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BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

- MIKE GLEASON, Chairman
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AZ CORP COMMISSION  
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IN THE MATTER OF THE  
APPLICATION OF ARIZONA PUBLIC  
SERVICE COMPANY FOR A  
HEARING TO DETERMINE THE FAIR  
VALUE OF THE UTILITY PROPERTY  
OF THE COMPANY FOR  
RATEMAKING PURPOSES, TO FIX A  
JUST AND REASONABLE RATE OF  
RETURN 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  
**DOCKETED**

MAY 15 2007

EXCEPTIONS  
OF  
ARIZONA PUBLIC SERVICE COMPANY

DOCKETED BY

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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
<b>Base Increase</b>	<b>\$ 425.8</b>	<b>\$ (139.7)</b>	<b>\$ 286.1</b>	<b>\$ 290.2</b>

**\*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

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

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

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

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

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28

## II. COST OF CAPITAL AND REVENUE ENHANCEMENT

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

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

22 Although fuel and purchased power costs are about 70 percent of the revenue  
23 requirements of the Company's current rate request, they account for only about 32 percent of  
24 APS's total revenue requirements. (APS Exhibit No. 80.) The balance of the increase is  
25 composed of increased non-fuel costs over 2002 levels, both operating and capital, that like  
26 fuel, are driven both by price increases in components ranging from copper wire to steel to  
27 concrete to equity capital and, perhaps to a greater extent, by the continued rapid growth of  
28 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

1 Exhibit No. 59.) APS's need in recent years to fund a huge capital expenditure program  
2 coupled with the regulatory lag in recovering those expenses as part of rate base, has  
3 prevented APS from maintaining a level of earnings commensurate with its allowed ROE.  
4 (APS Exhibit No. 4 at 29-31 [Brandt].) Even Staff and RUCO witnesses agreed that the  
5 "attrition" of earnings resulting from the lag in recovering capital expenditures is causing  
6 APS to under-earn its allowed rate of return. (Tr. Vol. XVII at 3267 [Parcell]; Tr. Vol. X at  
7 2090-91[Hill].)

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

10 The Recommended Order errs by stating that "it is not the rate of return or the level of  
11 revenues received that must be just and reasonable, but the rates and charges."  
12 (Recommended Order at 65.) In fact, the two concepts (just and reasonable rates and **earning**  
13 a reasonable return) are inseparable. Under applicable constitutional and regulatory  
14 principles, "rates cannot be considered just and reasonable if they fail to produce a reasonable  
15 rate of return." *Scates v. Arizona Corporation Comm'n*, 118 Ariz. 531, 533-34, 578 P.2d 612,  
16 614-15 (Ariz. App. 1978); *see also Bluefield*, 262 U.S. at 692 ("A public utility is entitled to  
17 such rates as will permit it to earn a return on the value of property which it employs for the  
18 convenience of the public equal to that generally being made at the same time and in the same  
19 general part of the country on investments in other business undertakings which are attended  
20 by corresponding risks and uncertainties").

21 APS has demonstrated that it substantially under-earned its allowed ROE for the last  
22 several years. (APS Initial Brief Exhibit 4; APS Exhibit No 5, Attachment DEB-10RB  
23 [Brandt].) The evidence showed that, over the more than three-year period from March 31,  
24 2003 to June 30, 2006, APS consistently under-earned its allowed rate of return by as much  
25 as half, resulting in a \$134,000,000 annual earnings shortfall as of June 30, 2006, relative to  
26 APS's current allowed rate of return of 10.25 percent. (*Id.*) Over this period, APS's actual  
27 ROE eroded from 8.4 percent for the twelve months ending March 31, 2003, to 5.7 percent  
28 for the twelve months ending June 30, 2006. (*Id.*) Nothing in the record suggests that this

1 trend will be reversed by the rate changes in the Recommended Order. On the contrary, all  
2 the evidence supports the proposition that attrition will continue.

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

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

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

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

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

22 Instead, the Recommended Order concludes that the Commission must rigidly adhere  
23 to the "historical test year cost-of-service analysis" in setting rates and that "it would not be  
24 constitutional for us to set rates based upon the achievement of certain targeted financial  
25 credit metrics or return on equity." (Recommended Order at 67.) On that basis, the  
26 Recommended Order concludes "that no additional adjustments or modifications to our  
27 traditional ratemaking method are necessary or appropriate to set just and reasonable rates."  
28 (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

1 financial metrics and potentially a “junk” credit rating for the Company are somehow “just  
2 and reasonable” (as the Constitution requires they be), the Recommended Order turns the  
3 rate-making process on its head and ignores the fundamental principle that the Commission  
4 can and should exercise its broad discretion to ensure that rates are just and reasonable **under**  
5 **all the facts and circumstances**, which necessarily includes consideration of the Company’s  
6 ROE, its credit status, and its overall financial integrity. The United States Supreme Court has  
7 made this point abundantly clear:

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

14 *Federal Power Comm’n v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1942).<sup>1</sup>

15       Contrary to what the Recommended Order states, a Company’s financial metrics and  
16 credit rating are often considered by regulatory agencies engaged in ratemaking and even this  
17 Commission has done so in the past. (*See* case citations and discussion in APS Initial Brief at  
18 8-11.) In fact, the Company is **required** by Commission rules and regulations to submit such  
19 information in a rate case and in monthly filings with the Commission. Taking such credit-  
20 rating and related financial factors into consideration is especially warranted in the current

---

21 <sup>1</sup> The Recommended Order (at page 60) purports to distinguish the *Hope* case and suggests that the *Hope* case does not  
22 apply in Arizona, citing to an argument made by Staff. But the *Hope* case -- a constitutional pronouncement of the United  
23 States Supreme Court -- certainly does apply in Arizona, as it does in every other state. The language of the Arizona  
24 Supreme Court in the *Simms* case (cited in the Recommended Order) that *Hope* could not be used by the Commission to  
25 support the kind of fair value determination at issue in the *Simms* case is of no relevance here. There are two aspects to  
26 the *Hope* decision: (1) a statement of the constitutional principles that must be followed to ensure that ratemaking  
27 comports with due process, and (2) a discussion of the application of those constitutional principles to the particular  
28 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.

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

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

22       After discussing the demonstrable lag between the Company's growth expenditures  
23 and the recovery of those expenditures, the Recommended Order erroneously states that  
24 "APS failed to demonstrate that the near-term costs of customer growth are greater than the  
25 increased revenues generated by that growth." (Recommended Order at 65.) That statement  
26 simply cannot be squared with the evidence in the record. As Don Brandt explained, the  
27 Company's expected customer growth requires the Company to make "massive capital  
28 expenditures" in order to enable APS to increase its load capacity to meet the rapidly growing

1 demand, averaging \$900 million a year for the next five years (comparable to the growth in  
2 the last several years). (Tr. Vol. IV at 783.) The increased revenue generated by serving a  
3 larger customer base decidedly does not provide sufficient revenue to offset the increased  
4 costs associated with serving that customer base in the short term. To the contrary, over a  
5 three-year period, the growth in expenses and capital investment exceeds the growth in  
6 revenues by a factor of approximately one-third. (*Id.* at 783-84.) APS Exhibits 27, 59 and 77,  
7 and the testimony of the various APS witnesses relating to those exhibits provide ample and  
8 unrefuted evidence that there is a significant lag between the costs of growth and the recovery  
9 of those costs in rates, and that such lag has a substantial adverse impact on the Company's  
10 available cash flow and is the major cause of the large gap between its earned return on  
11 equity and its allowed return on equity. (APS Exhibit No. 5 at Attachment DEB-10RB  
12 [Brandt].) Moreover, the resultant loss in earnings is irretrievable. Thus, this "regulatory lag"  
13 not only results in earnings attrition (which will be addressed in more detail below) but also  
14 depresses the Company's financial metrics because of the negative impact on cash flow. (*Id.*)

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

25               By the time those [new] rates are in effect [for two years], the additional  
26               \$2 billion or so of capital investment, plus the increase in operating  
27               expenses over that period of time, it's virtually impossible to implement  
28               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

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

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

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

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

25 With financial metrics at or below the minimum required for an investment grade  
26 credit rating, there can be no doubt that, if the rates proposed in the Recommended Order are  
27

28 <sup>2</sup> See letter dated July 21, 2006 from then Chairman Hatch-Miller (APS Exhibit No. 5 at Attachment DEB-11RB.).

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

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

21         The Commission should not turn a blind eye to this downgrade possibility and the dire  
22 financial consequences that it would produce for the Company and its customers. The  
23 Recommended Order seems to take the position, as one of RUCO's witnesses put it, that a  
24 downgrade of the Company's credit rating to "junk" is just "a situation we will deal with  
25 when we get there." (Tr. Vol. X at 2130 [Hill].) But such a downgrade has real and dire  
26  
27  
28

1 consequences that cannot be so cavalierly dismissed and from which it would be extremely  
2 difficult for the Company and its customers to recover.<sup>3</sup>

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

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

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

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23 <sup>3</sup> As Mr. Fetter explained (citing to the recent downgrades of Nevada Power and Central Vermont Public Service to  
24 "junk" credit status):

25 [O]nce a company goes below investment grade, it is not like turning on a dime, and the Commission  
26 by itself cannot divine decisions that return investment grade immediately. Even if all the parties in this  
27 room are in agreement, it could not bring APS back from the fall off the cliff within a day or a month or  
28 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].)

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

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

14 Because there would be an increase in the recording of depreciation  
15 expense that would be equivalent to the increase in revenues being  
16 collected, the Company would not experience any reduction in earnings  
17 attrition. However, depreciation is a “non-cash” expense. Accordingly, the  
18 recovery of depreciation expense on an accelerated basis would improve  
19 the Company’s cash flow metrics.

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

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

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26 <sup>4</sup> Commenting on the inclusion of CWIP in rate base by the Colorado Commission, S&P stated:

27 This is a major step forward in eliminating the tug-of-war over cost recovery that, in the past, has  
28 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.)

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

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

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

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

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

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

10           As a matter of fact, it is growth itself and the capital, the massive capital  
11 expenditure program and the regulatory lag that impacts that capital  
12 expenditure program that is the source of the cash flow problem and the  
13 earnings erosion. I mean the way it works under traditional historic test  
14 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.

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

18           The Recommended Order compounds its incomplete analysis of this issue by stating  
19 that "attrition in and of itself, is not especially significant. It is a normal, expected, and to  
20 some degree, necessary, component of the rate setting process." (Recommended Order at 66.)  
21 Attrition is not "normal" or "necessary" but rather a red flag that the rate-setting process has  
22 not functioned properly. Setting inadequate rates that will not produce the allowed return is a  
23 regulatory failure, not a desired result. Moreover, even assuming the Recommended Order's  
24 assertion has some validity in the ordinary rate-setting circumstance -- one in which a  
25 company is **not** chronically experiencing significant earnings attrition due to huge capital  
26 expenditures the Company is required to make in order to meet the demand of a customer  
27 base that is growing at unprecedented levels -- the statement in this instance ignores the  
28 reality that this is not the "normal" case where "some degree" of earnings attrition might be

1 expected to occur. The undisputed evidence here is that the Company has consistently under-  
2 earned its allowed ROE over the last 3 to 4 years by thirty to fifty percent, and can be  
3 expected to do so in coming years because of the growth phenomenon with which its is faced.

