag is used because accumulated depreciation, the contra account to the depreciation provision [expense], is deducted from rate base. However, on occasion, the issue has been raised that depreciation is a non-cash charge and therefore cannot produce a need for cash working capital. While it is true that recording depreciation does not require the expenditure of cash at the time the expense is recorded and charged to the customer, cash **was** expended at the time the property was acquired, and the recorded depreciation is used to reduce the investment in that property even though approximately one-and-one-half month's depreciation (equivalent to the revenue lag) has not yet been received from the consumer.
>
> It can be noted from figure 5-3 that a zero lag has also been used for deferred income taxes. The same issue is involved with respect to provisions for deferred income taxes which are used to reduce rate base as that for depreciation. In the case of deferred income taxes, the balance also includes approximately 45 days of uncollected tax provisions. These provisions are used to reduce other investments made for rate base components even though the last 45 days have not yet been received from the consumer.

ROBERT L. HAHNE & GREGORY E. ALIFF, ACCOUNTING FOR PUBLIC UTILITIES 5-2 (1990) (*emphasis added*).

Although APS has been able to reduce its revenue lag to 35 days from the 45 days assumed in the above example, the principle is the same regarding the necessity of including these expense components in the calculation of cash working capital. Alternatively, the Commission could make a direct downward adjustment of equal magnitude to the depreciation and deferred tax reserves. (APS Exhibit No. 66 at 4 [Balluff].)

The Recommended Order raises several arguments for removing the cash working capital requirement associated with the lag in the cash receipt of depreciation and deferred tax expense. One is that although the depreciation and deferred tax reserves at the end of the test period were not fully recovered in cash receipts as of the same date, APS eventually received such cash receipts. (*Id.* at 7.) This is true but irrelevant to the issue at hand for the reasons explained by APS witness Balluff in his Rebuttal Testimony:

> 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 depreciation and deferred income taxes recorded

> by September 30, 2005 will be collected by October 2006. But that is true with **all** other expenses with a revenue lag. APS calculated a revenue lag of over 35 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 has any relevance, there would be no reason to do a lead/lag study.

(APS Exhibit No. 66 at 3-4 [Balluff] (emphasis in original).)

Perhaps a simple and somewhat familiar example will help explain this issue. Assume you had a bank account that earned interest monthly at a rate of 6% per annum. If you had initially placed $1000 in that account, you would expect to receive $5 interest at the end of the first month ($1000 x .06 ÷ 12). If, however, the bank did not actually **pay** you the interest until the end of month two, you would reasonably expect that they would also owe you interest on that first month's interest, or $5.025 in total. The Recommended Order would give you just the $5. The same principle applies here but the dollars involved are far more significant.

Let's reverse the above example. You have the same $1000 invested in a bank account, and you have instructed the bank to withdraw $100 per month and place it in your checking account. If after the first month the bank debited your savings account by the $100 but did not actually deposit it in your checking account until the end of month two, you would not have earned any interest on that $100 in month two even though you had yet to receive it. You would be out $.50 in interest that was rightfully yours ($100 x .06 ÷ 12). Again the principle is the same - excepting APS is not out the return on $100 but on nearly $40,000,000.

The Recommended Order further states that although the depreciation and deferred tax reserves at the end of the test period were not fully recovered in cash receipts, neither did all the plant in service reflect cash outlays. (*Id.*) However, as noted by Mr. Balluff in his Rejoinder Testimony, the amount of plant not representing actual cash outlays as of September 30, 2005 was less than $2,000,000 -- far less than the impact of excluding depreciation and deferred taxes from the lead/lag computation of cash working capital. (APS

Exhibit No. 67 at 2 [Balluff].) And even that less than $2,000,000 is dwarfed by the lag in recovery of additional test period plant costs that will occur from their actual in service date to the date rates become effective in this case, a lag reflected in neither the Company nor Staff rate base numbers. (*Id.* at 2-3.)

The Recommended Order finally states that APS is seeking to address regulatory lag through this adjustment: "... an allowance for cash working capital is to address cash flow timing problems, not 'regulatory lag' issues related to earnings." (Recommended Order at 8.) Again, this misstates the Company position. The issue is not regulatory lag, *i.e.*, the time between the establishment of a test period and the final implementation of new rates based on that test period. Regulatory lag can lead to either attrition or, under rare circumstances such as are hypothesized by the Recommended Order at page 8, lines 19-21, what is called accretion. Rather the issue is the lag in the cash receipt of an expense that results in a diminution of the investor's return (just as it did in the two simplified examples discussed above) unless compensated for by a reflection of that lag in the calculation of cash working capital.

The Commission has previously taken conflicting positions on the use of interest expense, adopting it in Decision No. 55931 (April 1, 1988), while admitting in that same Decision that it had previously rejected the concept. (Decision No. 55931 at 67.) The testimony in this case is that the lag in paying interest, a non-operating expense, is an inherent part of the return to equity investors, *i.e.*, part of the "leverage" provided by debt capital to equity. 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 rate base (including the weighted cost of debt) in the calculation of working capital. (APS Exhibit No. 66 at 11 [Balluff].) To use it to reduce rate base is tantamount to making equity investors use a component of their rightful return to finance plant used to serve APS customers. Moreover, as Mr. Balluff pointed out, there is also a lag in the receipt by equity investors of their return. If one form of investment (*i.e.*, debt) is to be factored in the calculation of cash working capital, then all other forms should be in play, which would have <u>increased</u> the Company's overall cash working capital allowance from that requested. *(Id.)*[10]

Again, with regard to the inclusion of interest payment lags in the determination of cash working capital, Messrs. Hahne and Aliff state:

> The operating income component is subject to a wide difference of opinion in treatment when lead-lag studies are prepared. From a theoretical standpoint, operating income is earned when service is provided, and the operating income is the property of the investors in the company when earned. This view would recognize a cash working capital requirement for the lag in receipt of operating income. Such a requirement is equal to the revenue lag days times an amount equal to one day's operating income. The amount for interest or preferred dividends would not be offset, since those amounts are paid from investor-supplied funds (operating income). At the opposite end of the spectrum are those who take the position that a source of cash working capital exists in the delay in disbursement of interest and preferred dividends without any consideration of the lag in the receipt of operating income.
>
> In recent years, few commissions have accepted either of these opposing points of view. Usually, the decisions are somewhere between the two poles. **The most prevalent is probably to not consider the operating income component in the lead-lag study, which results in not recognizing a need for cash working capital to cover operating income and not recognizing accruals of interest and preferred dividends as a source of cash working capital.**
>
> The procedure of ignoring operating income generally produces approximately the same effect as does the procedure of recognizing the lag in collecting the operating income component of revenues while also recognizing a lag in the payment of interest expense and preferred dividends. The majority of commissions considering the question have adopted one of these latter two methodologies.

ROBERT L. HAHNE & GREGORY E. ALIFF, ACCOUNTING FOR PUBLIC UTILITIES 5-2 (1990) (*emphasis added*).

The "lag" in the receipt of operating income referenced above is the lag in overall return discussed in the Company's Initial Brief (APS Initial Brief at 43) and by Mr. Balluff in his Rebuttal Testimony. (APS Exhibit 66 at 11 [Balluff].) As noted, most jurisdictions either include both that operating income lag and interest or exclude both, as has APS. Thus,

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10 The Recommended Order cites a Staff argument that had the lag in paying dividends been included, cash working capital would be even lower. It is not the "lag" in paying common equity dividends that is relevant but the lag in the equity investors' receipt of income.

Decision No. 55931 and, correspondingly, the Recommended Order is out of step with what would appear to be the general treatment of cash working capital throughout the country. APS Amendment No. 16 would restore the Company's full cash working capital requirement as set forth in the Company's Rebuttal Testimony.

2. <u>SERP</u>.

As noted in the Company's earlier exception to the Recommended Order's exclusion of SERP expenses, the Recommended Order does not accept RUCO's corresponding adjustment to increase APS rate base by $30.6 million. This RUCO adjustment represents the net of the deferred credits and associated deferred income taxes associated with the SERP expense. Although the Recommended Order contends that the rate base offset that would ordinarily be associated with expense is "for past periods and remain valid" (Recommended Order at 27), the period during which these credits arose is irrelevant if, as the Recommended Order maintains, SERP expense is not a valid cost of service. APS Proposed Amendment No. 17, attached hereto would restore these rate base adjustments proposed by RUCO.

V. FUEL AND PSA ISSUES

As noted in the Introduction, the Recommended Order would significantly improve the current Power Supply Adjustment Mechanism ("PSA"). APS does, however, continue to object to the establishment of an artificially low base fuel cost, the treatment of broker costs, and the retention of a 90/10 penalty provision in the prospective PSA

1. <u>Base Fuel Cost</u>.

The Recommended Order determines a Base Fuel Cost of 3.1202¢/kWh, which is the Company's originally proposed Base Fuel Cost adjusted for the agreed upon change in the APS position on hedging gains and losses. (Recommended Order at 33.) APS believes this should be increased to at least 3.2491¢/kWh. That figure would increase to 3.2610¢/kWh should the Commission not adopt the Company's proposed DSM conservation adjustment.

A. APS Base Fuel Cost Calculation.

APS has calculated its proposed Base Fuel Cost using the methodology suggested by Staff witness Antonuk for determining 2007 fuel and purchased power costs. (APS Exhibit No. 18 at 4-5 [Ewen].) In his Supplemental Testimony, Mr. Antonuk agreed that the 3.2491¢/kWh figure was a reasonable estimate of 2007 fuel and purchased power costs:

> [T]his [the APS Rejoinder forecast of 2007 fuel costs], we conclude, is comprehensively and logically structured, consistent with reasonable expectations about system assets, and reflective of market price expectations current as of its vintage.

(Staff Exhibit No. 30 at 23 [Antonuk].) He went on to recommend that Mr. Ewen's number be adopted by the Commission in establishing the "forward component" of Staff's PSA for 2007. (*Id.* at 3; Tr. Vol. XXI at 3993 [Antonuk].) And, the Recommended Order also adopts that number for the "forward component." (Recommended Order at 109.) The question becomes: if Mr. Ewen's Rejoinder Testimony calculation of 2007 fuel costs is sufficiently accurate for adoption as the "forward component" under the Recommended Order, why should it not be used to establish a new Base Fuel Cost?

Unlike the Base Fuel Cost proposals in the Company's Direct and Rebuttal testimonies, APS has not annualized price changes scheduled to take effect in 2007, nor has it annualized generation levels for end of year customers. Both these omissions reduced the 2007 Base Fuel Cost compared to the methodology used by APS in its prior testimony and used by the Commission in establishing the Base Fuel Cost in Decision No. 67744.

Moreover, the 3.2491¢/kWh figure is an annual average cost that includes the lower fuel and purchased power costs generally incurred by APS during the non-summer months of the year. (APS Exhibit No. 105 at 5). As shown in APS Exhibit No. 105, costs during the peak use months of 2007 would be 3.6915¢/kWh. (*Id.*). Assuming the Company's proposed Base Fuel Cost was adopted effective June 1, 2007, APS still projects an unrecovered balance of 2007 fuel and purchased power costs of over $50 million. (APS Initial Brief at 33.) For this reason, APS believes its Base Fuel Cost is a reasonable, even conservative, estimate of what fuel costs will be in 2007. And, using the Company's Base Fuel Cost would obviate the need for setting a "forward component" to the PSA in 2007, or more precisely, that "forward component" could be set at zero. (Tr. Vol. V at 109 [Ewen].)

B. Conservation Adjustment Impact.

If the Commission were to adopt the Recommended Order's rejection of the Company's DSM conservation adjustment (Recommended Order at 30), there needs to an upward adjustment to the Base Fuel Cost irrespective of how the Commission otherwise resolves the issue of Base Fuel Cost. It is uncontroverted that APS factored the impact of the DSM conservation adjustment into its calculation of Base Fuel Cost. Without the DSM's expected impact on sales, Base Fuel Cost would be increased by $.7 million or .0024¢/kWh (assuming a Base Fuel Cost of 3.1202¢/kWh with the DSM adjustment rejected by the Recommended Order), and by $3.2 million or .0119¢/kWh assuming a Base Fuel Cost of 3.2491¢/kWh which also included the DSM conservation adjustment. Attachment D to these Exceptions sets forth these calculations. If the Commission rejects APS's DSM conservation adjustment to revenues, there is simply no principled reason to reflect that conservation in either the Base Fuel Cost suggested in the Recommended Order or that proposed by APS (which is used as the "forward element" in the Recommended Order.).[11]

2. <u>PSA</u>.

A. 90/10 Sharing.

The Recommended Order adopts two important changes requested by APS to the 90/10 sharing mechanism, thus significantly improving the fairness of the PSA.[12] This is clearly progress towards more effective and timely recovery of prudent fuel and purchased power costs. But, the need to establish an accurate Base Fuel Cost is heightened to the extent the Commission retains most of the elements of the present 90/10 sharing. In practice, the 90/10 sharing feature has served as a penalty provision that automatically denies APS's

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[11] Thus, the new Base Fuel Cost and forward component of the PSA would be 3.2610¢/kWh and zero under the Company's proposal and 3.1226¢/kWh and .1384¢/kWh under the Recommended Order's determination, assuming the Commission also rejects the DSM conservation adjustment. APS Proposed Amendments Nos. 18 and 18A address both alternatives.

[12] APS's original proposal kept most elements of the 90/10 sharing on the assumption that the Base Fuel Cost would reflect current (as of the rate case) fuel costs, which in this case are at least 3.2491¢/kWh.

recovery of 10 percent of its increased fuel and purchased power costs. (APS Exhibit No. 8 at 7 [Robinson].) This is especially true if the Base Fuel cost is set at less than 3.2491¢/kWh (or 3.2610¢ assuming the DSM conservation adjustment is not adopted). The penalty is at least $4 million per year under the Recommended Order.

Mr. Antonuk, the Staff's consultant on PSA issues, agreed that the 90/10 sharing feature would result in the non-recovery of costs APS would reasonably expect to incur. (Tr. Vol. XXII at 4149 [Antonuk].) Mr. Antonuk described it as a "blunt instrument" at best with regard to providing an incentive, and he suggested that the Commission focus in on the "drivers" of fuel cost. (Tr. Vol. XXI at 3896.) APS believes Staff made a valid point and that, rather than attempt to modify the 90/10 provision to alleviate some of its most obvious inequities, eliminating it (as Staff recommended) is appropriate, especially in view of the findings by Liberty Consulting and R.W. Beck concerning the overall prudence and effectiveness of the Company's fuel procurement and hedging practices. (Staff Exhibit No. 33 at 6-7 [Fuel Audit]; APS Exhibit No. 72 at 5-1 through 5-4 [R.W. Beck].) For example, Liberty concluded that:

> "Fuel and power procurement work groups have the necessary skills and experience, operate under adequate job descriptions, communicate effectively, have access to appropriate training, use generally adequate procedures and decision processes, document decisions sufficiently, operate under established procurement approval limits, and under regular internal auditing."

(Staff Exhibit 28 at 12[Antonuk].)

> "APS bases its marketing and trading activities on sound hedging policies and procedures, and conducts electricity sales and purchases consistently with least-cost dispatch guidelines."

(Staff Exhibit 28 at 14 [Antonuk].)

R.W. Beck stated:

> "APS has a high-quality energy risk management and hedging program," that it was "consistent with leading industry practices."

(November 1, 2006) ("R.W. Beck Report") was entered into evidence as APS Exhibit No. 72.)

APS Proposed Amendment No. 19 would remove the 90/10 provision from the PSA as recommended by Staff.

B. Broker Fees.

APS and each of the other parties[13] have included approximately $200,000 in broker fees in their calculation of Base Fuel Cost. (Tr. Vol. XXIII at 4438 [Ewen].) It is undisputed that such fees are a legitimate cost of acquiring fuel and purchased power for the benefit of APS customers. (Tr. Vol. XXI at 4010 [Antonuk].) The Recommended Order has proposed that increases in such costs nevertheless be excluded from the costs recoverable through the PSA.[14]

In Decision No. 68437, the Commission denied recovery of increased broker fees through the PSA because it believed that they had been excluded from the Base Fuel Cost established in Decision No. 67744, and that such exclusion might result in double-recovery of such fees. (Decision No. 68437 at 25.) Whether either the assertion in Decision No. 68437 about the calculation of Base Fuel Cost in Decision No. 67744 or the potential for over-recovery were accurate in the first instance is beside the point. There is no disagreement that they are included in Base Fuel Costs in this proceeding, and that they are legitimate and necessary costs of fuel and purchased power procurement. APS Amendment No. 20 would expressly include any increase or decrease in broker fees from that level reflected in the Base Fuel Cost in the PSA.

VI. RATE DESIGN

1. <u>Revised H-3 Schedule</u>.

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[13] The RUCO, Staff and AECC Base Fuel Cost recommendations are all variants of the original Base Fuel Cost proposed by APS and, thus, implicitly reflect the level of broker fees included by APS.

[14] APS believes the Recommended Order would exclude broker fees from the PSA only to the extent they increase from the level included in Base Fuel Cost. Otherwise, these costs would not be recovered even at the level found reasonable in the Recommended Order. (Tr. Vol. XX1 at 4010 [Antonuk].)

On May 2, 2007, a Procedural Order was issued that included four schedules/spreadsheets that purportedly supported or reflected the determinations contained in the Recommended Order. In reviewing the rate design, it appears that the residential rate designs contained in the Procedural Order will result in an estimated $2.7 to $2.9 million revenue undercollection. This undercollection results from the proposed Recommended Orders' rate design in rate schedules due to be eliminated. It appears that Rate Schedule E-10 was designed to recover a specific revenue target without consideration of the intended elimination of the Schedule. Rate Schedules E-10 and E-12 must be designed in concert to prevent a guaranteed loss of revenue. Under the proposed rate design, and assuming customers will react to the rate changes in a manner that will mitigate their bills, customers on Schedule E-10 will transfer to other rate schedules immediately because they would save money under <u>any</u> alternative rate. Thus, the calculated $15.7 million increase from Schedule E-10 (per the revenue table attached to the May 2 Procedural Schedule) would not be achieved. If it were assumed Rate Schedule E-10 customers transferred to Rate Schedule E-12, test year E-10 revenues would be $82,132,843, which is $1,871,085 less than the revenue anticipated in the Recommended Order. Similarly, rate schedules EC-1 and ECT-1R must be designed together because EC-1 is also scheduled to be cancelled. Furthermore, the Rate Schedules ET-2 and ECT-2 in the Procedural Order are not revenue neutral with Rate Schedules ET-1 and ECT-1R respectively, as required in the Recommended Order. (Recommended Order page 73 lines 18-19, page 74 line 5.) Although Staff has designed revenue targets by rate class, specific targets by class may not be achievable but the overall targets will be met in conformance with the Recommended Order.

APS has prepared and is submitting an H2 and H-3 schedule using Staff's rates and APS' billing determinants. (Attachment E). The attached H-3 schedule reflects APS' interpretation of the rate design set forth in the Recommended Order and the increases associated with Residential and General Services rates. The "rate spread" as shown on the attached exhibits generally follows the trends reflected in the Procedural Order rate attachment. However, there are some deviations. For example, in APS's filed case, irrigation customers would have received a de minimus rate change. The Staff proposal increased irrigation charges by approximately 8% while the APS proposal attached herein recommends irrigation rate changes of approximately 4% due to the effects of combining rate schedules E-38 and E-221. The APS rate proposals also reflect the changed method for recovery of transmission charges. APS agreed with AECC that the transmission expenses charged to retail customers should better track the charges found in the APS OATT. This rate design change results in some inter-class and intra-class shifts in revenue. However, slight adjustments to non-OATT charges were developed so that the rate spread proposed by Staff was generally maintained.

2. <u>Net Metering</u>.

APS takes exception to the Recommended Order's modifications to Schedule EPR-5, specifically, the calculation of "uncollected fixed costs."

The Recommended Order would also limit the recovery of the Company's fixed costs to the customer's excess generation,[15] rather than total generation. Yet, EPR-5 was designed to recover all of the incurred transmission and distribution costs, as well as non-avoidable charges, including the Competition Rules Compliance Charge ("CRCC"), Environmental Portfolio Standard ("EPS") Surcharge, DSM Cost Adjustment, PSA (for deferred fuel costs incurred during prior periods), and Transmission Cost Adjustment from those customers choosing to be on this rate. (APS Exhibit No. 37 at 11 [DeLizio].) Under the Company's proposal, the incremental cost for this pilot net metering program would be funded through revenues collected through the current EPS surcharge. (*Id.* at 10.) In addition, infrastructure costs, such as changes to the customer billing systems, would also be funded through the EPS surcharge. (*Id.*) Revenue associated with transmission and distribution, as well as non-avoidable costs that are not recovered from EPR-5 customers would also be funded by the EPS surcharge. (*Id.*)

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[15] The difference between the retail value of the kWh that's rolled over to the next month and the Company's avoided cost. (Tr. Vol. XIX at 3510-3511 [Keene].)

At hearing, the Company prepared and entered an exhibit into the record entitled, "Net Loss Revenue Sample Calculation," which provides a detailed methodology as to how it calculates uncollected fixed costs (APS Exhibit No. 38, Attachment GAD-5RB [DeLizio].) As APS witness Greg DeLizio testified, to determine the Company's total revenue loss, the Company first calculates a net metering customer's energy use to determine the total revenue requirement based upon the installed system capacity and the energy generated by the system. (Tr. Vol. XII at 2499 [DeLizio].) Next, the Company calculates the benefit of the systems that are being installed by pricing the energy produced at the Company's avoided costs (based upon the Palo Verde index). (*Id.*) To calculate the Company's uncollected fixed costs, the Company offsets its total lost revenue figure by the benefits. (*Id.*) The Company will track net metering customer usage and output to calculate the Company's uncollected fixed costs, based upon historical actual data. (*Id.* at 2559-2560.)

As the program grows, the revenue loss associated with these uncollected fixed costs will continue to increase. There are two mechanisms that can provide for collection of these lost dollars:

1. Collect the revenues associated with the uncollected fixed costs through the EPS/RES surcharge (the Company's preferred method); or

2. Defer the revenues associated with the uncollected fixed costs for collection in a subsequent rate case from other APS customers.

As the Company pointed out in its Reply Brief, unless one of the methods above is adopted, APS will incur significant revenue loss associated with these uncollected fixed costs as part of its net metering program that cannot be later recouped in future rate cases. (APS Reply Brief at 36.)

The Company requests that the Commission approve EPR-5 as initially proposed in its filing. In the alternative, instead of authorizing recovery of its uncollected fixed costs through the EPS surcharge, APS would request that it be allowed to defer its uncollected fixed costs and seek recovery of such costs in a future rate case proceeding. Attached APS Proposed Amendment No. 21 allows for the recovery of uncollected fixed costs in this proceeding. Attached APS Proposed Amendment No. 21A allows for the deferment of uncollected fixed costs to a future rate proceeding.

3. Elimination and Freezing of Schedules.

The Recommended Order is silent as to APS's request to eliminate, freeze, and consolidate the following rate schedules: (1) eliminate existing rate schedules DA E-12, DA ET-1, DA ECT-1R, DA E-32, DA E-34, DA E-35, EC-1, E-10, E-38, E-38-8T, EPR-3, EQF-S, EQF-M, E-52 and Solar 1; (2) eliminate rate schedule E-51 in the Company's next rate case; (3) close (freeze) existing rate schedules SP-1, E-32R, and E-55 to new customers and eliminate them in the next rate case; and (4) consolidate Schedule EPR-4 into the revised Schedule EPR-2. No party to the proceeding objected to the above proposal. The Company requests language in the Recommended Order authorizing the above changes. APS Proposed Amendment No. 22 makes this modification.

4. Total Solar Rate.

On page 96 of the Recommended Order, the Order incorrectly lists the Total Solar Rate as $.0225 per kWh. As set forth in Schedule Solar-3, the Solar Power Premium Rate is listed at $.166 per kWh, which is calculated by subtracting the avoided cost credit in the amount of $0.059 per kWh from the Solar Power Price of $.225. APS Proposed Amendment No. 23 makes this modification.

5. Schedule E-56 and E-57.

The Company takes exception to the Recommended Order's rejection of APS's proposed Partial Requirement Schedules E-56 and E-57. Partial Service Rate Schedule E-56 is applicable to general service customers having distributed generating equipment 100 kW or greater capable of supplying all or a portion of their power requirements. Rate schedule E-57 is applicable to general service customers having solar/photovoltaic generating equipment greater than 100 kW but less than 1,000 kW capable of supplying all or a portion of their power requirements.

APS currently has customers that want and would benefit today from these rate schedules, as these proposed rates are superior to the current partial requirement rates offered by the Company for general service customers in these classes. In Decision No. 69416, the Commission approved an electric supply agreement between the Company and Luke Air Force Base, which contained a special contract rate that tracked the terms of Rate Schedule E-57. The special rate was offered to Luke after the installation of two separate photovoltaic ("PV") inverter systems that were interconnected to the Company's system to facilitate Luke's operation of its PV systems for displacing electric power purchases from APS. In recommending approval of the special contract, Staff did a comparative analysis of rates between E-57, E-34 and E-55 (all partial requirement rates available to Luke) and determined that E-57 resulted in the most savings to Luke.

If E-56 and E-57 are not approved at this time, APS customers will have to decide whether to take service under the existing E-34 or E-55 rate schedules or enter into a special contract with APS. If the latter is chosen, the special contracts will need to be approved by the Commission thereby resulting in the expenditure of additional Staff, Company and Commission resources to prepare, analyze and approve each application.

The Company certainly is not opposed to meeting with Staff and other interested parties in an effort to improve E-56 and E-57 in the future or to develop additional alternative partial requirements rate schedules that are cost justified. In fact, the provisions specified in Decision No. 67744 (APS Rate Case Settlement) set up a workshop process (which is currently on-going in Docket No. E-00000A-99-0431) to address and develop experimental partial requirements rate schedules. Such a workshop would be an appropriate venue to address additional partial requirements rate schedules. In the meantime, the Commission should approve E-56 and E-57 so that APS customers can take advantage of these rates. (APS Proposed Amendment No. 24 approves the E-56 and E-57 rate schedules.)

VII. MISCELLANEOUS ISSUES

1. EPS Uniform Credit Purchase Program.

Commission Decision No. 68668[16] required APS to set aside $4.25 million for additional funding for the Environmental Portfolio Standard ("EPS") Uniform Credit Purchase Program ("UCPP") for 2006, and provided that recovery of those funds could be recovered through the Company's on-going rate case. That Decision specifically required APS to ensure that reserved UCPP projects funds were applied to those projects when they were completed, regardless of the year in which they were completed. The Recommended Order authorizes the Company to "true-up" the $4.25 million with actual UCPP costs for 2006; the Recommended Order fails to authorize APS to carry-forward any funds that: 1) have been committed, but are not yet spent; or 2) are unspent funds that were not committed in 2006.

Currently there are various UCPP projects for which funds were reserved in 2006, but the projects were not/will not be completed until sometime in 2007. In addition, as reported in its 2006 EPS Annual Report[17], $1.4 million of the additional funds that were allocated to the UCPP were unreserved in 2006. To maximize the numbers of customers that could benefit from the additional funding, the Company requests that rather than a true-up for calendar year 2006, it be authorized to carry-forward to the subsequent year any unspent or unreserved funds from the additional $4.25 million. Those funds would be earmarked for customer incentive payments.

As part of its case, the Company submitted Adjusted Rate Schedule EPS-1,[18] which was designed to collect the additional $4.25 million over a period of one-year and to terminate at the conclusion of that year, unless expressly continued by the Commission. To meet the intent of Decision No. 68668, the Commission must allow the funds for the reserved-but-not-yet-paid projects, as well as the remaining portion of the original $4.25 million that has not yet been reserved to be disbursed in 2007. The Company requests that the Order specifically adopt Adjustment Schedule EPS-1, and authorize the Company to spend

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[16] Issued April 20, 2006.

[17] Filed in Docket No. E-01345A-01-0034 on March 1, 2007.

[18] *See*, Attachment GAD-2RB, which is attached to the Rebuttal Testimony of Gregory DeLizio.

the remaining reserved and unreserved funds from the $4.25 million for its UCCP program in 2007. The attached Amendment No. 25 will effectuate these changes.

2. Renewable Procurement: Requirements of the RES Rules Are Not in Effect and Have No Place in This Docket.

In its discussion of APS's procurement of renewable energy resources, the Recommended Order makes a troubling suggestion that APS should now be required by virtue of this Recommended Order to acquire resources pursuant to the proposed (but not yet effective) Renewable Energy Standard ("RES") Rules[19]. (Recommended Order, pp. 91-94.) The Recommended Order could be interpreted as imposing the proposed RES Rules on the Company, even though those rules have not yet been certified by the Office of the Attorney General ("AG") and are not yet in force.

The Recommended Order states as follows:

> We note that WRA's recommended 1,300 GWH per year level of renewables is only a goal, not a requirement. We have recently adopted requirements for renewables in our Decision adopting the RES rules, and find that the record in this case supports a finding that the requirement contained in the RES rules is appropriate at this time. Accordingly, we decline to adopt a specific target in this proceeding in addition to what is contained in the RES rules.[20]

The Recommended further recommends a finding[21] that:

> [T]he requirement contained in the RES rules is appropriate for APS at this time, and accordingly, it is not necessary to adopt a specific target in this proceeding in addition to what is contained in the RES rules.[22]

There is simply no need for the Recommended Order to take a position on the RES Rules in this docket. If the AG certifies the Commission's proposed RES Rules, clearly APS will abide by them. If the AG does not certify the Rules because he determines that they are beyond the scope of the Commission's authority, it would be also beyond the Commission's

[19] A.A.C. R14-2-1801 *et seq.*

[20] Recommended Order, p. 93, lines 3-9.

[21] Recommended Order, Finding of Fact 60, p. 140, lines 20-22.

[22] The Recommended Order also contains corresponding Ordering paragraphs.

authority to implement the proposed Rules in this rate proceeding. Either way, the Company should not be subject to them by virtue of this order.

Moreover, there is simply no evidence that the RES Rule requirements belong in this case, much less sufficient evidence in this docket to support their adoption in general. Indeed, the evidence at the hearing was the exact opposite: that the RES Rules were not yet adopted and that any adoption of these Rules should take place in a proceeding apart from APS's rate case. (Trans. Vol. V at 970-971 [Lockwood]; Vol. XIX at 3544, 3565-3566 [Keene].)

To be clear, the Company has recognized the benefit of increasing the role of clean renewable energy for many years. Indeed, APS agreed to abide by additional renewable energy requirements as part of the settlement adopted in Decision No. 67744, and it has successfully implemented those requirements. Even so, the proposed RES Rules are the subject of a separate rule-making docket -- wholly distinct from this rate case -- which should stand on its own.

For these reasons, the Company requests that the Commission delete any discussion about the propriety of the proposed RES Rules and their applicability to the Company from the Recommended Order. (APS Proposed Amendment No. 26 is attached hereto.)

3. <u>Rate Implementation</u>.

Pursuant to the first two Ordering paragraphs in the Recommended Order (pages 148-149), the Company is directed to file revised schedules of rates and charges on or before May 31, 2007, with rates to go into effect on June 1, 2007. However, Finding of Fact No. 34 (Recommended Order at 138) requires that such filing be submitted to Staff for its "review and confirmation" prior to the rates being implemented; there is no timeline set for Staff's "review and confirmation" of any such schedules. From a practical perspective, there may be insufficient time for the Staff to review and confirm the Company's rates and charges before rates would go into effect. Therefore, the Commission should delete the language in Finding of Fact No. 34 that requires "Staff review and confirmation prior to their implementation." APS Proposed Amendment No. 27 makes this modification.

VIII. PALO VERDE ISSUES

APS takes exception to the Recommended Order's conclusions that APS was imprudent in connection with three of the outages Palo Verde experienced during 2005 and to the Recommended Order's directive to APS to work with the Staff to develop a nuclear performance standard ("NPS"). With respect to the three outages, the Recommended Order violates the prudence standard by ignoring the presumption of prudence and engaging in patent speculation about how the outages in question might have been avoided. The Recommended Order's conclusion that, had APS allegedly acted differently, "it is entirely possible that the NRC would not have felt the need to ask the question" that required Units 2 and 3 to shut down in October of 2005, is one such example of purely speculative reasoning. The Recommended Order inappropriately rejects the answers of the NRC's Regional Administrator, Bruce Mallett, that APS should not have anticipated his inspector's question. The Recommended Order also ignores the evidence establishing that whoever posed the question (APS or the Nuclear Regulatory Commission ("NRC")), the result would have been the same, *i.e.*, the plant would have had to shut down and the replacement power costs still would have been incurred.