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

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

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

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

25 All of the Company's financial projections fully accounted for the proposed changes to  
26 the PSA. Moreover, none of these changes could or did impact the Company's projected  
27 ROE, and thus the need for an attrition adjustment. In addition, Mr. Brandt testified that the  
28 financial forecast and other projected financial information presented by the Company in this

1 proceeding were prepared using the same forecasting methodology that the Company uses in  
2 the ordinary course of business, in its regular dealings with rating agencies and financial  
3 analysts, and in its filings with the SEC and other government agencies (Tr. Vol. IV at 769-72  
4 [Brandt].) (APS Reply Brief at 4.)

5 Recommended Order Assertion No. 2: “APS has not provided such a breakdown comparing  
6 the cost of providing service to a particular class of customer now and at some future point.”  
7 *Id.* at 64.

8 As APS understands the above statement, the Recommended Order criticizes the  
9 Company for not distinguishing between increasing costs attributable to new customers and  
10 increased costs to serve existing customers. This criticism is repeated at the bottom of page  
11 64 and the top of page 65. However, the Recommended Order misses the point. If cost of  
12 service, *i.e.*, revenue requirements, is increasing faster than revenues, attrition to earned  
13 return must necessarily occur. In fact, that is the very definition of attrition. The reasons for  
14 these increases in revenue requirements, whether they be growth, inflation, or simply the  
15 replacement of old depreciated plant with new plant, is irrelevant to the existence and  
16 measurement of attrition.

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

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

26 Recommended Order Assertion No. 4: “including demand charges in the PSA significantly  
27 addresses any attrition costs...”

28

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

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

8 In his Supplemental Testimony, Staff witness Dittmer calculated a revenue deficiency for the  
9 Company's non-jurisdictional activities during the historical test period of some  
10 \$50,000,000. (Staff Exhibit No. 39 at 8 [Dittmer]; Staff Exhibit No. 40, Supplemental  
11 Schedule JRD-1 [Dittmer]). Aside from the fact that this assertion at best identifies  
12 \$50,000,000 of what is a more than \$120,000,000 problem, the forecasted data used by APS  
13 for 2007-2008 does **not** reflect such a level of revenue deficiency from non-jurisdictional  
14 operations.

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

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

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

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

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

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

### 20 III. OPERATING INCOME ADJUSTMENTS

21 1. Administrative and General Expense Associated with the Generating Units Acquired  
22 by APS from Pinnacle West Energy Corporation.

23 The Recommended Order disallows nearly \$6.3 million in administrative and general  
24 (“A&G”) expense allocated to the five generating units acquired by APS from Pinnacle West  
25 Energy Corporation (“PWEC”) pursuant to Decision No. 67744. (Recommended Order at  
26 19.) Because this acquisition took place during the test year, it was necessary to annualize  
27 the two months of actual A&G expense included in the test year to reflect a full year’s A&G  
28 expense related to these five generating units. As explained by APS witness Rockenberger

1 and acknowledged by the Recommended Order, this A&G expense was incurred in support  
2 of the generating units and should be charged to the affiliate that owns the generating units.  
3 Prior to the APS asset acquisition, the A&G incurred in support of these units was being  
4 charged to PWEC. Accordingly, when APS acquired the generating units, the A&G incurred  
5 to support these generating units was appropriately charged to APS. Neither Staff nor RUCO  
6 took any exception to the Company's proposed adjustment for A&G expense.

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

15       It is important to understand that A&G is an allocated expense for costs incurred by  
16 **both** APS and its parent corporation, Pinnacle West Capital Corporation ("Pinnacle West")  
17 for overall corporate governance and shared services such as accounting, tax, legal, HR, etc.  
18 The allocation of these costs to any particular affiliate depends on the direct activities  
19 performed in support of the affiliate and an indirect cost allocation based on the relative debt  
20 and equity investment by Pinnacle West in each subsidiary, and complies with the Policy and  
21 Procedure No. 1 to the APS Code of Conduct, which was approved by the Commission in  
22 Decision No. 68741. The transfer of the PWEC generation to APS, along with the associated  
23 increase in APS equity and employees and corresponding decrease in Pinnacle West's equity  
24 investment in PWEC (as well as the decline in PWEC employees) appropriately allocates a  
25 greater percentage of overall A&G to be allocated to APS. In other words, the shrinking  
26

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27 <sup>5</sup> The Recommended Order contends this represented the Company's position in "late 2004." However, by that time,  
28 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.

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

5 A simple example should help to illustrate this point. Assume there is total A&G of \$1  
6 million, half of which is allocated based on investment and half on employees. Prior to the  
7 transfer of the PWEC generation, Pinnacle West had, say, \$1 billion invested in APS, \$400  
8 million in PWEC, and \$100 million in other affiliates. APS had, for illustrative purposes,  
9 1000 employees, PWEC 200, and 100 in all other affiliates.

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

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

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

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

5 2. Underfunded Pension.

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

12 3. SERP.

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

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

27 SERPs are routinely made available by all companies, including utilities, that  
28 otherwise offer "qualified" benefit programs. (APS Exhibit No. 5 at 62-63 [Brandt]). There

1 has been no allegation that APS's program is out of line with these other retirement  
2 programs. Neither has there been any evidence that overall management compensation is  
3 excessive (and indeed, in APS Exhibit No. 51 [Gordon], an expert executive compensation  
4 witness testified to precisely the opposite). Thus, the only remaining rationale is the  
5 Southwest Gas decision cited by RUCO and the Recommended Order.

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

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

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

27 4. Stock Incentive Compensation.  
28

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

7 APS's stock incentive component, or "long-term" incentive, is integral in attracting  
8 and retaining high quality management personnel. The program benefits APS customers by:

- 9       ▪ Minimizing costs associated with high turnover at the executive level,  
10 including recruiting, productivity reductions and continuity of leadership.
- 11       ▪ Minimizing the need for additional base pay or other fixed benefits to provide  
12 competitive compensation levels.
- 13       ▪ Providing focus and accountability for the executive and management team to  
14 develop and implement effective business strategies that span multiple year  
15 periods.
- 16       ▪ Long-term financial health provides stability and allows the Company to  
17 continue to invest in the business operations, grow its asset base and continue  
18 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.

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

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

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

13 5. Lobbying.

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

22 APS must qualify its acquiescence to the RUCO adjustment because the second part  
23 of the Recommended Order's discussion on this point completely vitiates the above  
24 compromise. By requiring APS to present "the itemized lobbying costs associated with each  
25 benefit it alleges resulted from the specific lobbying activity" in future rate cases in order to  
26 justify even the 50% of such costs found reasonable in the Recommended Order, the  
27 Recommended Order establishes an impossible hurdle to the recognition of these costs. The  
28 efforts of entities such as APS in the legislative process cannot be broken down by task like

1 an expense account and assigned specific costs. APS may contact key legislators dozens of  
2 times on a variety of issues important either to APS or the legislators in question before  
3 seeing positive results for its customers on even a single issue. Was it the last visit that  
4 persuaded a legislator -- the first -- or was it all of them? That is unknown and unknowable.

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

9 6. Demand Side Management Conservation Adjustment.

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

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

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1 prevent APS from recovering net lost revenues related to DSM “in this case on a going  
2 forward basis.” Each of these contentions is fundamentally flawed.

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

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

28

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

13 The Recommended Order’s position that the proposed DSM conservation adjustment  
14 is not “sufficiently known and measurable” disregards APS’s Rebuttal Testimony and  
15 evidence submitted on the subject, and is simply wrong. In his Rejoinder Testimony, Mr.  
16 Ewen expressly responded to the argument that “the Company’s proposed pro forma  
17 adjustment for revenue reductions attributed to DSM measures should be disallowed because  
18 they are not known and measurable,” noting that, while the Company’s initial calculation  
19 was based on estimated values, he had since modified that calculation “to reflect the **actual**  
20 spending to date [October 2006] and the amounts planned to be spent in the 4<sup>th</sup> quarter of this  
21 year [2006].” (*Emphasis added*.) (APS Exhibit No. 18 at 9 [Ewen].) The revised calculations  
22 thus rely on “known program expenditures, and these expenditures have resulted in the  
23 implementation of quantifiable energy-saving measures.” (*Id.* at 10 [Ewen].) As the hearing  
24 testimony made clear, most of the Company’s 2005-2006 DSM spending was for programs,  
25 such as the compact fluorescent light program, for which the savings can be precisely  
26 calculated. (Tr. Vol. VII at 1404 [Orlick].) Thus, APS’s DSM conservation adjustment  
27 calculation is based, not on estimates, but on “known and measurable” adjustments to  
28

1 expenditures and corresponding revenue losses that need to be reflected in the adjusted test  
2 year.

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

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

15 This language does three salient things: first, it establishes that the terms of the Agreement  
16 alone do not compensate APS for its net lost revenues related to the DSM programming  
17 required by the Agreement; second, it establishes that, "on a going-forward basis" (that is,  
18 from the time the parties execute the Agreement onward) APS may recover net lost revenues  
19 related to its DSM programming to the extent reflected in an adjusted test year used to  
20 establish APS rates in future rate proceedings (or in a non-rate proceeding if authorized by  
21 the Commission); and third, it prevents APS from recovering net lost revenues incurred  
22 prior to such test year. There is simply nothing in this language or elsewhere in the  
23 Agreement that prevents APS from normalizing its test year based on complete, known data  
24 to reflect DSM programming implemented during the test year, as is the case here. The  
25 "going forward" language on which the Recommended Order relies was intended simply to  
26 convey that the parameters set for APS's net lost revenue recovery were to apply "going-  
27 forward" -- it certainly was not meant to prevent APS from using future data to normalize its  
28 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

1 simply seeks to make a necessary pro forma adjustment to revenue loss attributable to DSM  
2 programming that was reflected in the adjusted test year, predicated on known and  
3 measurable conditions. The failure to allow APS to recover its lost revenue attributable to  
4 DSM-related conservation in this rate proceeding will prevent the Company from recovering  
5 its full cost of service. (APS Proposed Amendment No. 10 attached hereto.)

6 7. Bark Beetle Regulatory Asset.

7 With respect to bark beetle remediation costs, the Recommended Order adopted APS's  
8 proposed rate base adjustment in the amount of \$4,360,000, and agreed conceptually to  
9 APS's proposed amortization of that amount. (Recommended Order at 11, 16.) However, the  
10 \$1,437,983 amortization adjustment recommended by and reflected in the Recommended  
11 Order is incorrect, because it reflected an incremental expense adjustment to the wrong base  
12 amount of this expense. The \$1,437,983 adjustment awarded in the Recommended Order  
13 does not include a \$110,000 pre-tax adjustment to operating income that the Company  
14 provided in rebuttal as an update to its pro forma (an update that was not disputed by any  
15 party to the proceeding). (Attachment LLR-4-2RB to Rockenberger Rebuttal Testimony.)  
16 That adjustment should be included in the Commission's decision. (APS Proposed  
17 Amendment No. 11 attached hereto.)

18 8. Sundance O&M Adjustment.

19 The Recommended Order adopts RUCO's proposed adjustment to the Sundance O&M  
20 expense, and orders APS to recognize a regulatory liability in the amount of \$226,500 per  
21 month. (Recommended Order at 17.) Although APS does not take exception to the  
22 adjustment itself, it believes that the Recommended Order has incorrectly calculated the  
23 amount of regulatory liability accrual that applies to the Sundance non-routine maintenance  
24 expense. The \$226,500 per month proposed in the Recommended Order is erroneously based  
25 on RUCO's entire pro forma adjustment, rather than simply the non-routine maintenance  
26 portion of it. The regulatory liability accrual should include only the non-routine expenses at

1 issue – a modification that results in a regulatory liability accrual of \$134,100 per month.<sup>6</sup>  
2 Amending the Recommended Order in this manner does not affect the Company’s operating  
3 income, only the amount of regulatory liability the Company is required to accrue. (APS  
4 Proposed Amendment No. 12 attached hereto.)

5 9. Business Lunches.

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

16 Significantly, although APS’s practice of providing employee meals as described  
17 above is a long-standing one, no adjustment to APS’s operating expenses related to that cost  
18 has ever been proposed by any party to any other APS rate case until now. (*Id.* (citing Tr.  
19 Vol. XIII at 2687-89 [Rockenberger]).) Even now, of the many parties to this proceeding  
20 (including Staff), only RUCO challenged the Company’s meeting meal expense. But,  
21 significantly, RUCO did not provide any evidence that the amount claimed by the Company  
22 was excessive or that the meals did not serve a valid business purpose. (APS Initial Brief at  
23 58-59; APS Post-Hearing Reply Brief at 20.)

24 APS’s costs in this regard are thus no different than those incurred by businesses in  
25 any number of industries, many of which provide food to employees that are required to work  
26

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

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

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

11 (APS Proposed Amendment No. 13 attached hereto.)

12 10.   Income Tax Impacts of Interest Synchronization.

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

1 million over that increase proposed by the Recommended Order. (APS Proposed Amendment  
2 No. 14 attached hereto.)

3 11. Annualized Amortization.

4 The Recommended Order finds that the Company's proposed adjustment to annual  
5 depreciation and amortization is reasonable, and should be adopted (Recommended Order at  
6 30, lines 1-2.) However, the corresponding ordering paragraph (Recommended Order at 150,  
7 lines 26-27) only specifies that the Company's depreciation rates are appropriate to use in this  
8 case, so the Company is requesting that the ordering paragraph be modified to include  
9 amortization. Attached Amendment 15 makes this modification.

10 **IV. RATE BASE ADJUSTMENTS**

11 1. Cash Working Capital.

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

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

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

21 Unlike other rate base elements, which can be taken directly from the Company's  
22 balance sheet with or without adjustments, cash working capital is a calculated number that  
23 identifies the additional cash investment made by the Company in order to operate and  
24 maintain its electric system over and above those items specifically included in rate base  
25 such as net utility plant, inventories and prepayments. Simply put, if cash revenues are  
26 received after an expense has been incurred and reflected on the Company's income  
27 statement or balance sheet, investors have to provide funds to bridge that gap. If cash is  
28

1 received prior to that expense being incurred, the opposite is true, *i.e.*, customers are  
2 providing that bridge and should receive credit in the form of an offset to the utility's rate  
3 base.

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

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

1 over \$35,000,000 of unrecovered invested capital. (APS Exhibit No. 66 at 3 [Balluff].)  
2 Excluding deferred tax expense leads to another understatement of rate base of \$7,872,000.  
3 (APS Exhibit No. 65 at Attachment FB-1 [Balluff].)

4 APS is aware that the Commission has rejected the inclusion of depreciation and  
5 deferred taxes in prior decisions. As the arguments on this issue have become focused, an  
6 increasing number of jurisdictions have taken a new look and have concluded that one or  
7 both of these costs are appropriate elements of cash working capital. A few examples of  
8 states that have included depreciation and deferred income taxes in lead lag studies are:  
9 South Carolina, where these items must be included in a lead lag to reflect the delay in the  
10 collection of these components of revenue;<sup>7</sup> Connecticut, where the Department of Public  
11 Utility Control agreed that non-cash expenses such as depreciation, amortization, and  
12 deferred income taxes create a working capital requirement;<sup>8</sup> and California, which includes  
13 both depreciation expense and deferred taxes at zero lag days because of the reduction of rate  
14 base by accumulated depreciation and accumulated deferred income taxes.<sup>9</sup> Each of these  
15 jurisdictions likely faced the same contrary precedents as is currently the case in Arizona  
16 before finally recognizing the need to reflect all the expense elements that lead to the need  
17 for working capital.

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

22 [2] Depreciation and Deferred Tax Lag

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

25 <sup>7</sup> 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).

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

28 <sup>9</sup> See, generally, Water Division, California Public Utilities Commission, Standard Practice U-16-W, Determination of  
Working Cash Allowance (May 16, 2002).

1 maintenance expenses, the next item, depreciation, reflects a zero lag. This  
2 zero lag is used because accumulated depreciation, the contra account to the  
3 depreciation provision [expense], is deducted from rate base. However, on  
4 occasion, the issue has been raised that depreciation is a non-cash charge  
5 and therefore cannot produce a need for cash working capital. While it is  
6 true that recording depreciation does not require the expenditure of cash at  
7 the time the expense is recorded and charged to the customer, cash was  
8 expended at the time the property was acquired, and the recorded  
9 depreciation is used to reduce the investment in that property even though  
10 approximately one-and-one-half month's depreciation (equivalent to the  
11 revenue lag) has not yet been received from the consumer.

12 It can be noted from figure 5-3 that a zero lag has also been used for  
13 deferred income taxes. The same issue is involved with respect to  
14 provisions for deferred income taxes which are used to reduce rate base as  
15 that for depreciation. In the case of deferred income taxes, the balance also  
16 includes approximately 45 days of uncollected tax provisions. These  
17 provisions are used to reduce other investments made for rate base  
18 components even though the last 45 days have not yet been received from  
19 the consumer.

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

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

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

33 Q. WHAT IS THE RELEVANCE OF STAFF'S STATEMENT ON  
34 DEPRECIATION AND DEFERRED INCOME TAXES?

35 A. There is none – Mr. Dittmer's statement is not relevant to the issue  
36 at hand. Of course depreciation and deferred income taxes recorded

1 by September 30, 2005 will be collected by October 2006. But that  
2 is true with **all** other expenses with a revenue lag. APS calculated a  
3 revenue lag of over 35 days, and it is that lag in recovery and not the  
4 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.

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

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

14 Let's reverse the above example. You have the same \$1000 invested in a bank  
15 account, and you have instructed the bank to withdraw \$100 per month and place it in your  
16 checking account. If after the first month the bank debited your savings account by the \$100  
17 but did not actually deposit it in your checking account until the end of month two, you  
18 would not have earned any interest on that \$100 in month two even though you had yet to  
19 receive it. You would be out \$.50 in interest that was rightfully yours ( $\$100 \times .06 \div 12$ ).  
20 Again the principle is the same - excepting APS is not out the return on \$100 but on nearly  
21 \$40,000,000.

22 The Recommended Order further states that although the depreciation and deferred  
23 tax reserves at the end of the test period were not fully recovered in cash receipts, neither did  
24 all the plant in service reflect cash outlays. (*Id.*) However, as noted by Mr. Balluff in his  
25 Rejoinder Testimony, the amount of plant not representing actual cash outlays as of  
26 September 30, 2005 was less than \$2,000,000 -- far less than the impact of excluding  
27 depreciation and deferred taxes from the lead/lag computation of cash working capital. (APS  
28

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

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

16         The Commission has previously taken conflicting positions on the use of interest  
17 expense, adopting it in Decision No. 55931 (April 1, 1988), while admitting in that same  
18 Decision that it had previously rejected the concept. (Decision No. 55931 at 67.) The  
19 testimony in this case is that the lag in paying interest, a non-operating expense, is an  
20 inherent part of the return to equity investors, *i.e.*, part of the "leverage" provided by debt  
21 capital to equity. If it is appropriate to include the interest component of the return in the  
22 calculation of cash working capital, it is necessary to include the entire rate base (including  
23 the weighted cost of debt) in the calculation of working capital. (APS Exhibit No. 66 at 11  
24 [Balluff].) To use it to reduce rate base is tantamount to making equity investors use a  
25 component of their rightful return to finance plant used to serve APS customers. Moreover,  
26 as Mr. Balluff pointed out, there is also a lag in the receipt by equity investors of their return.  
27 If one form of investment (*i.e.*, debt) is to be factored in the calculation of cash working  
28

1 capital, then all other forms should be in play, which would have increased the Company's  
2 overall cash working capital allowance from that requested. (*Id.*)<sup>10</sup>

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

5 The operating income component is subject to a wide difference of opinion  
6 in treatment when lead-lag studies are prepared. From a theoretical  
7 standpoint, operating income is earned when service is provided, and the  
8 operating income is the property of the investors in the company when  
9 earned. This view would recognize a cash working capital requirement for  
10 the lag in receipt of operating income. Such a requirement is equal to the  
11 revenue lag days times an amount equal to one day's operating income.  
12 The amount for interest or preferred dividends would not be offset, since  
13 those amounts are paid from investor-supplied funds (operating income).  
14 At the opposite end of the spectrum are those who take the position that a  
15 source of cash working capital exists in the delay in disbursement of  
16 interest and preferred dividends without any consideration of the lag in the  
17 receipt of operating income.

18 In recent years, few commissions have accepted either of these opposing  
19 points of view. Usually, the decisions are somewhere between the two  
20 poles. **The most prevalent is probably to not consider the operating  
21 income component in the lead-lag study, which results in not  
22 recognizing a need for cash working capital to cover operating income  
23 and not recognizing accruals of interest and preferred dividends as a  
24 source of cash working capital.**

25 The procedure of ignoring operating income generally produces  
26 approximately the same effect as does the procedure of recognizing the lag  
27 in collecting the operating income component of revenues while also  
28 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.

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

22 The "lag" in the receipt of operating income referenced above is the lag in overall return  
23 discussed in the Company's Initial Brief (APS Initial Brief at 43) and by Mr. Balluff in his  
24 Rebuttal Testimony. (APS Exhibit 66 at 11 [Balluff].) As noted, most jurisdictions either  
25 include both that operating income lag and interest or exclude both, as has APS. Thus,  
26

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27 <sup>10</sup> The Recommended Order cites a Staff argument that had the lag in paying dividends been included, cash working  
28 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.

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

5 2. SERP.

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

16 **V. FUEL AND PSA ISSUES**

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

21 1. Base Fuel Cost.

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

27 A. *APS Base Fuel Cost Calculation.*

28

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

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

8 (Staff Exhibit No. 30 at 23 [Antonuk].) He went on to recommend that Mr. Ewen's number  
9 be adopted by the Commission in establishing the "forward component" of Staff's PSA for  
10 2007. (*Id.* at 3; Tr. Vol. XXI at 3993 [Antonuk].) And, the Recommended Order also adopts  
11 that number for the "forward component." (Recommended Order at 109.) The question  
12 becomes: if Mr. Ewen's Rejoinder Testimony calculation of 2007 fuel costs is sufficiently  
13 accurate for adoption as the "forward component" under the Recommended Order, why  
14 should it not be used to establish a new Base Fuel Cost?

15 Unlike the Base Fuel Cost proposals in the Company's Direct and Rebuttal  
16 testimonies, APS has not annualized price changes scheduled to take effect in 2007, nor has  
17 it annualized generation levels for end of year customers. Both these omissions reduced the  
18 2007 Base Fuel Cost compared to the methodology used by APS in its prior testimony and  
19 used by the Commission in establishing the Base Fuel Cost in Decision No. 67744.

20 Moreover, the 3.2491¢/kWh figure is an annual average cost that includes the lower  
21 fuel and purchased power costs generally incurred by APS during the non-summer months of  
22 the year. (APS Exhibit No. 105 at 5). As shown in APS Exhibit No. 105, costs during the  
23 peak use months of 2007 would be 3.6915¢/kWh. (*Id.*) Assuming the Company's proposed  
24 Base Fuel Cost was adopted effective June 1, 2007, APS still projects an unrecovered  
25 balance of 2007 fuel and purchased power costs of over \$50 million. (APS Initial Brief at  
26 33.) For this reason, APS believes its Base Fuel Cost is a reasonable, even conservative,  
27 estimate of what fuel costs will be in 2007. And, using the Company's Base Fuel Cost would

28

1 obviate the need for setting a “forward component” to the PSA in 2007, or more precisely,  
2 that “forward component” could be set at zero. (Tr. Vol. V at 109 [Ewen].)