Similarly speculative is the Recommended Order's conclusion of imprudence regarding the August Unit 1 reactor trip. That conclusion assumes that had APS management been aware of certain perceptions of operators regarding the digital feedwater control system (the record being clear that management was not so aware), management would have initiated supplemental training on this system prior to plant restart, even though use of the system had never caused a reactor trip, and that training would have resulted in the operator in question not violating the procedures that led to the outage. There is simply nothing in the record to support this extended chain of causation.

Finally, even if the Commission were to agree with the Recommended Order regarding the prudence of these three outages, the amount proposed for disallowance is wrong. For example, although the Recommended Order correctly concluded that the performance of other unquestionably prudent work on Unit 2 during the Refueling Water

Tank ("RWT") outages offset $5.1 million in replacement power costs, the Recommended Order proposes to give APS credit for only half that amount (and makes a calculation error in subtracting the half). Similarly, although the Staff witness acknowledged that his calculations for lost off-system sales margins were incorrect and that APS's "approach is probably the more accurate way to do it," the Recommended Order adopts the Staff's admittedly incorrect numbers. When these and other errors are corrected, the proposed disallowance is reduced to $8.464 million (plus interest). Finally, once one appropriately takes into account the superior performance of APS's other baseload units, the disallowance is offset in its entirety.

Turning to the issue of a NPS, the record evidence provides no basis for adoption of a NPS. To the contrary, the evidence establishes that a NPS would be both ineffective and inappropriate. Even if the Commission were ultimately to establish some form of performance standard, the Recommended Order incorrectly concludes, inconsistent with past ACC precedent, that the standard should not include all of APS's baseload generation, but should be limited to Palo Verde performance.

1. <u>The Recommended Order Incorrectly Concludes That There is No Presumption of Utility Prudence and Fails to Adequately Articulate How NRC and Company Documents Are Relevant to a Prudence Review</u>.

APS takes exception to the Recommended Order's characterization of both the prudence standard and the use of certain documents in a prudence determination. (Recommended Order at 117-18.) The Recommended Order accurately states that it is APS's position that there is a presumption of prudence that can only be overcome by the admission of clear and convincing evidence of imprudence. APS cited the Arizona Administrative Code's definition of "prudently invested" at A.A.C. R14-2-103(A)(3)(1), which provides that the presumption of prudence "may be set aside only by clear and convincing evidence." (APS Initial Brief at 141.) The Recommended Order rejects APS's position, stating that the Code's definition applies only to rate base elements and not to operating expenses such as those at issue herein. (Recommended Order at 118 and n. 76.) This is a distinction without a difference. There is no basis why the presumption from A.A.C. R14-2-103(A)(3)(1) should not apply to Palo Verde outages. As demonstrated in Section VIII. 2 below, had the

Recommended Order applied the presumption of prudence to APS's actions in connection with the RWT outages, it is inconceivable that the Recommended Order would have concluded that APS was imprudent simply based on the speculative conclusion that "it is entirely possible" that the NRC would not have felt the need to ask the question that required the plant to shut down. (Recommended Order at 132.)

Additionally, the Recommended Order's description of how certain documents may be used in a prudence determination is inadequate. Although the Recommended Order states that it is "cognizant of the danger of using hindsight" and that only facts that were known or reasonably should have been known should be used (*Id.* at 118), the Recommended Order goes on to merely state that "the use of NRC, Company or other documents . . . is not using 'hindsight' just because the documents were created after the time of the event involved." This is a strawman argument, as APS's position is not based on the fact that the documents in question were created after the event involved. APS's point is that, given that it is normal practice for nuclear industry documents to use hindsight (APS Exhibit 88 at 21 [Mattson].) such documents should be used in a prudence review only to the extent that it is clear that no hindsight was used with respect to the portion of the document in question. (Recommended Order at 118.)

The Recommended Order also mischaracterizes APS's position by stating that "APS chose not to present or offer such a rebuttal" to NRC and Company documents relied on by Staff. (*Id.*) "Rebuttal" of these documents is unnecessary. Rather, APS disputed, among other things, the Staff's and Recommended Order's failure to analyze whether the "information contained in those documents" (*id.*) was only known in hindsight. A perfect example of this failure occurred in the Recommended Order's analysis of the Unit 1 August reactor trip as demonstrated in Section VIII. 3 below. (APS Initial Brief at 143-45.) (APS Proposed Amendments Nos. 28 and 30 make these modifications.)

2. <u>The Recommended Order's Finding that APS Was Imprudent with Respect to the October RWT Outages is Based on Pure Speculation and Improperly Rejects the Views of the NRC Regional Administrator that APS Should Not Have Anticipated the Issue</u>.

The Recommended Order finds that APS was imprudent with respect to the October outages at Units 2 and 3 resulting from the NRC's raising of a question that the most senior NRC official involved, Regional Administrator Bruce Mallett, characterized as a "new question." (Recommended Order at 132.) The Recommended Order concludes that APS was imprudent even though Dr. Mallett stated that the NRC "evaluate[d] whether they [APS] should have found it beforehand," and that "we didn't determine that they should have found it beforehand." (APS Exhibit No. 104 at 43, 46.) The Recommended Order reaches its result on an incorrect factual basis and a patently speculative conclusion that "if APS had initially demonstrated knowledge, competency and experience in how the design was intended to address the air entrainment issue, and had studied relevant operating experience, **it is entirely possible** that the NRC would not have felt the need to ask the question about performance under 'dynamic conditions.'" (Recommended Order at 132 (*emphasis added*).) Disallowance of replacement power costs on such speculative grounds is an incorrect application of the prudence standard.

Turning to the factual basis of the Recommended Order, despite its lengthy discussion of the parties' positions, the Recommended Order ignores key documentation demonstrating that APS did address for the NRC how "the design was intended to address the air entrainment issue." (*Id.*) As Dr. Mattson explained, the designer of the plant had recognized the potential for air entrainment in the RWT suction line, and had established design requirements that were implemented at Palo Verde to foreclose this possibility. When the NRC inspector raised the issue of air entrainment, Palo Verde personnel provided the original design basis documentation from Combustion Engineering demonstrating that air entrainment would not occur. (APS Exhibit No. 88 at 7-8 [Mattson].) However, the NRC inspector was not satisfied with this response, and posed what NRC Regional Administrator Mallett later described as the "new question" of how dynamic conditions would affect the issue of air entrainment.

In addition to being speculative, the Recommended Order is also circular. Since the NRC inspector's criticism of Palo Verde personnel's purported lack of knowledge of "how the design was intended to address the air entrainment issue" is based on their lack of knowledge of the answer to his question about how the design behaves under dynamic conditions, the only way it can be said that the inspector "would not have felt the need to ask the question" about dynamic conditions is if Palo Verde personnel had anticipated his question and affirmatively provided him the dynamic calculation before he asked for it. Thus, the Recommended Order is demonstrably wrong in stating that "the question to be asked is not should APS have anticipated the NRC's question, but why did the NRC inspector feel the need to ask the question."

Of course, once one frames the question as being whether APS should have anticipated the NRC's question, the answer is clear. As noted above, NRC Regional Administrator Mallett told this Commission that his inspector's question was a "new question" and that "we didn't determine that they should have found it beforehand." (APS Exhibit No. 104 at 46.) The Recommended Order's rejection of Dr. Mallett's statements to this Commission on the ground that he was not making a "prudence determination" is unwarranted. (Recommended Order at 130.)

Contrary to the Recommended Order's assertion, APS is not attempting to "have it both ways." (*Id.*) Obviously, Dr. Mallett was not making a prudence determination -- that is a function of the Commission. However, as the Recommended Order itself states, NRC statements can be used in a prudence case and in this case Dr. Mallett was expressing his expert opinion on an issue directly relevant to a prudence determination. (*Id.* at 118.) As pointed out above, such use should be limited to those situations where it is clear that the NRC statements are not based on hindsight. Dr. Mallett was not exercising hindsight on this issue. As he told this Commission in response to questioning by Commissioner Mayes, the NRC evaluated whether APS should have asked itself the question beforehand and concluded that it should not have done so.[23] Dr. Mallett was considering this issue -- not because he was

[23] This is quite different from most of the NRC's activities where it is irrelevant to the NRC whether the licensee's actions were reasonable, but instead the NRC uses hindsight to continually improve safety performance. (APS Exhibit No. 87 at 8 [Mattson].) Moreover, even if Dr. Mallett had been applying the more rigorous NRC standard that relies on hindsight, this would not save the Recommended Order, as it would only provide added weight to Dr. Mallett's

making a prudence determination but a determination nonetheless within his area of special expertise. Dr. Mallett had to address the issue whether APS should have anticipated his inspector's question because he had to answer the question of whether APS had done an adequate "extent of condition" review. (Tr. Vol. XXIX at 5389 [Jacobs].) Dr. Mallett voluntarily appeared before this Commission and provided full and complete answers to the Commission's questions. The Recommended Order's rejection of Dr. Mallett's answers on the ground that he was not making a prudence determination should be rejected.

Instead of accepting Dr. Mallett's direct response to the Commission on the issue of whether APS should have anticipated the question that led to the outage, the Recommended Order instead relies on inapposite excerpts from the NRC's January 27, 2006 inspection report (which Dr. Mallett approved.). For example, because the NRC inspector's question had not previously been posed by the NRC, it is not of any significance that the inspection report observed that the licensee did not fully understand the "dynamics of the system at the time of a RAS." (Recommended Order at 125.) Other quotations from the NRC inspection report included in the Recommended Order are similarly irrelevant to the issues before this Commission and are reflective of the hindsight the NRC normally employs. For example, the comment that "there was not a thorough effort by the licensee to validate the design criteria" (*Id.* at 127) has no bearing on whether APS should have anticipated the inspector's question. As Dr. Mattson testified, there was no requirement for APS to validate the adequacy of the design prior to the NRC inspector's question. Design compliance rather than design adequacy was the issue in the yellow finding. (APS Exhibit No. 88 at 9-10 [Mattson].) Similarly, although the NRC inspection report states that Palo Verde did not consider all relevant operating experience, NRC did not find that APS should have found these arcane instances of "operating experience" before the NRC inspector asked the question and which arguably become "relevant" only in hindsight. (APS Exhibit No. 87 at 59-62 [Mattson]). The Recommended Order's reliance on such hindsight-laden comments from the NRC inspection

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conclusion that APS management should not have anticipated the NRC inspector's question, and thus would not have avoided the outage.

report and its rejection of Dr. Mallett's answers to the direct questions this Commission posed to him are unreasonable and should be rejected.

Finally, even if one accepts the reasoning of the Recommended Order, no disallowance would be appropriate. Even if the NRC inspector had not felt the need to ask the question about performance under dynamic conditions because APS personnel had "adequately familiarized themselves" with the voided pipe event and how it related to the RWT (Recommended Order at 132), that scenario would still have resulted in a shutdown in the summer of 2005 until an analysis, like that actually performed in October 2005, was completed. As Dr. Mattson explained, if the issue was raised during preparations for the NRC inspection, "then the technical specifications require a SRO [senior reactor operator] in the control room of each operating unit to declare the RWTs inoperable and shut the operating units down, just like APS did for the question raised by the NRC contract inspector." (APS Exhibit No. 88 at 6 [Mattson].) As Dr. Mallett told this Commission, until the issue was resolved, APS was required to shut down the plant under its technical specifications, and APS "did the right thing" when it did so. (APS Exhibit No. 104 at 46.) Thus, the replacement power costs in question still would have been incurred. Disallowing these costs would inappropriately penalize APS for "doing the right thing" in the interest of nuclear safety. APS Proposed Amendment No. 32 makes these modifications.

3. <u>The Recommended Order Improperly Applies the Prudence Standard to the Unit 1 August 2005 Reactor Trip, which was Not Caused by Management Imprudence</u>.

APS takes exception to the conclusion in the Recommended Order that the Unit 1 August reactor trip was the result of APS's imprudence. (Recommended Order at 124.) The Recommended Order asserts that "[t]hese facts and the existence of the operators' opinions concerning the reliability of system procedures were known and knowable at the time of the startup." In fact, the record is clear that APS management did not know of operator concerns with the Digital Feedwater Control System ("DFWCS") or that those concerns would lead to a reactor trip. At the hearing, Staff's witness was unable to demonstrate that APS management was aware of any concerns with this system. (Tr. Vol. XXIX at 5395-97

[Jacobs]; APS Reply Brief at 43.) Moreover, the Recommended Order expressly acknowledges that "Mr. Levine and [Palo Verde] management were unaware of relevant opinions and facts," demonstrating that they did not have knowledge of concerns with the DFWCS at the time of the reactor trip. (Recommended Order at 123.)

Second, regarding whether APS management should have known of operator concerns with the DFWCS, the Recommended Order both relies on hindsight and an erroneous impression of operators' roles during a plant outage, concluding that "Unit 1 had been shut down for two weeks when APS began the startup and it should have used that time to insure that the operators were adequately trained on the startup procedure." (*Id.*) When a unit shuts down, the operators do not stop their jobs and simply wait to restart the unit. Rather, these operators remain at their stations monitoring plant status and safety, as well as being intimately involved in addressing problems associated with the outage.

Similarly, the Recommended Order's statement that "APS should ask and know what the concerns are of the operators, especially when those operators have a 'common mindset' that there is a problem in a system or procedures that can trip a reactor" reflects the circularity of its reasoning as this presumes, contrary to its own finding, that management was aware of the concern. (*Id.* at 123-24.) Indeed, the root cause evaluation, which the Recommended Order relies heavily upon, characterized the concerns with the DFWCS as an "unidentified difficulty." (*Id.* at 122.)

Finally, the Recommended Order improperly gives short shrift to the fact that the reactor trip was due to the failure of the secondary control room operator to follow procedures, including informing his supervisor of the actions he planned to take. (*Id.* at 123.) Even Dr. Jacobs acknowledges that "the unit tripped due to an operator error in controlling the feedwater to the steam generator." (Staff Exhibit No. 46 at 24 [GDS Report].) Had the operator simply followed procedures and left the steam generator feedwater level control system in automatic, the reactor would not have tripped. (APS Exhibit No. 95 at 8 [Levine].) Thus, the Recommended Order's proposed disallowance is dependent on: (1) had APS management known of the later-recognized "perception" of difficulties with the DFWCS, and even though this perception had never resulted in a reactor trip, (2) APS nonetheless would have required further training prior to restart, and (3) this training would have prevented the operator from failing to follow procedures, thereby avoiding the outage. The degree of speculation required to reach this result is extraordinary and is in plain violation of the prudence standard. APS Proposed Amendment No. 31 makes these modifications.

4. <u>The Recommended Order's Disallowance is Improperly Calculated and Does Not Incorporate Valid Offsets</u>.

As discussed above, the Commission should not approve any disallowance, because none of the 2005 Palo Verde outages was imprudent. Nonetheless, if the Commission determines that any of the outages were imprudent, APS takes exception to the offsets and calculations in the Recommended Order. The following changes should be made.

A. Offset For Prudent Maintenance During the RWT Outage.

The Recommended Order states that Staff recommended disallowance of $16.186 million. This includes $13.757 million of replacement power costs during the PSA period and $2.103 million of reduced margins on off-system and opportunity sales, totaling $15.860 million, plus $0.326 million of interest. (Recommended Order at 111; GDS Report at 49.) Although APS agrees with the Recommended Order's conclusion that reactor coolant pump oil seal work performed during the Unit 2 October RWT outage was prudent and saved $5,100,000 of later costs, APS takes exception to the Recommended Order's arbitrary conclusion that this amount "should be shared between ratepayers and shareholders." (Recommended Order. at 133.)

This issue becomes moot if the Commission concurs with APS that the RWT outages were not the result of imprudence. However, if the Commission agrees with the Recommended Order that these outages were caused by APS imprudence, APS is entitled to offset from the replacement power costs incurred during those outages the entire $5,100,000 because, as the Recommended Order recognizes (*Id.*), it performed prudent maintenance during the Unit 2 October RWT outage that prevented a later outage. (APS Initial Brief at 157-59). The Recommended Order provides no reason for splitting this amount, and no party to this proceeding has even proposed this as an option. The $5,100,000 should be treated the same as the costs of any other prudent outage. Disallowing recovery of any of these costs is inappropriate because APS is entitled to recover all prudent costs deferred under the PSA. (Recommended Order at 111.)

Even if the Commission were to agree with the Recommended Order and split the $5,100,000 amount in half, the Recommended Order still must be changed to correct a typographical error in its calculations. (*Id.* at 133.) The Recommended Order incorrectly uses the value of $2,250,000 for this offset instead of $2,550,000. Therefore, simply fixing the typographical error decreases the Recommended Order's disallowance from $13.610 million (plus interest of $0.326 million) to $13.310 million (plus interest). Properly applying the entire amount of $5,100,000 to the Recommended Order's disallowance yields a disallowance of $10.760 million (plus interest). However, this number remains incorrect because of other errors contained in the Recommended Order as discussed below.

B. Disallowance For Lost Off-System Sales Margins.

APS also takes exception to the Recommended Order's use of the Staff's calculation for lost off-system sales margins. (*Id.* at 132.) In fact, Staff's own witness stated that this calculation is incorrect and APS's calculation is more accurate, and APS used a methodology that has been used by the Commission in the past. The Recommended Order disregards these facts.

At the hearing, Staff's own witness, Dr. Jacobs, admitted that his calculation for lost off-system sales margins, which resulted in a disallowance of $2,103,000[24], was inaccurate, because it makes the erroneous conclusion that every megawatt hour of power that could have been produced by Palo Verde would have been sold. (Tr. Vol. XXIX at 5303-04 [Jacobs].) APS presented its own calculation (APS Initial Brief at 177-78) using a methodology which the Recommended Order admits "has been used by the Commission in the past," which

[24] All of the disallowances for lost off-system sales margins in this section assume that the Commission concludes that the August reactor trip and the October RWT outages were imprudent. If any of these outages are determined to be prudent, then these amounts must decrease. These values are shown in the chart on page 181 of APS's initial brief.

resulted in a much lower disallowance of $322,000. (Recommended Order at 132.) At the hearing, Dr. Jacobs also conceded that APS's "approach is probably the more accurate way to do it." (Tr. Vol. XXIX at 5314 [Jacobs]). Notwithstanding Staff's witness's own admission that his calculation is inaccurate and his concession that APS's methodology is more accurate, Staff and the Recommended Order continue to maintain that Staff's original erroneous calculation should be used.[25] (Recommended Order at 132.) For these reasons, the Commission should use APS's calculation for any lost off-system sales margins.

If the appropriate disallowance for lost off-system sales margins is used, then the disallowance (offsetting the full $5.1 million for prudent maintenance) of $10.760 million is further reduced to $8.979 million (plus interest).[26]

C. Offset For Costs Already Expensed.

APS takes exception to the Recommended Order's omission of an offset for costs already expensed due to Dr. Jacobs' incorrect disallowance calculation. (*Id.* at 133.) The Recommended Order and Staff's briefs in this proceeding do not even address APS's argument that Dr. Jacobs' methodology for calculating his recommended disallowances did not accurately apply the 90/10 sharing, because his methodology discounted the normal amount of outages in the base rates, resulting in APS expensing $515,000 twice. (APS Initial Brief at 178; APS Reply Brief at 45). This additional amount should be deducted from any disallowance by the Commission.

If this offset is appropriately included, then the $8.979 million from above is further reduced to $8.464 million (plus interest).

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[25] Even if the Commission were to give credence to Dr. Jacobs' claimed discrepancies, this would only increase the lost off-system sales margins from $322,000 to $522,000 – still a far cry from the $2,100,000 disallowance that Dr. Jacobs initially proposed. (APS Initial Brief at 178.)

[26] In addition to the option of concluding that the August reactor trip and the October RWT outages are either all prudent or all imprudent, the Commission could conclude that only one of the outages was imprudent. If the Commission concludes that the August reactor trip was imprudent, but the October RWT outages were prudent, then the appropriate disallowance amount would be $1.113 million ($1.046 million replacement power costs and $0.067 million margin) (plus interest). Conversely, if the Commission concludes that the August reactor trip was prudent, but the October RWT outages were imprudent, then the appropriate disallowance amount would be $7.812 million ($12.710 million replacement power costs and $0.202 million margin minus $5.100 million prudent maintenance) (plus interest). (APS Initial Brief at 181.)

D. The Superior Performance of APS's Baseload Generation System During 2005 More Than Offsets Any Disallowance Associated With the Palo Verde Outages.

APS takes exception to the Recommended Order's rejection of an offset for superior coal plant performance. (Recommended Order at 133.) The Recommended Order's conclusion that "improved coal performance has nothing to do with the Palo Verde outages" (*Id.*) fails to recognize that APS customers are impacted by the performance of the entire APS baseload generation system. (APS Initial Brief at 149; APS Reply Brief at 46.) As Mr. Ewen testified, the Company's coal plants set an all-time high for capacity factor in 2005. (APS Exhibit No. 17 at 25 [Ewen].) The plants had 40 percent less unplanned outage time than the normalized amount included in the Company's base rates, and this "better than normal" performance reduced fuel costs by $10,000,000. (*Id.*) As Mr. Ewen explained further at the hearing, had the coal plants not performed so well, there would have been 300 gigawatt hours more of unplanned outages that would have had to have been replaced at a cost of $10,000,000. (Tr. Vol. XXVIII at 5223 [Ewen].) That $10,000,000 savings is not reflected in the replacement power costs for Palo Verde, and thus, it is an appropriate offset to these costs. (*Id.* at 5222 [Ewen].) Therefore, this amount should be deducted from any disallowed costs. Offsetting the Palo Verde outages based on excellent coal plant performance is consistent with the principle that "a realistic analysis of operating performance must look at both the 'successes' and the 'failures' if it is to avoid setting unobtainable goals of absolute perfection." (Decision No. 55118 (July 24, 1986).) Since the $10,000,000 is larger than the amount of $8.464 million calculated above, the entire disallowance is offset. Similarly, comparing APS's outstanding 2005 coal plant performance against its industry peers results in an even more dramatic savings of $27,492,000, which would offset the entire disallowance proposed by Staff and the Recommended Order. (APS Exhibit 91 at 13 [Fitzpatrick].) APS Proposed Amendments Nos. 33 and 36 makes these modifications.

5. <u>A Performance Standard is Unnecessary and Inappropriate, but if One is Ultimately Adopted, it Should Include All Baseload Plants</u>.

APS takes exception to the Recommended Order's directions that the Staff and APS "work out a detailed NPS" to be considered in a separate proceeding and that such a standard should be limited to Palo Verde and "not includ[e] baseload coal or other non-nuclear plants." (Recommended Order at 117 and n. 75.) The Recommended Order directs the development of a NPS despite its recognition that (1) Staff's own consultant, Dr. Jacobs, testified before the Georgia Commission that a NPS should be terminated because it had no impact on how the utility operated the plant, and (2) the Georgia Commission accepted Dr. Jacobs' recommendation. (*Id.* at 115-16). There is nothing in the Recommended Order to indicate that a NPS would have any different or salutary effect with respect to Palo Verde performance. In fact, the evidence is to the contrary. (*E.g.,* Tr. Vol. XXVII at 5127 [Levine].) Accordingly, a NPS is unnecessary because it will not affect APS performance.

A NPS also is inappropriate because as the NRC's Policy Statement declares: "an incentive program could directly or indirectly encourage the utility to maximize measured performance in the short term at the expense of plant safety (public health and safety)." (APS Exhibit No. 101.) The Recommended Order recommends adoption of a NPS apparently based on the view that "the Commission should be concerned about Palo Verde's recent performance and should be monitoring APS operation of the Palo Verde plants." (Recommended Order at 117.) Adoption of an ineffective and inappropriate tool such as a NPS, however, is not a reasonable way to address this concern.

The Recommended Order also recommends that, in the interim until a NPS is developed by APS and Staff and adopted by the Commission, APS should file documentation with the Commission explaining the reason for each planned or unplanned outage and associated costs within 60 days of the conclusion of the outage. This recommendation is unnecessarily duplicative and burdensome. The Staff has already submitted data requests to APS regarding the 2006 outages, which APS has answered. As part of these answers, APS has provided extensive documentation regarding these outages. Staff also recommended and APS has agreed to file semi-annual reports with the Commission regarding Palo Verde performance. (*See* Section VIII. 6 below.) Additionally, APS already files a comprehensive list of all generating unit outages monthly in its PSA reports as well as the monthly replacement power costs associated with unplanned outages disaggregated by resource type.

The Recommended Order's requirement to file similar information is unnecessary and duplicative. Finally, APS currently advises the Staff by telephone of every upcoming planned outage and as soon as possible after commencement of any unplanned outage. There is no need for yet more reports.

Finally, even if the Commission adopts the recommendation in the Recommended Order that the Staff and APS develop a performance standard, the Commission should reject the Recommended Order's directive that the standard should be limited to Palo Verde and not include baseload coal plants. First, this recommendation also contradicts the NRC's Policy Statement, which states that a performance standard should incorporate "performance measures of the entire system . . . ." (APS Exhibit No. 101 at 4.) Second, nuclear units are similar to coal units because both provide baseload power and both "enjoy a significant cost advantage over purchased power and have the potential to confer a substantial benefit on APS' customers when run successfully." (APS Exhibit No. 91 at 9 -10 [Fitzpatrick].) Third, although Staff states that nuclear and coal plants "use different operational and safety processes, are subject to different forms of regulation, and have costs that are unrelated and not directly comparable," neither Staff nor the Recommended Order provide any reason why any of these alleged differences would preclude coal units from being included in a performance standard. (Recommended Order at 116.) Indeed, this Commission has adopted a performance standard in the past that included both nuclear and coal generating units. (Decision No. 54247 at 15-16 (Nov. 28, 1984).) The Recommended Order provides no explanation why this past precedent should not be followed. The Recommended Order's directive that baseload coal plants should not be included in a performance standard accordingly should be rejected as arbitrary and unreasonable. At the very least, if the Commission instructs APS and Staff to work together to develop a performance standard that would be considered in a separate proceeding, then the Commission should not preclude discussion of any performance standard attributes, including the inclusion of coal plant performance. APS Proposed Amendments Nos. 29 and 35 make these modifications.

6. APS Will Submit the Recommended Reports, but as Recognized By the Recommended Order, there May be Limitations on the Information Provided.

Although APS has agreed to submit the reports proposed by Staff if so required, as the Recommended Order recognizes, "APS testified that it was willing to file the reports to the extent it was possible." (Recommended Order at 135.) These reports must be submitted with certain limitations.

The first report recommended by GDS was "a semi-annual report to the Commission's Docket Control, describing plant performance, explaining any negative regulatory reports by the NRC or INPO [Institute of Nuclear Power Operations], and providing details of corrective actions." (*Id.* at 112.) If required, APS will submit these reports, but APS can only submit information from INPO to the extent that INPO consents to disclosure of such information. Likewise, APS may be prohibited from submitting other confidential information (e.g., vendor proprietary information), or may only be able to make certain information available for review. Additionally, APS suggests that the period for which these reports must be provided should have a self-executing termination point, such as when the NRC moves Palo Verde to the "Licensee Response Column" (Column 1) of the Reactor Oversight Process Action Matrix.

The second and third reports recommended by GDS are an evaluation of APS's "programs to deal with aging equipment at Palo Verde" and "programs for receipt inspection and verification of parts prior to installation," including evaluation of "programs established at other nuclear plants that have been successful" with these issues. (*Id.* at 112-13.) In response to a data request, GDS stated that it had not identified specific plants with successful programs in these areas, but suggested that APS contact INPO for a list of such plants. (APS Exhibit No. 94 at 31 [Levine].) APS remains willing to provide these reports but wishes to make clear that the content of these reports will be dependent upon the results of any information received from INPO. APS Proposed Amendment No. 34 makes these modifications.

RESPECTFULLY SUBMITTED this 15th day of May, 2007.

PINNACLE WEST CAPITAL CORPORATION
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ORIGINAL and thirteen (13) copies of the foregoing filed this 15th day of May, 2007, with:

Docket Control
ARIZONA CORPORATION COMMISSION
1200 West Washington Street
Phoenix, Arizona 85007

AND copies of the foregoing mailed, hand-delivered, faxed or transmitted electronically this 15th day of May, 2007 to:

Mike Gleason, Chairman
William A. Mundell, Commissioner
Jeff Hatch-Miller, Commissioner
Kristin K. Mayes, Commissioner
Gary Pierce, Commissioner

Lyn Farmer, Chief Administrative Law Judge
Christopher Kempley, Chief Counsel
Ernest Johnson, Utilities Division Director
All Parties of Record

Donna Turner

ATTACHMENT A

INDEX

FINANCIAL INTEGRITY

APS PROPOSED AMENDMENT # 1

<u>Cost of Equity</u>

Page 49, Line 14: DELETE "10.75", REPLACE WITH "11.50"

Line 19: DELETE "10.75%", REPLACE WITH "11.50%"

Line 19: DELETE "5.86%", REPLACE WITH "6.27%"

Line 20: DELETE "8.32%", REPLACE WITH "8.73%"

MAKE ALL CONFORMING CHANGES TO FINDINGS OF FACT NOS. 28 AND 30, AND ELSEWHERE AS REQUIRED.

APS PROPOSED AMENDMENT # 2

APS Revenue Enhancement Proposals – CWIP, Accelerated Depreciation and Attrition

Page 49, Line 14: After "do', DELETE "not"

Line 14: DELETE "a flotation adjustment or", REPLACE WITH "an"

Line 15: DELETE "or", REPLACE WITH "and"

Page 63, Line 4: After "will", INSERT "not"

Lines 15-17: DELETE "APS" through "flow."

Page 63, Line 18- Page 67, Line 2: DELETE paragraphs, REPLACE WITH the following:

"However, it is clear that in establishing "just and reasonable" rates, the Commission may consider the projected impact of the rate decision on a regulated utility's financial criteria, including its ability to "maintain and support its credit" and to "raise the money" necessary for the further operation of its business. In fact, the law requires that rates be just and reasonable when they are in effect, which necessitates some forward looking and not just rigid adherence to the historical test year to the extent that the evidence in the record supports a finding that the test year is unrepresentative of present conditions.[1] Other regulatory commissions often take into consideration the projected impact of a rate decision on a company's financial indicators, particularly the company's credit standing with the major credit rating agencies.[2] So has this

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[1] *See*, *Scates.*

[2] (*See, e.g.*, Tr. Vol. XXIV at 4577-78 [Brandt] (citing Tom McGhee, *State Oks Xcel rate hike*, Denver Post, Nov. 21, 2006. Responding to questions about an Xcel Energy settlement agreement (Decision No. C06-1379) that increased rates, PUC Chairman Gregory Sopkin "said a smaller rate increase could damage Xcel's credit rating and increase its borrowing costs."); APS Exhibit No. 23 at 25 [Fetter] (referring to Missouri Public Service Commission ("MPSC") Case No. EO-2005-0329 at 14-15, where the MPSC decided that in making rate decisions for the next several years for Kansas City Power & Light ("KCPL") it will rely on "S&P's publicly-disseminated credit ratio guidelines to ensure that KCPL's key financial measures would remain at levels adequate for its 'BBB' credit ratings."); *see, also,* Tr. Vol. VI at

Commission in the past Decisions. *See, e.g.,* Decision No. 54204 (October 11, 1984).

Moreover, in response to a letter from Chairman Hatch-Miller[3] that requested APS to propose methods for improvement of the Company's cash flow and related financial metrics such as its FFO/Debt ratio, APS proposed several additional measures for the Commission to consider that would address the Company's ongoing cash flow problems and the earnings attrition that results from the delay in recovering large capital expenditures. These measures included: a) inclusion of CWIP in rate base; b) allowance of accelerated depreciation; and c) an attrition allowance to give the Company an opportunity to earn its allowed ROE.

The inclusion of CWIP in rate base and accelerated depreciation produces no increased earnings for the Company and will eventually yield reductions in revenue requirements for future ratepayers. These devices merely increase cash flow by accelerating cost recovery. Both of these revenue enhancement tools address the timing of cost recovery, not the entitlement to that cost recovery. They are recognized methods for a regulatory commission to address cash flow shortfalls or regulatory lag in the recovery of capital expenditures that have been utilized by this Commission (as well as other commissions) in the past. (Tr. Vol. I at 106 [Wheeler]; APS Exhibit No. 5 at 25 [Brandt].) Just in the last two years, both the Colorado Public Utility Commission and the Missouri Commission

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1284-86 [Fetter]; APS Exhibit No. 23 at 27-28 [Fetter] (noting that last year the Colorado Public Service Commission approved a comprehensive settlement agreement (Decision No. C06-1379) allowing the Public Service Company of Colorado to peg certain rate increases to that company's "credit quality" rating.); *see, also, e.g., In re Public Service Co. of Indiana*, 72 P.U.R. 4th 660, 677 (Mar. 7, 1986); Cause No. 37414 (taking into consideration the company's S&P and Moody's ratings and the company's need to "have reasonable access to the capital markets to provide for its future capital needs...."); *see, also, In re Commonwealth Edison Co.*, 49 P.U.R. 4th 62, 76 (May 6, 1982); Decision No. 82-0026 (recognizing that a "further downgrading of Edison's credit ratings, particularly as to commercial paper, would immediately restrict Edison's day-to-day financing of all expenditures...."); *see, also, Public Serv. Co. of Colorado v. Publ. Utilities Comm'n of Colorado*, 653 P.2d 1117, 1122-23 (1982)(upholding rate increase where evidence showed that the company's "ability to raise capital was seriously impaired due to decreased earnings and a downgrading of [the company's] rating by both Moody's and Standard & Poors [sic].")).