3 *B. Conservation Adjustment Impact.*

4 If the Commission were to adopt the Recommended Order’s rejection of the  
5 Company’s DSM conservation adjustment (Recommended Order at 30), there needs to an  
6 upward adjustment to the Base Fuel Cost irrespective of how the Commission otherwise  
7 resolves the issue of Base Fuel Cost. It is uncontroverted that APS factored the impact of the  
8 DSM conservation adjustment into its calculation of Base Fuel Cost. Without the DSM’s  
9 expected impact on sales, Base Fuel Cost would be increased by \$.7 million or .0024¢/kWh  
10 (assuming a Base Fuel Cost of 3.1202¢/kWh with the DSM adjustment rejected by the  
11 Recommended Order), and by \$3.2 million or .0119¢/kWh assuming a Base Fuel Cost of  
12 3.2491¢/kWh which also included the DSM conservation adjustment. Attachment D to these  
13 Exceptions sets forth these calculations. If the Commission rejects APS’s DSM conservation  
14 adjustment to revenues, there is simply no principled reason to reflect that conservation in  
15 either the Base Fuel Cost suggested in the Recommended Order or that proposed by APS  
16 (which is used as the “forward element” in the Recommended Order).<sup>11</sup>

17 2. PSA.

18 *A. 90/10 Sharing.*

19 The Recommended Order adopts two important changes requested by APS to the  
20 90/10 sharing mechanism, thus significantly improving the fairness of the PSA.<sup>12</sup> This is  
21 clearly progress towards more effective and timely recovery of prudent fuel and purchased  
22 power costs. But, the need to establish an accurate Base Fuel Cost is heightened to the extent  
23 the Commission retains most of the elements of the present 90/10 sharing. In practice, the  
24 90/10 sharing feature has served as a penalty provision that automatically denies APS’s

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

28 <sup>12</sup> 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.

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

5 Mr. Antonuk, the Staff's consultant on PSA issues, agreed that the 90/10 sharing  
6 feature would result in the non-recovery of costs APS would reasonably expect to incur. (Tr.  
7 Vol. XXII at 4149 [Antonuk].) Mr. Antonuk described it as a "blunt instrument" at best with  
8 regard to providing an incentive, and he suggested that the Commission focus in on the  
9 "drivers" of fuel cost. (Tr. Vol. XXI at 3896.) APS believes Staff made a valid point and  
10 that, rather than attempt to modify the 90/10 provision to alleviate some of its most obvious  
11 inequities, eliminating it (as Staff recommended) is appropriate, especially in view of the  
12 findings by Liberty Consulting and R.W. Beck concerning the overall prudence and  
13 effectiveness of the Company's fuel procurement and hedging practices. (Staff Exhibit No.  
14 33 at 6-7 [Fuel Audit]; APS Exhibit No. 72 at 5-1 through 5-4 [R.W. Beck].) For example,  
15 Liberty concluded that:

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

20 (Staff Exhibit 28 at 12[Antonuk].)

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

23 (Staff Exhibit 28 at 14 [Antonuk].)

24 R.W. Beck stated:

25 "APS has a high-quality energy risk management and hedging program,"  
26 that it was "consistent with leading industry practices."  
27  
28

1 (November 1, 2006) ("R.W. Beck Report") was entered into evidence as APS Exhibit No.  
2 72.)

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

5 *B. Broker Fees.*

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

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

22 **VI. RATE DESIGN**

23 1. Revised H-3 Schedule.

24  
25  
26 <sup>13</sup> 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.

27 <sup>14</sup> APS believes the Recommended Order would exclude broker fees from the PSA only to the extent they increase from  
28 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. XXI at 4010 [Antonuk].)

1 On May 2, 2007, a Procedural Order was issued that included four  
2 schedules/spreadsheets that purportedly supported or reflected the determinations contained  
3 in the Recommended Order. In reviewing the rate design, it appears that the residential rate  
4 designs contained in the Procedural Order will result in an estimated \$2.7 to \$2.9 million  
5 revenue undercollection. This undercollection results from the proposed Recommended  
6 Orders' rate design in rate schedules due to be eliminated. It appears that Rate Schedule E-10  
7 was designed to recover a specific revenue target without consideration of the intended  
8 elimination of the Schedule. Rate Schedules E-10 and E-12 must be designed in concert to  
9 prevent a guaranteed loss of revenue. Under the proposed rate design, and assuming  
10 customers will react to the rate changes in a manner that will mitigate their bills, customers  
11 on Schedule E-10 will transfer to other rate schedules immediately because they would save  
12 money under any alternative rate. Thus, the calculated \$15.7 million increase from Schedule  
13 E-10 (per the revenue table attached to the May 2 Procedural Schedule) would not be  
14 achieved. If it were assumed Rate Schedule E-10 customers transferred to Rate Schedule E-  
15 12, test year E-10 revenues would be \$82,132,843, which is \$1,871,085 less than the revenue  
16 anticipated in the Recommended Order. Similarly, rate schedules EC-1 and ECT-1R must be  
17 designed together because EC-1 is also scheduled to be cancelled. Furthermore, the Rate  
18 Schedules ET-2 and ECT-2 in the Procedural Order are not revenue neutral with Rate  
19 Schedules ET-1 and ECT-1R respectively, as required in the Recommended Order.  
20 (Recommended Order page 73 lines 18-19, page 74 line 5.) Although Staff has designed  
21 revenue targets by rate class, specific targets by class may not be achievable but the overall  
22 targets will be met in conformance with the Recommended Order.

23 APS has prepared and is submitting an H2 and H-3 schedule using Staff's rates and  
24 APS' billing determinants. (Attachment E). The attached H-3 schedule reflects APS'  
25 interpretation of the rate design set forth in the Recommended Order and the increases  
26 associated with Residential and General Services rates. The "rate spread" as shown on the  
27 attached exhibits generally follows the trends reflected in the Procedural Order rate  
28 attachment. However, there are some deviations. For example, in APS's filed case, irrigation

1 customers would have received a de minimus rate change. The Staff proposal increased  
2 irrigation charges by approximately 8% while the APS proposal attached herein recommends  
3 irrigation rate changes of approximately 4% due to the effects of combining rate schedules E-  
4 38 and E-221. The APS rate proposals also reflect the changed method for recovery of  
5 transmission charges. APS agreed with AECC that the transmission expenses charged to  
6 retail customers should better track the charges found in the APS OATT. This rate design  
7 change results in some inter-class and intra-class shifts in revenue. However, slight  
8 adjustments to non-OATT charges were developed so that the rate spread proposed by Staff  
9 was generally maintained.

10 2. Net Metering.

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

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

26  
27  
28 <sup>15</sup> 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].)

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

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

- 16 1. Collect the revenues associated with the uncollected fixed costs through the  
17 EPS/RES surcharge (the Company's preferred method); or
- 18 2. Defer the revenues associated with the uncollected fixed costs for collection in  
19 a subsequent rate case from other APS customers.

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

23 The Company requests that the Commission approve EPR-5 as initially proposed in  
24 its filing. In the alternative, instead of authorizing recovery of its uncollected fixed costs  
25 through the EPS surcharge, APS would request that it be allowed to defer its uncollected  
26 fixed costs and seek recovery of such costs in a future rate case proceeding. Attached APS  
27 Proposed Amendment No. 21 allows for the recovery of uncollected fixed costs in this  
28

1 proceeding. Attached APS Proposed Amendment No. 21A allows for the deferment of  
2 uncollected fixed costs to a future rate proceeding.

3 3. Elimination and Freezing of Schedules.

4 The Recommended Order is silent as to APS's request to eliminate, freeze, and  
5 consolidate the following rate schedules: (1) eliminate existing rate schedules DA E-12, DA  
6 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-  
7 S, EQF-M, E-52 and Solar 1; (2) eliminate rate schedule E-51 in the Company's next rate  
8 case; (3) close (freeze) existing rate schedules SP-1, E-32R, and E-55 to new customers and  
9 eliminate them in the next rate case; and (4) consolidate Schedule EPR-4 into the revised  
10 Schedule EPR-2. No party to the proceeding objected to the above proposal. The Company  
11 requests language in the Recommended Order authorizing the above changes. APS Proposed  
12 Amendment No. 22 makes this modification.

13 4. Total Solar Rate.

14 On page 96 of the Recommended Order, the Order incorrectly lists the Total Solar  
15 Rate as \$.0225 per kWh. As set forth in Schedule Solar-3, the Solar Power Premium Rate is  
16 listed at \$.166 per kWh, which is calculated by subtracting the avoided cost credit in the  
17 amount of \$.059 per kWh from the Solar Power Price of \$.225. APS Proposed Amendment  
18 No. 23 makes this modification.

19 5. Schedule E-56 and E-57.

20 The Company takes exception to the Recommended Order's rejection of APS's  
21 proposed Partial Requirement Schedules E-56 and E-57. Partial Service Rate Schedule E-56  
22 is applicable to general service customers having distributed generating equipment 100 kW  
23 or greater capable of supplying all or a portion of their power requirements. Rate schedule E-  
24 57 is applicable to general service customers having solar/photovoltaic generating equipment  
25 greater than 100 kW but less than 1,000 kW capable of supplying all or a portion of their  
26 power requirements.

27 APS currently has customers that want and would benefit today from these rate  
28 schedules, as these proposed rates are superior to the current partial requirement rates offered

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

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

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

## 24 VII. MISCELLANEOUS ISSUES

### 25 1. EPS Uniform Credit Purchase Program.

26  
27  
28

1 Commission Decision No. 68668<sup>16</sup> required APS to set aside \$4.25 million for  
2 additional funding for the Environmental Portfolio Standard (“EPS”) Uniform Credit  
3 Purchase Program (“UCPP”) for 2006, and provided that recovery of those funds could be  
4 recovered through the Company’s on-going rate case. That Decision specifically required  
5 APS to ensure that reserved UCPP projects funds were applied to those projects when they  
6 were completed, regardless of the year in which they were completed. The Recommended  
7 Order authorizes the Company to “true-up” the \$4.25 million with actual UCPP costs for  
8 2006; the Recommended Order fails to authorize APS to carry-forward any funds that: 1)  
9 have been committed, but are not yet spent; or 2) are unspent funds that were not committed  
10 in 2006.

11 Currently there are various UCPP projects for which funds were reserved in 2006, but  
12 the projects were not/will not be completed until sometime in 2007. In addition, as reported in  
13 its 2006 EPS Annual Report<sup>17</sup>, \$1.4 million of the additional funds that were allocated to the  
14 UCPP were unreserved in 2006. To maximize the numbers of customers that could benefit  
15 from the additional funding, the Company requests that rather than a true-up for calendar year  
16 2006, it be authorized to carry-forward to the subsequent year any unspent or unreserved  
17 funds from the additional \$4.25 million. Those funds would be earmarked for customer  
18 incentive payments.

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

26 <sup>16</sup> Issued April 20, 2006.

27 <sup>17</sup> Filed in Docket No. E-01345A-01-0034 on March 1, 2007.

28 <sup>18</sup> See, Attachment GAD-2RB, which is attached to the Rebuttal Testimony of Gregory DeLizio.

1 the remaining reserved and unreserved funds from the \$4.25 million for its UCCP program in  
2 2007. The attached Amendment No. 25 will effectuate these changes.

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

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

12 The Recommended Order states as follows:

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

20 The Recommended further recommends a finding<sup>21</sup> that:

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

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

26 <sup>19</sup> A.A.C. R14-2-1801 *et seq.*

27 <sup>20</sup> Recommended Order, p. 93, lines 3-9.

28 <sup>21</sup> Recommended Order, Finding of Fact 60, p. 140, lines 20-22.

<sup>22</sup> The Recommended Order also contains corresponding Ordering paragraphs.

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

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

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

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

17 3.     Rate Implementation.

18       Pursuant to the first two Ordering paragraphs in the Recommended Order (pages 148-  
19 149), the Company is directed to file revised schedules of rates and charges on or before May  
20 31, 2007, with rates to go into effect on June 1, 2007. However, Finding of Fact No. 34  
21 (Recommended Order at 138) requires that such filing be submitted to Staff for its "review  
22 and confirmation" prior to the rates being implemented; there is no timeline set for Staff's  
23 "review and confirmation" of any such schedules. From a practical perspective, there may be  
24 insufficient time for the Staff to review and confirm the Company's rates and charges before  
25 rates would go into effect. Therefore, the Commission should delete the language in Finding  
26 of Fact No. 34 that requires "Staff review and confirmation prior to their implementation."  
27 APS Proposed Amendment No. 27 makes this modification.

28

## VIII. PALO VERDE ISSUES

1  
2 APS takes exception to the Recommended Order's conclusions that APS was  
3 imprudent in connection with three of the outages Palo Verde experienced during 2005 and to  
4 the Recommended Order's directive to APS to work with the Staff to develop a nuclear  
5 performance standard ("NPS"). With respect to the three outages, the Recommended Order  
6 violates the prudence standard by ignoring the presumption of prudence and engaging in  
7 patent speculation about how the outages in question might have been avoided. The  
8 Recommended Order's conclusion that, had APS allegedly acted differently, "it is entirely  
9 possible that the NRC would not have felt the need to ask the question" that required Units 2  
10 and 3 to shut down in October of 2005, is one such example of purely speculative reasoning.  
11 The Recommended Order inappropriately rejects the answers of the NRC's Regional  
12 Administrator, Bruce Mallett, that APS should not have anticipated his inspector's question.  
13 The Recommended Order also ignores the evidence establishing that whoever posed the  
14 question (APS or the Nuclear Regulatory Commission ("NRC")), the result would have been  
15 the same, *i.e.*, the plant would have had to shut down and the replacement power costs still  
16 would have been incurred.

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

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

1 Tank ("RWT") outages offset \$5.1 million in replacement power costs, the Recommended  
2 Order proposes to give APS credit for only half that amount (and makes a calculation error in  
3 subtracting the half). Similarly, although the Staff witness acknowledged that his calculations  
4 for lost off-system sales margins were incorrect and that APS's "approach is probably the  
5 more accurate way to do it," the Recommended Order adopts the Staff's admittedly incorrect  
6 numbers. When these and other errors are corrected, the proposed disallowance is reduced to  
7 \$8.464 million (plus interest). Finally, once one appropriately takes into account the superior  
8 performance of APS's other baseload units, the disallowance is offset in its entirety.

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

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

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

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

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

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

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

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

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

27           In addition to being speculative, the Recommended Order is also circular. Since the  
28 NRC inspector's criticism of Palo Verde personnel's purported lack of knowledge of "how

1 the design was intended to address the air entrainment issue” is based on their lack of  
2 knowledge of the answer to his question about how the design behaves under dynamic  
3 conditions, the only way it can be said that the inspector “would not have felt the need to ask  
4 the question” about dynamic conditions is if Palo Verde personnel had anticipated his  
5 question and affirmatively provided him the dynamic calculation before he asked for it. Thus,  
6 the Recommended Order is demonstrably wrong in stating that “the question to be asked is  
7 not should APS have anticipated the NRC’s question, but why did the NRC inspector feel the  
8 need to ask the question.”

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

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

26 \_\_\_\_\_  
27 <sup>23</sup> This is quite different from most of the NRC’s activities where it is irrelevant to the NRC whether the licensee’s  
28 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

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

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

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

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

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

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

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

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

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

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

20 Finally, the Recommended Order improperly gives short shrift to the fact that the  
21 reactor trip was due to the failure of the secondary control room operator to follow  
22 procedures, including informing his supervisor of the actions he planned to take. (*Id.* at 123.)  
23 Even Dr. Jacobs acknowledges that "the unit tripped due to an operator error in controlling  
24 the feedwater to the steam generator." (Staff Exhibit No. 46 at 24 [GDS Report].) Had the  
25 operator simply followed procedures and left the steam generator feedwater level control  
26 system in automatic, the reactor would not have tripped. (APS Exhibit No. 95 at 8 [Levine].)  
27 Thus, the Recommended Order's proposed disallowance is dependent on: (1) had APS  
28 management known of the later-recognized "perception" of difficulties with the DFWCS, and

1 even though this perception had never resulted in a reactor trip, (2) APS nonetheless would  
2 have required further training prior to restart, and (3) this training would have prevented the  
3 operator from failing to follow procedures, thereby avoiding the outage. The degree of  
4 speculation required to reach this result is extraordinary and is in plain violation of the  
5 prudence standard. APS Proposed Amendment No. 31 makes these modifications.

6 4. The Recommended Order's Disallowance is Improperly Calculated and Does Not  
7 Incorporate Valid Offsets.

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

12 A. *Offset For Prudent Maintenance During the RWT Outage.*

13 The Recommended Order states that Staff recommended disallowance of \$16.186  
14 million. This includes \$13.757 million of replacement power costs during the PSA period and  
15 \$2.103 million of reduced margins on off-system and opportunity sales, totaling \$15.860  
16 million, plus \$0.326 million of interest. (Recommended Order at 111; GDS Report at 49.)  
17 Although APS agrees with the Recommended Order's conclusion that reactor coolant pump  
18 oil seal work performed during the Unit 2 October RWT outage was prudent and saved  
19 \$5,100,000 of later costs, APS takes exception to the Recommended Order's arbitrary  
20 conclusion that this amount "should be shared between ratepayers and shareholders."  
21 (Recommended Order. at 133.)

22 This issue becomes moot if the Commission concurs with APS that the RWT outages  
23 were not the result of imprudence. However, if the Commission agrees with the  
24 Recommended Order that these outages were caused by APS imprudence, APS is entitled to  
25 offset from the replacement power costs incurred during those outages the entire \$5,100,000  
26 because, as the Recommended Order recognizes (*Id.*), it performed prudent maintenance  
27 during the Unit 2 October RWT outage that prevented a later outage. (APS Initial Brief at  
28 157-59). The Recommended Order provides no reason for splitting this amount, and no party

1 to this proceeding has even proposed this as an option. The \$5,100,000 should be treated the  
2 same as the costs of any other prudent outage. Disallowing recovery of any of these costs is  
3 inappropriate because APS is entitled to recover all prudent costs deferred under the PSA.  
4 (Recommended Order at 111.)

5 Even if the Commission were to agree with the Recommended Order and split the  
6 \$5,100,000 amount in half, the Recommended Order still must be changed to correct a  
7 typographical error in its calculations. (*Id.* at 133.) The Recommended Order incorrectly uses  
8 the value of \$2,250,000 for this offset instead of \$2,550,000. Therefore, simply fixing the  
9 typographical error decreases the Recommended Order's disallowance from \$13.610 million  
10 (plus interest of \$0.326 million) to \$13.310 million (plus interest). Properly applying the  
11 entire amount of \$5,100,000 to the Recommended Order's disallowance yields a  
12 disallowance of \$10.760 million (plus interest). However, this number remains incorrect  
13 because of other errors contained in the Recommended Order as discussed below.

14 *B. Disallowance For Lost Off-System Sales Margins.*

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

20 At the hearing, Staff's own witness, Dr. Jacobs, admitted that his calculation for lost  
21 off-system sales margins, which resulted in a disallowance of \$2,103,000<sup>24</sup>, was inaccurate,  
22 because it makes the erroneous conclusion that every megawatt hour of power that could have  
23 been produced by Palo Verde would have been sold. (Tr. Vol. XXIX at 5303-04 [Jacobs].)  
24 APS presented its own calculation (APS Initial Brief at 177-78) using a methodology which  
25 the Recommended Order admits "has been used by the Commission in the past," which  
26

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27 <sup>24</sup> All of the disallowances for lost off-system sales margins in this section assume that the Commission concludes that  
28 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.

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

8 If the appropriate disallowance for lost off-system sales margins is used, then the  
9 disallowance (offsetting the full \$5.1 million for prudent maintenance) of \$10.760 million is  
10 further reduced to \$8.979 million (plus interest).<sup>26</sup>

11 *C. Offset For Costs Already Expensed.*

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

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

22  
23 <sup>25</sup> Even if the Commission were to give credence to Dr. Jacobs' claimed discrepancies, this would only increase the lost  
24 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.)

25 <sup>26</sup> In addition to the option of concluding that the August reactor trip and the October RWT outages are either all  
26 prudent or all imprudent, the Commission could conclude that only one of the outages was imprudent. If the Commission  
27 concludes that the August reactor trip was imprudent, but the October RWT outages were prudent, then the appropriate  
28 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.)

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

3 APS takes exception to the Recommended Order's rejection of an offset for superior  
4 coal plant performance. (Recommended Order at 133.) The Recommended Order's  
5 conclusion that "improved coal performance has nothing to do with the Palo Verde outages"  
6 (*Id.*) fails to recognize that APS customers are impacted by the performance of the entire APS  
7 baseload generation system. (APS Initial Brief at 149; APS Reply Brief at 46.) As Mr. Ewen  
8 testified, the Company's coal plants set an all-time high for capacity factor in 2005. (APS  
9 Exhibit No. 17 at 25 [Ewen].) The plants had 40 percent less unplanned outage time than the  
10 normalized amount included in the Company's base rates, and this "better than normal"  
11 performance reduced fuel costs by \$10,000,000. (*Id.*) As Mr. Ewen explained further at the  
12 hearing, had the coal plants not performed so well, there would have been 300 gigawatt hours  
13 more of unplanned outages that would have had to have been replaced at a cost of  
14 \$10,000,000. (Tr. Vol. XXVIII at 5223 [Ewen].) That \$10,000,000 savings is not reflected in  
15 the replacement power costs for Palo Verde, and thus, it is an appropriate offset to these  
16 costs. (*Id.* at 5222 [Ewen].) Therefore, this amount should be deducted from any disallowed  
17 costs. Offsetting the Palo Verde outages based on excellent coal plant performance is  
18 consistent with the principle that "a realistic analysis of operating performance must look at  
19 both the 'successes' and the 'failures' if it is to avoid setting unobtainable goals of absolute  
20 perfection." (Decision No. 55118 (July 24, 1986).) Since the \$10,000,000 is larger than the  
21 amount of \$8.464 million calculated above, the entire disallowance is offset. Similarly,  
22 comparing APS's outstanding 2005 coal plant performance against its industry peers results  
23 in an even more dramatic savings of \$27,492,000, which would offset the entire disallowance  
24 proposed by Staff and the Recommended Order. (APS Exhibit 91 at 13 [Fitzpatrick].) APS  
25 Proposed Amendments Nos. 33 and 36 makes these modifications.

26 5. A Performance Standard is Unnecessary and Inappropriate, but if One is Ultimately  
27 Adopted, it Should Include All Baseload Plants.