[3] *See* letter dated July 21, 2006 from then Chairman Hatch-Miller (APS Exhibit No. 5 at Attachment DEB-11RB).

used combinations of CWIP in rate base and accelerated depreciation to deal with recurring cash flow problems of the utilities in question and the adverse impact that such cash flow problems was having on the credit metrics and credit ratings of those utilities. (*See* APS's Initial Brief at 28-29; APS Exhibit No. 23 at 25-28 [Fetter].)[4]

As of June 30, 2006, the Company's CWIP accounts included $261 million of generation and distribution plant expenditures. (APS Exhibit No. 24 at 17-18 [Fetter]). By placing these amounts in rate base, the Company would obtain cash flow to pay the financing costs it currently incurs on these existing expenditures. (APS Exhibit 5 at 25 [Brandt]). Specifically, inclusion of $261 million of CWIP in rate base would increase APS's annual revenue by $33 million. (*Id.* at 25-26). This additional $33 million in annual revenue would generate for the Company after taxes a total of $20 million in positive cash flow annually. (*Id.*). As a result, the Company's FFO/Debt ratio would improve by an additional one-half percent in each of the next several years. (*Id.* at 27).

Like the inclusion of CWIP in rate base, an allowance for accelerated depreciation will help improve the Company's cash flow, and, therefore, the Company's creditworthiness. Accelerating some of this depreciation expense has the beneficial impact of increasing cash flow, thereby increasing FFO. For example, an allowance of $50,000,000 per year in accelerated depreciation would generate about $30,000,000, after income taxes, of additional positive cash flow, which would have the effect of improving the Company's FFO/Debt ratio by about seven-tenths of a percent in each of those years. (*Id.* at 25).

An attrition allowance is also a regulatory tool that allows the Commission to address concerns that the Company will

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[4] Commenting on the inclusion of CWIP in rate base by the Colorado Commission , S&P stated:

> This is a major step forward in eliminating the tug-of-war over cost recovery that, in the past, has plagued the credit of so many utilities when the time comes to build again.

(APS Exhibit No. 23 at 28 [Fetter], citing *S&P Research: PS Colorado Garners Support for Credit Quality Up-Front; a Viable Model for the Electric Industry*, March 29, 2005.)

be unable to earn its allowed rate of return because of the lag between the Company's current need to expend huge sums for expansion of plant and equipment to meet the needs of a rapidly growing customer base and the eventual recovery of those sums in future rate base adjustments approved by the Commission. (*See* APS Exhibit No. 5 at 28 [Brandt]."

Page 67, Line 8: DELETE Footnote 44.

Page 67, Line 15-
Page 68, Line 13: DELETE "Thus" through "rates.", REPLACE WITH the following:

"This does not, however, preclude the Commission from taking into consideration other relevant factors in establishing "just and reasonable" rates. As the largest electric utility in the State, it is in the public interest that APS be given the regulatory tools necessary to maintain its investment grade credit rating. Should APS fall below investment grade to "junk" status, it will limit the Company's ability to access the capital markets and increase its borrowing costs thereby resulting in higher future rates for customers. Such a credit rating drop would likely also prevent business (such as some of the counterparties to this case) from doing business with APS, thus limiting the Company's ability to engage in business opportunities that would prove beneficial to it and its customers.

The inclusion of CWIP in rate base and accelerated depreciation produces no increased earnings for the Company, increase cash flow by accelerating cost recovery and may eventually yield reductions in rates for future ratepayers. Further, the approval of an attrition allowance will provide the Company with the opportunity to earn its allowed rate of return because of the lag between the Company's current need to expend huge sums for expansion of plant and equipment to meet the needs of a rapidly growing customer base and the eventual recovery of those sums in future rate base adjustments approved by the Commission.

Based upon the discussion contained herein, we find that it is appropriate and in the public interest in establishing just and reasonable rates to: 1) include $261 million of CWIP in rate base; 2) accelerate depreciation by $50,000,000 per year; and 3) provide an attrition allowance of 1.7% to be added to the Company's ROE."

Page 138, Lines 14-15: DELETE "not" and "or necessary" and "any of"

Line 17: After "rates", INSERT "except as provided herein."

Lines 18-21: DELETE Findings of Fact Nos. 37 and 38.

Page 141, Line 12: INSERT new Finding of Fact 67 as follows: "67. APS should be permitted to accelerate depreciation by an additional $50,000,000 per year which will increase its cash flow and further improve its creditworthiness."

Page 148, Line 7: DELETE "not" and "or necessary" and "any of"

Line 11: After "rates", INSERT "except as provided herein."

Page 151, Line 2: INSERT new Ordering paragraph as follows: "IT IS THEREFORE ORDERED that APS is authorized to include an additional $50,000,000 per year in its proposed depreciation rates for jurisdictional plant-in-service."

MAKE ALL CONFORMING CHANGES TO ORIGINAL COST RATE BASE, FAIR VALUE RATE BASE, REQUIRED OPERATING INCOME, AND REVENUE REQUIREMENTS.

APS PROPOSED AMENDMENT # 3

APS Revenue Enhancement Proposals – CWIP Only

Page 63, Line 4: After "will" INSERT "not"

Lines 15- 17: DELETE "APS' through "flow."

Page 63, Line 18-
Page 67, Line 2: DELETE paragraphs, REPLACE WITH the following:

"However, it is clear that in establishing "just and reasonable" rates, the Commission may consider the projected impact of the rate decision on a regulated utility's financial criteria, including its ability to "maintain and support its credit" and to "raise the money" necessary for the further operation of its business. In fact, the law requires that rates be just and reasonable when they are in effect, which necessitates some forward looking and not just rigid adherence to the historical test year to the extent that the evidence in the record supports a finding that the test year is unrepresentative of present conditions.[5] Other regulatory commissions often take into consideration the projected impact of a rate decision on a company's financial indicators, particularly the company's credit standing with the major credit rating agencies.[6] So has this

[5] *See, Scates.*

[6] (*See, e.g.*, Tr. Vol. XXIV at 4577-78 [Brandt] (citing Tom McGhee, *State Oks Xcel rate hike*, Denver Post, Nov. 21, 2006. Responding to questions about an Xcel Energy settlement agreement (Decision No. C06-1379) that increased rates, PUC Chairman Gregory Sopkin "said a smaller rate increase could damage Xcel's credit rating and increase its borrowing costs."); APS Exhibit No. 23 at 25 [Fetter] (referring to Missouri Public Service Commission ("MPSC") Case No. EO-2005-0329 at 14-15, where the MPSC decided that in making rate decisions for the next several years for Kansas City Power & Light ("KCPL") it will rely on "S&P's publicly-disseminated credit ratio guidelines to ensure that KCPL's key financial measures would remain at levels adequate for its 'BBB' credit ratings."); *see, also,* Tr. Vol. VI at 1284-86 [Fetter]; APS Exhibit No. 23 at 27-28 [Fetter] (noting that last year the Colorado Public Service Commission approved a comprehensive settlement agreement (Decision No. C06-1379) allowing the Public Service Company of Colorado to peg certain rate increases to that company's "credit quality" rating.); *see, also, e.g., In re Public Service Co. of Indiana*, 72 P.U.R. 4th 660, 677 (Mar. 7, 1986); Cause No. 37414 (taking into consideration the company's S&P and Moody's ratings and the company's need to "have reasonable access to the capital markets to provide for its future capital needs...."); *see, also, In re Commonwealth Edison Co.*, 49 P.U.R. 4th 62, 76 (May 6, 1982); Decision No. 82-0026 (recognizing that a "further downgrading of Edison's credit ratings, particularly as to commercial paper, would immediately restrict Edison's day-to-day financing of all expenditures...."); *see, also, Public Serv. Co. of Colorado v.*

Commission in past Decisions. *See, e.g.*, Decision No. 52404 (October 11, 1984).

Moreover, in response to a letter from Chairman Hatch-Miller[7] that requested APS to propose methods for improvement of the Company's cash flow and related financial metrics such as its FFO/Debt ratio, APS proposed several additional measures for the Commission to consider that would address the Company's ongoing cash flow problems and the earnings attrition that results from the delay in recovering large capital expenditures. These measures included: a) inclusion of CWIP in rate base; b) allowance of accelerated depreciation; and c) an attrition allowance to give the Company an opportunity to earn its allowed ROE.

The inclusion of CWIP in rate base produces no increased earnings for the Company and will eventually yield reductions in revenue requirements for future ratepayers. It merely increases cash flow by accelerating cost recovery. This revenue enhancement tool addresses the timing of cost recovery, not the entitlement to that cost recovery. It is a recognized method for a regulatory commission to address cash flow shortfalls or regulatory lag in the recovery of capital expenditures that has been utilized by this Commission (as well as other commissions) in the past. (Tr. Vol. I at 106 [Wheeler]; APS Exhibit No. 5 at 25 [Brandt].) Just in the last two years, both the Colorado Public Utility Commission and the Missouri Commission used combinations of CWIP in rate base and accelerated depreciation to deal with recurring cash flow problems of the utilities in question and the adverse impact that such cash flow problems was having on the credit metrics and credit ratings of those utilities. (*See* APS's Initial Brief at 28-29; APS Exhibit No. 23 at 25-28 [Fetter].)[8]

Publ. Utilities Comm'n of Colorado, 653 P.2d 1117, 1122-23 (1982)(upholding rate increase where evidence showed that the company's "ability to raise capital was seriously impaired due to decreased earnings and a downgrading of [the company's] rating by both Moody's and Standard & Poors [sic].")).

[7] *See* letter dated July 21, 2006 from then Chairman Hatch-Miller (APS Exhibit No. 5 at Attachment DEB-11RB).

[8] Commenting on the inclusion of CWIP in rate base by the Colorado Commission , S&P stated:

> This is a major step forward in eliminating the tug-of-war over cost recovery that, in the

As of June 30, 2006, the Company's CWIP accounts included $261 million of generation and distribution plant expenditures. (APS Exhibit No. 24 at 17-18 [Fetter]). By placing these amounts in rate base, the Company would obtain cash flow to pay the financing costs it currently incurs on these existing expenditures. (APS Exhibit 5 at 25 [Brandt]). Specifically, inclusion of $261 million of CWIP in rate base would increase APS's annual revenue by $33 million. (*Id.* at 25-26). This additional $33 million in annual revenue would generate for the Company after taxes a total of $20 million in positive cash flow annually. (*Id.*). As a result, the Company's FFO/Debt ratio would improve by an additional one-half percent in each of the next several years. (*Id.* at 27)."

Page 67, Line 8: DELETE Footnote 44.

Page 67, Line 15-
Page 68, Line 13: DELETE "Thus" through "rates.", REPLACE WITH the following:

"This does not, however, preclude the Commission from taking into consideration other relevant factors in establishing "just and reasonable" rates. As the largest electric utility in the State, it is in the public interest that APS be given the regulatory tools necessary to maintain its investment grade credit rating. Should APS fall below investment grade to "junk" status, it will limit the Company's ability to access the capital markets and increase its borrowing costs thereby resulting in higher future rates for customers. Such a credit rating drop would likely also prevent businesses (such as some of the counterparties to this case) from doing business with APS, thus limiting the Company's ability to engage in business opportunities that would prove beneficial to it and its customers. The inclusion of CWIP in rate base produces no increased earnings for the Company, increases cash flow by

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past, has plagued the credit of so many utilities when the time comes to build again.

(APS Exhibit No. 23 at 28 [Fetter], citing *S&P Research: PS Colorado Garners Support for Credit Quality Up-Front; a Viable Model for the Electric Industry*, March 29, 2005.)

accelerating cost recovery and may eventually yield reductions in rates for future ratepayers.

Based upon the discussion contained herein, we find that it is appropriate and in the public interest in establishing just and reasonable rates to include $261 million of CWIP in rate base."

Page 138, Lines 14-15: DELETE "not" and "or necessary" and "any", INSERT "some" after "adopt"

Line 17: After "rates", INSERT "except as provided herein."

Lines 18-21: DELETE Finding of Fact No. 37

Page 148, Line 7: DELETE "not" and "or necessary" and "any of"

Line 11: After "rates", INSERT "except as provided herein."

MAKE ALL CONFORMING CHANGES TO ORIGINAL COST RATE BASE, FAIR VALUE RATE BASE, REQUIRED OPERATING INCOME, AND REVENUE REQUIREMENTS.

APS PROPOSED AMENDMENT # 4

APS Revenue Enhancement Proposals – Accelerated Depreciation Only

Page 63, Line 4: After "will", INSERT "not"

Lines 15-17: DELETE "APS" through "flow."

Page 63, Line 18-
Page 67, Line 2: DELETE paragraphs, REPLACE WITH the following:

"However, it is clear that in establishing "just and reasonable" rates, the Commission may consider the projected impact of the rate decision on a regulated utility's financial criteria, including its ability to "maintain and support its credit" and to "raise the money" necessary for the further operation of its business. In fact, the law requires that rates be just and reasonable when they are in effect, which necessitates some forward looking and not just rigid adherence to the historical test year to the extent that the evidence in the record supports a finding that the test year is unrepresentative of present conditions.[9] Other regulatory commissions often take into consideration the projected impact of a rate decision on a company's financial indicators, particularly the company's credit standing with the major credit rating agencies.[10] So has

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[9] *See, Scates.*

[10] (*See, e.g.*, Tr. Vol. XXIV at 4577-78 [Brandt] (citing Tom McGhee, *State Oks Xcel rate hike*, Denver Post, Nov. 21, 2006. Responding to questions about an Xcel Energy settlement agreement (Decision No. C06-1379) that increased rates, PUC Chairman Gregory Sopkin "said a smaller rate increase could damage Xcel's credit rating and increase its borrowing costs."); APS Exhibit No. 23 at 25 [Fetter] (referring to Missouri Public Service Commission ("MPSC") Case No. EO-2005-0329 at 14-15, where the MPSC decided that in making rate decisions for the next several years for Kansas City Power & Light ("KCPL") it will rely on "S&P's publicly-disseminated credit ratio guidelines to ensure that KCPL's key financial measures would remain at levels adequate for its 'BBB' credit ratings."); *see, also,* Tr. Vol. VI at 1284-86 [Fetter]; APS Exhibit No. 23 at 27-28 [Fetter] (noting that last year the Colorado Public Service Commission approved a comprehensive settlement agreement (Decision No. C06-1379) allowing the Public Service Company of Colorado to peg certain rate increases to that company's "credit quality" rating.); *see, also, e.g., In re Public Service Co. of Indiana*, 72 P.U.R. 4th 660, 677 (Mar. 7, 1986); Cause No. 37414 (taking into consideration the company's S&P and Moody's ratings and the company's need to "have reasonable access to the capital markets to provide for its future capital needs...."); *see, also, In re Commonwealth Edison Co.*, 49 P.U.R. 4th 62, 76 (May 6, 1982); Decision No. 82-0026 (recognizing that a "further downgrading of Edison's credit ratings, particularly as to commercial paper, would immediately restrict Edison's day-to-day financing of all expenditures...."); *see, also, Public Serv. Co. of Colorado v.*

this Commission in past Decisions. *See*, *e.g.*, Decision No. 54204 (October 11, 1984).

Moreover, in response to a letter from Chairman Hatch-Miller[11] that requested APS to propose methods for improvement of the Company's cash flow and related financial metrics such as its FFO/Debt ratio, APS proposed several additional measures for the Commission to consider that would address the Company's ongoing cash flow problems and the earnings attrition that results from the delay in recovering large capital expenditures. These measures included: a) inclusion of CWIP in rate base; b) allowance of accelerated depreciation; and c) an attrition allowance to give the Company an opportunity to earn its allowed ROE.

The inclusion of accelerated depreciation produces no increased earnings for the Company and will eventually yield reductions in revenue requirements for future ratepayers. It merely increases cash flow by accelerating cost recovery. This revenue enhancement tool addresses the timing of cost recovery, not the entitlement to that cost recovery. It is a recognized method for a regulatory commission to address cash flow shortfalls or regulatory lag in the recovery of capital expenditures that has been utilized by this Commission (as well as other commissions) in the past. (Tr. Vol. I at 106 [Wheeler]; APS Exhibit No. 5 at 25 [Brandt].) Just in the last two years, both the Colorado Public Utility Commission and the Missouri Commission used combinations of CWIP in rate base and accelerated depreciation to deal with recurring cash flow problems of the utilities in question and the adverse impact that such cash flow problems was having on the credit metrics and credit ratings of those utilities. (*See* APS's Initial Brief at 28-29; APS Exhibit No. 23 at 25-28 [Fetter].)[12]

Publ. Utilities Comm'n of Colorado, 653 P.2d 1117, 1122-23 (1982)(upholding rate increase where evidence showed that the company's "ability to raise capital was seriously impaired due to decreased earnings and a downgrading of [the company's] rating by both Moody's and Standard & Poors [sic].")).

[11] *See* letter dated July 21, 2006 from then Chairman Hatch-Miller (APS Exhibit No. 5 at Attachment DEB-11RB).

[12] Commenting on the inclusion of CWIP in rate base by the Colorado Commission , S&P stated:

> This is a major step forward in eliminating the tug-of-war over cost recovery that, in the

An allowance for accelerated depreciation will help improve the Company's cash flow, and, therefore, the Company's creditworthiness. Accelerating some of this depreciation expense has the beneficial impact of increasing cash flow, thereby increasing FFO. For example, an allowance of $50,000,000 per year in accelerated depreciation would generate about $30,000,000, after income taxes, of additional positive cash flow, which would have the effect of improving the Company's FFO/Debt ratio by about seven-tenths of a percent in each of those years. (*Id*. at 25)."

Page 67, Line 8: DELETE Footnote 44.

Page 67, Line 15-
Page 68, Line 13: DELETE "Thus" through "rates.", REPLACE WITH the following:

"This does not, however, preclude the Commission from taking into consideration other relevant factors in establishing "just and reasonable" rates. As the largest electric utility in the State, it is in the public interest that APS be given the regulatory tools necessary to maintain its investment grade credit rating. Should APS fall below investment grade to "junk" status, it will limit the Company's ability to access the capital markets and increase its borrowing costs thereby resulting in higher future rates for customers. Such a credit rating drop would likely also prevent businesses (such as some of the counterparties to this case) from doing business with APS, thus limiting the Company's ability to engage in business opportunities that would prove beneficial to it and its customers. Accelerating depreciation produces no increased earnings for the Company, increases cash flow by accelerating cost recovery and may eventually yield reductions in rates for future ratepayers.

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past, has plagued the credit of so many utilities when the time comes to build again.

(APS Exhibit No. 23 at 28 [Fetter], citing *S&P Research: PS Colorado Garners Support for Credit Quality Up-Front; a Viable Model for the Electric Industry*, March 29, 2005.)

Based upon the discussion contained herein, we find that it is appropriate and in the public interest in establishing just and reasonable rates to accelerate depreciation by $50,000,000 per year."

Page 138, Lines 14-15: DELETE "not" and "or necessary" and "any", INSERT "some" after "adopt"

Line 17: After "rates", INSERT "except as provided herein."

Lines 18-21: DELETE Finding of Fact No. 37

Page 141, Line 12: INSERT new Finding of Fact No. 67 as follows: "APS should be permitted to accelerate depreciation by an additional $50,000,000 per year which will increase its cash flow and further improve its creditworthiness."

Page 148, Line 7: DELETE "not" and "or necessary" and "any of"

Line 11: After "rates", INSERT "except as provided herein."

Page 151, Line 2: INSERT new Ordering paragraph as follows: "IT IS THEREFORE ORDERED that APS is authorized to include an additional $50,000,000 per year in its proposed depreciation rates for jurisdictional plant-in-service."

MAKE ALL CONFORMING CHANGES TO ADJUSTED TEST YEAR OPERATING INCOME, REVENUE REQUIREMENTS, AND ELSEWHERE AS REQUIRED.

APS PROPOSED AMENDMENT # 5

APS Revenue Enhancement Proposals – Attrition Adjustment Only

Page 49, Line 14: After "do", DELETE "not"

Line 14: DELETE "a flotation adjustment or", REPLACE WITH "an"

Line 15: DELETE "or", REPLACE WITH "and"

Page 63, Line 4: After "will", INSERT "not"

Lines 15-17: DELETE "APS" through "flow."

Page 63, Line 18-
Page 67, Line 2: DELETE paragraphs, REPLACE WITH the following:

"However, it is clear that in establishing "just and reasonable" rates, the Commission may consider the projected impact of the rate decision on a regulated utility's financial criteria, including its ability to "maintain and support its credit" and to "raise the money" necessary for the further operation of its business. In fact, the law requires that rates be just and reasonable when they are in effect, which necessitates some forward looking and not just rigid adherence to the historical test year to the extent that the evidence in the record supports a finding that the test year is unrepresentative of present conditions.[13] Other regulatory commissions often take into consideration the projected impact of a rate decision on a company's financial indicators, particularly the company's credit standing with the major credit rating agencies.[14] So has

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[13] *See, Scates.*

[14] (*See, e.g.*, Tr. Vol. XXIV at 4577-78 [Brandt] (citing Tom McGhee, *State Oks Xcel rate hike*, Denver Post, Nov. 21, 2006. Responding to questions about an Xcel Energy settlement agreement (Decision No. C06-1379) that increased rates, PUC Chairman Gregory Sopkin "said a smaller rate increase could damage Xcel's credit rating and increase its borrowing costs."); APS Exhibit No. 23 at 25 [Fetter] (referring to Missouri Public Service Commission ("MPSC") Case No. EO-2005-0329 at 14-15, where the MPSC decided that in making rate decisions for the next several years for Kansas City Power & Light ("KCPL") it will rely on "S&P's publicly-disseminated credit ratio guidelines to ensure that KCPL's key financial measures would remain at levels adequate for its 'BBB' credit ratings."); *see, also,* Tr. Vol. VI at

this Commission in past Decisions. *See, e.g.,* Decision No. 54204 (October 11, 1984).

Moreover, in response to a letter from Chairman Hatch-Miller[15] that requested APS to propose methods for improvement of the Company's cash flow and related financial metrics such as its FFO/Debt ratio, APS proposed several additional measures for the Commission to consider that would address the Company's ongoing cash flow problems and the earnings attrition that results from the delay in recovering large capital expenditures. These measures included: a) inclusion of CWIP in rate base; b) allowance of accelerated depreciation; and c) an attrition allowance to give the Company an opportunity to earn its allowed ROE.

An attrition allowance is a regulatory tool that allows the Commission to address concerns that the Company will be unable to earn its allowed rate of return because of the lag between the Company's current need to expend huge sums for expansion of plant and equipment to meet the needs of a rapidly growing customer base and the eventual recovery of those sums in future rate base adjustments approved by the Commission. (*See* APS Exhibit No. 5 at 28 [Brandt]."

Page 67, Line 8: DELETE Footnote 44.

Page 67, Line 15-
Page 68, Line 13: DELETE "Thus" through "rates.", REPLACE WITH the following:

1284-86 [Fetter]; APS Exhibit No. 23 at 27-28 [Fetter] (noting that last year the Colorado Public Service Commission approved a comprehensive settlement agreement (Decision No. C06-1379) allowing the Public Service Company of Colorado to peg certain rate increases to that company's "credit quality" rating.); *see, also, e.g., In re Public Service Co. of Indiana*, 72 P.U.R. 4th 660, 677 (Mar. 7, 1986); Cause No. 37414 (taking into consideration the company's S&P and Moody's ratings and the company's need to "have reasonable access to the capital markets to provide for its future capital needs...."); *see, also, In re Commonwealth Edison Co.*, 49 P.U.R. 4th 62, 76 (May 6, 1982); Decision No. 82-0026 (recognizing that a "further downgrading of Edison's credit ratings, particularly as to commercial paper, would immediately restrict Edison's day-to-day financing of all expenditures...."); *see, also, Public Serv. Co. of Colorado v. Publ. Utilities Comm'n of Colorado*, 653 P.2d 1117, 1122-23 (1982)(upholding rate increase where evidence showed that the company's "ability to raise capital was seriously impaired due to decreased earnings and a downgrading of [the company's] rating by both Moody's and Standard & Poors [sic].")).

[15] *See* letter dated July 21, 2006 from then Chairman Hatch-Miller (APS Exhibit No. 5 at Attachment DEB-11RB).

"This does not, however, preclude the Commission from taking into consideration other relevant factors in establishing "just and reasonable" rates. As the largest electric utility in the State, it is in the public interest that APS be given the regulatory tools necessary to maintain its investment grade credit rating. Should APS fall below investment grade to "junk" status, it will limit the Company's ability to access the capital markets and increase its borrowing costs thereby resulting in higher future rates for customers. Such a credit rating drop would likely also prevent business (such as some of the counterparties to this case) from doing business with APS, thus limiting the Company's ability to engage in business opportunities that would prove beneficial to it and its customers. The approval of an attrition allowance will provide the Company with the opportunity to earn its allowed rate of return because of the lag between the Company's current need to expend huge sums for expansion of plant and equipment to meet the needs of a rapidly growing customer base and the eventual recovery of those sums in future rate base adjustments approved by the Commission.

Based upon the discussion contained herein, we find that it is appropriate and in the public interest in establishing just and reasonable rates to provide an attrition allowance of 1.7% to be added to the Company's ROE."

Page 138, Lines 14-15: DELETE "not" and "or necessary" and "any", INSERT "some" after "adopt"

Line 17: After "rates", INSERT "except as provided herein."

Lines 18-21: DELETE Findings of Fact Nos. 37 and 38

Page 148, Line 11: After "rates", INSERT "except as provided herein."

MAKE ALL CONFORMING CHANGES TO COST OF CAPITAL, FAIR VALUE RATE OF RETURN, REQUIRED OPERATING INCOME, REVENUE REQUIREMENTS, AND ELSEWHERE AS REQUIRED.

OPERATING INCOME ADJUSTMENTS

APS PROPOSED AMENDMENT # 6

PWEC A&G Expenses

Page 19, Lines 10-14: DELETE lines 10-14 beginning with "APS has not... ", REPLACE WITH "A&G is an allocated expense for costs incurred by **both** APS and its parent corporation, Pinnacle West Capital Corporation ("Pinnacle West") for overall corporate governance and shared services such as accounting, tax, legal, HR, etc. Although in its last rate case filing, the Company told the Commission that $8.797 million was a "fair representation of the A&G costs for the plants," those A&G figures cited were for a 2002 test period (some three years prior to the present Test Year and now more than four and a half years ago. That 2002 Test Year was prior to the transfer of the PWEC units to APS) and, thus, reflects a period when more A&G expense was allocated to PWEC and less to APS. Accordingly, we will adopt the Company's proposal to include $6.285 million as a legitimate operating income adjustment associated with A&G expenses associated with the PWEC units and correspondingly reject AECC's proposed adjustment."

Lines 27½-28: DELETE Footnote 15.

MAKE ALL CONFORMING CHANGES TO OPERATING INCOME, REVENUE REQUIREMENT, AND ELSEWHERE AS REQUIRED.

APS PROPOSED AMENDMENT # 7

SERP Operating Income Adjustment

Page 27, Lines 5-17: DELETE lines 5-17, REPLACE WITH "However, there are critical differences between the facts, as described by the Commission in the Southwest Gas case, and those that exist here. (Tr. Vol. III at 496-502 [Brandt]). First, the APS program is **not** limited to officers, as was the case in Southwest Gas. Second, APS employees covered by the SERP would **not** enjoy the same retirement benefits as all other APS employees in the absence of this plan. Finally, the Company's SERP only places all APS employees, including management, on the **same** level with regard to retirement benefits, and **not** on a higher level as is stated in the Southwest Gas decision. In short, SERP is not some management "perk," but an important tool in retaining qualified professionals over the long term. (*Id.*). Accordingly, we find that the $4.7 million of SERP expenses should be included as part of the Company's operating income adjustments."

Line 28: DELETE Footnote 22.

MAKE ALL CONFORMING CHANGES TO OPERATING INCOME, REVENUE REQUIREMENT, AND ELSEWHERE AS REQUIRED.

APS PROPOSED AMENDMENT # 8

<u>Stock Incentive Compensation</u>

Page 36, Line 12-24: DELETE lines 12-24, REPLACE WITH "APS's stock incentive component, or "long-term" incentive, is integral in attracting and retaining high quality management personnel. The program 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.
- Long-term financial health provides 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.

(APS Exhibit No. 50 at 19-20 [Gordon] at 21-22).

Accordingly, we will approve APS' request to include $4.8 million in operating expenses related to its employee stock incentive program."

Line 28: DELETE Footnote 28

Page 37, Line 21: DELETE "Staff"

MAKE ALL CONFORMING CHANGES TO OPERATING INCOME, REVENUE REQUIREMENT, AND ELSEWHERE AS REQUIRED.

APS PROPOSED AMENDMENT # 9

Lobbying Costs

Page 35, Lines 17-21: DELETE last three sentences of paragraph.

MAKE ALL CONFORMING CHANGES.

APS PROPOSED AMENDMENT # 10

Demand Side Management – Conservation Adjustment

Page 31, Lines 15-19: DELETE lines 15 through 19, up to the word "Further", REPLACE WITH "We find that"

Line 20: DELETE "APS is not allowed", REPLACE WITH "APS is allowed"

Line 22: DELETE "and will not adopt APS' net lost revenue adjustment", REPLACE WITH "and will adopt APS' adjustment to reduce TY revenues by $4,907,000 to reflect Commission approved DSM programs."

MAKE ALL CONFORMING CHANGES.

APS PROPOSED AMENDMENT # 11

Bark Beetle Regulatory Asset

Page 16, Line 7: DELETE "$1,437,983", REPLACE WITH "$1,547,983"

Line 28: DELETE Footnote 12

MAKE ALL CONFORMING CHANGES TO OPERATING INCOME, REVENUE REQUIREMENT, AND ELSEWHERE AS REQUIRED.

APS PROPOSED AMENDMENT # 12

Sundance O&M

Page 17, Line 23: DELETE "$226,500", REPLACE WITH "$134,100"

Line 27: DELETE Footnote 13

MAKE ALL CONFORMING CHANGES.

APS PROPOSED AMENDMENT # 13

Business Lunches

Page 20, Line 13: DELETE "Although", REPLACE WITH "We agree with APS that" and end sentence with "employees."

Lines 13-18: DELETE line 13 beginning with last "APS" on that line, through Line 18 "paid work day."

Line 18: DELETE "disallow", REPLACE WITH "allow"

Line 20: DELETE "$6,664,000", REPLACE WITH "$6,264,000"

MAKE ALL CONFORMING CHANGES TO OPERATING INCOME, REVENUE REQUIREMENT, AND ELSEWHERE AS REQUIRED.

APS PROPOSED AMENDMENT # 14

Income Tax Impacts of Interest Synchronization

Page 42, Line 13: DELETE $607,000, REPLACE WITH "$3,036,000"

Line 28: DELETE Footnote 30

MAKE ALL CONFORMING CHANGES TO TEST YEAR, OPERATING INCOME, REVENUE REQUIREMENT, AND ELSEWHERE AS REQUIRED.

APS PROPOSED AMENDMENT # 15

Annualized Amortization

Page 150, Line 26: After "depreciation", INSERT "and amortization"

MAKE ALL CONFORMING CHANGES.

RATE BASE ADJUSTMENTS

APS PROPOSED AMENDMENT # 16

Cash Working Capital

Page 8: DELETE Lines 14-28

Page 9, Lines 1-2: DELETE Lines 1-2, REPLACE WITH "The Commission is aware that it has rejected the inclusion of depreciation and deferred taxes in prior decisions. As the arguments on this issue have become focused, an increasing number of jurisdictions have taken a new look and have concluded that one or both of these costs are appropriate elements of cash working capital. A few examples of states that have included depreciation and deferred income taxes in lead lag studies are: South Carolina, where these items must be included in a lead lag to reflect the delay in the collection of these components of revenue;[16] Connecticut, where the Department of Public Utility Control agreed that no-cash expenses such as depreciation, amortization, and deferred income taxes create a working capital requirement;[17] and California, which includes both depreciation expense and deferred taxes at zero lag days because of the reduction of rate base by accumulated depreciation and deferred income taxes.[18] Each of these jurisdictions likely faced the same contrary precedents as is currently the case in Arizona before recognizing the need to reflect **all** the expense elements that lead to the need for working capital.

Both depreciation and deferred taxes generate additional investment needs that must be reflected in rate base as part of the Allowance for Cash Working Capital. (APS Exhibit No. 66 at 2-3 [Balluff]). It is indisputable that the construction of depreciable utility plant, which gives rise to both depreciation and deferred taxes, involves a cash investment. It is equally clear that the utility is entitled to a return on that

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[16] In re Application of South Carolina Electric & Gas Company for Adjustments in the Company's Electric Rate Schedule and Tariffs, Docket No. 88-681-E – Order No. 89-588 at 37 (July 3, 1989).

[17] DPUC Review of the United Illuminating Company's Rate Filing and Rate Plan Proposal, Docket No. 01-10-10 at 44 (Sept. 26, 2002).

[18] *See, generally,* Water Division, California Public Utilities Commission, Standard Practice U-16-W, Determination of Working Cash Allowance (May 16, 2002).

investment until it has been recovered from customers in the form of cash receipts. When depreciation expense is recorded and deferred income tax charges are recorded, accumulated depreciation and deferred income tax credits are recorded. The reserve for accumulated depreciation and the accumulated balance of deferred taxes offset the investment in plant for ratemaking purposes. (*Id.* at 3-4 [Balluff]). Those two reserves, which reduce rate base, are credited (increased) monthly based on the depreciation and deferred tax expense recorded for the month. The corresponding cash receipts will not be received until the following billing month. Because the Company's rate base is reduced by the **recorded** level of accumulated depreciation and deferred taxes (rather than the **received** level of actual cash recovery), there is a gap between when customers are credited (through a rate base deduction) for their payment of depreciation expense and deferred tax expense and the time they actual pay for these items. (APS Exhibit No. 65 at 10-11 [Balluff]). This gap represents additional investment by the Company that must either be reflected in the calculation of cash working capital or recognized as direct adjustments to the depreciation and deferred tax reserves. Exclusion of depreciation expense alone prevents APS from earning a return on over $32,000,000 of unrecovered invested capital. (APS Exhibit No. 66 at 3 [Balluff]). Excluding deferred tax expense leads to another understatement of rate base of $7,872,000. (APS Exhibit No. 65 at Attachment FB-1 [Balluff]).

We agree with the Company that both depreciation and deferred income taxes should be included in the cash capital working calculation."

Page 10, Lines 2-7: DELETE Lines 2-7, REPLACE WITH "The Commission has previously taken conflicting positions on the use of interest expense, adopting it in Decision No. 55931 (April 1, 1988), while admitting in that same Decision that it had previously rejected the concept. (Decision No. 55931 at 67). The testimony in this case is that the lag in paying interest, a non-operating expense, is an inherent part of the return to equity investors, *i.e.*, part of the "leverage" provided by debt capital to equity. 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 rate base (including the weighted cost of debt) in the calculation of working capital. To use it to reduce rate base is tantamount to making equity investors use a component of their rightful return to finance plant used to serve APS customers. Moreover, as Mr. Balluff pointed out, there is also a lag in the receipt by equity investors of their return. If one form of investment (*i.e.*, debt) is to be factored in the calculation of cash working capital, then all other forms should be in play, which would have increased the Company's overall cash working capital allowance from that requested. The "lag" in the receipt of operating income referenced above is the lag in overall return discussed in the Company's Initial Brief (APS's Initial Brief at a43) and by Mr. Balluff in his Rebuttal Testimony. (APS Exhibit 66 at 11 [Balluff]). As noted, most jurisdictions either include both that operating income lag and interest or exclude both, as has APS. Accordingly, we agree with APS and will exclude interest expense in the cash working capital calculation."

Line 15: DELETE "excluded from", REPLACE WITH "included in"

Line 25: DELETE "negative $86,391,274", REPLACE WITH "negative $34,158,000"

MAKE ALL CONFORMING CHANGES TO ORIGINAL COST RATE BASE, RECONSTRUCTION COST NEW RATE BASE, FAIR VALUE RATE BASE, REVENUE REQUIREMENT, AND ELSEWHERE AS REQUIRED.

APS PROPOSED AMENDMENT # 17

SERP-Rate Base Adjustment

Page 27, Line 20: DELETE "disagree", REPLACE WITH "agree"

MAKE ALL CONFORMING CHANGES TO ORIGINAL COST RATE BASE, RECONSTRUCTION COST NEW RATE BASE, FAIR VALUE RATE BASE, REVENUE REQUIREMENT, AND ELSEWHERE AS REQUIRED.

FUEL AND PSA ISSUES

APS PROPOSED AMENDMENT # 18

PSA Base Fuel Rate

Page 33, Lines 8-11: DELETE "We agree. . . purchased power."

Line 20: After "increase later." INSERT "APS has calculated its proposed Base Fuel Cost using the methodology suggested by Staff witness Antonuk for determining 2007 fuel and purchased power costs. (APS Exhibit No. 18 at 4-5 [Ewen]). In his Supplemental Testimony, Mr. Antonuk agreed that the 3.2491¢/kWh figure was a reasonable estimate of 2007 fuel and purchased power costs. (Staff Exhibit No. 30 at 23 [Antonuk]). Unlike the Base Fuel Cost proposals in the Company's Direct and Rebuttal testimonies, APS has not annualized price changes scheduled to take effect in 2007 nor has it annualized generation levels for end of year customers. Both these omissions reduced the 2007 Base Fuel Cost compared to the methodology used by APS in its prior testimony and used by the Commission in establishing the Base Fuel Cost in Decision No. 67744. For this reason, APS believes its Base Fuel Cost is a very reasonable, even conservative, estimate of what fuel costs will be in 2007. And, using the Company's Base Fuel Cost would obviate the need for setting a "forward component" to the PSA in 2007, or more precisely, that "forward component" could be set at zero. (Tr. Vol. V at 109 [Ewen]).

Moreover, the 3.2491¢ figure is an annual average cost that includes the lower fuel and purchased power costs generally incurred by APS during the non-summer months of the year. (APS Exhibit No. 105 at 5). As shown in APS Exhibit No. 105, costs during the peak use months of 2007 would be 3.6915¢/kWh. (*Id.*). Assuming the Company's proposed Base Fuel Cost was adopted effective June 1, 2007, APS still projects an unrecovered balance of 2007 fuel and purchased power costs of some $60 million."

Line 22: DELETE "3.1202¢kWh", REPLACE WITH "3.2491¢kWh."

Page 109, Lines 23-26: DELETE Line 23-26 "Staff has agreed . . . of 3.2491¢."

Line 28: DELETE "Footnote No. 65"

Page 143, Lines 14-16: DELETE Finding of Fact No. 87

MAKE ALL CONFORMING CHANGES TO BASE FUEL COST, FORWARD ELEMENT, ADJUSTED TEST YEAR OPERATING INCOME, REVENUE REQUIREMENTS, AND ELSEWHERE AS REQUIRED.

APS PROPOSED AMENDMENT # 18A

PSA Base Fuel Rate

Page 33, Line 22:	DELETE "3.1202¢kWh", REPLACE WITH "3.1226¢kWh, taking into effect our rejection of the Company's DSM conversation adjustment."
OR	Same as APS Proposed Amendment No. 18, except: line 22, REPLACE "3.2491¢kWh" with "3.2610¢kWh taking into effect rejection of the Company's DSM conversation adjustment."

MAKE ALL CONFORMING CHANGES TO BASE FUEL COST, FORWARD ELEMENT, ADJUSTED TEST YEAR OPERATING INCOME, REVENUE REQUIREMENTS, AND ELSEWHERE AS REQUIRED.

APS PROPOSED AMENDMENT # 19

PSA – 90/10 Sharing

Page 104, Lines 17-28: DELETE Lines 17-28, REPLACE WITH "Mr. Antonuk, the Staff's consultant on PSA issues, agreed that the 90/10 sharing feature would result in the non-recovery of costs APS would reasonably expect to occur. (Tr. Vol. XXII at 4149 [Antonuk]). Mr. Antonuk described it as a "blunt instrument" at best with regard to providing an incentive, and he suggested that the Commission focus in on the "drivers" of fuel cost. (Tr. Vol. XXI at 3896). Accordingly, it is appropriate to eliminate the present 90/10 sharing, especially in view of the findings by Liberty Consulting and R.W. Beck concerning the overall prudence and effectiveness of the Company's fuel procurement and hedging practices (Staff Exhibit No 33 at 6-7 [Fuel Audit]); APS Exhibit No. 72 at 5-1 through 5-4 [R.W. Beck])."

Page 109, Line 22: DELETE "Staff's", REPLACE WITH "The Company's"

Lines 22-23: DELETE "as modified to include the sharing mechanism above."

Page 143, Lines 4-13: DELETE Findings of Fact Nos. 84, 85 and 86, REPLACE WITH "84. Based on the foregoing, the prospective PSA as described herein, should be adopted."

MAKE ALL CONFORMING CHANGES.

APS PROPOSED AMENDMENT # 20

PSA – Broker Fees

Page 105, Lines 12-16: DELETE Lines 12-16 after the word "adjustor", REPLACE WITH "APS and each of the other parties[19] have included approximately $200,000 in broker fees in their calculation of Base Fuel Cost. (Tr. Vol. XXIII at 4438 [Ewen]). It is undisputed that such fees are a legitimate cost of acquiring fuel and purchased power for the benefit of APS customers. (Tr. Vol. XXI at 4010 [Antonuk]). Excluding such fees would have the effect of not only denying the Company any recovery of cost increases attributable to such fees, but also effectively denies recovery of even the amount included in the Base Fuel Cost. (Tr. Vol. XXI at 4010 [Antonuk]). Accordingly, it is appropriate to flow broker fees through the PSA adjustor."

Page 109, Line 22: DELETE "Staff's", REPLACE WITH "the Company's"

Lines 22-23: DELETE "as modified to include the sharing mechanism above."

MAKE ALL CONFORMING CHANGES.

[19] The RUCO, Staff and AECC Base Fuel Cost recommendations are all variants of the original Base Fuel Cost proposed by APS and, thus, implicity reflect the level of broker fees included by APS.

RATE DESIGN

APS PROPOSED AMENDMENT # 21

Net Metering

Page 87, Line 8: AFTER "costs.", INSERT "At hearing, the Company prepared and entered an exhibit into the record entitled, "Net Loss Revenue Sample Calculation," which provides a detailed methodology as to how it calculates uncollected fixed costs. (APS Exhibit No. 38, Attachment GAD-5RB [DeLizio])."

Page 88, Line 11: DELETE "Staff's", REPLACE WITH "the Company's"

Line 11: DELETE "however,", REPLACE WITH "and"

Page 140, Line 4: DELETE "as modified herein"

Page 149, Line 26: DELETE "as modified herein"

MAKE ALL CONFORMING CHANGES.

APS PROPOSED AMENDMENT # 21A

Net Metering

Page 87, Line 8: AFTER "costs.", INSERT "At hearing, the Company prepared and entered an exhibit into the record entitled, "Net Loss Revenue Sample Calculation," which provides a detailed methodology as to how it calculates uncollected fixed costs. (APS Exhibit No. 38, Attachment GAD-5RB [DeLizio])."

Page 88, Lines 11-12: DELETE "We agree with Staff's recommendation and will adopt them, however, we believe that APS should be able to require the use of a bidirectional meter.", REPLACE WITH "We agree that the Company should be entitled to recover its "uncollected fixed costs." As a result, instead of authorizing recovery of its uncollected fixed costs through the EPS surcharge as proposed by the Company, the Company will be allowed to defer such costs and seek their recovery in their next rate case."

MAKE ALL CONFORMING CHANGES.

APS PROPOSED AMENDMENT # 22

Elimination and Freezing of Schedules

Page 139, Line 27: INSERT new Findings of Fact Nos. 50-51: "50. APS is hereby authorized to eliminate, freeze, and consolidate the following rate schedules: (1) eliminate existing rate schedules DA E-12, DA ET-1, DA ECT-1R, DA E-32, DA E-34, DA E-35, EC-1, E-10, E-38, E-38-8T, EPR-3, EQF-S, EQF-M, E-52 and Solar 1; and the Direct Access Rate Schedules (2) eliminate rate schedule E-51 in the Company's next rate case; (3) close (freeze) existing rate schedules SP-1, E-32R, and E-55 to new customers and eliminate them in the next rate case; and (4) consolidate Schedule EPR-4 into the revised Schedule EPR-2.

51. Customers on experimental TOU rates E-21, E-22, E-23 and E-24 will have a six month transition period to evaluate and choose a rate option. At the end of the transition period, APS would then cancel E-21, E-22, E-23 and E-24, and customers who have not chosen an alternate rate schedule will be automatically switched to the default rate E-32 TOU."

MAKE ALL CONFORMING CHANGES.

APS PROPOSED AMENDMENT # 23

Total Solar Rate

Page 96, Line 4: DELETE "$.0225 per kWh", REPLACE WITH "$0.166 per kWh"

MAKE ALL CONFORMING CHANGES.

APS PROPOSED AMENDMENT # 24

Schedule E-56 and E-57

Page 81, Lines 17-21: DELETE "Because Staff has not analyzed these tariffs and has not recommended their approval, and because of the concerns cited by the Solar Advocates, we believe that APS should meet with Staff and the interested parties to discuss and possibly revise the E-56 and 57 tariffs.", REPLACE WITH "The implementation of E-56 and E-57 is in the public interest and should be adopted as filed."

Page 139, Line 22: DELETE Finding of Fact 48, REPLACE WITH "48. APS' proposed Partial Requirements Schedules E-56 and E-57 are in the public interest and are hereby approved. APS should submit its proposed tariffs for our approval within 60 days."

MAKE ALL CONFORMING CHANGES.

MISCELLANEOUS ISSUES

APS PROPOSED AMENDMENT # 25

EPS Uniform Credit Purchase Program

Page 82, Line 4: DELETE Lines 3-4 "true up … for 2006", REPLACE WITH "carry forward any funds from the additional $4.25 million that: 1) have been committed, but are not yet spent; or 2) are unspent funds that were not committed in 2006, to maximize the numbers of customers that could benefit from the additional funding.
In addition, we hereby adopt the Company's Adjusted Rate Schedule EPS-1, which was designed to collect the additional $4.25 million over a period of one-year."

Page 139, Lines 27-28: DELETE "true-up … for 2006", REPLACE WITH "carry forward any funds from the additional $4.25 million that: 1) have been committed, but are not yet spent; or 2) are unspent funds that were not committed in 2006; and Adjusted Rate Schedule EPS-1 should be adopted."

Page 151, Lines 5-6: DELETE "true-up … 2006", REPLACE WITH "carry forward any funds from the additional $4.25 million that have been committed, but are not yet spent or are unspent funds that were not committed in 2006."

IT IS FURTHER ORDERED that adjusted rate Schedule EPS-1 is adopted."

MAKE ALL CONFORMING CHANGES.

APS PROPOSED AMENDMENT # 26

<u>Application of RES Rules</u>

Page 93, Line 5: DELETE ", and we find … at this time."

Page 94, Line 15: DELETE "the requirement in the RES rules … in this Decision,"

Page 140, Line 20: DELETE Finding of Fact 60 in its entirety.

Page 150, Lines 13-15: DELETE Lines 13-15

Lines 17-18: DELETE "the requirement in the RES rules … in this Decision"

MAKE ALL CONFORMING CHANGES.

APS PROPOSED AMENDMENT # 27

Rate Implementation

Page 138, Lines 12-13: DELETE "for Staff review and confirmation"

MAKE ALL CONFORMING CHANGES.

PALO VERDE ISSUES

APS PROPOSED AMENDMENT # 28

Palo Verde Performance

Page 110, Lines 16-17:	Before "contractors", INSERT "oversees the"; DELETE "makes all decisions regarding", REPLACE WITH "is responsible for"
Page 111, Line 22:	DELETE "and"
Line 23:	After "sales", INSERT ", and accumulated interest."
Page 114, Line 6 ½:	After "improvement.", INSERT "Mr. Levine contested Dr. Jacobs' conclusion, pointing out that the discussion of performance in the Performance Improvement Plan is not focused on economic performance, and that the same page from which Dr. Jacobs quotes expressly states that "while the economic performance at Palo Verde continues to be at or near the top industry quartile there is a need for improvement in implementing programs and processes." (APS Exhibit No. 95, Levine Rejoinder, p. 14)."
Page 143, Lines 26-27:	Before "contractors", INSERT "oversees the"; DELETE "makes all decisions regarding", REPLACE WITH "is responsible for"
Page 144, Line 26:	After "sales", INSERT "and accumulated interest."

MAKE ALL CONFORMING CHANGES.

APS PROPOSED AMENDMENT # 29

Performance Standard

Page 117, Lines 1-12: DELETE entire paragraph, REPLACE WITH "Upon review of the evidence, we agree with APS that a performance standard for Palo Verde is unnecessary at this time because there is no evidence that such a standard would have a positive effect on performance and Palo Verde's nuclear safety regulator, the NRC, has cautioned against such standards."

Page 145, Lines 7-19: DELETE Findings of Fact Nos. 106-108, REPLACE WITH "106. A performance standard for Palo Verde is unnecessary at this time because there is no evidence that such a standard would have a positive effect on performance and Palo Verde's nuclear safety regulator, the NRC, has cautioned against such standards."

Page 151, Lines 15-23: DELETE Ordering paragraphs.

MAKE ALL CONFORMING CHANGES.

APS PROPOSED AMENDMENT # 30

Prudence Standard

Page 117, Lines 25-26: DELETE "As pointed out by Staff's legal counsel in opening arguments,", REPLACE WITH "Staff's legal counsel stated in opening arguments that"

Page 118, Lines 9-13: DELETE paragraph, REPLACE WITH "We agree with the prudence standard as agreed upon by both APS and Staff, *i.e.,* the actions and decisions of APS management must be judged on what they knew, or reasonably should have known, at the time the action was taken or the decision was made, without benefit of hindsight. However, we also agree that APS is entitled to a presumption that its actions with respect to outages at Palo Verde are prudent, and Staff may only overcome this presumption by presenting clear and convincing evidence that APS was imprudent, after which APS has the ultimate burden to demonstrate that its replacement costs for fuel and purchased power are reasonable, appropriate and not the result of imprudence."

Lines 20-24: After "appropriate," DELETE remainder of paragraph, REPLACE WITH "but only the facts from these documents that were known or reasonably should have been known at the time of the event may be used in a prudence determination, and any conclusions or evaluations from these documents should not be used to establish imprudence, unless it is clear that no hindsight was used in reaching those conclusions or evaluations."

Page 145, Line 20: DELETE "personnel", REPLACE WITH "management"

Line 23: Before "APS", INSERT APS is entitled to a presumption that its actions with respect to outages at Palo Verde are prudent, and Staff may only overcome this presumption by presenting clear and convincing evidence that APS was imprudent, after which"

Line 26: After "appropriate," DELETE "and is not using "hindsight just because the documents were created after the time or event involved", REPLACE WITH "but only the facts from these documents that were known or reasonably should have been known at the time of the event may be used in a prudence determination, and any conclusions or evaluations from these documents should not be used to establish imprudence, unless it is clear that no hindsight was used in reaching those conclusions or evaluations."

MAKE ALL CONFORMING CHANGES.

APS PROPOSED AMENDMENT # 31

August Unit 1 Reactor Trip

Page 123, Line 13-
Page 124, Line 6: DELETE paragraph, REPLACE WITH "APS witness Levine testified upon questioning by Staff that if he had been asked prior to the reactor trip whether he thought the operator "had been trained, was knowledgeable, had adequate procedures, and would be able to execute the startup effectively," he would have answered "yes." Thus, it is clear that Mr. Levine and management were unaware of relevant opinions and facts known by others prior to and at the time of the trip. We agree with APS that accepting Staff's position would require us to engage in impermissible hindsight. The reactor trip was a result of an individual operator not following the appropriate plant procedures. Staff's proposed disallowance is dependent on: (1) had APS management known of the later-recognized "perception" of difficulties with the DFWCS, and even though this perception had never resulted in a reactor trip, (2) APS nonetheless would have required further training prior to restart, and (3) this training would have prevented the operator from failing to follow procedures, thereby avoiding the outage. The record will not support the extended chain of causation required by Staff's theory. The speculation required to reach Staff's result is in plain violation of the prudence standard. Therefore, we find that the outage associated with the reactor trip on August 26, 2005 was not the result of APS' imprudence."

Page 146, Line 11: After "2005", DELETE "was due to imprudence", REPLACE WITH "was not due to imprudence because the reactor trip was the result of an individual operator not following the appropriate plant procedures; and accepting Staff's position would require us to engage in impermissible hindsight and speculation."

MAKE ALL CONFORMING CHANGES.

APS PROPOSED AMENDMENT # 32

October Unit 2 and Unit 3 RWT Outages

Page 124, Line 8: DELETE "August 2004", REPLACE WITH "January 2005"; before "violation" INSERT "potential"

Line 10: DELETE "subsequently", REPLACE WITH "issued in April 2005 and"

Line 13: After "Matrix.", INSERT "(Staff Exhibit 45, GDS Report, Attachment 3 (January 27, 2006 letter and report from Bruce Mallet, NRC Regional Administrator, p. 1)) ("January 2006 NRC Report")."; after "conducted" INSERT "between September and December 2005"

Lines 24-25: DELETE "(Staff Exhibit 45, GDS Report, Attachment 3 (January 27, 2006 letter and report from Bruce Mallet, NRC Regional Administrator, p. 7))s ("January 2006 NRC Report").", REPLACE WITH "(*Id.* at 7)."

Page 126, Line 19: After "suctions", INSERT "[and therefore no damage to pumps would occur]"

Page 128, Line 13: After "Finding", INSERT "(issued in April 2005)"

Page 129, Line 14: After "(*Id.*)", INSERT "The relevant Combustion Engineering document reads, in part, as follows:

> Under present design . . . the closing of the RWT discharge valves during the switchover from injection to recirculation is the result of operator action. The consequence of the operator failing to close the valves at the proper time, assuming the combination of (1) low containment pressure relative to refueling water ambient pressure and (2) an insufficient elevation of the sump water level above the piping junction (the TEE) between the RWT, sump, and safeguards pumps . . . could be the following. With safeguards pump suction being taken from the sump, the water level in the RWT and then in the RWT [suction] lines

> continues to drop until it reaches the TEE. This exposes the sump-to-pumps flow to dry lines and pump cavitation results from air in the suction lines. The calculation which follows will define an elevation for a suitable pressure differential which will preclude the above described system dysfunction [i.e., air entrainment into the pumps].

There follows in this Combustion Engineering document a calculation to prove that 16 feet of elevation difference between the sump water level and the top of the piping junction between the RWT and the sump is sufficient to preclude air entrainment. The Palo Verde units in actuality have 40 feet of elevation difference between these two points, much more than enough to satisfy the design requirement. (APS Exhibit No. 88, Mattson Rejoinder, p. 8)."

Line 16: After "unable", INSERT "to"

Page 130, Line 15-
Page 132, Line 16: DELETE paragraphs, REPLACE WITH "After reviewing the arguments of APS and Staff, we conclude that APS' actions surrounding the October RWT outages do not reach the level of imprudence. Dr. Mallett concluded that the reason for the outage arose from a new question from the NRC and that APS should not have identified the question regarding air entrainment earlier. Staff's response to Dr. Mallett's conclusions is unconvincing. Even though Dr. Mallett was not making a "prudence" determination (as we are called upon to do) when he made these statements, his conclusions as the senior NRC official involved with the outage must factor into our own prudence analysis.

Additionally, even though the NRC was critical of some of APS' actions surrounding the October event, we do not find that any of these criticisms demonstrate that APS was imprudent. The NRC reviewed APS' actions using hindsight, which is not allowable under the prudence standard, and using a standard that is much stricter than prudence. Important to our review is that the NRC approved the design of the RWT system at the time of plant construction and that APS followed that design. The NRC inspector's questions in October of 2005 appear to go beyond this design.

The portion of the January 2006 NRC Report quoted at length above and heavily relied on by Dr. Jacobs does not alter our view. For example, because the NRC inspector's question had not previously been posed by the NRC, it is not of any significance that the inspection report observed that the licensee did not fully understand the "dynamics of the system at the time of a RAS." Similarly, the comment that "there was not a thorough effort by the licensee to validate the design criteria" has no bearing on whether APS should have anticipated the inspector's question. As Dr. Mattson testified, there was no requirement for APS to validate the adequacy of the design prior to the NRC inspector's question. Design compliance rather than design adequacy was the issue in the yellow finding. (APS Exhibit No. 88, Mattson Rejoinder, at 9-10). Furthermore, the NRC did not find that APS should have found the arcane instances of "operating experience" mentioned in the inspection report. (APS Exhibit No. 87, Mattson Rebuttal, at 59-62). We believe that the NRC's inspection report, which was approved and authorized for issuance by Dr. Mallett, should be viewed in a manner consistent with Dr. Mallett's answers to this Commission regarding whether APS should have anticipated the NRC's raising of the question which required the October outages.

We also find that the actions taken by APS prior to and during the supplemental inspection related to the RWT issue were reasonable based upon the knowledge and information that APS had and should have had at the time. Even if we agreed with Staff that APS should have identified the question about air entrainment in the RWT system earlier as part of its preparation for the supplemental inspection, Palo Verde still would have had to shut down. The NRC did not issue the Yellow finding until April 2005, and therefore, any identification of issues with the RWT system in response to this finding would have occurred during the PSA period. An earlier shutdown would likely have occurred during the peak summer months, and could have had a much greater economic impact on the Arizona ratepayers. In sum, we find that APS was not imprudent with respect to the October RWT outages. Accordingly, we will allow recovery of the replacement power costs associated with this outage."

Page 146, Lines 12-18: DELETE Findings of Fact Nos. 115 – 116, REPLACE WITH "115. We find that the Unit 2 and Unit 3 October 2005 Outages were not due to imprudence, because we agree with Dr. Mallett's conclusion that the reason for the outage arose from a new question from the NRC that APS should not have identified earlier; the NRC's criticisms of APS in the January 2006 inspection report do not establish imprudence, but should be understood in a manner consistent with the views of Dr. Mallett who approved and authorized issuance of the report; APS followed the design approved by the NRC; and the actions taken by APS prior to and during the supplemental inspection related to the RWT issue were reasonable based upon the knowledge and information that APS had and should have had at the time.

116. Even if we agreed with Staff that APS should have identified the question about air entrainment in the RWT system earlier as part of its preparation for the supplemental inspection, Palo Verde still would have had to shut down in the summer of 2005."

MAKE ALL CONFORMING CHANGES.

APS PROPOSED AMENDMENT # 33

Calculation of Disallowance for Imprudent Costs

Page 132, Line 18-
Page 133, Line 23: DELETE paragraphs, REPLACE WITH "Based on our conclusion above that no outages were imprudent, no amount should be deducted from the balance of unrecovered Palo Verde replacement costs to be recovered through a surcharge.

APS' application for a Step 2 surcharge should be approved and implemented concurrently with the implementation of rates in this proceeding. APS should calculate the correct amount, and submit the proposed surcharge level to Commission Staff for approval, within 30 days of the date of this Decision."

Page 146, Lines 19-25: DELETE Findings of Fact Nos. 117 – 119, REPLACE WITH "117. APS should be allowed to recover the costs of all of the outages."

Page 147, Line 3: DELETE "as adjusted for our determination herein".

Page 151, Lines 27-28: DELETE Ordering paragraph.

MAKE ALL CONFORMING CHANGES.

APS PROPOSED AMENDMENT # 34

Palo Verde Reports

Page 134, Line 10: After "it", INSERT "and require APS to file the report to the extent possible."

Line 25: After "may", DELETE "be necessary to provide some information confidentially", REPLACE WITH "not be able to provide INPO information due to confidentiality concerns or it may be necessary to provide some information confidentially (e.g., vendor proprietary information) or only make the information available for review. This report should only be necessary until the NRC moves Palo Verde to the "Licensee Response Column" (Column 1) of the Reactor Oversight Process Action Matrix."

Page 147, Lines 13-18: DELETE Findings of Fact Nos. 124 and 125, REPLACE WITH "124. Staff is directed to provide an update on the Unit 1 shutdown associated with the shutdown cooling line vibration within 90 days of this Decision.

125. APS shall submit a semi-annual report to the Commission's Docket Control, describing plant performance, explaining any negative regulatory reports by the NRC or INPO (to the extent INPO consents to disclosure of information from its reports), and providing details of corrective actions taken, until the NRC moves Palo Verde to the "Licensee Response Column" (Column I) of the Reactor Oversight Process Action Matrix."

Page 152, Lines 11-14: DELETE Ordering paragraph, REPLACE WITH "IT IS FURTHER ORDERED that Arizona Public Service Company shall file with Docket Control as a compliance item in this Docket, a semi-annual report describing plant performance, explaining any negative regulatory reports by the NRC or INPO (to the extent INPO consents to disclosure of information from its reports), and providing details of corrective actions taken, until the NRC moves Palo Verde to the "Licensee Response Column" (Column I) of the Reactor Oversight Process Action Matrix."

MAKE ALL CONFORMING CHANGES.

APS PROPOSED AMENDMENT # 35

If a Performance Standard Should be Considered in a Separate Proceeding

Page 117, Line 5: DELETE Footnote 75

Lines 6-12: DELETE "In" through the end of the paragraph, REPLACE WITH "As part of their effort, Staff and APS should consider further whether a performance standard should include baseload coal units."

Page 145, Line 12: After "proceeding.", INSERT ", in addition to considering whether APS coal plants should be part of such performance standard."

Lines 13-19: DELETE Finding of Fact No. 108

MAKE ALL CONFORMING CHANGES.

APS PROPOSED AMENDMENT # 36

<u>If the Commission Determines the August Reactor Trip and the October RWT were Imprudent</u>

Page 132, Line 18-
Page 133, Line 23: DELETE paragraphs and REPLACE WITH the following:

"Staff calculated that $16.186 million, including $13.757 million of replacement power costs during the period the PSA was in effect, the cost of reduced margins on off-system and opportunity sales, and accumulated interest represents the costs associated with the outages caused by imprudence.

Staff recommended that the Commission allow APS to recover the costs resulting from the Palo Verde outages that were not imprudent through a surcharge. APS argued that if the Commission determined that all or part of the RWT outage was imprudent, any disallowance of associated replacement power costs should be offset by the replacement power costs that were avoided because of the performance of this other work during the outage. APS witness Levine presented testimony that had Unit 2 not been shut down for the RWT outage, it would have had to have been shut down shortly thereafter to repair the Reactor Coolant Pump ("RCP") 2A oil seal. (APS Exhibit No. 95, Levine Rejoinder, pp. 6-7) We believe that it was appropriate for APS to perform other needed maintenance during the outage, and the $5,100,000 amount of offset requested by APS reduces the overall amount of disallowance to $10.760 million (plus interest).

APS disagrees with Staff's calculation of the measure of the lost sales, and proposed to use its production cost model to calculate the value of the margins on those lost sales. At the hearing, Staff's own witness, Dr. Jacobs, admitted that his calculation was erroneous and conceded that APS' "approach is probably the more accurate way to do it." Tr. Vol. XXIX pp. 5303-04, 5314. As a result, we agree with APS' calculation of $322,000 for these costs.

Applying the appropriate amount of disallowance for lost off-system sales margins further reduces the overall disallowance from $10.760 million to $8.979 million (plus interest).

Additionally, Staff's methodology for calculating recommended disallowances did not accurately apply the 90/10 sharing, because the methodology discounted the normal amount of outages in the base rates, resulting in APS expensing $515,000 twice. This amount should be deducted from the disallowance, further reducing the overall disallowance from $8.979 million to $8.464 million (plus interest).

We also agree with APS that improved performance of its coal generation should offset losses of generation at Palo Verde. As APS witness Ewen testified, APS' coal plants set an all-time high for capacity factor in 2005. The plants had 40 percent less unplanned outage time than the normalized amount included in APS' base rates, and this better than normal performance reduced fuel costs by $10,000,000. That $10,000,000 savings is not reflected in the replacement power costs for Palo Verde, and thus, it is an appropriate offset to these costs. Since the $10,000,000 is larger than the disallowance amount from above, the entire disallowance is offset. Similarly, comparing APS' outstanding 2005 coal plant performance against its industry peers results in an even more dramatic savings of $27,492,000, which also offsets the entire disallowance proposed by Staff."