28 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

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

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

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

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

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

28

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

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

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

18 The second and third reports recommended by GDS are an evaluation of APS's  
19 "programs to deal with aging equipment at Palo Verde" and "programs for receipt inspection  
20 and verification of parts prior to installation," including evaluation of "programs established  
21 at other nuclear plants that have been successful" with these issues. (*Id.* at 112-13.) In  
22 response to a data request, GDS stated that it had not identified specific plants with successful  
23 programs in these areas, but suggested that APS contact INPO for a list of such plants. (APS  
24 Exhibit No. 94 at 31 [Levine].) APS remains willing to provide these reports but wishes to  
25 make clear that the content of these reports will be dependent upon the results of any  
26 information received from INPO. APS Proposed Amendment No. 34 makes these  
27 modifications.  
28

1 RESPECTFULLY SUBMITTED this 15<sup>th</sup> day of May, 2007.

2 PINNACLE WEST CAPITAL CORPORATION  
3 LAW DEPARTMENT

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5 Thomas L. Mumaw  
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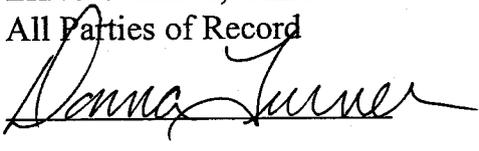
15  
16 ORIGINAL and thirteen (13) copies  
17 of the foregoing filed this 15th day of  
18 May, 2007, with:

19 Docket Control  
20 ARIZONA CORPORATION COMMISSION  
21 1200 West Washington Street  
22 Phoenix, Arizona 85007

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

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

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

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## ATTACHMENT A

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**FINANCIAL INTEGRITY**

**APS PROPOSED AMENDMENT # 1**

**Cost of Equity**

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.<sup>1</sup> 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.<sup>2</sup> So has this

---

<sup>1</sup> See, *Scates*.

<sup>2</sup> (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<sup>3</sup> 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

---

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 & Pools [sic].").

<sup>3</sup> *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].)<sup>4</sup>

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

---

<sup>4</sup> 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 Earns 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.<sup>5</sup> 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.<sup>6</sup> So has this

---

<sup>5</sup> See, *Scates*.

<sup>6</sup> (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<sup>7</sup> 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].)<sup>8</sup>

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*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].").

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

<sup>8</sup> 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 Earns 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.<sup>9</sup> 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.<sup>10</sup> So has

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<sup>9</sup> See, *Scates*.

<sup>10</sup> (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<sup>11</sup> 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].)<sup>12</sup>

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*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].").

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

<sup>12</sup> 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 Earns 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.<sup>13</sup> 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.<sup>14</sup> So has

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<sup>13</sup> See, *Scates*.

<sup>14</sup> (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<sup>15</sup> 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:

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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].").

<sup>15</sup> *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

### Stock Incentive Compensation

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;<sup>16</sup> 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;<sup>17</sup> 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.<sup>18</sup> 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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<sup>16</sup> 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).

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

<sup>18</sup> 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<sup>19</sup> 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.

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<sup>19</sup> 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.

**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**

**Application of RES Rules**

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**

**If the Commission Determines the August Reactor Trip and the October RWT were Imprudent**

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.

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## 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.

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## 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

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ATTACHMENT D

	APS Direct			ALJ Recommended Order		ALJ Recommended Order with Conservation Removed		APS Rejoinder		APS Rejoinder with Conservation Removed	
	Actual 2005 Test Year	APS Direct Case 11/30/2005 Market Prices	Direct Case F&PP Pro Forma Adjustment	Adjusted Direct Case	Change From APS Direct Case	Adjusted Direct Case Recommendation	Change From ALJ Recommendation	APS Rejoinder Case 9/29/2006 Market Prices	Rejoinder F&PP Pro Forma Adjustment	Adjusted Rejoinder Case	Change from Rejoinder Case
<b>FUEL AND PURCHASED POWER:</b>											
1. Retail Expense (\$/kwh)	2,6983 <sup>1/</sup>	3,2859 <sup>8/</sup>	0,5876	3,2156	(0,0703)	3,2181	0,0025	3,2702 <sup>13/</sup>	0,5719	3,2821	0,0119
2. Test Year Retail Sales (Unadjusted -- MWH)	26,088,197 <sup>2/</sup>	29,281 <sup>9/</sup>	940,929	29,281	(20,557)	29,276	15	29,480 <sup>14/</sup>	259,467	29,589	129
3. Native Load Sales (GWH)	703,938	961,486		940,929	(20,557)	942,129	1,200	963,405		971,145	7,740
4. F&PP Expense on Unadjusted TY Sales											
5. Adjusted TY Retail Sales (MWH)	26,759,478 <sup>3/</sup>	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) <sup>4/</sup>		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
<b>OFF SYSTEM MARGIN:</b>											
9. Off System Expense	75,344 <sup>5/</sup>	127,134 <sup>10/</sup>	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 <sup>6/</sup>	153,098 <sup>11/</sup>	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) <sup>15/</sup>	(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)	2,7070 <sup>7/</sup>	3,1904 <sup>12/</sup>	0,4895	3,1202	(0,0703)	3,1226	0,0025	3,2491 <sup>16/</sup>	0,5481	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\_1R1.  
14/ Rejoinder Workpapers of Pete Ewen, PME\_WPIR1J.  
15/ Rejoinder Workpapers of Pete Ewen, PME\_WPIR1J.  
16/ Rejoinder Testimony of Pete Ewen, page 2.

ATTACHMENT E

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 <sup>11</sup> (\$000)	(F) Proposed Rate Designation	(G) Base Revenues (\$000)	(H) Amount (\$000)	(I) % (H) / (E)	Line No.
1	Residential									1
2	E-10	78,292	750,189	9,582	68,276	E-10	82,965	14,089	20.64%	2
3	E-12	411,939	3,781,967	9,181	373,352	E-12	412,728	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	328,062	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	888,460	12,405,859	13,995	1,092,047		1,240,651	148,504	13.60%	7
8	General Service									8
9	E-20	349	39,717	113,002	3,596	E-20	3,659	63	1.75%	9
10	E-21	25	1,631	65,240	133	E-21	186	53	38.86%	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	11,159	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	1,646	616,000	144	E-32TOU	185	51	35.42%	16
17	E-34	38	1,189,008	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	8,778	198,523	620	E-38, E-38-8T, E-38TOW	674	54	8.71%	23
24	E-221, E-221-8T, E-221TOW	1,422	283,660	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	687	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.

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

ATTACHMENT E

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

Line No.	Rate Schedule	Description	Billing Designation	Season	(E) Present Rates		(G) Present Rates		Block	(H) Proposed Rates		Change (J) - (E)	Line No.
					(C) Rate	(D) Minimum	(F) Rate	(I) Rate		(J) Rate	(K) Rate		
30	ET-1	Residential Service	Rate	Summer	\$ 0.493 /day		\$ 0.493 /day		Basic Service Charge	0.49300 /day	\$ -	30	
31		Time of Use			0.13310 /kWh		0.13310 /kWh		All On-Peak kWh	0.15570 /kWh	0.02260 /kWh	31	
32					0.04299 /kWh		0.04299 /kWh		All Off-Peak kWh	0.05032 /kWh	0.00733 /kWh	32	
33				Winter	\$ 0.493 /day		\$ 0.493 /day		Basic Service Charge	0.49300 /day	\$ -	33	
34					0.10918 /kWh		0.10918 /kWh		All On-Peak kWh	0.12650 /kWh	0.01732 /kWh	34	
35					\$ 0.04167 /kWh		\$ 0.04167 /kWh		All Off-Peak kWh	0.04850 /kWh	0.00683 /kWh	35	
36				Sum & Win	\$ 0.493 /day		\$ 0.493 /day		Basic Service Charge	0.493 /day	\$ -	36	
37	ET-2	Residential Service	Rate	Summer	0.493 /day		0.493 /day		Basic Service Charge	0.493 /day	\$ -	37	
38		Time of Use			0.18200 /kWh		0.18200 /kWh		All On-Peak kWh	0.21272 /kWh	0.03072 /kWh	38	
39					0.04519 /kWh		0.04519 /kWh		All Off-Peak kWh	0.05331 /kWh	0.00812 /kWh	39	
40				Winter	0.493 /day		0.493 /day		Basic Service Charge	0.493 /day	\$ -	40	
41					0.08703 /kWh		0.08703 /kWh		All On-Peak kWh	0.17250 /kWh	0.08547 /kWh	41	
42					\$ 0.05783 /kWh		\$ 0.05783 /kWh		All Off-Peak kWh	0.05330 /kWh	(0.00453) /kWh	42	
43				Sum & Win	0.493 /day		0.493 /day		Basic Service Charge	0.493 /day	\$ -	43	
44	ECT-1R	Residential Service	Rate	Summer	\$ 0.493 /day		\$ 0.493 /day		Basic Service Charge	0.493 /day	\$ -	44	
45		Time of Use with			11.81 /kW		11.81 /kW		All On-Peak kW	11.86000 /kW	0.05 /kW	45	
46		Demand Charge			0.04765 /kWh		0.04765 /kWh		All On-Peak kWh	0.06470 /kWh	0.01705 /kWh	46	
47					0.02672 /kWh		0.02672 /kWh		All Off-Peak kWh	0.03618 /kWh	0.00946 /kWh	47	
48				Winter	\$ 0.493 /day		\$ 0.493 /day		Basic Service Charge	0.493 /day	\$ -	48	
49					8.11 /kW		8.11 /kW		All On-Peak kW	8.15000 /kW	0.04 /kW	49	
50					0.03641 /kWh		0.03641 /kWh		All On-Peak kWh	0.04882 /kWh	0.01241 /kWh	50	
51					0.02570 /kWh		0.02570 /kWh		All Off-Peak kWh	0.03456 /kWh	0.00886 /kWh	51	
52				Sum & Win	\$ 0.493 /day		\$ 0.493 /day		Basic Service Charge	0.493 /day	\$ -	52	
53	ECT-2	Residential Service	Rate	Summer	0.493 /day		0.493 /day		Basic Service Charge	0.493 /day	\$ -	53	
54		Time of Use with			11.81 /kW		11.81 /kW		All On-Peak kW	11.87000 /kW	0.06 /kW	54	
55		Demand Charge			0.05690 /kWh		0.05690 /kWh		All On-Peak kWh	0.07680 /kWh	0.01996 /kWh	55	
56					0.02792 /kWh		0.02792 /kWh		All Off-Peak kWh	0.03790 /kWh	0.00998 /kWh	56	
57				Winter	0.493 /day		0.493 /day		Basic Service Charge	0.493 /day	\$ -	57	
58					8.11 /kW		8.11 /kW		All On-Peak kW	8.15000 /kW	0.04 /kW	58	
59					0.03730 /kWh		0.03730 /kWh		All On-Peak kWh	0.05050 /kWh	0.01322 /kWh	59	
60					0.02733 /kWh		0.02733 /kWh		All Off-Peak kWh	0.03710 /kWh	0.00978 /kWh	60	
61				Sum & Win	0.493 /day		0.493 /day		Basic Service Charge	0.493 /day	\$ -	61	

Supporting Schedules:  
N/A

Recap Schedules:  
N/A

**NOTES TO SCHEDULE:**

- Proposed rates are shown on a bundled basis. See tariff sheets for unbundled components.
- 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**