Page 146, Lines 16-25: DELETE Findings of Fact Nos. 116 – 119, REPLACE WITH the following:

"116. It was appropriate for APS to perform other needed maintenance during the October 2005 outage, and the $5,100,000 amount requested by APS should be an offset to any disallowance.

117. The appropriate amount of disallowance for lost off-system sales margins is $322,000.

118. Staff's methodology for calculating recommended disallowances did not accurately apply the 90/10 sharing, because the methodology discounted the normal amount of outages in the base rates, resulting in APS expensing $515,000 twice, which should be deducted from any disallowance.

119. Improved performance of coal generation should be used to offset losses of generation at Palo Verde in the amount of at least $10,000,000.

120. After applying the appropriate offset for prudent maintenance, correct disallowance for lost off-system sales margins, offset for costs already expensed, and offset for superior coal plant performance, the entire disallowance for the imprudent outages is eliminated."

MAKE ALL CONFORMING CHANGES.

ATTACHMENT B

STANDARD & POOR'S **RatingsDirect**

RESEARCH

Bulletin:

ALJ Order Would Help Ariz Public Service Co. Cash Flows, But Overall Ratings Impact Is Neutral

Publication date: 30-Apr-2007
Primary Credit Analyst: Anne Selting, San Francisco (1) 415-371-5009; mailto:anne_selting@standardandpoors.com

SAN FRANCISCO (Standard & Poor's) April 30, 2007--Standard & Poor's Ratings Services said today that the draft decision issued late Friday in Arizona Public Service Co.'s (APS) rate case, if adopted, would be modestly beneficial for cash flows, but unlikely to result in an improvement in the current ratings.

Relative to the company's request for $434 million, the draft decision would provide $286 million in rate relief, an average rate increase of 13.5%. Much of the recommended increase stems from adopting the company's cost projections for fuel and purchased power (about $280 million of the recommended increase). The draft also recommends the use of a forward power supply adjuster that would significantly reduce the risk that APS will incur large fuel and power cost deferrals.

The draft decision rejected other requests to improve APS' cash flow position, including allowing recovery of construction work in progress. A final vote has not been scheduled. We do not expect revised rates to be in place before June 1.

ATTACHMENT C

Moody's Investors Service

Global Credit Research
Issuer Comment
7 MAY 2007

Issuer Comment: Arizona Public Service Company

Moody's comments on ACC Administrative Law Judge's recommendation in Arizona Public Service rate case

Moody's Investor's Service views the recommendation of the Arizona Corporation Commission's (ACC) Chief Administrative Law Judge (ALJ) in Arizona Public Service Company's (APS: Baa2 senior unsecured, negative outlook) pending rate case as neutral to the credit quality of APS and its parent company Pinnacle West Capital Corporation (PNW: Baa3 senior unsecured, negative outlook) and having no impact on the rating or outlook of APS or PNW at this time.

On April 27, 2007, the ACC's Chief ALJ issued an order recommending that APS be granted an electric revenue increase of approximate $286 million, or approximately two-thirds of the $435 million requested by APS. Although the ALJ's recommended increase is significantly lower than APS' requested amount, the order also proposed that a prospective Power Supply Adjustor (PSA) be included in APS rates. A prospective PSA should provide more timely recovery of fuel and purchased power costs, which should improve cash flows, and reduce the need to finance significant deferral balances. If the ALJ order is accepted as written, Moody's anticipates that in the near term, APS and Pinnacle's financial credit metrics would remain at the lower end of the ranges considered appropriate for their ratings. For example, we have indicated that the outlooks could be stabilized at the current ratings levels if we believed credit metrics such as the ratio of cash flow from operations excluding changes in working capital to adjusted debt (adjusted in accordance with Moody's standard analytical adjustments) ((CFO x WC)/Debt) would remain in the range of 17-20% at APS and 15-18% at Pinnacle, on a sustainable basis.

The ALJ also recommended against all of the revenue enhancement proposals introduced by APS for consideration as a means of creating more timely recovery of non-fuel related costs. Rather than adopting any of the proposals, the ALJ recommended that APS continue to seek recovery of non-fuel costs via the regular rate case process. Given the significant amount of capital expenditures that APS is planning to provide for its growing load, Moody's believes it is likely the company will need to seek additional rate relief in the near term.

Based on the time that it has recently taken to conclude APS' general rate cases (the June 2003 case was concluded in April 2005; the current case was initially filed November 2005), we believe there remains a significant risk that credit metrics will weaken over the medium term. As a result, the outlooks for both APS and Pinnacle remain negative reflecting our assessment of the regulatory overhang risk still facing the companies, their most recent financial position, and their significant projected capital expenditure requirements. Moody's recognizes that the final ACC decision may ultimately be different from the recommended order, and notes that the recommended order would likely result in limited "headroom" or financial flexibility for APS and Pinnacle to address any unanticipated adverse developments such as increased expenses due to significant operational difficulties, material cost overruns on capital expenditure programs or prolonged rate case outcomes.

Headquartered in Phoenix Arizona, Pinnacle West Capital Corporation provides electric service to a substantial portion of the state of Arizona, sells energy-related products and services, and develops residential, commercial and industrial real estate. While Pinnacle conducts these businesses through separate subsidiaries, wholly owned Arizona Public Service Company is its principal subsidiary.

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ATTACHMENT C

William L. Hess/New York 212-553-3837

ATTACHMENT D

	Actual 2005 Test Year	APS Direct: APS Direct Case 11/30/2005 Market Prices	APS Direct: Direct Case F&PP Pro Forma Adjustment	ALJ Recommended Order: Adjusted Direct Case	ALJ Recommended Order: Change From APS Direct Case	ALJ Recommended Order with Conservation Removed: Adjusted Direct Case	ALJ Recommended Order with Conservation Removed: Change From ALJ Recommendation	APS Rejoinder: APS Rejoinder Case 9/29/2006 Market Prices	APS Rejoinder: Rejoinder F&PP Pro Forma Adjustment	APS Rejoinder with Conservation Removed: Adjusted Rejoinder Case	APS Rejoinder with Conservation Removed: Change from Rejoinder Case
FUEL AND PURCHASED POWER:											
1. Retail Expense (¢/kwh)	2.6983 1/	3.2859 8/	0.5876	3.2156	(0.0703)	3.2181	0.0025	3.2702 13/	0.5719	3.2821	0.0119
2. Test Year Retail Sales (Unadjusted -- MWH)	26,088,197 2/										
3. Native Load Sales (GWH)		29,261 9/		29,261		29,276	15	29,460 14/		29,589	129
4. F&PP Expense on Unadjusted TY Sales	703,938	961,486		940,929	(20,557)	942,129	1,200	963,405	259,467	971,145	7,740
5. Adjusted TY Retail Sales (MWH)	26,759,478 3/	26,759,478	26,759,478	26,759,478	26,759,478	26,759,478	26,759,478	26,759,478	26,759,478	26,759,478	26,759,478
6. Retail F&PP Expense on Adj. TY Sales	722,051	879,289	157,237	860,489	(18,800)	861,145	656	875,092	153,041	878,277	3,185
7. PSA and MTM Deferral	(112,844) 4/	-	112,844	-	-	-	-	-	112,844	-	-
8. Total Retail F&PP Expense	609,207	879,289	270,081	860,489	(18,800)	861,145	656	875,092	265,885	878,277	3,185
OFF SYSTEM MARGIN:											
9. Off System Expense	75,344 5/	127,134 10/	51,790	127,134	-	127,134	-	86,365	11,021	86,365	-
10. ACC Jurisdictional	74,131	125,087	50,956	125,087	-	125,087	-	84,975	10,844	84,975	-
11. Off System Revenue	74,619 6/	153,098 11/	78,479	153,098	-	153,098	-	92,113	17,494	92,113	-
12. ACC Jurisdictional	73,418	150,633	77,215	150,633	-	150,633	-	90,630	17,212	90,630	-
13. Off System Margin Credit	713	(25,546)	(26,259)	(25,546)	-	(25,546)	-	(5,655) 15/	(6,369)	(5,655)	-
14. **TOTAL FUEL EXPENSE**	609,921	853,743	243,822	834,943	(18,800)	835,599	656	869,437	259,516	872,621	3,185
15. Effective Base Fuel Rate (¢/kwh)	$\boxed{2.7010}$ 7/	$\boxed{3.1904}$ 12/	0.4895	$\boxed{3.1202}$	(0.0703)	$\boxed{3.1226}$	0.0025	$\boxed{3.2491}$ 16/	0.5481	$\boxed{3.2610}$	0.0119

1/ Direct Workpapers of Pete Ewen, PME_WP6, page 6 of 13.
2/ Direct Testimony of Pete Ewen, Attachment PME-6, line 6.
3/ Direct Testimony of Pete Ewen, Attachment PME-6, line 10.
4/ Direct Testimony of Pete Ewen, Attachment PME-6, line 15.
5/ Direct Testimony of Pete Ewen, Attachment PME-7, line 8.
6/ Direct Testimony of Pete Ewen, Attachment PME-7, line 3.
7/ Direct Testimony of Pete Ewen, page 7.
8/ Direct Testimony of Pete Ewen, Attachment PME-6, line 5
9/ Direct Workpapers of Pete Ewen, PME_WP1, page 1.
10/ Direct Testimony of Pete Ewen, Attachment PME-7, line 7.
11/ Direct Testimony of Pete Ewen, Attachment PME-7, line 2.
12/ Direct Testimony of Pete Ewen, page 2.
13/ Rejoinder Workpapers of Pete Ewen, PME_1RJ.
14/ Rejoinder Workpapers of Pete Ewen, PME_WP1RJ.
15/ Rejoinder Workpapers of Pete Ewen, PME_WP1RJ.
16/ Rejoinder Testimony of Pete Ewen, page 2.

ARIZONA PUBLIC SERVICE COMPANY
ANALYSIS OF BASE REVENUES BY DETAILED CLASS
BASED ON RECOMMENDED ORDER AND OPINION
IN DOCKET E-01345A-05-0816 et. al.

Line No.	(A) Customer Classification and Current Rate Designation	(B) Average Number of Customers	(C) MWh Sales	(D) Average Annual kWh Usage per Customer [(C) x 1000] / (B)	(E) Base Revenues under Present Rates [1] ($000)	(F) APS Rates - ROO Compliance: Proposed Rate Designation	(G) APS Rates - ROO Compliance: Base Revenues ($000)	(H) Increase: Amount ($000) (G) - (E)	(I) Increase: % (H) / (E)	Line No.
1	Residential									1
2.	E-10	78,292	750,189	9,582	68,276	E-10	82,365	14,089	20.64%	2.
3.	E-12	411,939	3,781,967	9,181	373,352	E-12	412,729	39,377	10.55%	3.
4.	EC-1	20,840	456,882	21,923	35,508	EC-1	43,236	7,728	21.76%	4.
5.	ET-1	329,062	6,038,905	18,352	511,936	ET-1	583,728	71,792	14.02%	5.
6.	ECT-1R	46,327	1,377,916	29,743	102,975	ECT-1R	118,493	15,518	15.07%	6.
7.	Total Residential	886,460	12,405,859	13,995	1,092,047		1,240,551	148,504	13.60%	7.
8.	General Service									8.
9.	E-20	349	39,717	113,802	3,596	E-20	3,659	63	1.75%	9.
10.	E-21	25	1,631	65,240	133	E-21	186	53	39.85%	10.
11.	E-22	17	3,658	215,176	339	E-22	427	88	25.96%	11.
12.	E-23	144	42,679	296,382	3,324	E-23	3,571	247	7.43%	12.
13.	E-24	45	164,984	3,666,311	9,784	E-24	11,158	1,374	14.04%	13.
14.	E-30	3,890	5,669	1,457	945	E-30	1,071	126	13.33%	14.
15.	E-32, E-32R, E-53, E-54, Contract	103,231	10,921,665	105,798	846,071	E-32, E-32R, E-53, E-54, Contract	959,065	112,994	13.36%	15.
16.	E-32TOU	3	1,848	616,000	144	E-32TOU	195	51	35.42%	16.
17.	E-34	38	1,188,008	31,263,368	66,832	E-34	76,453	9,621	14.40%	17.
18.	E-35	19	1,384,977	72,893,526	67,717	E-35	77,464	9,747	14.39%	18.
19.	E-40	1	-	-	1	E-40	1	-	0.00%	19.
20.	E-51	2	10,718	5,359,000	666	E-51	794	128	19.22%	20.
21.	Total General Service	107,764	13,765,554	127,738	999,552		1,134,044	134,492	13.46%	21.
22.	Irrigation and Water Pumping									22.
23.	E-38, E-38-8T, E-38TOW	44	8,779	199,523	620	E-38, E-38-8T, E-38TOW	674	54	8.71%	23.
24.	E-221, E-221-8T, E-221TOW	1,422	283,860	199,620	20,244	E-221, E-221-8T, E-221TOW	20,969	725	3.58%	24.
25.	Total Irrigation	1,466	292,639	199,617	20,864		21,643	779	3.73%	25.
26.	Outdoor Lighting									26.
27.	E-58	564	27,332	48,461	6,208	E-58	7,534	1,326	21.36%	27.
28.	E-59, City Streetlight Contracts	184	73,953	401,918	6,281	E-59, City Streetlight Contracts	6,947	666	10.60%	28.
29.	E-67	210	4,384	20,876	159	E-67	199	40	25.16%	29.
30.	Contract	39	10,750	275,641	697	Contract	816	119	17.07%	30.
31.	Total Outdoor Lighting	997	116,419	116,769	13,345		15,496	2,151	16.12%	31.
32.	Dusk to Dawn Lighting Service	See Note 5)	27,037	See Note 5)	6,423		6,642	219	3.41%	32.
33.	Total Sales to Ultimate Retail Customers	996,687	26,607,508	26,696	2,132,231		2,418,376	286,145	13.42%	33.

NOTES TO SCHEDULE:
1) Base Revenues under Present Rates reflect adjusted test year revenues including applicable proforma adjustments as set forth in the Recommended Opinion and Order.
2) EPR Rate Schedules and Share the Light Rate Schedules are included in each customer's primary billing rate schedule.
3) The following rate schedules will not change: Rate Schedules Solar-2 and SP-1, Rate Schedule E-55, and Rate Schedules E-3 and E-4.
4) Rate Schedule E-36 is not included as proposed price changes are market-related.
5) Dusk to Dawn Lighting customers are included in residential and general service counts as this service is included on each customer's primary billing.
6) This schedule excludes Rate Schedules ET-2, ECT-2, GPS-1, GPS-2, E-56 and E-57.

ATTACHMENT E

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

TEST YEAR ENDING SEPTEMBER 30, 2005

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	
					Present Rates			Proposed Rates					
Line No.	Rate Schedule	Description	Billing Designation	Season	Block	Rates		Block	Rates		Change (J) - (E)		Line No.
1	E-3	Residential Energy	Rate	Sum & Win	For Bills 0-400 kWh	40%	disc.	For Bills 0-400 kWh	40%	disc.	-		1
2		Support Program			For Bills 401-800 kWh	26%	disc.	For Bills 401-800 kWh	26%	disc.	-		2
3					For Bills 801-1200 kWh	14%	disc.	For Bills 801-1200 kWh	14%	disc.	-		3
4					For Bills 1201 kWh and above	$ 13.00	disc.	For Bills 1201 kWh and above	$ 13.00	disc.	-		4
5	E-4	Medical Care	Rate	Sum & Win	For Bills 0-800 kWh	40%	disc.	For Bills 0-800 kWh	40%	disc.	-		5
6		Equipment			For Bills 801-1400 kWh	26%	disc.	For Bills 801-1400 kWh	26%	disc.	-		6
7		Support Program			For Bills 1401-2000 kWh	14%	disc.	For Bills 1401-2000 kWh	14%	disc.	-		7
8					For Bills 2001 kWh and above	$ 26.00	disc.	For Bills 2001 kWh and above	$ 26.00	disc.	-		8
9	E-10	Residential Service	Rate	Summer	Basic Service Charge	$ 0.253	/day	Basic Service Charge	0.2530	/day	$ -		9
10	(INTERIM)				First 400 kWh	0.06929	/kWh	First 400 kWh	0.08434	/kWh	0.01505		10
11					Next 400 kWh	0.09490	/kWh	Next 400 kWh	0.11989	/kWh	0.02499		11
12					All additional kWh	0.09760	/kWh	All additional kWh	0.14212	/kWh	0.04452		12
13				Winter	Basic Service Charge	$ 0.253	/day	Basic Service Charge	0.2530	/day	$ -		13
14					All kWh	0.07601	/kWh	All kWh	0.08195	/kWh	0.00594		14
15			Minimum	Sum & Win	Basic Service Charge	$ 0.253	/day		0.2530	/day			15
16	E-12	Residential Service	Rate	Summer	Basic Service Charge	$ 0.253	/day	Basic Service Charge	0.2530	/day	$ -	/day	16
17					First 400 kWh	0.07570	/kWh	First 400 kWh	0.08411	/kWh	0.00841	/kWh	17
18					Next 400 kWh	0.10556	/kWh	Next 400 kWh	0.11961	/kWh	0.01405	/kWh	18
19					All additional kWh	0.12314	/kWh	All additional kWh	0.14200	/kWh	0.01886	/kWh	19
20				Winter	Basic Service Charge	$ 0.253	/day	Basic Service Charge	0.2530	/day	$ -	/day	20
21					All kWh	0.07361	/kWh	All kWh	0.08223	/kWh	0.00862	/kWh	21
22			Minimum	Sum & Win	Basic Service Charge	$ 0.253	/day	Basic Service Charge	$ 0.253	/day	$ -	/day	22
23	EC-1	Residential Service	Rate	Summer	Basic Service Charge	$ 0.329	/day	Basic Service Charge	$ 0.4930	/day	$ 0.16		23
24	(INTERIM)	With Demand Charge			All kW	10.00	/kW	All kW	$ 11.8600	/kW	$ 1.86		24
25					All kWh	0.03943	/kWh	All kWh	$ 0.04889	/kWh	$ 0.01		25
26				Winter	Basic Service Charge	$ 0.329	/day	Basic Service Charge	$ 0.4930	/day	$ 0.16		26
27					All kW	7.10	/kW	All kW	$ 8.1500	/kW	$ 1.05		27
28					All kWh	0.02978	/kWh	All kWh	$ 0.03692	/kWh	$ 0.01		28
											$ -		
29			Minimum	Sum & Win	Basic Service Charge	$ 0.329	/day	Basic Service Charge	$ 0.493	/day	$ 0.16		29

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Proposed rates are shown on a bundled basis. See tariff sheets for unbundled components.
2) Present rates are those rates effective 4/01/2005.

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES
TEST YEAR ENDING SEPTEMBER 30, 2005

ATTACHMENT E

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	
					Present Rates			Proposed Rates					
Line No.	Rate Schedule	Description	Billing Designation	Season	Block	Rates		Block	Rates		Change (J) - (E)		Line No.
30	ET-1	Residential Service	Rate	Summer	Basic Service Charge	$ 0.493	/day	Basic Service Charge	0.49300	/day	$ -	/day	30
31		Time of Use			All On-Peak kWh	0.13310	/kWh	All On-Peak kWh	0.15570	/kWh	0.02260	/kWh	31
32					All Off-Peak kWh	0.04299	/kWh	All Off-Peak kWh	0.05032	/kWh	0.00733	/kWh	32
33				Winter	Basic Service Charge	$ 0.493	/day	Basic Service Charge	0.49300	/day	$ -	/day	33
34					All On-Peak kWh	0.10918	/kWh	All On-Peak kWh	0.12650	/kWh	0.01732	/kWh	34
35					All Off-Peak kWh	$ 0.04167	/kWh	All Off-Peak kWh	0.04850	/kWh	0.00683	/kWh	35
36			Minimum	Sum & Win	Basic Service Charge	$ 0.493	/day	Basic Service Charge	$ 0.493	/day	$ -	/day	36
37	ET-2	Residential Service	Rate	Summer	Basic Service Charge	0.493	/day	Basic Service Charge	0.493	/day	$ -	/day	37
38		Time of Use			All On-Peak kWh	0.18200	/kWh	All On-Peak kWh	0.21272	/kWh	0.03072	/kWh	38
39					All Off-Peak kWh	0.04519	/kWh	All Off-Peak kWh	0.05331	/kWh	0.00812	/kWh	39
40				Winter	Basic Service Charge	0.493	/day	Basic Service Charge	0.493	/day	$ -	/day	40
41					All On-Peak kWh	0.08703	/kWh	All On-Peak kWh	0.17250	/kWh	0.08547	/kWh	41
42					All Off-Peak kWh	$ 0.05783	/kWh	All Off-Peak kWh	0.05330	/kWh	(0.00453)	/kWh	42
43			Minimum	Sum & Win	Basic Service Charge	0.493	/day	Basic Service Charge	0.493	/day	$ -	/day	43
44	ECT-1R	Residential Service	Rate	Summer	Basic Service Charge	$ 0.493	/day	Basic Service Charge	$ 0.493	/day	$ -	/day	44
45		Time of Use with			All On-Peak kW	11.81	/kW	All On-Peak kW	11.86000	/kW	0.05	/kW	45
46		Demand Charge			All On-Peak kWh	0.04765	/kWh	All On-Peak kWh	0.06470	/kWh	0.01705	/kWh	46
47					All Off-Peak kWh	0.02672	/kWh	All Off-Peak kWh	0.03618	/kWh	0.00946	/kWh	47
48				Winter	Basic Service Charge	$ 0.493	/day	Basic Service Charge	$ 0.493	/day	$ -	/day	48
49					All On-Peak kW	8.11	/kW	All On-Peak kW	8.15000	/kW	0.04	/kW	49
50					All On-Peak kWh	0.03641	/kWh	All On-Peak kWh	0.04882	/kWh	0.01241	/kWh	50
51					All Off-Peak kWh	0.02570	/kWh	All Off-Peak kWh	0.03456	/kWh	0.00886	/kWh	51
52			Minimum	Sum & Win	Minimum	$ 0.493	/day	Basic Service Charge	$ 0.493	/day	$ -	/day	52
53	ECT-2	Residential Service	Rate	Summer	Basic Service Charge	0.493	/day	Basic Service Charge	0.493	/day	$ -	/day	53
54		Time of Use with			All On-Peak kW	11.81	/kW	All On-Peak kW	11.870000	/kW	0.06	/kW	54
55		Demand Charge			All On-Peak kWh	0.05690	/kWh	All On-Peak kWh	0.076860	/kWh	0.01996	/kWh	55
56					All Off-Peak kWh	0.02792	/kWh	All Off-Peak kWh	0.037900	/kWh	0.00998	/kWh	56
57				Winter	Basic Service Charge	0.493	/day	Basic Service Charge	0.493	/day	$ -	/day	57
58					All On-Peak kW	8.11	/kW	All On-Peak kW	8.150000	/kW	0.04	/kW	58
59					All On-Peak kWh	0.03730	/kWh	All On-Peak kWh	0.050520	/kWh	0.01322	/kWh	59
60					All Off-Peak kWh	0.02733	/kWh	All Off-Peak kWh	0.037110	/kWh	0.00978	/kWh	60
61			Minimum	Sum & Win	Minimum	0.493	/day	Basic Service Charge	0.493	/day	$ -	/day	61

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Proposed rates are shown on a bundled basis. See tariff sheets for unbundled components.
2) Present rates are those rates effective 4/01/2005.

ARIZONA PUBLIC SERVICE COMPANY
CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES
TEST YEAR ENDING SEPTEMBER 30, 2005

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	
					Present Rates			Proposed Rates					
Line No.	Rate Schedule	Description	Billing Designation	Season	Block	Rates		Block	Rates		Change (J) - (E)		Line No.
62	E-20	General Service	Rate	Summer	Basic Service Charge	$ 0.941	/day	Basic Service Charge	$ 0.941	/day	$ -	/day	62
63		Time of Use for			All On-Peak kW	2.046	/kW	All On-Peak kW	$ 2.080	/kW	0.03	/kW	63
64		Religious Houses of			Excess Off-Peak kW	1.023	/kW	Excess Off-Peak kW	$ 1.098	/kW	0.07500	/kWh	64
65		Worship			All On-Peak kWh	0.12305	/kWh	All On-Peak kWh	$ 0.12516	/kWh	0.00211	/kWh	65
66					All Off-Peak kWh	0.05943	/kWh	All Off-Peak kWh	$ 0.06044	/kWh	0.00101	/kWh	66
67				Winter	Basic Service Charge	$ 0.941	/day	Basic Service Charge	$ 0.941	/day	$ -	/day	67
68					All On-Peak kW	1.845	/kW	All On-Peak kW	$ 1.880	/kW	0.03	/kW	68
69					Excess Off-Peak kW	0.923	/kW	Excess Off-Peak kW	$ 0.940	/kW	0.01700	/kWh	69
70					All On-Peak kWh	0.10820	/kWh	All On-Peak kWh	$ 0.11006	/kWh	0.00186	/kWh	70
71					All Off-Peak kWh	0.05327	/kWh	All Off-Peak kWh	$ 0.05418	/kWh	0.00091	/kWh	71
72			Minimum	Sum & Win	Basic Service Charge	$ 0.685	/day	Basic Service Charge	$ 0.941	/day	$ 0.256	/day	72
73					Demand Charge	1.67	/kW	Demand Charge	1.699	/kW	0.03	/kW	73
74	E-21	General Service	Rate	Summer	Basic Service Charge	$ 0.925	/day						74
75		Time of Use			All On-Peak kW	2.010	/kW						75
76		Less Than 100 kW			Excess Off-Peak kW	1.005	/kW						76
77					All On-Peak kWh	0.12097	/kWh						77
78					All Off-Peak kWh	0.05843	/kWh						78
79				Winter	Basic Service Charge	$ 0.925	/day	RATE E-21 CANCELLED;					79
80					All On-Peak kW	1.810	/kW	CUSTOMERS MOVED TO E-32TOU					80
81					Excess Off-Peak kW	0.905	/kW						81
82					All On-Peak kWh	0.10638	/kWh						82
83					All Off-Peak kWh	0.05237	/kWh						83
84			Minimum	Sum & Win	Basic Service Charge	$ 0.685	/day						84
85					Demand Charge	1.67	/kW						85
86	E-22	Small General Service	Rate	Summer	Basic Service Charge	$ 0.925	/day						86
87		Time of Use			All On-Peak kW	2.230	/kW						87
88					Excess Off-Peak kW	1.115	/kW						88
89					All On-Peak kWh	0.12125	/kWh						89
90					All Off-Peak kWh	0.07475	/kWh						90
91				Winter	Basic Service Charge	$ 0.925	/day	RATE E-22 CANCELLED;					91
92					All On-Peak kW	2.020	/kW	CUSTOMERS MOVED TO E-32TOU					92
93					Excess Off-Peak kW	1.010	/kW						93
94					All On-Peak kWh	0.10285	/kWh						94
95					All Off-Peak kWh	0.06430	/kWh						95
96			Minimum	Sum & Win	Basic Service Charge	$ 0.685	/day						96
97					Demand Charge	1.67	/kW						97

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Proposed rates are shown on a bundled basis. See tariff sheets for unbundled components.
2) Present rates are those rates effective 4/01/2005.

ATTACHMENT E

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

TEST YEAR ENDING SEPTEMBER 30, 2005

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	
					Present Rates			Proposed Rates					
Line No.	Rate Schedule	Description	Billing Designation	Season	Block	Rates		Block	Rates		Change (J) - (E)		Line No.
98	E-23	Medium General Service Time of Use	Rate	Summer	Basic Service Charge	$ 1.988	/day	RATE E-23 CANCELLED; CUSTOMERS MOVED TO E-32TOU					98
99					All On-Peak kW	6.410	/kW						99
100					Excess Off-Peak kW	3.205	/kW						100
101					All On-Peak kWh	0.08163	/kWh						101
102					All Off-Peak kWh	0.05843	/kWh						102
103				Winter	Basic Service Charge	$ 1.988	/day						103
104					All On-Peak kW	5.820	/kW						104
105					Excess Off-Peak kW	2.910	/kW						105
106					All On-Peak kWh	0.07328	/kWh						106
107					All Off-Peak kWh	0.05237	/kWh						107
108			Minimum	Sum & Win	Basic Service Charge	$ 0.685	/day						108
109					Demand Charge	1.67	/kW						109
100	E-24	Large General Service Time of Use	Rate	Summer	Basic Service Charge	$ 34.271	/day	RATE E-24 CANCELLED; CUSTOMERS MOVED TO E-32TOU					100
101					All On-Peak kW	9.390	/kW						101
102					Excess Off-Peak kW	4.695	/kW						102
103					All On-Peak kWh	0.05283	/kWh						103
104					All Off-Peak kWh	0.03797	/kWh						104
105				Winter	Basic Service Charge	$ 34.271	/day						105
106					All On-Peak kW	8.510	/kW						106
107					Excess Off-Peak kW	4.255	/kW						107
108					All On-Peak kWh	0.04723	/kWh						108
109					All Off-Peak kWh	0.03393	/kWh						109
110			Minimum	Sum & Win	Basic Service Charge	$ 0.685	/day						110
111					Demand Charge	1.67	/kW						111
102	E-30	Extra Small General Service Unmetered	Rate	Summer	Basic Service Charge	$ 0.275	/day	Basic Service Charge	$ 0.275	/day	$ -	/day	102
103					All kWh	0.09684	/kWh	All kWh	$ 0.126210	/kWh	0.02937	/kWh	103
105				Winter	Basic Service Charge	$ 0.275	/day	Basic Service Charge	$ 0.275	/day	$ -	/day	105
106					All kWh	0.08724	/kWh	All kWh	$ 0.113350	/kWh	0.02611	/kWh	106

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Proposed rates are shown on a bundled basis. See tariff sheets for unbundled components.
2) Present rates are those rates effective 4/01/2005.

ATTACHMENT E

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

TEST YEAR ENDING SEPTEMBER 30, 2005

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	
					Present Rates			Proposed Rates					
Line No.	Rate Schedule	Description	Billing Designation	Season	Block	Rates		Block	Rates		Change (J) - (E)		Line No.
107	E-32	General Service 20 kW or Less	Rate	Summer	BSC: Self-Contained Meters	$ 0.575	/day	BSC: Self-Contained Meters	$ 0.575	/day	$ -	/day	107
108					BSC: Instrument-rated Meters	1.134	/day	BSC: Instrument-rated Meters	1.134	/day	-	/day	108
109					BSC: Primary Meters	2.926	/day	BSC: Primary Meters	2.926	/day	-	/day	109
110					BSC: Transmission Meters	22.422	/day	BSC: Transmission Meters	22.422	/day	-	/day	110
111					First 5,000 kWh: Secondary	0.09892	/kWh	First 5,000 kWh: Secondary	0.11293	/kWh	0.01401	/kWh	111
112					All remaining kWh: Secondary	0.04711	/kWh	All remaining kWh: Secondary	0.06161	/kWh	0.01450	/kWh	112
113					First 5,000 kWh: Primary	0.09610	/kWh	First 5,000 kWh: Primary	0.11015	/kWh	0.01405	/kWh	113
114					All remaining kWh: Primary	0.04429	/kWh	All remaining kWh: Primary	0.05883	/kWh	0.01454	/kWh	114
115				Winter	BSC: Self-Contained Meters	$ 0.575	/day	BSC: Self-Contained Meters	$ 0.575	/day	$ -	/day	115
116					BSC: Instrument-rated Meters	1.134	/day	BSC: Instrument-rated Meters	1.134	/day	-	/day	116
117					BSC: Primary Meters	2.926	/day	BSC: Primary Meters	2.926	/day	-	/day	117
118					BSC: Transmission Meters	22.422	/day	BSC: Transmission Meters	22.422	/day	-	/day	118
119					First 5,000 kWh: Secondary	0.08892	/kWh	First 5,000 kWh: Secondary	0.09813	/kWh	0.00921	/kWh	119
120					All remaining kWh: Secondary	0.03711	/kWh	All remaining kWh: Secondary	0.04681	/kWh	0.00970	/kWh	120
121					First 5,000 kWh: Primary	0.08610	/kWh	First 5,000 kWh: Primary	0.09535	/kWh	0.00925	/kWh	121
122					All remaining kWh: Primary	0.03429	/kWh	All remaining kWh: Primary	0.04403	/kWh	0.00974	/kWh	122
123			Minimum	Sum & Win	BSC: Self-Contained Meters	$ 0.575	/day	BSC: Self-Contained Meters	$ 0.575	/day	$ -	/day	123
124					BSC: Instrument-rated Meters	1.134	/day	BSC: Instrument-rated Meters	1.134	/day	-	/day	124
125					BSC: Primary Meters	2.926	/day	BSC: Primary Meters	2.926	/day	-	/day	125
126					BSC: Transmission Meters	22.422	/day	BSC: Transmission Meters	22.422	/day	-	/day	126
127		General Service Above 20 kW	Rate	Summer	BSC: Self-Contained Meters	$ 0.575	/day	BSC: Self-Contained Meters	$ 0.575	/day	$ -	/day	127
128					BSC: Instrument-rated Meters	1.134	/day	BSC: Instrument-rated Meters	1.134	/day	-	/day	128
129					BSC: Primary Meters	2.926	/day	BSC: Primary Meters	2.926	/day	-	/day	129
130					BSC: Transmission Meters	22.422	/day	BSC: Transmission Meters	22.422	/day	-	/day	130
131					First 100 kW: Secondary	7.722	/kW	First 100 kW: Secondary	8.477	/kW	0.755	/kW	131
132					All remaining kW: Secondary	3.497	/kW	All remaining kW: Secondary	4.509	/kW	1.012	/kW	132
133					First 100 kW: Primary	7.102	/kW	First 100 kW: Primary	7.865	/kW	0.763	/kW	133
134					All remaining kW: Primary	2.877	/kW	All remaining kW: Primary	3.897	/kW	1.020	/kW	134
135					First 100 kW: Transmission	4.232	/kW	First 100 kW: Transmission	6.132	/kW	1.900	/kW	135
136					All remaining kW: Transmission	0.007	/kW	All remaining kW: Transmission	2.164	/kW	2.157	/kW	136
137					First 200 kWh per kW	0.07938	/kWh	First 200 kWh per kW	0.08944	/kWh	0.01006	/kWh	137
138					All remaining kWh	0.04175	/kWh	All remaining kWh	0.05231	/kWh	0.01056	/kWh	138

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Proposed rates are shown on a bundled basis. See tariff sheets for unbundled components.
2) Present rates are those rates effective 4/01/2005.

ATTACHMENT E

ARIZONA PUBLIC SERVICE COMPANY
CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES
TEST YEAR ENDING SEPTEMBER 30, 2005

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	
					Present Rates			Proposed Rates					
Line No.	Rate Schedule	Description	Billing Designation	Season	Block	Rates		Block	Rates		Change (J) - (E)		Line No.
139	E-32	General Service	Rate	Winter	BSC: Self-Contained Meters	$ 0.575	/day	BSC: Self-Contained Meters	$ 0.575	/day	$ -	/day	139
140	(cont)	Above 20 kW			BSC: Instrument-rated Meters	1.134	/day	BSC: Instrument-rated Meters	1.134	/day	-	/day	140
141		(cont)			BSC: Primary Meters	2.926	/day	BSC: Primary Meters	2.926	/day	-	/day	141
142					BSC: Transmission Meters	22.422	/day	BSC: Transmission Meters	22.422	/day	-	/day	142
143					First 100 kW: Secondary	7.722	/kW	First 100 kW: Secondary	8.477	/kW	0.755	/kW	143
144					All remaining kW: Secondary	3.497	/kW	All remaining kW: Secondary	4.509	/kW	1.012	/kW	144
145					First 100 kW: Primary	7.102	/kW	First 100 kW: Primary	7.865	/kW	0.763	/kW	145
146					All remaining kW: Primary	2.877	/kW	All remaining kW: Primary	3.897	/kW	1.020	/kW	146
147					First 100 kW: Transmission	4.232	/kW	First 100 kW: Transmission	6.132	/kW	1.900	/kW	147
148					All remaining kW: Transmission	0.007	/kW	All remaining kW: Transmission	2.164	/kW	2.157	/kW	148
149					First 200 kWh per kW	0.06945	/kWh	First 200 kWh per kW	0.07471	/kWh	0.00526	/kWh	149
150					All remaining kWh	0.03182	/kWh	All remaining kWh	0.03758	/kWh	0.00576	/kWh	150
151			Minimum	Sum & Win	BSC: Self-Contained Meters	$ 0.575	/day	BSC: Self-Contained Meters	$ 0.575	/day	$ -	/day	151
152					BSC: Instrument-rated Meters	1.134	/day	BSC: Instrument-rated Meters	1.134	/day	-	/day	152
153					BSC: Primary Meters	2.926	/day	BSC: Primary Meters	2.926	/day	-	/day	153
154					BSC: Transmission Meters	22.422	/day	BSC: Transmission Meters	22.422	/day	-	/day	154
155					Demand Charge:	1.66	/kW	Demand Charge:	1.99	/kW	0.33	/kW	155
156	E-32R	Partial Requirements	Rate	Sum & Win	Billed on Rate E-32 or Rate E-32TOU			NO CHANGE					156
157		General Service											157
158			Minimum	Sum & Win	Includes contract minimums in kW determination								158
159	E-32TOU	General Service	Rate	Summer	BSC: Self-Contained Meters	$ 0.575	/day	BSC: Self-Contained Meters	$ 0.608	/day	$ 0.033	/day	159
160		Time of Use			BSC: Instrument-rated Meters	1.134	/day	BSC: Instrument-rated Meters	1.134	/day	-	/day	160
161		20 kW or Less			BSC: Primary Meters	2.926	/day	BSC: Primary Meters	2.926	/day	-	/day	161
162					BSC: Transmission Meters	22.422	/day	BSC: Transmission Meters	22.422	/day	-	/day	162
163					First 5,000 On-Peak kWh: Secondary	0.11172	/kWh	First 5,000 On-Peak kWh: Secondary	0.14035	/kWh	0.02863	/kWh	163
164					All remaining On-Peak kWh: Secondary	0.05991	/kWh	All remaining On-Peak kWh: Secondary	0.06920	/kWh	0.00929	/kWh	164
165					First 5,000 Off-Peak kWh: Secondary	0.09172	/kWh	First 5,000 Off-Peak kWh: Secondary	0.10383	/kWh	0.01211	/kWh	165
166					All remaining Off-Peak kWh: Secondary	0.03991	/kWh	All remaining Off-Peak kWh: Secondary	0.03722	/kWh	(0.00269)	/kWh	166
167					First 5,000 On-Peak kWh: Primary	0.10890	/kWh	First 5,000 On-Peak kWh: Primary	0.13753	/kWh	0.02863	/kWh	167
168					All remaining On-Peak kWh: Primary	0.05709	/kWh	All remaining On-Peak kWh: Primary	0.06572	/kWh	0.00863	/kWh	168
169					First 5,000 Off-Peak kWh: Primary	0.08890	/kWh	First 5,000 Off-Peak kWh: Primary	0.10101	/kWh	0.01211	/kWh	169
170					All remaining Off-Peak kWh: Primary	0.03709	/kWh	All remaining Off-Peak kWh: Primary	0.03444	/kWh	(0.00265)	/kWh	170
171				Winter	BSC: Self-Contained Meters	$ 0.575	/day	BSC: Self-Contained Meters	$ 0.608	/day	$ 0.033	/day	171
172					BSC: Instrument-rated Meters	1.134	/day	BSC: Instrument-rated Meters	1.134	/day	-	/day	172
173					BSC: Primary Meters	2.926	/day	BSC: Primary Meters	2.926	/day	-	/day	173
174					BSC: Transmission Meters	22.422	/day	BSC: Transmission Meters	22.422	/day	-	/day	174
175					First 5,000 On-Peak kWh: Secondary	0.10172	/kWh	First 5,000 On-Peak kWh: Secondary	0.12627	/kWh	0.02455	/kWh	175
176					All remaining On-Peak kWh: Secondary	0.04991	/kWh	All remaining On-Peak kWh: Secondary	0.05511	/kWh	0.00520	/kWh	176
177					First 5,000 Off-Peak kWh: Secondary	0.08172	/kWh	First 5,000 Off-Peak kWh: Secondary	0.08976	/kWh	0.00804	/kWh	177
178					All remaining Off-Peak kWh: Secondary	0.02991	/kWh	All remaining Off-Peak kWh: Secondary	0.02714	/kWh	(0.00277)	/kWh	178
179					First 5,000 On-Peak kWh: Primary	0.09890	/kWh	First 5,000 On-Peak kWh: Primary	0.12345	/kWh	0.02455	/kWh	179
180					All remaining On-Peak kWh: Primary	0.04709	/kWh	All remaining On-Peak kWh: Primary	0.05163	/kWh	0.00454	/kWh	180
181					First 5,000 Off-Peak kWh: Primary	0.07890	/kWh	First 5,000 Off-Peak kWh: Primary	0.08694	/kWh	0.00804	/kWh	181
182					All remaining Off-Peak kWh: Primary	0.02709	/kWh	All remaining Off-Peak kWh: Primary	0.02432	/kWh	(0.00277)	/kWh	182

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Proposed rates are shown on a bundled basis. See tariff sheets for unbundled components.
2) Present rates are those rates effective 4/01/2005.

ARIZONA PUBLIC SERVICE COMPANY

ATTACHMENT E

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

TEST YEAR ENDING SEPTEMBER 30, 2005

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	
					Present Rates			Proposed Rates					
Line No.	Rate Schedule	Description	Billing Designation	Season	Block	Rates		Block	Rates		Change (J) - (E)		Line No.
183	E-32TOU	General Service	Minimum	Sum & Win	BSC: Self-Contained Meters	$ 0.575	/day	BSC: Self-Contained Meters	$ 0.608	/day	$ 0.033	/day	183
184	(cont)	Time of Use			BSC: Instrument-rated Meters	1.134	/day	BSC: Instrument-rated Meters	1.134	/day	-	/day	184
185		20 kW or Less			BSC: Primary Meters	2.926	/day	BSC: Primary Meters	2.926	/day	-	/day	185
186		(cont)			BSC: Transmission Meters	22.422	/day	BSC: Transmission Meters	22.422	/day	-	/day	186
187		General Service	Rate	Summer	BSC: Self-Contained Meters	$ 0.575	/day	BSC: Self-Contained Meters	$ 0.60800	/day	$ 0.033	/day	187
188		Time of Use			BSC: Instrument-rated Meters	1.134	/day	BSC: Instrument-rated Meters	$ 1.13400	/day	-	/day	188
189		Above 20 kW			BSC: Primary Meters	2.926	/day	BSC: Primary Meters	$ 2.92600	/day	-	/day	189
190					BSC: Transmission Meters	22.422	/day	BSC: Transmission Meters	$ 22.42200	/day	-	/day	190
191					First 100 On-Peak kW: Secondary	15.112	/kW	First 100 On-Peak kW: Secondary	$ 12.49800	/kW	(2.614)	/kW	191
192					All remaining On-Peak kW: Secondary	10.887	/kW	All remaining On-Peak kW: Secondary	$ 8.42300	/kW	(2.464)	/kW	192
193					First 100 Residual kW: Secondary	7.972	/kW	First 100 Off-Peak kW: Secondary	$ 4.75500	/kW	(3.217)	/kW	193
194					All remaining Residual kW: Secondary	3.747	/kW	All remaining Off-Peak kW: Secondary	$ 2.64800	/kW	(1.099)	/kW	194
195					First 100 On-Peak kW: Primary	14.492	/kW	First 100 On-Peak kW: Primary	$ 12.00200	/kW	(2.490)	/kW	195
196					All remaining On-Peak kW: Primary	10.267	/kW	All remaining On-Peak kW: Primary	$ 8.36100	/kW	(1.906)	/kW	196
197					First 100 Residual kW: Primary	7.352	/kW	First 100 Off-Peak kW: Primary	$ 2.98100	/kW	(4.371)	/kW	197
198					All remaining Residual kW: Primary	3.127	/kW	All remaining Off-Peak kW: Primary	$ 2.45900	/kW	(0.668)	/kW	198
199					First 100 On-Peak kW: Transmission	11.622	/kW	First 100 On-Peak kW: Transmission	$ 11.29100	/kW	(0.331)	/kW	199
200					All remaining On-Peak kW: Transmission	7.397	/kW	All remaining On-Peak kW: Transmission	$ 8.11600	/kW	0.719	/kW	200
201					First 100 Residual kW: Transmission	4.482	/kW	First 100 Off-Peak kW: Transmission	$ 3.69300	/kW	(0.789)	/kW	201
202					All remaining Residual kW: Transmission	0.257	/kW	All remaining Off-Peak kW: Transmission	$ 2.48600	/kW	2.229	/kW	202
203					All On-Peak kWh:	0.04815	/kWh	All On-Peak kWh:	$ 0.06166	/kWh	0.01351	/kWh	203
204					All Off-Peak kWh:	0.03815	/kWh	All Off-Peak kWh:	$ 0.04870	/kWh	0.01055	/kWh	204
205				Winter	BSC: Self-Contained Meters	$ 0.575	/day	BSC: Self-Contained Meters	$ 0.60800	/day	$ 0.033	/day	205
206					BSC: Instrument-rated Meters	1.134	/day	BSC: Instrument-rated Meters	$ 1.13400	/day	-	/day	206
207					BSC: Primary Meters	2.926	/day	BSC: Primary Meters	$ 2.92600	/day	-	/day	207
208					BSC: Transmission Meters	22.422	/day	BSC: Transmission Meters	$ 22.42200	/day	-	/day	208
209					First 100 On-Peak kW: Secondary	15.112	/kW	First 100 On-Peak kW: Secondary	$ 12.49800	/kW	(2.614)	/kW	209
210					All remaining On-Peak kW: Secondary	10.887	/kW	All remaining On-Peak kW: Secondary	$ 8.42300	/kW	(2.464)	/kW	210
211					First 100 Residual kW: Secondary	7.972	/kW	First 100 Off-Peak kW: Secondary	$ 4.75500	/kW	(3.217)	/kW	211
212					All remaining Residual kW: Secondary	3.747	/kW	All remaining Off-Peak kW: Secondary	$ 2.64800	/kW	(1.099)	/kW	212
213					First 100 On-Peak kW: Primary	14.492	/kW	First 100 On-Peak kW: Primary	$ 12.00200	/kW	(2.490)	/kW	213
214					All remaining On-Peak kW: Primary	10.267	/kW	All remaining On-Peak kW: Primary	$ 8.36100	/kW	(1.906)	/kW	214
215					First 100 Residual kW: Primary	7.352	/kW	First 100 Off-Peak kW: Primary	$ 2.98100	/kW	(4.371)	/kW	215
216					All remaining Residual kW: Primary	3.127	/kW	All remaining Off-Peak kW: Primary	$ 2.45900	/kW	(0.668)	/kW	216
217					First 100 On-Peak kW: Transmission	11.622	/kW	First 100 On-Peak kW: Transmission	$ 11.29100	/kW	(0.331)	/kW	217
218					All remaining On-Peak kW: Transmission	7.397	/kW	All remaining On-Peak kW: Transmission	$ 8.11600	/kW	0.719	/kW	218
219					First 100 Residual kW: Transmission	4.482	/kW	First 100 Off-Peak kW: Transmission	$ 3.69300	/kW	(0.789)	/kW	219
220					All remaining Residual kW: Transmission	0.257	/kW	All remaining Off-Peak kW: Transmission	$ 2.48600	/kW	2.229	/kW	220
221					All On-Peak kWh:	0.03822	/kWh	All On-Peak kWh:	$ 0.04725	/kWh	0.00903	/kWh	221
222					All Off-Peak kWh:	0.02822	/kWh	All Off-Peak kWh:	$ 0.03429	/kWh	0.00607	/kWh	222

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Proposed rates are shown on a bundled basis. See tariff sheets for unbundled components.
2) Present rates are those rates effective 4/01/2005.

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

ATTACHMENT E

TEST YEAR ENDING SEPTEMBER 30, 2005

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	
					Present Rates			Proposed Rates					
Line No.	Rate Schedule	Description	Billing Designation	Season	Block	Rates		Block	Rates		Change (J) - (E)		Line No.
223	E-32TOU	General Service	Minimum	Sum & Win	BSC: Self-Contained Meters	$ 0.575	/day	BSC: Self-Contained Meters	$ 0.608	/day	$ 0.033	/day	223
224	(cont)	Time of Use			BSC: Instrument-rated Meters	1.134	/day	BSC: Instrument-rated Meters	1.134	/day	-	/day	224
225		Above 20 kW			BSC: Primary Meters	2.926	/day	BSC: Primary Meters	2.926	/day	-	/day	225
226		(cont)			BSC: Transmission Meters	22.422	/day	BSC: Transmission Meters	22.422	/day	-	/day	226
227					Demand Charge	1.66	/kW	Demand Charge	1.99	/kW	0.33	/kW	227
228	E-34	Extra Large	Rate	Sum & Win	BSC: Self-Contained Meters	$ 0.575	/day	BSC: Self-Contained Meters	$ 0.575	/day	$ -	/day	228
229		General Service			BSC: Instrument-rated Meters	1.134	/day	BSC: Instrument-rated Meters	1.134	/day	-	/day	229
230					BSC: Primary Meters	2.926	/day	BSC: Primary Meters	2.926	/day	-	/day	230
231					BSC: Transmission Meters	22.422	/day	BSC: Transmission Meters	22.422	/day	-	/day	231
232					All kW: Secondary	12.343	/kW	All kW: Secondary	14.4010	/kW	2.058	/kW	232
233					All kW: Primary	11.683	/kW	All kW: Primary	11.15100	/kW	(0.532)	/kW	233
234					All kW: Primary on Military Bases	8.943	/kW	All kW: Primary on Military Bases	8.41100	/kW	(0.532)	/kW	234
235					All kW: Transmission	8.043	/kW	All kW: Transmission	$ 10.4710	/kW	2.428	/kW	235
236					All kWh	0.03183	/kWh	All kWh	0.040170	/kWh	0.00834	/kWh	236
237			Minimum	Sum & Win	BSC: Self-Contained Meters	$ 0.575	/day	BSC: Self-Contained Meters	$ 0.575	/day	$ -	/day	237
238					BSC: Instrument-rated Meters	1.134	/day	BSC: Instrument-rated Meters	1.134	/day	-	/day	238
239					BSC: Primary Meters	2.926	/day	BSC: Primary Meters	2.926	/day	-	/day	239
240					BSC: Transmission Meters	22.422	/day	BSC: Transmission Meters	22.422	/day	-	/day	240
241					Demand Charge: Secondary	12.343	/kW	Demand Charge: Secondary	14.40100	/kW	2.058	/kW	241
242					Demand Charge: Primary	11.683	/kW	Demand Charge: Primary	11.15100	/kW	(0.532)	/kW	242
243					Demand Charge: Primary on Military Bases	8.943	/kW	Demand Charge: Primary on Military Bases	8.41100	/kW	(0.532)	/kW	243
244					Demand Charge: Transmission	8.043	/kW	Demand Charge: Transmission	10.47100	/kW	2.428	/kW	244
245	E-35	Extra Large	Rate	Sum & Win	BSC: Self-Contained Meters	$ 0.575	/day	BSC: Self-Contained Meters	$ 0.608	/day	$ 0.033	/day	245
246		General Service			BSC: Instrument-rated Meters	1.134	/day	BSC: Instrument-rated Meters	1.134	/day	-	/day	246
247		Time Of Use			BSC: Primary Meters	2.926	/day	BSC: Primary Meters	2.926	/day	-	/day	247
248					BSC: Transmission Meters	22.422	/day	BSC: Transmission Meters	22.422	/day	-	/day	248
249					All On-Peak kW: Secondary	12.869	/kW	All On-Peak kW: Secondary	$ 13.313	/kW	0.444	/kW	249
250					All Excess Off-Peak kW: Secondary	6.388	/kW	All Off-Peak kW: Secondary	$ 2.412	/kW	(3.976)	/kW	250
251					All On-Peak kW: Primary	12.209	/kW	All On-Peak kW: Primary	$ 12.653	/kW	0.444	/kW	251
252					All Excess Off-Peak kW: Primary	5.728	/kW	All Off-Peak kW: Primary	$ 2.346	/kW	(3.3820)	/kW	252
253					All On-Peak kW: Primary on Military Bases	9.469	/kW	All On-Peak kW: Primary on Military Bases	$ 10.187	/kW	0.718	/kW	253
254					All Excess Off-Peak kW; Primary on Military	5.728	/kW	All Off-Peak kW: Primary on Military Bases	$ 2.099	/kW	(3.6290)	/kW	254
255					All On-Peak kW: Trans.	8.569	/kW	All On-Peak kW: Transmission	$ 9.248	/kW	0.679	/kW	255
256					All Excess Off-Peak kW: Trans.	2.088	/kW	All Off-Peak kW: Transmission	2.005	/kW	(0.083)	/kW	256
257					All On-Peak kWh	0.03529	/kWh	All On-Peak kWh	0.03978	/kWh	0.00449	/kWh	257
258					All Off-Peak kWh	0.02792	/kWh	All Off-Peak kWh	0.02994	/kWh	0.00202	/kWh	258
259			Minimum	Sum & Win	BSC: Self-Contained Meters	$ 0.575	/day	BSC: Self-Contained Meters	$ 0.608	/day	$ 0.033	/day	259
260					BSC: Instrument-rated Meters	1.134	/day	BSC: Instrument-rated Meters	1.134	/day	-	/day	260
261					BSC: Primary Meters	2.926	/day	BSC: Primary Meters	2.926	/day	-	/day	261
262					BSC: Transmission Meters	22.422	/day	BSC: Transmission Meters	22.422	/day	-	/day	262
263					Demand Charge: Secondary	12.869	/kW	Demand Charge: Secondary	13.3130	/kW	0.444	/kW	263
264					Demand Charge: Primary	12.209	/kW	Demand Charge: Primary	12.6530	/kW	0.444	/kW	264
265					Demand Charge: Primary on Military Bases	9.469	/kW	Demand Charge: Primary on Military Bases	10.1870	/kW	0.718	/kW	265
266					Demand Charge: Transmission	8.569	/kW	Demand Charge: Transmission	9.2480	/kW	0.679	/kW	266

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Proposed rates are shown on a bundled basis. See tariff sheets for unbundled components.
2) Present rates are those rates effective 4/01/2005.

ARIZONA PUBLIC SERVICE COMPANY

ATTACHMENT E

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES
TEST YEAR ENDING SEPTEMBER 30, 2005

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	
					Present Rates			Proposed Rates					
Line No.	Rate Schedule	Description	Billing Designation	Season	Block	Rates		Block	Rates		Change (J) - (E)		Line No.
267	E-36	Station Use Service	Rate	Sum & Win	Basic Service Charge	$ 6,100.00	/mo	Basic Service Charge	$ 6,100.00	/mo	$ -	/mo	267
268					Metering Charge Company Owned	1.29%		Metering Charge Company Owned	1.29%		-		268
269					Metering Charge Customer Owned	0.35%		Metering Charge Customer Owned	0.35%		-		269
270					All kW: Secondary	4.58	/kW	All kW: Secondary	4.58	/kW	-	/kW	270
271					All kW: Primary	4.42	/kW	All kW: Primary	4.42	/kW	-	/kW	271
272					All kW: Transmission	1.43	/kW	All kW: Transmission	1.43	/kW	-	/kW	272
273					All kWh: Market Price plus	0.0005	/kWh	All kWh: Hourly Pricing Proxy plus	0.0005	/kWh	-	/kWh	273
274	E-38	Agricultural	Rate	Summer	Basic Service Charge	$ 0.493	/day						274
275		Irrigation Service			All kW	0.430	/kW						275
276					First 275 kWh per kW	0.06846	/kWh						276
277					All remaining kWh	0.05634	/kWh						277
278				Winter	Basic Service Charge	0.493	/day						278
279					All kW	0.430	/kW						279
280					All kWh	0.05634	/kWh	RATE E-38 CANCELLED;					280
281			Minimum	Sum & Win	Basic Service Charge	0.493	/day	CUSTOMERS MOVED TO RATE E-221					281
282					Annual Minimum	513.00	/yr						282
283		Customer Owned	Discount	Sum & Win	First 275 kWh per kW	(0.00298)	/kWh						283
284		Transformer Option			All remaining kWh	(0.00098)	/kWh						284
285		Time of Week Option	Adjustment	Sum & Win	2 kWh per kW or less	(0.00659)	/kWh						285
286			to Bill		> 2 kWh per kW; < 8 kWh per kW	-	/kWh						286
287					Greater than 8 kWh per kW	0.00330	/kWh						287
288	E-38-8T	Agricultural	Rate	Sum & Win	Basic Service Charge	$ 0.493	/day						288
289		Irrigation Service			All On-Peak kW	8.68	/kW						289
290		Time of Use			All Off-Peak kW	0.43	/kW						290
291					All On-Peak kWh	0.06846	/kWh						291
292					All Off-Peak kWh	0.04491	/kWh	RATE E-38-8T CANCELLED;					292
293			Minimum	Sum & Win	Basic Service Charge	0.493	/day	CUSTOMERS MOVED TO RATE E-221-8T					293
294					Annual Minimum	513.00	/yr						294
295		Customer Owned	Discount	Sum & Win	All kWh	(0.00098)	/kWh						295
296		Transformer Option											296
297	E-40	Agricultural Wind		Sum & Win	Service Charge $/HP	$ 0.0350	/day	Service Charge $/HP	0.043000	/day	$ 0.00800	/day	297
298		Machine Service			All kWh	0.06569	/kWh	All kWh	0.079840	/kWh	0.07984	/kWh	298

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Proposed rates are shown on a bundled basis. See tariff sheets for unbundled components.
2) Present rates are those rates effective 4/01/2005.

ATTACHMENT E

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

TEST YEAR ENDING SEPTEMBER 30, 2005

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	
					Present Rates			Proposed Rates					
Line No.	Rate Schedule	Description	Billing Designation	Season	Block	Rates		Block	Rates		Change (J) - (E)		Line No.
299	E-47	Dusk to Dawn Lighting Service	Rate	Sum & Win	**FIXTURES** (Company Owned)			**FIXTURES** (Company Owned)					299
300					A. Acorn 9,500 HPS	$ 20.27	/mo	A. Acorn 9,500 HPS	$ 23.79	/mo	$ 3.52	/mo	300
301					Acorn 16,000 HPS	22.45	/mo	Acorn 16,000 HPS	$ 26.40	/mo	3.95	/mo	301
302					B. Architectural 9,500 HPS	13.79	/mo	B. Architectural 9,500 HPS	13.51	/mo	(0.28)	/mo	302
303					Architectural 16,000 HPS	16.03	/mo	Architectural 16,000 HPS	15.79	/mo	(0.24)	/mo	303
304					Architectural 30,000 HPS	18.93	/mo	Architectural 30,000 HPS	18.73	/mo	(0.20)	/mo	304
305					Architectural 50,000 HPS	23.24	/mo	Architectural 50,000 HPS	23.11	/mo	(0.13)	/mo	305
306					Architectural 14,000 MH	19.07	/mo	Architectural 14,000 MH	18.91	/mo	(0.16)	/mo	306
307					Architectural 21,000 MH	21.58	/mo	Architectural 21,000 MH	21.46	/mo	(0.12)	/mo	307
308					Architectural 36,000 MH	25.87	/mo	Architectural 36,000 MH	26.84	/mo	0.97	/mo	308
309					Architectural 8,000 LPS	19.83	/mo	Architectural 8,000 LPS	19.64	/mo	(0.19)	/mo	309
310					Architectural 13,500 LPS	23.30	/mo	Architectural 13,500 LPS	23.17	/mo	(0.13)	/mo	310
311					Architectural 22,500 LPS	26.55	/mo	Architectural 22,500 LPS	26.46	/mo	(0.09)	/mo	311
312					Architectural 33,000 LPS	30.59	/mo	Architectural 33,000 LPS	31.84	/mo	1.25	/mo	312
313					C. Cobra/Roadway 5,800 HPS	8.03	/mo	C. Cobra/Roadway 5,800 HPS	7.68	/mo	(0.35)	/mo	313
314					Cobra/Roadway 9,500 HPS	9.37	/mo	Cobra/Roadway 9,500 HPS	9.03	/mo	(0.34)	/mo	314
315					Cobra/Roadway 16,000 HPS	11.62	/mo	Cobra/Roadway 16,000 HPS	11.32	/mo	(0.30)	/mo	315
316					Cobra/Roadway 30,000 HPS	13.91	/mo	Cobra/Roadway 30,000 HPS	13.64	/mo	(0.27)	/mo	316
317					Cobra/Roadway 50,000 HPS	18.70	/mo	Cobra/Roadway 50,000 HPS	18.51	/mo	(0.19)	/mo	317
318					Cobra/Roadway 14,000 MH	10.96	/mo	Cobra/Roadway 14,000 MH	13.15	/mo	2.19	/mo	318
319					Cobra/Roadway 21,000 MH	12.76	/mo	Cobra/Roadway 21,000 MH	15.38	/mo	2.62	/mo	319
320					Cobra/Roadway 36,000 MH	16.67	/mo	Cobra/Roadway 36,000 MH	20.24	/mo	3.57	/mo	320
321					Cobra/Roadway 8,000 FL	13.03	/mo	Cobra/Roadway 8,000 FL	15.12	/mo	2.09	/mo	321
322					D. Decorative Transit 9,500 HPS	27.63	/mo	D. Decorative Transit 9,500 HPS	32.60	/mo	4.97	/mo	322
323					Decorative Transit 30,000 HPS	31.57	/mo	Decorative Transit 30,000 HPS	37.32	/mo	5.75	/mo	323
324					E. Flood 30,000 HPS	17.60	/mo	E. Flood 30,000 HPS	18.11	/mo	0.51	/mo	324
325					Flood 50,000 HPS	21.72	/mo	Flood 50,000 HPS	22.46	/mo	0.74	/mo	325
326					Flood 21,000 MH	15.94	/mo	Flood 21,000 MH	19.33	/mo	3.39	/mo	326
327					Flood 36,000 MH	19.35	/mo	Flood 36,000 MH	23.57	/mo	4.22	/mo	327
328					F. Post Top gray 8,000 FL	14.01	/mo	F. Post Top gray 8,000 FL	16.29	/mo	2.28	/mo	328
329					Post Top gray 9,500 HPS	9.65	/mo	Post Top gray 9,500 HPS	9.32	/mo	(0.33)	/mo	329
330					Post Top black 9,500 HPS	11.03	/mo	Post Top black 9,500 HPS	10.73	/mo	(0.30)	/mo	330
331					Post Top Transit 9,500 HPS	24.24	/mo	Post Top Transit 9,500 HPS	28.54	/mo	4.30	/mo	331
332					G. FROZEN 4,000 INC	12.91	/mo	G. FROZEN 4,000 INC	8.60	/mo	(4.31)	/mo	332
333					FROZEN 7,000 MV	12.56	/mo	FROZEN 7,000 MV	11.14	/mo	(1.42)	/mo	333
334					FROZEN 20,000 MV	17.43	/mo	FROZEN 20,000 MV	21.91	/mo	4.48	/mo	334
335					FROZEN Brackets 8ft to 16ft	1.26	/mo	FROZEN Brackets 8ft to 16ft	1.51	/mo	0.25	/mo	335
336					**FIXTURES** (Customer Owned)			**FIXTURES** (Customer Owned)					336
337					A. Acorn 9,500 HPS	$ 5.00	/mo	A. Acorn 9,500 HPS	$ 8.10	/mo	$ 3.10	/mo	337
338					Acorn 16,000 HPS	6.71	/mo	Acorn 16,000 HPS	$ 10.24	/mo	3.53	/mo	338

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Proposed rates are shown on a bundled basis. See tariff sheets for unbundled components.
2) Present rates are those rates effective 4/01/2005.