Line No.	Rate Schedule	Description	Billing Designation	Season	Present Rates		Proposed Rates		Change (J) - (E)	Line No.
					(E)	(F)	(G)	(H)		
62	E-20	General Service	Rate	Summer	\$ 0.941 /day	\$ 0.941 /day	\$ 0.941 /day	\$ -	0.03 /kW	62
63		Time of Use for Religious Houses of Worship	Rate	Summer	2.046 /kW	2.080 /kW	2.080 /kW	0.03 /kW	0.07500 /kWh	63
64			Rate	Summer	1.023 /kW	1.098 /kW	1.098 /kW	0.07500 /kWh	0.00211 /kWh	64
65			Rate	Summer	0.12305 /kWh	0.12516 /kWh	0.12516 /kWh	0.00211 /kWh	0.00101 /kWh	65
66			Rate	Summer	0.05943 /kWh	0.06044 /kWh	0.06044 /kWh	0.00101 /kWh		66
67			Rate	Winter	\$ 0.941 /day	\$ 0.941 /day	\$ 0.941 /day	\$ -	0.03 /kW	67
68			Rate	Winter	1.846 /kW	1.880 /kW	1.880 /kW	0.03 /kW	0.01700 /kWh	68
69			Rate	Winter	0.923 /kW	0.940 /kW	0.940 /kW	0.01700 /kWh	0.00186 /kWh	69
70			Rate	Winter	0.10820 /kWh	0.11006 /kWh	0.11006 /kWh	0.00186 /kWh	0.00091 /kWh	70
71			Rate	Winter	0.05327 /kWh	0.05418 /kWh	0.05418 /kWh	0.00091 /kWh		71
72			Minimum	Sum & Win	\$ 0.685 /day	\$ 0.685 /day	\$ 0.685 /day	\$ 0.256 /day	0.03 /kW	72
73			Minimum	Sum & Win	1.67 /kW	1.67 /kW	1.699 /kW	0.03 /kW		73
74	E-21	General Service	Rate	Summer	\$ 0.925 /day	\$ 0.925 /day				74
75		Time of Use Less Than 100 kW	Rate	Summer	2.010 /kW	2.010 /kW				75
76			Rate	Summer	1.005 /kW	1.005 /kW				76
77			Rate	Summer	0.12097 /kWh	0.12097 /kWh				77
78			Rate	Summer	0.05843 /kWh	0.05843 /kWh				78
79			Rate	Winter	\$ 0.925 /day	\$ 0.925 /day				79
80			Rate	Winter	1.810 /kW	1.810 /kW				80
81			Rate	Winter	0.905 /kW	0.905 /kW				81
82			Rate	Winter	0.10638 /kWh	0.10638 /kWh				82
83			Rate	Winter	0.05237 /kWh	0.05237 /kWh				83
84			Minimum	Sum & Win	\$ 0.685 /day	\$ 0.685 /day				84
85			Minimum	Sum & Win	1.67 /kW	1.67 /kW				85
86	E-22	Small General Service	Rate	Summer	\$ 0.925 /day	\$ 0.925 /day				86
87		Time of Use	Rate	Summer	2.230 /kW	2.230 /kW				87
88			Rate	Summer	1.115 /kW	1.115 /kW				88
89			Rate	Summer	0.12125 /kWh	0.12125 /kWh				89
90			Rate	Summer	0.07475 /kWh	0.07475 /kWh				90
91			Rate	Winter	\$ 0.925 /day	\$ 0.925 /day				91
92			Rate	Winter	2.020 /kW	2.020 /kW				92
93			Rate	Winter	1.010 /kW	1.010 /kW				93
94			Rate	Winter	0.10285 /kWh	0.10285 /kWh				94
95			Rate	Winter	0.06430 /kWh	0.06430 /kWh				95
96			Minimum	Sum & Win	\$ 0.685 /day	\$ 0.685 /day				96
97			Minimum	Sum & Win	1.67 /kW	1.67 /kW				97

RATE E-21 CANCELLED;  
CUSTOMERS MOVED TO E-32TOU

RATE E-22 CANCELLED;  
CUSTOMERS MOVED TO E-32TOU

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**

Line No.	Rate Schedule	Description	Billing Designation	Season	Present Rates		Proposed Rates		Change (J) - (E)	Line No.
					Block	Rate	Block	Rate		
98	E-23	Medium General Service	Rate	Summer		\$ 1.988 /day				98
99		Time of Use	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			Basic Service Charge	Winter		\$ 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			Basic Service Charge	Sum & Win		\$ 0.685 /day				108
109			Demand Charge			1.67 /KW				109
100	E-24	Large General Service	Rate	Summer		\$ 34.271 /day				100
101		Time of Use	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			Basic Service Charge	Winter		\$ 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			Basic Service Charge	Sum & Win		\$ 0.685 /day				110
111			Demand Charge			1.67 /KW				111
102	E-30	Extra Small General	Rate	Summer		\$ 0.275 /day				102
103		Service Unmetered	All kWh			0.09684 /kWh				103
105			Basic Service Charge	Winter		\$ 0.275 /day				105
106			All kWh			0.08724 /kWh				106

RATE E-23 CANCELLED;  
CUSTOMERS MOVED TO E-32TOU

RATE E-24 CANCELLED;  
CUSTOMERS MOVED TO E-32TOU

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**

Line No.	Rate Schedule	Description	Billing Designation	Season	Present Rates		Proposed Rates		Change (J) - (E)	Line No.
					Block	Rate	Block	Rate		
107	E-32	General Service	Rate	Summer	BSC: Self-Contained Meters	\$ 0.575 /day	BSC: Self-Contained Meters	\$ 0.575 /day	\$ -	107
108		20 kW or Less			BSC: Instrument-rated Meters	1.134 /day	BSC: Instrument-rated Meters	1.134 /day	-	108
109					BSC: Primary Meters	2.926 /day	BSC: Primary Meters	2.926 /day	-	109
110					BSC: Transmission Meters	22.422 /day	BSC: Transmission Meters	22.422 /day	-	110
111					First 5,000 kWh: Secondary	0.09892 /kWh	First 5,000 kWh: Secondary	0.11293 /kWh	0.01401	111
112					All remaining kWh: Secondary	0.04711 /kWh	All remaining kWh: Secondary	0.06161 /kWh	0.01450	112
113					First 5,000 kWh: Primary	0.09610 /kWh	First 5,000 kWh: Primary	0.11015 /kWh	0.01405	113
114					All remaining kWh: Primary	0.04429 /kWh	All remaining kWh: Primary	0.05883 /kWh	0.01454	114
115				Winter	BSC: Self-Contained Meters	\$ 0.575 /day	BSC: Self-Contained Meters	\$ 0.575 /day	\$ -	115
116					BSC: Instrument-rated Meters	1.134 /day	BSC: Instrument-rated Meters	1.134 /day	-	116
117					BSC: Primary Meters	2.926 /day	BSC: Primary Meters	2.926 /day	-	117
118					BSC: Transmission Meters	22.422 /day	BSC: Transmission Meters	22.422 /day	-	118
119					First 5,000 kWh: Secondary	0.08892 /kWh	First 5,000 kWh: Secondary	0.09813 /kWh	0.00921	119
120					All remaining kWh: Secondary	0.03711 /kWh	All remaining kWh: Secondary	0.04681 /kWh	0.00970	120
121					First 5,000 kWh: Primary	0.08610 /kWh	First 5,000 kWh: Primary	0.09535 /kWh	0.00925	121
122					All remaining kWh: Primary	0.03429 /kWh	All remaining kWh: Primary	0.04403 /kWh	0.00974	122
123				Sum & Win	BSC: Self-Contained Meters	\$ 0.575 /day	BSC: Self-Contained Meters	\$ 0.575 /day	\$ -	123
124					BSC: Instrument-rated Meters	1.134 /day	BSC: Instrument-rated Meters	1.134 /day	-	124
125					BSC: Primary Meters	2.926 /day	BSC: Primary Meters	2.926 /day	-	125
126					BSC: Transmission Meters	22.422 /day	BSC: Transmission Meters	22.422 /day	-	126
127		General Service	Rate	Summer	BSC: Self-Contained Meters	\$ 0.575 /day	BSC: Self-Contained Meters	\$ 0.575 /day	\$ -	127
128		Above 20 kW			BSC: Instrument-rated Meters	1.134 /day	BSC: Instrument-rated Meters	1.134 /day	-	128
129					BSC: Primary Meters	2.926 /day	BSC: Primary Meters	2.926 /day	-	129
130					BSC: Transmission Meters	22.422 /day	BSC: Transmission Meters	22.422 /day	-	130
131					First 100 kW: Secondary	7.722 /kW	First 100 kW: Secondary	8.477 /kW	0.755	131
132					All remaining kW: Secondary	3.497 /kW	All remaining kW: Secondary	4.509 /kW	1.012	132
133					First 100 kW: Primary	7.102 /kW	First 100 kW: Primary	7.865 /kW	0.763	133
134					All remaining kW: Primary	2.877 /kW	All remaining kW: Primary	3.897 /kW	1.020	134
135					First 100 kW: Transmission	4.232 /kW	First 100 kW: Transmission	6.132 /kW	1.900	135
136					All remaining kW: Transmission	0.007 /kW	All remaining kW: Transmission	2.157 /kW	2.150	136
137					First 200 kWh per kW	0.07938 /kWh	First 200 kWh per kW	0.08944 /kWh	0.01006	137
138					All remaining kWh	0.04175 /kWh	All remaining kWh	0.05231 /kWh	0.01056	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.