ARIZONA PUBLIC SERVICE COMPANY

ATTACHMENT E

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

TEST YEAR ENDING SEPTEMBER 30, 2005

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	
					Present Rates			Proposed Rates					
Line No.	Rate Schedule	Description	Billing Designation	Season	Block	Rates		Block	Rates		Change (J) - (E)		Line No.
339	E-47	Dusk to Dawn Lighting	Rate	Sum & Win	**FIXTURES** (Customer Owned) (cont)			**FIXTURES** (Customer Owned) (cont)					339
340	(cont)	Service			B. Architectural 9,500 HPS	$ 6.17	/mo	B. Architectural 9,500 HPS	6.44	/mo	$ 0.27	/mo	340
341		(cont)			Architectural 16,000 HPS	8.28	/mo	Architectural 16,000 HPS	8.62	/mo	0.34	/mo	341
342					Architectural 30,000 HPS	10.53	/mo	Architectural 30,000 HPS	11.08	/mo	0.55	/mo	342
343					Architectural 50,000 HPS	15.16	/mo	Architectural 50,000 HPS	15.93	/mo	0.77	/mo	343
344					Architectural 14,000 MH	10.22	/mo	Architectural 14,000 MH	10.36	/mo	0.14	/mo	344
345					Architectural 21,000 MH	12.53	/mo	Architectural 21,000 MH	12.78	/mo	0.25	/mo	345
346					Architectural 36,000 MH	17.07	/mo	Architectural 36,000 MH	17.57	/mo	0.50	/mo	346
347					Architectural 8,000 LPS	7.80	/mo	Architectural 8,000 LPS	8.62	/mo	0.82	/mo	347
348					Architectural 13,500 LPS	8.82	/mo	Architectural 13,500 LPS	10.41	/mo	1.59	/mo	348
349					Architectural 22,500 LPS	11.17	/mo	Architectural 22,500 LPS	12.70	/mo	1.53	/mo	349
350					Architectural 33,000 LPS	12.99	/mo	Architectural 33,000 LPS	14.96	/mo	1.97	/mo	350
351					C. Cobra/Roadway 5,800 HPS	5.27	/mo	C. Cobra/Roadway 5,800 HPS	4.54	/mo	(0.73)	/mo	351
352					Cobra/Roadway 9,500 HPS	6.17	/mo	Cobra/Roadway 9,500 HPS	5.56	/mo	(0.61)	/mo	352
353					Cobra/Roadway 16,000 HPS	8.28	/mo	Cobra/Roadway 16,000 HPS	7.75	/mo	(0.53)	/mo	353
354					Cobra/Roadway 30,000 HPS	10.53	/mo	Cobra/Roadway 30,000 HPS	10.07	/mo	(0.46)	/mo	354
355					Cobra/Roadway 50,000 HPS	14.60	/mo	Cobra/Roadway 50,000 HPS	14.39	/mo	(0.21)	/mo	355
356					Cobra/Roadway 14,000 MH	7.97	/mo	Cobra/Roadway 14,000 MH	8.97	/mo	1.00	/mo	356
357					Cobra/Roadway 21,000 MH	9.78	/mo	Cobra/Roadway 21,000 MH	11.15	/mo	1.37	/mo	357
358					Cobra/Roadway 36,000 MH	13.32	/mo	Cobra/Roadway 36,000 MH	15.50	/mo	2.18	/mo	358
359					Cobra/Roadway 8,000 FL	3.58	/mo	Cobra/Roadway 8,000 FL	4.43	/mo	0.85	/mo	359
360					D. Decorative Transit 9,500 HPS	5.00	/mo	D. Decorative Transit 9,500 HPS	9.76	/mo	4.76	/mo	360
361					Decorative Transit 30,000 HPS	8.54	/mo	Decorative Transit 30,000 HPS	14.09	/mo	5.55	/mo	361
362					E. Flood 30,000 HPS	10.94	/mo	E. Flood 30,000 HPS	11.26	/mo	0.32	/mo	362
363					Flood 50,000 HPS	15.16	/mo	Flood 50,000 HPS	15.62	/mo	0.46	/mo	363
364					Flood 21,000 MH	9.78	/mo	Flood 21,000 MH	11.89	/mo	2.11	/mo	364
365					Flood 36,000 MH	13.32	/mo	Flood 36,000 MH	16.13	/mo	2.81	/mo	365
366					F. Post Top gray 8,000 FL	3.58	/mo	F. Post Top gray 8,000 FL	4.60	/mo	1.02	/mo	366
367					Post Top gray 9,500 HPS	6.17	/mo	Post Top gray 9,500 HPS	5.85	/mo	(0.32)	/mo	367
368					Post Top black 9,500 HPS	6.41	/mo	Post Top black 9,500 HPS	6.05	/mo	(0.36)	/mo	368
369					Post Top Transit 9,500 HPS	5.00	/mo	Post Top Transit 9,500 HPS	9.00	/mo	4.00	/mo	369
370					G. FROZEN 4,000 INC	4.59	/mo	G. FROZEN 4,000 INC	3.10	/mo	(1.49)	/mo	370
371					FROZEN 7,000 MV	5.09	/mo	FROZEN 7,000 MV	6.38	/mo	1.29	/mo	371
372					FROZEN 20,000 MV	11.51	/mo	FROZEN 20,000 MV	12.41	/mo	0.90	/mo	372
373					**POLES**			**POLES**					373
374					A. Anchor Flush, Round, 1X, 12ft	$ 8.68	/mo	A. Anchor Flush, Round, 1X, 12ft	$ 10.70	/mo	$ 2.02	/mo	374
375					Anchor Flush, Round, 1X, 22ft	9.80	/mo	Anchor Flush, Round, 1X, 22ft	12.04	/mo	2.24	/mo	375
376					Anchor Flush, Round, 1X, 25ft	10.63	/mo	Anchor Flush, Round, 1X, 25ft	13.03	/mo	2.40	/mo	376
377					Anchor Flush, Round, 1X, 30ft	12.25	/mo	Anchor Flush, Round, 1X, 30ft	14.97	/mo	2.72	/mo	377
378					Anchor Flush, Round, 1X, 32ft	12.88	/mo	Anchor Flush, Round, 1X, 32ft	15.73	/mo	2.85	/mo	378
379					Anchor Flush, Round, 2X, 12ft	9.27	/mo	Anchor Flush, Round, 2X, 12ft	11.40	/mo	2.13	/mo	379
380					Anchor Flush, Round, 2X, 22ft	10.69	/mo	Anchor Flush, Round, 2X, 22ft	13.10	/mo	2.41	/mo	380
381					Anchor Flush, Round, 2X, 25ft	11.16	/mo	Anchor Flush, Round, 2X, 25ft	13.67	/mo	2.51	/mo	381
382					Anchor Flush, Round, 2X, 30ft	13.01	/mo	Anchor Flush, Round, 2X, 30ft	15.88	/mo	2.87	/mo	382
383					Anchor Flush, Round, 2X, 32ft	13.90	/mo	Anchor Flush, Round, 2X, 32ft	16.95	/mo	3.05	/mo	383
384					Anchor Flush, Square, 5", 13ft	9.99	/mo	Anchor Flush, Square, 5", 13ft	12.27	/mo	2.28	/mo	384
385					Anchor Flush, Square, 5", 15ft	8.90	/mo	Anchor Flush, Square, 5", 15ft	10.96	/mo	2.06	/mo	385
386					Anchor Flush, Square, 5", 23ft	10.60	/mo	Anchor Flush, Square, 5", 23ft	13.00	/mo	2.40	/mo	386
387					Anchor Flush, Square, 5", 25ft	11.68	/mo	Anchor Flush, Square, 5", 25ft	14.29	/mo	2.61	/mo	387
388					Anchor Flush, Square, 5", 28ft	12.50	/mo	Anchor Flush, Square, 5", 28ft	15.86	/mo	3.36	/mo	388

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Proposed rates are shown on a bundled basis. See tariff sheets for unbundled components.
2) Present rates are those rates effective 4/01/2005.

ARIZONA PUBLIC SERVICE COMPANY

ATTACHMENT E

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES
TEST YEAR ENDING SEPTEMBER 30, 2005

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	
Line No.	Rate Schedule	Description	Billing Designation	Season	Present Rates Block	Present Rates		Proposed Rates Block	Proposed Rates		Change (J) - (E)		Line No.
389	E-47	Dusk to Dawn Lighting	Rate	Sum & Win	POLES (cont)			POLES (cont)					389
390	(cont)	Service			A. Anchor Flush, Square, 5", 32ft	$ 13.47	/mo	A. Anchor Flush, Square, 5", 32ft	$ 15.78	/mo	$ 2.31	/mo	390
391		(cont)			Anchor Flush, Concrete, 12ft	30.26	/mo	Anchor Flush, Concrete, 12ft	36.54	/mo	6.28	/mo	391
392					Anchor Flush, Fiberglass, 12ft	25.59	/mo	Anchor Flush, Fiberglass, 12ft	30.95	/mo	5.36	/mo	392
393					Anchor Flush, Dec Transit Ped, 4", 16ft	24.94	/mo	Anchor Flush, Dec Transit Ped, 4", 16ft	30.17	/mo	5.23	/mo	393
394					Anchor Flush, Dec Transit, 6", 30ft	48.39	/mo	Anchor Flush, Dec Transit, 6", 30ft	58.26	/mo	9.87	/mo	394
395					B. Anchor Pedstl, Round, 1X, 12ft	8.34	/mo	B. Anchor Pedstl, Round, 1X, 12ft	10.29	/mo	1.95	/mo	395
396					Anchor Pedstl, Round, 1X, 22ft	9.46	/mo	Anchor Pedstl, Round, 1X, 22ft	11.63	/mo	2.17	/mo	396
397					Anchor Pedstl, Round, 1X, 25ft	10.28	/mo	Anchor Pedstl, Round, 1X, 25ft	12.61	/mo	2.33	/mo	397
398					Anchor Pedstl, Round, 1X, 30ft	11.91	/mo	Anchor Pedstl, Round, 1X, 30ft	14.57	/mo	2.66	/mo	398
399					Anchor Pedstl, Round, 1X, 32ft	12.53	/mo	Anchor Pedstl, Round, 1X, 32ft	15.31	/mo	2.78	/mo	399
400					Anchor Pedstl, Round, 2X, 12ft	8.93	/mo	Anchor Pedstl, Round, 2X, 12ft	11.00	/mo	2.07	/mo	400
401					Anchor Pedstl, Round, 2X, 22ft	10.00	/mo	Anchor Pedstl, Round, 2X, 22ft	12.28	/mo	2.28	/mo	401
402					Anchor Pedstl, Round, 2X, 25ft	10.82	/mo	Anchor Pedstl, Round, 2X, 25ft	13.26	/mo	2.44	/mo	402
403					Anchor Pedstl, Round, 2X, 30ft	12.67	/mo	Anchor Pedstl, Round, 2X, 30ft	15.48	/mo	2.81	/mo	403
404					Anchor Pedstl, Round, 2X, 32ft	13.55	/mo	Anchor Pedstl, Round, 2X, 32ft	16.53	/mo	2.98	/mo	404
405					Anchor Pedstl, Round, 3 Bolt, 32ft	15.61	/mo	Anchor Pedstl, Round, 3 Bolt, 32ft	19.00	/mo	3.39	/mo	405
406					Anchor Pedstl, Square, 5", 13ft	9.65	/mo	Anchor Pedstl, Square, 5", 13ft	11.86	/mo	2.21	/mo	406
407					Anchor Pedstl, Square, 5", 15ft	9.88	/mo	Anchor Pedstl, Square, 5", 15ft	12.13	/mo	2.25	/mo	407
408					Anchor Pedstl, Square, 5", 23ft	10.26	/mo	Anchor Pedstl, Square, 5", 23ft	12.59	/mo	2.33	/mo	408
409					Anchor Pedstl, Square, 5", 25ft	11.34	/mo	Anchor Pedstl, Square, 5", 25ft	13.88	/mo	2.54	/mo	409
410					Anchor Pedstl, Square, 5", 28ft	12.64	/mo	Anchor Pedstl, Square, 5", 28ft	15.44	/mo	2.80	/mo	410
411					Anchor Pedstl, Square, 5", 32ft	13.13	/mo	Anchor Pedstl, Square, 5", 32ft	16.03	/mo	2.90	/mo	411
412					C. Direct Bury, Round, 19ft	12.77	/mo	C. Direct Bury, Round, 19ft	16.19	/mo	3.42	/mo	412
413					Direct Bury, Round, 30ft	12.07	/mo	Direct Bury, Round, 30ft	12.64	/mo	0.57	/mo	413
414					Direct Bury, Round, 38ft	14.77	/mo	Direct Bury, Round, 38ft	15.43	/mo	0.66	/mo	414
415					Direct Bury, Self-Support, 40ft	17.51	/mo	Direct Bury, Self-Support, 40ft	19.00	/mo	1.49	/mo	415
416					Direct Bury, Stepped, 49ft	47.44	/mo	Direct Bury, Stepped, 49ft	57.12	/mo	9.68	/mo	416
417					Direct Bury, Square, 4", 34ft	13.34	/mo	Direct Bury, Square, 4", 34ft	13.95	/mo	0.61	/mo	417
418					Direct Bury, Square, 5", 20ft	12.15	/mo	Direct Bury, Square, 5", 20ft	13.25	/mo	1.10	/mo	418
419					Direct Bury, Square, 30ft	13.20	/mo	Direct Bury, Square, 30ft	13.80	/mo	0.60	/mo	419
420					Direct Bury, Square, 38ft	14.34	/mo	Direct Bury, Square, 38ft	14.98	/mo	0.64	/mo	420
421					Direct Bury, Steel Dist Pole, 35ft	17.02	/mo	Direct Bury, Steel Dist Pole, 35ft	20.69	/mo	3.67	/mo	421
422					D. Post Top, Dec Transit, 16ft	25.48	/mo	D. Post Top, Dec Transit, 16ft	30.82	/mo	5.34	/mo	422
423					Post Top, Gray Steel/Fiberglass, 23ft	10.18	/mo	Post Top, Gray Steel/Fiberglass, 23ft	10.68	/mo	0.50	/mo	423
424					Post Top, Black Steel, 23ft	11.20	/mo	Post Top, Black Steel, 23ft	11.79	/mo	0.59	/mo	424
425					E. FROZEN, Wood Poles, 30ft	5.86	/mo	E. FROZEN, Wood Poles, 30ft	7.86	/mo	2.00	/mo	425
426					FROZEN, Wood Poles, 35ft	7.38	/mo	FROZEN, Wood Poles, 35ft	7.86	/mo	0.48	/mo	426
427					FROZEN, Wood Poles, 40ft	9.34	/mo	FROZEN, Wood Poles, 40ft	11.19	/mo	1.85	/mo	427
428					ANCHOR BASE			ANCHOR BASE					428
429					Flush, 4ft	$ 7.27	/mo	Flush, 4ft	$ 8.71	/mo	$ 1.44	/mo	429
430					Flush, 6ft	8.67	/mo	Flush, 6ft	10.38	/mo	1.71	/mo	430
431					Pedestal, 8ft	9.94	/mo	Pedestal, 8ft	11.91	/mo	1.97	/mo	431
432					Pedestal, 32' round steel pole, 4ft 6"	6.89	/mo	Pedestal, 32' round steel pole, 4ft 6"	8.25	/mo	1.36	/mo	432
433					OPTIONAL EQUIPMENT			OPTIONAL EQUIPMENT					433
434					1. 100' OH, UG if conduit by customer	$ 2.57	/mo	1. 100' OH, UG if conduit by customer	$ 3.08	/mo	$ 0.51	/mo	434
435					2. HPS not accessible by bucket	2.05	/mo	2. HPS not accessible by bucket	2.46	/mo	0.41	/mo	435
436					3. MH not accessible by bucket	4.43	/mo	3. MH not accessible by bucket	5.31	/mo	0.88	/mo	436
437					NON-STANDARD FACILITIES			NON-STANDARD FACILITIES					437
438					Service Charge	$ 2.46	/mo	Service Charge	$ 2.95	/mo	$ 0.49	/mo	438
439					All kWh	0.04656	/kWh	All kWh	0.05577	/kWh	0.00921	/kWh	439

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Proposed rates are shown on a bundled basis. See tariff sheets for unbundled components.
2) Present rates are those rates effective 4/01/2005.

ATTACHMENT E

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

TEST YEAR ENDING SEPTEMBER 30, 2005

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	
					Present Rates			Proposed Rates					
Line No.	Rate Schedule	Description	Billing Designation	Season	Block	Rates		Block	Rates		Change (J) - (E)		Line No.
440	E-51	Optional Electric	Basic	Sum & Win	Basic Service Charge	$ 0.276	/day	Basic Service Charge	$ 0.276	/day	$ -	/day	440
441		Service for Qualified			Generator Meter Charge	0.828	/day	Generator Meter Charge	0.828	/day	-	/day	441
442		Cogeneration and Small		Sum & Win	Reservation Charge per kW	2.08	/kW	Reservation Charge per kW	$ 2.4880	/kW	0.41	/kW	442
443		Power Production			Initial Reservation Charge	20.78	/kW	Initial Reservation Charge	24.88	/kW	4.10	/kW	443
444		Facilities over 100 KW											444
445			Standby	Summer	All On-Peak kWh	0.04602	/kWh	All On-Peak kWh	0.05722	/kWh	0.01120	/kWh	445
446					All Off-Peak kWh	0.02142	/kWh	All Off-Peak kWh	0.03262	/kWh	0.01120	/kWh	446
447				Winter	All On-Peak kWh	0.03271	/kWh	All On-Peak kWh	0.04391	/kWh	0.01120	/kWh	447
448					All Off-Peak kWh	0.02142	/kWh	All Off-Peak kWh	0.03262	/kWh	0.01120	/kWh	448
449			Maintenance	Sum & Win	All kWh	0.02142	/kWh	All kWh	0.03262	/kWh	0.01120	/kWh	449
450	E-52	Electric Service for	Basic	Sum & Win	Basic Service Charge	$ 3.51	/day	RATE E-52 CANCELLED NO CURRENT CUSTOMERS					450
451		Partial Requirements			Generator Meter Charge	0.561	/mo						451
452		Service of less than											452
453		3000 kW	Standby	Sum & Win	Res Charge per kW 90% and above	$ 5.01	/kW						453
454					Res Charge per kW 80-89%	6.59	/kW						454
455				Summer	All On-Peak kWh	0.02961	/kWh						455
456					All Off-Peak kWh	0.01574	/kWh						456
457				Winter	All On-Peak kWh	0.02537	/kWh						457
458					All Off-Peak kWh	0.01006	/kWh						458
459			Maintenance	Sum & Win	All on-peak kWh	$ 0.02537	/kWh						459
460					All off-peak kWh	0.01006	/kWh						460
461			Penalty	Sum & Win	C.F. less than 75%	$ 18.79	/kW						461
462					C.F. less than 75% @ xmsn	14.39	/kW						462
463	E-53	Electric Service for	Rate	Sum & Win	Billed on Rate Schedule E-32 or Rate Schedule E-32TOU			NO CHANGE					463
464		Athletic Stadiums											464
465		and Sports Fields	Minimum	Sum & Win	No bills rendered when no usage								465
466	E-54	Seasonal Service	Rate	Sum & Win	Billed on Rate Schedule E-32 or Rate Schedule E-32TOU			NO CHANGE					466
467			Minimum	Sum & Win	"Floor" Annual Minimum	$ 603.49	/yr						467
468					Monthly Minimum	50.29	/mo						468

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Proposed rates are shown on a bundled basis. See tariff sheets for unbundled components.
2) Present rates are those rates effective 4/01/2005.

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

TEST YEAR ENDING SEPTEMBER 30, 2005

ATTACHMENT E

	(A)	(B)	(C)	(D)	(E)	(F) (G)	(H)	(I) (J)	(K) (L)	
Line No.	Rate Schedule	Description	Billing Designation	Season	Present Rates: Block	Present Rates: Rates	Proposed Rates: Block	Proposed Rates: Rates	Change (J) - (E)	Line No.
469	E-55	Electric Service for	Basic	Sum & Win	Basic Service Charge	$ 54.95 /day				469
470		Partial Requirements	Service		Generator Meter Charge	2.055 /day				470
471		Service of 3000 kW								471
472		or greater	Standby	Sum & Win	Res Charge per kW 95% abv	$ 4.21 /mo				472
473			Service		Res Charge per kW 90-94%	5.14 /mo				473
474					Res Charge per kW 80-89%	6.77 /mo				474
475				Summer	All On-Peak kWh	0.03040 /kWh				475
476				(Jun-Oct)	All Off-Peak kWh	0.01616 /kWh				476
477				Winter	All On-Peak kWh	0.02605 /kWh				477
478				(Nov-May)	All Off-Peak kWh	0.01033 /kWh				478
479			Maint.	Sum & Win	All On-Peak kWh	$ 0.02605 /kWh	RATE E-55 IS FROZEN, NO CHANGE IN CHARGES			479
480			Service		All Off-Peak kWh	0.01033 /kWh				480
481			C.F. penalty	Sum & Win	C.F. less than 75%	$ 21.28 /kW				481
482					C.F. less than 75% @ 69kV	18.94 /kW				482
483		Above 69 kV	Standby	Sum & Win	Res Charge per kW 95% abv	$ 1.45 /mo				483
484			Service		Res Charge per kW 90-94%	2.30 /mo				484
485					Res Charge per kW 80-89%	4.11 /mo				485
486			C.F. penalty	Sum & Win	C.F. less than 75%	$ 18.94 /kW				486
487					C.F. less than 75% @ 69kV	18.11 /kW				487
488	E-58	Street Lighting Service	Rate	Sum & Win	**FIXTURES** (Investment by Company)		**FIXTURES** (Investment by Company)			488
489					A. Acorn 9,500 HPS	$ 19.86 /mo	A. Acorn 9,500 HPS	$ 23.79 /mo	$ 3.93 /mo	489
490					Acorn 16,000 HPS	22.04 /mo	Acorn 16,000 HPS	$ 26.40 /mo	4.36 /mo	490
491					B. Architectural 9,500 HPS	11.28 /mo	B. Architectural 9,500 HPS	$ 13.51 /mo	2.23 /mo	491
492					Architectural 16,000 HPS	13.18 /mo	Architectural 16,000 HPS	$ 15.79 /mo	2.61 /mo	492
493					Architectural 30,000 HPS	15.64 /mo	Architectural 30,000 HPS	$ 18.73 /mo	3.09 /mo	493
494					Architectural 50,000 HPS	19.29 /mo	Architectural 50,000 HPS	$ 23.11 /mo	3.82 /mo	494
495					Architectural 14,000 MH	15.79 /mo	Architectural 14,000 MH	$ 18.91 /mo	3.12 /mo	495
496					Architectural 21,000 MH	17.92 /mo	Architectural 21,000 MH	$ 21.46 /mo	3.54 /mo	496
497					Architectural 36,000 MH	22.41 /mo	Architectural 36,000 MH	$ 26.84 /mo	4.43 /mo	497
498					Architectural 8,000 LPS	16.40 /mo	Architectural 8,000 LPS	$ 19.64 /mo	3.24 /mo	498
499					Architectural 13,500 LPS	19.34 /mo	Architectural 13,500 LPS	$ 23.17 /mo	3.83 /mo	499
500					Architectural 22,500 LPS	22.09 /mo	Architectural 22,500 LPS	$ 26.46 /mo	4.37 /mo	500
501					Architectural 33,000 LPS	26.58 /mo	Architectural 33,000 LPS	$ 31.84 /mo	5.26 /mo	501
502					C. Cobra/Roadway 5,800 HPS	6.41 /mo	C. Cobra/Roadway 5,800 HPS	$ 7.68 /mo	1.27 /mo	502
503					Cobra/Roadway 9,500 HPS	7.54 /mo	Cobra/Roadway 9,500 HPS	$ 9.03 /mo	1.49 /mo	503
504					Cobra/Roadway 16,000 HPS	9.45 /mo	Cobra/Roadway 16,000 HPS	$ 11.32 /mo	1.87 /mo	504
505					Cobra/Roadway 30,000 HPS	11.39 /mo	Cobra/Roadway 30,000 HPS	$ 13.64 /mo	2.25 /mo	505
506					Cobra/Roadway 50,000 HPS	15.45 /mo	Cobra/Roadway 50,000 HPS	$ 18.51 /mo	3.06 /mo	506
507					Cobra/Roadway 14,000 MH	10.98 /mo	Cobra/Roadway 14,000 MH	$ 13.15 /mo	2.17 /mo	507
508					Cobra/Roadway 21,000 MH	12.84 /mo	Cobra/Roadway 21,000 MH	$ 15.38 /mo	2.54 /mo	508
509					Cobra/Roadway 36,000 MH	16.90 /mo	Cobra/Roadway 36,000 MH	$ 20.24 /mo	3.34 /mo	509
510					Cobra/Roadway 8,000 FL	12.62 /mo	Cobra/Roadway 8,000 FL	$ 15.12 /mo	2.50 /mo	510
511					D. Decorative Transit 9,500 HPS	27.22 /mo	D. Decorative Transit 9,500 HPS	$ 32.60 /mo	5.38 /mo	511
512					Decorative Transit 30,000 HPS	31.16 /mo	Decorative Transit 30,000 HPS	$ 37.32 /mo	6.16 /mo	512

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Proposed rates are shown on a bundled basis. See tariff sheets for unbundled components.
2) Present rates are those rates effective 4/01/2005.

ATTACHMENT E

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

TEST YEAR ENDING SEPTEMBER 30, 2005

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	(E) Present Rates Block	(F) Present Rates Rates	(G)	(H) Proposed Rates Block	(I) Proposed Rates Rates	(J)	(K) Change (J) - (E)	(L)	Line No.
513	E-58	Street Lighting Service	Rate	Sum & Win	**FIXTURES** (Investment by Company) (cont)			**FIXTURES** (Investment by Company) (cont)					513
514	(cont)				E. Flood 30,000 HPS	$ 15.12	/mo	E. Flood 30,000 HPS	$ 18.11	/mo	$ 2.99	/mo	514
515					Flood 50,000 HPS	18.75	/mo	Flood 50,000 HPS	$ 22.46	/mo	3.71	/mo	515
516					Flood 21,000 MH	16.14	/mo	Flood 21,000 MH	$ 19.33	/mo	3.19	/mo	516
517					Flood 36,000 MH	19.68	/mo	Flood 36,000 MH	$ 23.57	/mo	3.89	/mo	517
518					F. Post Top gray 8,000 FL	13.60	/mo	F. Post Top gray 8,000 FL	$ 16.29	/mo	2.69	/mo	518
519					Post Top gray 9,500 HPS	7.78	/mo	Post Top gray 9,500 HPS	$ 9.32	/mo	1.54	/mo	519
520					Post Top black 9,500 HPS	8.96	/mo	Post Top black 9,500 HPS	$ 10.73	/mo	1.77	/mo	520
521					Post Top Transit 9,500 HPS	23.83	/mo	Post Top Transit 9,500 HPS	$ 28.54	/mo	4.71	/mo	521
522					G. FROZEN 4,000 INC	7.18	/mo	G. FROZEN 4,000 INC	$ 8.60	/mo	1.42	/mo	522
523					FROZEN 7,000 MV	9.30	/mo	FROZEN 7,000 MV	$ 11.14	/mo	1.84	/mo	523
524					FROZEN 11,000 MV	11.65	/mo	FROZEN 11,000 MV	$ 13.95	/mo	2.30	/mo	524
525					FROZEN 20,000 MV	18.29	/mo	FROZEN 20,000 MV	$ 21.91	/mo	3.62	/mo	525
526					**FIXTURES** (Investment by Others)			**FIXTURES** (Investment by Others)					526
527					A. Acorn 9,500 HPS	$ 6.76	/mo	A. Acorn 9,500 HPS	$ 8.10	/mo	$ 1.34	/mo	527
528					Acorn 16,000 HPS	8.55	/mo	Acorn 16,000 HPS	$ 10.24	/mo	1.69	/mo	528
529					B. Architectural 9,500 HPS	5.38	/mo	B. Architectural 9,500 HPS	$ 6.44	/mo	1.06	/mo	529
530					Architectural 16,000 HPS	7.20	/mo	Architectural 16,000 HPS	$ 8.62	/mo	1.42	/mo	530
531					Architectural 30,000 HPS	9.25	/mo	Architectural 30,000 HPS	$ 11.08	/mo	1.83	/mo	531
532					Architectural 50,000 HPS	13.30	/mo	Architectural 50,000 HPS	$ 15.93	/mo	2.63	/mo	532
533					Architectural 14,000 MH	8.65	/mo	Architectural 14,000 MH	$ 10.36	/mo	1.71	/mo	533
534					Architectural 21,000 MH	10.67	/mo	Architectural 21,000 MH	$ 12.78	/mo	2.11	/mo	534
535					Architectural 36,000 MH	14.67	/mo	Architectural 36,000 MH	$ 17.57	/mo	2.90	/mo	535
536					Architectural 8,000 LPS	7.20	/mo	Architectural 8,000 LPS	$ 8.62	/mo	1.42	/mo	536
537					Architectural 13,500 LPS	8.69	/mo	B. Architectural 13,500 LPS	$ 10.41	/mo	1.72	/mo	537
538					Architectural 22,500 LPS	10.60	/mo	Architectural 22,500 LPS	$ 12.70	/mo	2.10	/mo	538
539					Architectural 33,000 LPS	12.49	/mo	Architectural 33,000 LPS	$ 14.96	/mo	2.47	/mo	539
540					C. Cobra/Roadway 5,800 HPS	3.79	/mo	C. Cobra/Roadway 5,800 HPS	$ 4.54	/mo	0.75	/mo	540
541					Cobra/Roadway 9,500 HPS	4.64	/mo	Cobra/Roadway 9,500 HPS	$ 5.56	/mo	0.92	/mo	541
542					Cobra/Roadway 16,000 HPS	6.47	/mo	Cobra/Roadway 16,000 HPS	$ 7.75	/mo	1.28	/mo	542
543					Cobra/Roadway 30,000 HPS	8.41	/mo	Cobra/Roadway 30,000 HPS	$ 10.07	/mo	1.66	/mo	543
544					Cobra/Roadway 50,000 HPS	12.01	/mo	Cobra/Roadway 50,000 HPS	$ 14.39	/mo	2.38	/mo	544
545					Cobra/Roadway 14,000 MH	7.49	/mo	Cobra/Roadway 14,000 MH	$ 8.97	/mo	1.48	/mo	545
546					Cobra/Roadway 21,000 MH	9.31	/mo	Cobra/Roadway 21,000 MH	$ 11.15	/mo	1.84	/mo	546
547					Cobra/Roadway 36,000 MH	12.94	/mo	Cobra/Roadway 36,000 MH	$ 15.50	/mo	2.56	/mo	547
548					Cobra/Roadway 8,000 FL	3.70	/mo	Cobra/Roadway 8,000 FL	$ 4.43	/mo	0.73	/mo	548
549					D. Decorative Transit 9,500 HPS	8.15	/mo	D. Decorative Transit 9,500 HPS	$ 9.76	/mo	1.61	/mo	549
550					Decorative Transit 30,000 HPS	11.76	/mo	Decorative Transit 30,000 HPS	$ 14.09	/mo	2.33	/mo	550
551					E. Flood 30,000 HPS	9.40	/mo	E. Flood 30,000 HPS	$ 11.26	/mo	1.86	/mo	551
552					Flood 50,000 HPS	13.04	/mo	Flood 50,000 HPS	$ 15.62	/mo	2.58	/mo	552
553					Flood 21,000 MH	9.93	/mo	Flood 21,000 MH	$ 11.89	/mo	1.96	/mo	553
554					Flood 36,000 MH	13.47	/mo	Flood 36,000 MH	$ 16.13	/mo	2.66	/mo	554
555					F. Post Top gray 8,000 FL	3.84	/mo	F. Post Top gray 8,000 FL	$ 4.60	/mo	0.76	/mo	555
556					Post Top gray 9,500 HPS	4.88	/mo	Post Top gray 9,500 HPS	$ 5.85	/mo	0.97	/mo	556
557					Post Top black 9,500 HPS	5.05	/mo	Post Top black 9,500 HPS	$ 6.05	/mo	1.00	/mo	557
558					Post Top Transit 9,500 HPS	7.51	/mo	Post Top Transit 9,500 HPS	$ 9.00	/mo	1.49	/mo	558
559					G. FROZEN 4,000 INC	7.49	/mo	G. FROZEN 4,000 INC	$ 3.10	/mo	(4.39)	/mo	559
560					FROZEN 7,000 MV	5.33	/mo	FROZEN 7,000 MV	$ 6.38	/mo	1.05	/mo	560
561					FROZEN 11,000 MV	7.10	/mo	FROZEN 11,000 MV	$ 8.50	/mo	1.40	/mo	561
562					FROZEN 20,000 MV	10.36	/mo	FROZEN 20,000 MV	$ 12.41	/mo	2.05	/mo	562

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Proposed rates are shown on a bundled basis. See tariff sheets for unbundled components.
2) Present rates are those rates effective 4/01/2005.

ARIZONA PUBLIC SERVICE COMPANY

ATTACHMENT E

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES
TEST YEAR ENDING SEPTEMBER 30, 2005

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	
Line No.	Rate Schedule	Description	Billing Designation	Season	Present Rates Block	Rates		Proposed Rates Block	Rates		Change (J) - (E)		Line No.
563	E-58	Street Lighting Service	Rate	Sum & Win	POLES (Investment by Company)			POLES (Investment by Company)					563
564	(cont)				A. Anchor Flush, Round, 1X, 12ft	$ 8.93	/mo	A. Anchor Flush, Round, 1X, 12ft	$	10.70 /mo	$ 1.77	/mo	564
565					Anchor Flush, Round, 1X, 22ft	10.05	/mo	Anchor Flush, Round, 1X, 22ft	$	12.04 /mo	1.99	/mo	565
566					Anchor Flush, Round, 1X, 25ft	10.88	/mo	Anchor Flush, Round, 1X, 25ft	$	13.03 /mo	2.15	/mo	566
567					Anchor Flush, Round, 1X, 30ft	12.50	/mo	Anchor Flush, Round, 1X, 30ft	$	14.97 /mo	2.47	/mo	567
568					Anchor Flush, Round, 1X, 32ft	13.13	/mo	Anchor Flush, Round, 1X, 32ft	$	15.73 /mo	2.60	/mo	568
569					Anchor Flush, Round, 2X, 12ft	9.52	/mo	Anchor Flush, Round, 2X, 12ft	$	11.40 /mo	1.88	/mo	569
570					Anchor Flush, Round, 2X, 22ft	10.94	/mo	Anchor Flush, Round, 2X, 22ft	$	13.10 /mo	2.16	/mo	570
571					Anchor Flush, Round, 2X, 25ft	11.41	/mo	Anchor Flush, Round, 2X, 25ft	$	13.67 /mo	2.26	/mo	571
572					Anchor Flush, Round, 2X, 30ft	13.26	/mo	Anchor Flush, Round, 2X, 30ft	$	15.88 /mo	2.62	/mo	572
573					Anchor Flush, Round, 2X, 32ft	14.15	/mo	Anchor Flush, Round, 2X, 32ft	$	16.95 /mo	2.80	/mo	573
574					Anchor Flush, Square, 5", 13ft	10.24	/mo	Anchor Flush, Square, 5", 13ft	$	12.27 /mo	2.03	/mo	574
575					Anchor Flush, Square, 5", 15ft	9.15	/mo	Anchor Flush, Square, 5", 15ft	$	10.96 /mo	1.81	/mo	575
576					Anchor Flush, Square, 5", 23ft	10.85	/mo	Anchor Flush, Square, 5", 23ft	$	13.00 /mo	2.15	/mo	576
577					Anchor Flush, Square, 5", 25ft	11.93	/mo	Anchor Flush, Square, 5", 25ft	$	14.29 /mo	2.36	/mo	577
578					Anchor Flush, Square, 5", 28ft	13.24	/mo	Anchor Flush, Square, 5", 28ft	$	15.86 /mo	2.62	/mo	578
579					Anchor Flush, Square, 5", 32ft	13.17	/mo	Anchor Flush, Square, 5", 32ft	$	15.78 /mo	2.61	/mo	579
580					Anchor Flush, Concrete, 12ft	30.51	/mo	Anchor Flush, Concrete, 12ft	$	36.54 /mo	6.03	/mo	580
581					Anchor Flush, Fiberglass, 12ft	25.84	/mo	Anchor Flush, Fiberglass, 12ft	$	30.95 /mo	5.11	/mo	581
582					Anchor Flush, Dec Transit Ped, 4", 16ft	25.19	/mo	Anchor Flush, Dec Transit Ped, 4", 16ft	$	30.17 /mo	4.98	/mo	582
583					Anchor Flush, Dec Transit, 6", 30ft	48.64	/mo	Anchor Flush, Dec Transit, 6", 30ft	$	58.26 /mo	9.62	/mo	583
584					B. Anchor Pedstl, Round, 1X, 12ft	8.59	/mo	B. Anchor Pedstl, Round, 1X, 12ft	$	10.29 /mo	1.70	/mo	584
585					Anchor Pedstl, Round, 1X, 22ft	9.71	/mo	Anchor Pedstl, Round, 1X, 22ft	$	11.63 /mo	1.92	/mo	585
586					Anchor Pedstl, Round, 1X, 25ft	10.53	/mo	Anchor Pedstl, Round, 1X, 25ft	$	12.61 /mo	2.08	/mo	586
587					Anchor Pedstl, Round, 1X, 30ft	12.16	/mo	Anchor Pedstl, Round, 1X, 30ft	$	14.57 /mo	2.41	/mo	587
588					Anchor Pedstl, Round, 1X, 32ft	12.78	/mo	Anchor Pedstl, Round, 1X, 32ft	$	15.31 /mo	2.53	/mo	588
589					Anchor Pedstl, Round, 2X, 12ft	9.18	/mo	Anchor Pedstl, Round, 2X, 12ft	$	11.00 /mo	1.82	/mo	589
590					Anchor Pedstl, Round, 2X, 22ft	10.25	/mo	Anchor Pedstl, Round, 2X, 22ft	$	12.28 /mo	2.03	/mo	590
591					Anchor Pedstl, Round, 2X, 25ft	11.07	/mo	Anchor Pedstl, Round, 2X, 25ft	$	13.26 /mo	2.19	/mo	591
592					Anchor Pedstl, Round, 2X, 30ft	12.92	/mo	Anchor Pedstl, Round, 2X, 30ft	$	15.48 /mo	2.56	/mo	592
593					Anchor Pedstl, Round, 2X, 32ft	13.80	/mo	Anchor Pedstl, Round, 2X, 32ft	$	16.53 /mo	2.73	/mo	593
594					Anchor Pedstl, Round, 3 Bolt, 32ft	15.86	/mo	Anchor Pedstl, Round, 3 Bolt, 32ft	$	19.00 /mo	3.14	/mo	594
595					Anchor Pedstl, Square, 5", 13ft	9.90	/mo	Anchor Pedstl, Square, 5", 13ft	$	11.86 /mo	1.96	/mo	595
596					Anchor Pedstl, Square, 5", 15ft	10.13	/mo	Anchor Pedstl, Square, 5", 15ft	$	12.13 /mo	2.00	/mo	596
597					Anchor Pedstl, Square, 5", 23ft	10.51	/mo	Anchor Pedstl, Square, 5", 23ft	$	12.59 /mo	2.08	/mo	597
598					Anchor Pedstl, Square, 5", 25ft	11.59	/mo	Anchor Pedstl, Square, 5", 25ft	$	13.88 /mo	2.29	/mo	598
599					Anchor Pedstl, Square, 5", 28ft	12.89	/mo	Anchor Pedstl, Square, 5", 28ft	$	15.44 /mo	2.55	/mo	599
600					Anchor Pedstl, Square, 5", 32ft	13.38	/mo	Anchor Pedstl, Square, 5", 32ft	$	16.03 /mo	2.65	/mo	600
601					C. Direct Bury, Round, 19ft	13.52	/mo	C. Direct Bury, Round, 19ft	$	16.19 /mo	2.67	/mo	601
602					Direct Bury, Round, 30ft	10.55	/mo	Direct Bury, Round, 30ft	$	12.64 /mo	2.09	/mo	602
603					Direct Bury, Round, 38ft	12.88	/mo	Direct Bury, Round, 38ft	$	15.43 /mo	2.55	/mo	603
604					Direct Bury, Self-Support, 40ft	15.86	/mo	Direct Bury, Self-Support, 40ft	$	19.00 /mo	3.14	/mo	604
605					Direct Bury, Stepped, 49ft	47.69	/mo	Direct Bury, Stepped, 49ft	$	57.12 /mo	9.43	/mo	605
606					Direct Bury, Square, 4", 34ft	11.65	/mo	Direct Bury, Square, 4", 34ft	$	13.95 /mo	2.30	/mo	606
607					Direct Bury, Square, 5", 20ft	11.06	/mo	Direct Bury, Square, 5", 20ft	$	13.25 /mo	2.19	/mo	607
608					Direct Bury, Square, 30ft	11.52	/mo	Direct Bury, Square, 30ft	$	13.80 /mo	2.28	/mo	608
609					Direct Bury, Square, 38ft	12.51	/mo	Direct Bury, Square, 38ft	$	14.98 /mo	2.47	/mo	609
610					Direct Bury, Steel Dist Pole, 35ft	17.27	/mo	Direct Bury, Steel Dist Pole, 35ft	$	20.69 /mo	3.42	/mo	610

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Proposed rates are shown on a bundled basis. See tariff sheets for unbundled components.
2) Present rates are those rates effective 4/01/2005.

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

TEST YEAR ENDING SEPTEMBER 30, 2005

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	(E) Present Rates: Block	(F) (G) Present Rates: Rates	(H) Proposed Rates: Block	(I) (J) Proposed Rates: Rates	(K) (L) Change (J) - (E)	Line No.
611	E-58	Street Lighting Service	Rate	Sum & Win	POLES (Investment by Company) (cont)		POLES (Investment by Company) (cont)			611
612	(cont)				D. Post Top, Dec Transit, 16ft	$ 25.73 /mo	D. Post Top, Dec Transit, 16ft	$ 30.82 /mo	$ 5.09 /mo	612
613					Post Top, Gray Steel/Fiberglass, 23ft	8.92 /mo	Post Top, Gray Steel/Fiberglass, 23ft	$ 10.68 /mo	1.76 /mo	613
614					Post Top, Black Steel, 23ft	9.84 /mo	Post Top, Black Steel, 23ft	$ 11.79 /mo	1.95 /mo	614
615					E. Existing Distribution Pole	1.09 /mo	E. Existing Distribution Pole	$ 1.31 /mo	0.22 /mo	615
616					F. FROZEN, Wood Poles, 30ft	6.56 /mo	F. FROZEN, Wood Poles, 30ft	$ 7.86 /mo	1.30 /mo	616
617					FROZEN, Wood Poles, 35ft	6.56 /mo	FROZEN, Wood Poles, 35ft	$ 7.86 /mo	1.30 /mo	617
618					POLES (Investment by Others)		POLES (Investment by Others)			618
619					A. Anchor Flush, Round, 1X, 12ft	$ 1.23 /mo	A. Anchor Flush, Round, 1X, 12ft	$ 1.47 /mo	$ 0.24 /mo	619
620					Anchor Flush, Round, 1X, 22ft	1.38 /mo	Anchor Flush, Round, 1X, 22ft	$ 1.65 /mo	0.27 /mo	620
621					Anchor Flush, Round, 1X, 25ft	1.50 /mo	Anchor Flush, Round, 1X, 25ft	$ 1.80 /mo	0.30 /mo	621
622					Anchor Flush, Round, 1X, 30ft	1.72 /mo	Anchor Flush, Round, 1X, 30ft	$ 2.06 /mo	0.34 /mo	622
623					Anchor Flush, Round, 1X, 32ft	1.74 /mo	Anchor Flush, Round, 1X, 32ft	$ 2.08 /mo	0.34 /mo	623
624					Anchor Flush, Round, 2X, 12ft	1.31 /mo	Anchor Flush, Round, 2X, 12ft	$ 1.57 /mo	0.26 /mo	624
625					Anchor Flush, Round, 2X, 22ft	1.51 /mo	Anchor Flush, Round, 2X, 22ft	$ 1.81 /mo	0.30 /mo	625
626					Anchor Flush, Round, 2X, 25ft	1.57 /mo	Anchor Flush, Round, 2X, 25ft	$ 1.88 /mo	0.31 /mo	626
627					Anchor Flush, Round, 2X, 30ft	1.83 /mo	Anchor Flush, Round, 2X, 30ft	$ 2.19 /mo	0.36 /mo	627
628					Anchor Flush, Round, 2X, 32ft	1.95 /mo	Anchor Flush, Round, 2X, 32ft	$ 2.34 /mo	0.39 /mo	628
629					Anchor Flush, Square, 5", 13ft	1.41 /mo	Anchor Flush, Square, 5", 13ft	$ 1.69 /mo	0.28 /mo	629
630					Anchor Flush, Square, 5", 15ft	1.26 /mo	Anchor Flush, Square, 5", 15ft	$ 1.51 /mo	0.25 /mo	630
631					Anchor Flush, Square, 5", 23ft	1.49 /mo	Anchor Flush, Square, 5", 23ft	$ 1.78 /mo	0.29 /mo	631
632					Anchor Flush, Square, 5", 25ft	1.64 /mo	Anchor Flush, Square, 5", 25ft	$ 1.96 /mo	0.32 /mo	632
633					Anchor Flush, Square, 5", 28ft	1.82 /mo	Anchor Flush, Square, 5", 28ft	$ 2.18 /mo	0.36 /mo	633
634					Anchor Flush, Square, 5", 32ft	1.81 /mo	Anchor Flush, Square, 5", 32ft	$ 2.17 /mo	0.36 /mo	634
635					Anchor Flush, Concrete, 12ft	4.20 /mo	Anchor Flush, Concrete, 12ft	$ 5.03 /mo	0.83 /mo	635
636					Anchor Flush, Fiberglass, 12ft	3.56 /mo	Anchor Flush, Fiberglass, 12ft	$ 4.26 /mo	0.70 /mo	636
637					Anchor Flush, Dec Transit Ped, 4", 16ft	3.47 /mo	Anchor Flush, Dec Transit Ped, 4", 16ft	$ 4.16 /mo	0.69 /mo	637
638					Anchor Flush, Dec Transit, 6", 30ft	6.70 /mo	Anchor Flush, Dec Transit, 6", 30ft	$ 8.03 /mo	1.33 /mo	638
639					B. Anchor Pedstl, Round, 1X, 12ft	1.18 /mo	B. Anchor Pedstl, Round, 1X, 12ft	$ 1.41 /mo	0.23 /mo	639
640					Anchor Pedstl, Round, 1X, 22ft	1.34 /mo	Anchor Pedstl, Round, 1X, 22ft	$ 1.61 /mo	0.27 /mo	640
641					Anchor Pedstl, Round, 1X, 25ft	1.45 /mo	Anchor Pedstl, Round, 1X, 25ft	$ 1.74 /mo	0.29 /mo	641
642					Anchor Pedstl, Round, 1X, 30ft	1.68 /mo	Anchor Pedstl, Round, 1X, 30ft	$ 2.01 /mo	0.33 /mo	642
643					Anchor Pedstl, Round, 1X, 32ft	1.76 /mo	Anchor Pedstl, Round, 1X, 32ft	$ 2.11 /mo	0.35 /mo	643
644					Anchor Pedstl, Round, 2X, 12ft	1.26 /mo	Anchor Pedstl, Round, 2X, 12ft	$ 1.51 /mo	0.25 /mo	644
645					Anchor Pedstl, Round, 2X, 22ft	1.41 /mo	Anchor Pedstl, Round, 2X, 22ft	$ 1.69 /mo	0.28 /mo	645
646					Anchor Pedstl, Round, 2X, 25ft	1.52 /mo	Anchor Pedstl, Round, 2X, 25ft	$ 1.82 /mo	0.30 /mo	646
647					Anchor Pedstl, Round, 2X, 30ft	1.78 /mo	Anchor Pedstl, Round, 2X, 30ft	$ 2.13 /mo	0.35 /mo	647
648					Anchor Pedstl, Round, 2X, 32ft	1.90 /mo	Anchor Pedstl, Round, 2X, 32ft	$ 2.28 /mo	0.38 /mo	648
649					Anchor Pedstl, Round, 3 Bolt, 32ft	2.18 /mo	Anchor Pedstl, Round, 3 Bolt, 32ft	$ 2.61 /mo	0.43 /mo	649
650					Anchor Pedstl, Square, 5", 13ft	1.36 /mo	Anchor Pedstl, Square, 5", 13ft	$ 1.63 /mo	0.27 /mo	650
651					Anchor Pedstl, Square, 5", 15ft	1.39 /mo	Anchor Pedstl, Square, 5", 15ft	$ 1.66 /mo	0.27 /mo	651
652					Anchor Pedstl, Square, 5", 23ft	1.45 /mo	Anchor Pedstl, Square, 5", 23ft	$ 1.74 /mo	0.29 /mo	652
653					Anchor Pedstl, Square, 5", 25ft	1.60 /mo	Anchor Pedstl, Square, 5", 25ft	$ 1.92 /mo	0.32 /mo	653
654					Anchor Pedstl, Square, 5", 28ft	1.78 /mo	Anchor Pedstl, Square, 5", 28ft	$ 2.13 /mo	0.35 /mo	654
655					Anchor Pedstl, Square, 5", 32ft	1.84 /mo	Anchor Pedstl, Square, 5", 32ft	$ 2.20 /mo	0.36 /mo	655

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Proposed rates are shown on a bundled basis. See tariff sheets for unbundled components.
2) Present rates are those rates effective 4/01/2005.

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

TEST YEAR ENDING SEPTEMBER 30, 2005

ATTACHMENT E

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	
					Present Rates			Proposed Rates					
Line No.	Rate Schedule	Description	Billing Designation	Season	Block	Rates		Block	Rates		Change (J) - (E)		Line No.
656	E-58	Street Lighting Service	Rate	Sum & Win	**POLES** (Investment by Others) (cont)			**POLES** (Investment by Others) (cont)					656
657	(cont)				C. Direct Bury, Round, 19ft	$ 1.86	/mo	C. Direct Bury, Round, 19ft	$ 2.23	/mo	$ 0.37	/mo	657
658					Direct Bury, Round, 30ft	1.95	/mo	Direct Bury, Round, 30ft	$ 2.34	/mo	0.39	/mo	658
659					Direct Bury, Round, 38ft	2.00	/mo	Direct Bury, Round, 38ft	$ 2.40	/mo	0.40	/mo	659
660					Direct Bury, Self-Support, 40ft	2.51	/mo	Direct Bury, Self-Support, 40ft	$ 3.01	/mo	0.50	/mo	660
661					Direct Bury, Stepped, 49ft	6.57	/mo	Direct Bury, Stepped, 49ft	$ 7.87	/mo	1.30	/mo	661
662					Direct Bury, Square, 4", 34ft	2.02	/mo	Direct Bury, Square, 4", 34ft	$ 2.42	/mo	0.40	/mo	662
663					Direct Bury, Square, 5", 20ft	1.83	/mo	Direct Bury, Square, 5", 20ft	$ 2.19	/mo	0.36	/mo	663
664					Direct Bury, Square, 30ft	1.90	/mo	Direct Bury, Square, 30ft	$ 2.28	/mo	0.38	/mo	664
665					Direct Bury, Square, 38ft	2.17	/mo	Direct Bury, Square, 38ft	$ 2.60	/mo	0.43	/mo	665
666					Direct Bury, Steel Dist Pole, 35ft	2.28	/mo	Direct Bury, Steel Dist Pole, 35ft	$ 2.73	/mo	0.45	/mo	666
667					D. Post Top, Dec Transit, 16ft	3.54	/mo	D. Post Top, Dec Transit, 16ft	$ 4.24	/mo	0.70	/mo	667
668					Post Top, Gray Steel/Fiberglass, 23ft	1.47	/mo	Post Top, Gray Steel/Fiberglass, 23ft	$ 1.76	/mo	0.29	/mo	668
669					Post Top, Black Steel, 23ft	1.62	/mo	Post Top, Black Steel, 23ft	$ 1.94	/mo	0.32	/mo	669
670					E. Existing Distribution Pole	1.09	/mo	E. Existing Distribution Pole	$ -	/mo	(1.09)	/mo	670
671					F. FROZEN, Wood Poles, 30ft	1.14	/mo	F. FROZEN, Wood Poles, 30ft	$ 1.37	/mo	0.23	/mo	671
672					FROZEN, Wood Poles, 35ft	1.09	/mo	FROZEN, Wood Poles, 35ft	$ 1.31	/mo	0.22	/mo	672
673					**ANCHOR BASE** (Investment by Company)			**ANCHOR BASE** (Investment by Company)					673
674					Flush, 4ft	$ 7.27	/mo	Flush, 4ft	$ 8.71	/mo	$ 1.44	/mo	674
675					Flush, 6ft	8.67	/mo	Flush, 6ft	$ 10.38	/mo	1.71	/mo	675
676					Pedestal, 8ft	9.94	/mo	Pedestal, 8ft	$ 11.91	/mo	1.97	/mo	676
677					Pedestal, 32' round steel pole, 4ft 6"	6.89	/mo	Pedestal, 32' round steel pole, 4ft 6"	$ 8.25	/mo	1.36	/mo	677
678					**ANCHOR BASE** (Investment by Others)			**ANCHOR BASE** (Investment by Others)					678
679					Flush, 4ft	$ 1.00	/mo	Flush, 4ft	$ 1.20	/mo	$ 0.20	/mo	679
680					Flush, 6ft	1.50	/mo	Flush, 6ft	$ 1.80	/mo	0.30	/mo	680
681					Pedestal, 8ft	1.73	/mo	Pedestal, 8ft	$ 2.07	/mo	0.34	/mo	681
682					Pedestal, 32' round steel pole, 4ft 6"	1.20	/mo	Pedestal, 32' round steel pole, 4ft 6"	$ 1.44	/mo	0.24	/mo	682
683					**OPTIONAL EQUIPMENT**			**OPTIONAL EQUIPMENT**					683
684					Per foot of cable under paving	$ 0.11532	/mo	Per foot of cable under paving	$ 0.13813	/mo	$ 0.02	/mo	684
685					Per foot of cable not under paving	0.04101	/mo	Per foot of cable not under paving	$ 0.04912	/mo	0.01	/mo	685
686	E-59	Energy Services for Government		Sum & Win	Service Charge	$ 2.46	/mo	Service Charge	$ 2.46	/mo	$ -	/mo	686
687		Owned Streetlighting Systems			Energy Charge	0.04656	/kWh	Energy Charge	0.05255	/kWh	0.00599	/kWh	687
688	E-66	Share the Light	Rate	Sum & Win	Billed on Rate Schedule E-58			RATE E-66 CANCELLED;					688
689								NO CURRENT CUSTOMERS					689
690	E-67	Municipal Lighting	Rate	Sum & Win	All kWh	$ 0.03654	/kWh	All kWh	0.04580	/kWh	$ 0.00926	/kWh	690
691		Service -- City of Phoenix											691
692	E-114	Share the Light	Rate		Billed on Rate Schedule E-58			NO CHANGE					692
693	E-116	Share the Light	Rate		Billed on Rate Schedule E-58			NO CHANGE					693

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Proposed rates are shown on a bundled basis. See tariff sheets for unbundled components.
2) Present rates are those rates effective 4/01/2005.

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

TEST YEAR ENDING SEPTEMBER 30, 2005

ATTACHMENT E

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	
					Present Rates			Proposed Rates					
Line No.	Rate Schedule	Description	Billing Designation	Season	Block	Rates		Block	Rates		Change (J) - (E)		Line No.
694	E-145	Share the Light	Rate		Billed on Rate Schedule E-58			NO CHANGE					694
695	E-221	Water Pumping Service	Rate	Sum & Win	Basic Service Charge	$ 0.493	/day	Basic Service Charge	$ 0.493	/day	$ -	/day	695
696					All kW	1.66	/kW	All kW	$ 1.660	/kW	0.000	/kW	696
697					First 240 kWh	0.09726	/kWh	First 240 kWh	$ 0.10104	/kWh	0.00378	/kWh	697
698					Next 275 kWh per kW	0.06612	/kWh	Next 275 kWh per kW	$ 0.06869	/kWh	0.00257	/kWh	698
699					All additional kWh	0.05429	/kWh	All additional kWh	$ 0.05640	/kWh	0.00211	/kWh	699
700		Time of Week Option		Sum & Win	Based on Measured kWh in Control Period:			Based on Measured kWh in Control Period:					700
701					2 kWh per kW or less	$ (0.00693)	/kWh	2 kWh per kW or less	$ (0.00693)	/kWh	$ -	/kWh	701
702					Greater than 8 kWh/kW	0.00347	/kWh	Greater than 8 kWh/kW	0.00347	/kWh	0.00000	/kWh	702
703			Minimum	Sum & Win	Minimum Basic Service Charge	$ 0.493	/day	Minimum Basic Service Charge	$ 0.493	/day	$ -	/day	703
704					Minimum Demand Charge	1.66	/kW	Minimum Demand Charge	1.66	/kW	0.000	/kW	704
705					Minimum Annual kW Charge	19.92	/kW	Minimum Annual kW Charge	24.00	/kW	4.080	/kW	705
706	E-221-8T	Water Pumping Service Time Of Use	Rate	Sum & Win	Basic Service Charge	$ 0.851	/day	Basic Service Charge	$ 0.851	/day	$ -	/day	706
707					All On-Peak kW	3.95	/kW	All On-Peak kW	$ 3.950	/kW	0.000	/kW	707
708					All Off-Peak kW	2.36	/kW	All Off-Peak kW	$ 2.360	/kW	0.000	/kW	708
709					All On-Peak kWh	0.07975	/kWh	All On-Peak kWh	$ 0.082850	/kWh	0.00310	/kWh	709
710					All Off-Peak kWh	0.04289	/kWh	All Off-Peak kWh	$ 0.044460	/kWh	0.00157	/kWh	710
711			Minimum	Sum & Win	Minimum Basic Service Charge	$ 0.851	/day	Minimum Basic Service Charge	$ 0.851	/day	$ -	/day	711
712					Minimum Demand Charge	2.36	/kW	Minimum Demand Charge	2.360	/kW	0.000	/kW	712
713					Minimum Annual kW Charge	28.32	/kW	Minimum Annual kW Charge	34.20	/kW	5.880	/kW	713
714	E-249	Share the Light	Rate	Sum & Win	Billed on Rate Schedule E-58			NO CHANGE					714
715	EPR-2	Purchase Rates	Rate	Sum & Win	0-200 amps, 1-phase	$ 7.34	/mo	0-200 amps, 1-phase	$ -	/mo	$ (7.340)	/mo	715
716					0-200 amps, 3-phase	8.87	/mo	0-200 amps, 3-phase	0	/mo	$ (8.870)	/mo	716
717					200-400 amps, 3-phase	18.31	/mo	200-400 amps, 3-phase	0	/mo	$ (18.310)	/mo	717
718				Summer	Non-Firm On-Peak	0.03551	/kWh	Non-Firm On-Peak	0.06486	/kWh	$ 0.029	/kWh	718
719					Non-Firm Off-Peak	0.02257	/kWh	Non-Firm Off-Peak	0.04531	/kWh	$ 0.023	/kWh	719
720					Firm On-Peak	0.05433	/kWh	Firm On-Peak	0.07630	/kWh	$ 0.022	/kWh	720
721					Firm Off-Peak	0.03453	/kWh	Firm Off-Peak	0.05330	/kWh	$ 0.019	/kWh	721
722				Winter	Non-Firm On-Peak	0.02552	/kWh	Non-Firm On-Peak	0.06384	/kWh	$ 0.038	/kWh	722
723					Non-Firm Off-Peak	0.01871	/kWh	Non-Firm Off-Peak	0.04905	/kWh	$ 0.030	/kWh	723
724					Firm On-Peak	0.03904	/kWh	Firm On-Peak	0.07510	/kWh	$ 0.036	/kWh	724
725					Firm Off-Peak	0.02862	/kWh	Firm Off-Peak	0.05770	/kWh	$ 0.029	/kWh	725

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Proposed rates are shown on a bundled basis. See tariff sheets for unbundled components.
2) Present rates are those rates effective 4/01/2005.

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

TEST YEAR ENDING SEPTEMBER 30, 2005

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	
Line No.	Rate Schedule	Description	Billing Designation	Season	Present Rates Block	Present Rates Rates		Proposed Rates Block		Proposed Rates Rates	Change (J) - (E)		Line No.
726	EPR-3	Purchase Rates	Rate	Summer	Non-Firm On-Peak	0.03551	/kWh						726
727					Non-Firm Off-Peak	0.02257	/kWh						727
728					Firm On-Peak	0.05433	/kWh						728
729					Firm Off-Peak	0.03453	/kWh	RATE EPR-3 CANCELLED;					729
730				Winter	Non-Firm On-Peak	0.02552	/kWh	NO CURRENT CUSTOMERS					730
731					Non-Firm Off-Peak	0.01871	/kWh						731
732					Firm On-Peak	0.03904	/kWh						732
733					Firm Off-Peak	0.02862	/kWh						733
734	EPR-4	Purchase Rates	Rate	Summer	Non-Firm On-Peak	0.03551	/kWh						734
735					Non-Firm Off-Peak	0.02257	/kWh						735
736					Firm On-Peak	0.05433	/kWh						736
737					Firm Off-Peak	0.03453	/kWh	RATE EPR-4 CANCELLED;					737
738				Winter	Non-Firm On-Peak	0.02552	/kWh	CUSTOMERS TRANSFERRED TO EPR-2					738
739					Non-Firm Off-Peak	0.01871	/kWh						739
740					Firm On-Peak	0.03904	/kWh						740
741					Firm Off-Peak	0.02862	/kWh						741
742	EQF-M	Scheduled Maintenance Electric Service			Includes no rate charges			RATE EQF-M CANCELLED;					742
743		for Qualified CoGenerators and						NO CURRENT CUSTOMERS					743
744		Small Power Production Facilities											744
745	EQF-S	Standby Electric Service for Qualified			Includes no rate charges			RATE EQF-S CANCELLED;					745
746		CoGenerators and Small Power						NO CURRENT CUSTOMERS					746
747		Production Facilities											747
748	Solar-1	Photovoltaic Service	Rate	Sum & Win	Basic Service Charge	$ 20.00	/mo	RATE SOLAR-1 CANCELLED;					748
749		Pilot Program			Net Installed Cost Parts w/more than 10 yrs	1.6%	/mo	NO CURRENT CUSTOMERS					749
750					Net Installed Cost Parts w/less than 10 yrs	3.1%	/mo						750
751	Solar-2	Individual Solar	Initial Fee	Sum & Win	Up to $100,000	5%	one time						751
752		Electric Service			More than $100,000	10%	one time						752
753			Rate	Sum & Win	Service Fee:								753
754					Battery: None, sys size up to 2.5 kW	$ 5.00	/mo						754
755					Battery: None, sys size over 2.5 kW	5.00	/mo						755
756					Battery: Sealed, sys size up to 2.5 kW	45.00	/mo						756
757					Battery: Sealed, sys size over 2.5 kW	65.00	/mo	NO CHANGE					757
758					Battery: Flooded, sys size up to 2.5 kW	65.00	/mo						758
759					Battery: Flooded, sys size over 2.5 kW	85.00	/mo						759
760					Component Fee:								760
761					Long	1.41%	/mo						761
762					Medium	1.83%	/mo						762
763					Short	2.75%	/mo						763
764	SP-1	Solar Partners	Rate	Sum & Win	Residential/Business 15 kWh per month	$ 2.64	/mo	RATE SP-1 IS FROZEN, NO CHANGE TO CHARGES					764
	Solar-2	Solar Service Premium Power Rate	Rate	Sum & Win	NEW SCHEDULE			Solar Power Premium Rate		$ 0.1660 /kWh			
	GPS-1	Green Power Block	Rate	Sum & Win	NEW SCHEDULE			Green Power Block Rate		$ 1.00 /100 kWh block			

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

TEST YEAR ENDING SEPTEMBER 30, 2005

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	(E) Present Rates Block	(F) (G) Present Rates Rates	(H) Proposed Rates Block	(I) (J) Proposed Rates Rates	(K) (L) Change (J) - (E)	Line No.
	GPS-2	Green Power Percent	Rate	Sum & Win	NEW SCHEDULE		Green Power Additional Charge			
							100% Green Power	$ 0.0100 /kWh		
							50% Green Power	$ 0.0050 /kWh		
							35% Green Power	$ 0.0035 /kWh		
							10% Green Power	$ 0.0010 /kWh		
	EPR-5	Net Metering	Rate	Sum & Win	NEW SCHEDULE		Excess generation kWh credited against kWh purchased from APS in subsequent months. Credits will be zeroed out at the end of each calendar year.			
	E-56	Partial Requirements	Rate	Sum & Win	NEW SCHEDULE		Partial Requirement Services are billed on customer's otherwise applicable rate schedule			
	E-57	Solar Partial Requirements	Rate	Sum & Win	NEW SCHEDULE		Partial Requirement Services are billed on customer's otherwise applicable rate schedule			

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Proposed rates are shown on a bundled basis. See tariff sheets for unbundled components.
2) Present rates are those rates effective 4/01/2005.

ATTACHMENT E

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

TEST YEAR ENDING SEPTEMBER 30, 2005

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	
					Present Rates			Proposed Rates					
Line No.	Rate Schedule	Description	Billing Designation	Season	Block	Rates		Block	Rates		Change (J) - (E)		Line No.
765	EPS-1	Environmental	Adjustment	Sum & Win	All kWh	$0.000875	/kWh	All kWh	$ 0.001392	/kWh	$ 0.001		765
766		Portfolio			Cap for all Residential Services	0.35	/service	Cap for all Residential Services	0.56	/service	$ 0.210		766
767		Surcharge			Cap for General Services under 3MW	13.00	/service	Cap for General Services under 3MW	20.68	/service	$ 7.680		767
768					Cap for General Services 3MW and above	39.00	/service	Cap for General Services 3MW and above	62.04	/service	$ 23.040		768
769	CRCC-1	Competition Rules	Adjustment	Sum & Win	All kWh	$0.000338	/kWh	NO CHANGE					769
770		Compliance Charge											770
773	EIC	Environmental	Adjustment	Sum & Win	NEW SCHEDULE			TO BE FILED WITHIN 30 DAYS OF FINAL DECISION					773
774		Improvement Charge											774

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Proposed rates are shown on a bundled basis. See tariff sheets for unbundled components.
2) Present rates are those rates effective 4/01/2005.