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

**ATTACHMENT E**

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

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

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	(E) Present Rates		(F) Proposed Rates		(H) Block	(I) Rates	(J) - (E) Change	(K) (L)
					Block	Rates	Block	Rates				
183	E-32TOU (cont)	General Service Time of Use 20 kW or Less (cont)	Minimum	Sum & Win	\$ 0.575 /day	\$ 0.608 /day	BSC: Self-Contained Meters	\$ 0.608 /day		\$ 0.033 /day	183	
184					1.134 /day	1.134 /day	BSC: Instrument-rated Meters	1.134 /day		- /day	184	
185					2.926 /day	2.926 /day	BSC: Primary Meters	2.926 /day		- /day	185	
186					22.422 /day	22.422 /day	BSC: Transmission Meters	22.422 /day		- /day	186	
187		General Service Time of Use Above 20 kW	Rate	Summer	\$ 0.575 /day	\$ 0.608 /day	BSC: Self-Contained Meters	\$ 0.608 /day		\$ 0.033 /day	187	
188					1.134 /day	1.134 /day	BSC: Instrument-rated Meters	1.134 /day		- /day	188	
189					2.926 /day	2.926 /day	BSC: Primary Meters	2.926 /day		- /day	189	
190					22.422 /day	22.422 /day	BSC: Transmission Meters	22.422 /day		- /day	190	
191					15.112 /kW	15.112 /kW	First 100 On-Peak kW: Secondary	\$ 12.49800 /kW		(2.614) /kW	191	
192					10.887 /kW	10.887 /kW	All remaining On-Peak kW: Secondary	\$ 8.42300 /kW		(2.464) /kW	192	
193					7.972 /kW	7.972 /kW	First 100 Residual kW: Secondary	\$ 4.75500 /kW		(3.217) /kW	193	
194					3.747 /kW	3.747 /kW	All remaining Residual kW: Secondary	\$ 2.64800 /kW		(1.099) /kW	194	
195					14.492 /kW	14.492 /kW	First 100 On-Peak kW: Primary	\$ 12.00200 /kW		(2.490) /kW	195	
196					10.267 /kW	10.267 /kW	All remaining On-Peak kW: Primary	\$ 8.36100 /kW		(1.906) /kW	196	
197					7.352 /kW	7.352 /kW	First 100 Residual kW: Primary	\$ 2.98100 /kW		(4.371) /kW	197	
198					3.127 /kW	3.127 /kW	All remaining Residual kW: Primary	\$ 2.45900 /kW		(0.668) /kW	198	
199					11.622 /kW	11.622 /kW	First 100 On-Peak kW: Transmission	\$ 11.29100 /kW		(0.331) /kW	199	
200					7.397 /kW	7.397 /kW	All remaining On-Peak kW: Transmission	\$ 8.11600 /kW		0.719 /kW	200	
201					4.482 /kW	4.482 /kW	First 100 Residual kW: Transmission	\$ 3.69300 /kW		(0.789) /kW	201	
202					0.257 /kW	0.257 /kW	All remaining Residual kW: Transmission	\$ 2.48600 /kW		2.229 /kW	202	
203					0.04815 /kWh	0.04815 /kWh	All On-Peak kWh:	\$ 0.06166 /kWh		0.01351 /kWh	203	
204					0.03815 /kWh	0.03815 /kWh	All Off-Peak kWh:	\$ 0.04870 /kWh		0.01055 /kWh	204	
205			Winter		\$ 0.575 /day	\$ 0.608 /day	BSC: Self-Contained Meters	\$ 0.608 /day		\$ 0.033 /day	205	
206					1.134 /day	1.134 /day	BSC: Instrument-rated Meters	\$ 1.13400 /day		- /day	206	
207					2.926 /day	2.926 /day	BSC: Primary Meters	\$ 2.92600 /day		- /day	207	
208					22.422 /day	22.422 /day	BSC: Transmission Meters	\$ 22.42200 /day		- /day	208	
209					15.112 /kW	15.112 /kW	First 100 On-Peak kW: Secondary	\$ 12.49800 /kW		(2.614) /kW	209	
210					10.887 /kW	10.887 /kW	All remaining On-Peak kW: Secondary	\$ 8.42300 /kW		(2.464) /kW	210	
211					7.972 /kW	7.972 /kW	First 100 Residual kW: Secondary	\$ 4.75500 /kW		(3.217) /kW	211	
212					3.747 /kW	3.747 /kW	All remaining Residual kW: Secondary	\$ 2.64800 /kW		(1.099) /kW	212	
213					14.492 /kW	14.492 /kW	First 100 On-Peak kW: Primary	\$ 12.00200 /kW		(2.490) /kW	213	
214					10.267 /kW	10.267 /kW	All remaining On-Peak kW: Primary	\$ 8.36100 /kW		(1.906) /kW	214	
215					7.352 /kW	7.352 /kW	First 100 Residual kW: Primary	\$ 2.98100 /kW		(4.371) /kW	215	
216					3.127 /kW	3.127 /kW	All remaining Residual kW: Primary	\$ 2.45900 /kW		(0.668) /kW	216	
217					11.622 /kW	11.622 /kW	First 100 On-Peak kW: Transmission	\$ 11.29100 /kW		(0.331) /kW	217	
218					7.397 /kW	7.397 /kW	All remaining On-Peak kW: Transmission	\$ 8.11600 /kW		0.719 /kW	218	
219					4.482 /kW	4.482 /kW	First 100 Residual kW: Transmission	\$ 3.69300 /kW		(0.789) /kW	219	
220					0.257 /kW	0.257 /kW	All remaining Residual kW: Transmission	\$ 2.48600 /kW		2.229 /kW	220	
221					0.03822 /kWh	0.03822 /kWh	All On-Peak kWh:	\$ 0.04725 /kWh		0.00903 /kWh	221	
222					0.02822 /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**  
**TEST YEAR ENDING SEPTEMBER 30, 2005**

**ATTACHMENT E**

Line No.	Rate Schedule	Description	Billing Designation	Season	Present Rates		Proposed Rates		Change (J) - (E)	Line No.
					(E)	(F)	(G)	(H)		
223	E-32TOU (cont)	General Service	Minimum	Sum & Win	\$ 0.575 /day	\$ 0.575 /day	\$ 0.608 /day	\$ 0.033 /day	223	
224		Time of Use			1.134 /day	1.134 /day	1.134 /day	- /day	224	
225		Above 20 kW (cont)			2.926 /day	2.926 /day	2.926 /day	- /day	225	
226					22.422 /day	22.422 /day	22.422 /day	- /day	226	
227					1.66 /kW	1.66 /kW	1.99 /kW	0.33 /kW	227	
228	E-34	Extra Large General Service	Rate	Sum & Win	\$ 0.575 /day	\$ 0.575 /day	\$ 0.575 /day	- /day	228	
229					1.134 /day	1.134 /day	1.134 /day	- /day	229	
230					2.926 /day	2.926 /day	2.926 /day	- /day	230	
231					22.422 /day	22.422 /day	22.422 /day	- /day	231	
232					12.343 /kW	12.343 /kW	14.4010 /kW	2.058 /kW	232	
233					11.683 /kW	11.683 /kW	11.15100 /kW	(0.532) /kW	233	
234					8.943 /kW	8.943 /kW	8.41100 /kW	(0.532) /kW	234	
235					8.043 /kW	8.043 /kW	\$ 10.4710 /kW	2.428 /kW	235	
236					0.03183 /kWh	0.03183 /kWh	0.040170 /kWh	0.00834 /kWh	236	
237					\$ 0.575 /day	\$ 0.575 /day	\$ 0.575 /day	- /day	237	
238					1.134 /day	1.134 /day	1.134 /day	- /day	238	
239					2.926 /day	2.926 /day	2.926 /day	- /day	239	
240					22.422 /day	22.422 /day	22.422 /day	- /day	240	
241					12.343 /kW	12.343 /kW	14.40100 /kW	2.058 /kW	241	
242					11.683 /kW	11.683 /kW	11.15100 /kW	(0.532) /kW	242	
243					8.943 /kW	8.943 /kW	8.41100 /kW	(0.532) /kW	243	
244					8.043 /kW	8.043 /kW	10.47100 /kW	2.428 /kW	244	
245	E-35	Extra Large General Service	Rate	Sum & Win	\$ 0.575 /day	\$ 0.575 /day	\$ 0.608 /day	\$ 0.033 /day	245	
246		Time Of Use			1.134 /day	1.134 /day	1.134 /day	- /day	246	
247					2.926 /day	2.926 /day	2.926 /day	- /day	247	
248					22.422 /day	22.422 /day	22.422 /day	- /day	248	
249					12.869 /kW	12.869 /kW	\$ 13.313 /kW	0.444 /kW	249	
250					6.388 /kW	6.388 /kW	\$ 2.412 /kW	(3.976) /kW	250	
251					12.209 /kW	12.209 /kW	\$ 12.653 /kW	0.444 /kW	251	
252					5.728 /kW	5.728 /kW	\$ 2.346 /kW	(3.3820) /kW	252	
253					9.469 /kW	9.469 /kW	\$ 10.187 /kW	0.718 /kW	253	
254					5.728 /kW	5.728 /kW	\$ 2.099 /kW	(3.6290) /kW	254	
255					8.569 /kW	8.569 /kW	\$ 9.248 /kW	0.679 /kW	255	
256					2.088 /kW	2.088 /kW	\$ 2.005 /kW	(0.083) /kW	256	
257					0.03529 /kWh	0.03529 /kWh	0.03978 /kWh	0.00449 /kWh	257	
258					0.02792 /kWh	0.02792 /kWh	0.02994 /kWh	0.00202 /kWh	258	
259					\$ 0.575 /day	\$ 0.575 /day	\$ 0.608 /day	\$ 0.033 /day	259	
260					1.134 /day	1.134 /day	1.134 /day	- /day	260	
261					2.926 /day	2.926 /day	2.926 /day	- /day	261	
262					22.422 /day	22.422 /day	22.422 /day	- /day	262	
263					12.869 /kW	12.869 /kW	13.3130 /kW	0.444 /kW	263	
264					12.209 /kW	12.209 /kW	12.6530 /kW	0.444 /kW	264	
265					9.469 /kW	9.469 /kW	10.1870 /kW	0.718 /kW	265	
266					8.569 /kW	8.569 /kW	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  
CHANGES IN REPRESENTATIVE RATE SCHEDULES  
COMPARISON OF PRESENT AND PROPOSED RATES  
TEST YEAR ENDING SEPTEMBER 30, 2005**

ATTACHMENT E

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

RATE E-38 CANCELLED;  
CUSTOMERS MOVED TO RATE E-221

RATE E-38-8T CANCELLED;  
CUSTOMERS MOVED TO RATE E-221-8T

Supporting Schedules:

N/A

Recap Schedules:

N/A

NOTES TO SCHEDULE:

- Proposed rates are shown on a bundled basis. See tariff sheets for unbundled components.
- 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**

Line No.	Rate Schedule	(A)	(B) Description	(C) Billing Designation	(D) Season	Present Rates		Proposed Rates		(K) Change (J) - (E)	Line No.
						(E) Block	(F) Rates	(H) Block	(J) Rates		
299	E-47		Dusk to Dawn Lighting Service		Sum & Win						299
300							\$ 20.27 /mo		\$ 23.79 /mo	\$ 3.52 /mo	300
301							22.45 /mo		26.40 /mo	3.95 /mo	301
302							13.79 /mo		13.51 /mo	(0.28) /mo	302
303							16.03 /mo		15.79 /mo	(0.24) /mo	303
304							18.93 /mo		18.73 /mo	(0.20) /mo	304
305							23.24 /mo		23.11 /mo	(0.13) /mo	305
306							19.07 /mo		18.91 /mo	(0.16) /mo	306
307							21.58 /mo		21.46 /mo	(0.12) /mo	307
308							25.87 /mo		26.84 /mo	0.97 /mo	308
309							19.83 /mo		19.64 /mo	(0.19) /mo	309
310							23.30 /mo		23.17 /mo	(0.13) /mo	310
311							26.55 /mo		26.46 /mo	(0.09) /mo	311
312							30.59 /mo		31.84 /mo	1.25 /mo	312
313							8.03 /mo		7.88 /mo	(0.15) /mo	313
314							9.37 /mo		9.03 /mo	(0.34) /mo	314
315							11.62 /mo		11.32 /mo	(0.30) /mo	315
316							13.91 /mo		13.64 /mo	(0.27) /mo	316
317							18.70 /mo		18.51 /mo	(0.19) /mo	317
318							10.96 /mo		13.15 /mo	2.19 /mo	318
319							12.76 /mo		15.38 /mo	2.62 /mo	319
320							16.67 /mo		20.24 /mo	3.57 /mo	320
321							13.03 /mo		15.12 /mo	2.09 /mo	321
322							27.63 /mo		32.80 /mo	4.97 /mo	322
323							31.57 /mo		37.32 /mo	5.75 /mo	323
324							17.60 /mo		18.11 /mo	0.51 /mo	324
325							21.72 /mo		22.46 /mo	0.74 /mo	325
326							15.94 /mo		19.33 /mo	3.39 /mo	326
327							19.35 /mo		23.57 /mo	4.22 /mo	327
328							14.01 /mo		16.29 /mo	2.28 /mo	328
329							9.65 /mo		9.32 /mo	(0.33) /mo	329
330							11.03 /mo		10.73 /mo	(0.30) /mo	330
331							24.24 /mo		28.54 /mo	4.30 /mo	331
332							12.91 /mo		8.60 /mo	(4.31) /mo	332
333							12.56 /mo		11.14 /mo	(1.42) /mo	333
334							17.43 /mo		21.91 /mo	4.48 /mo	334
335							1.26 /mo		1.51 /mo	0.25 /mo	335
336											336
337							\$ 5.00 /mo		\$ 8.10 /mo	\$ 3.10 /mo	337
338							6.71 /mo		10.24 /mo	3.53 /mo	338

**FIXTURES (Company Owned)**  
**A. Acorn 9,500 HPS**  
 Acorn 16,000 HPS  
**B. Architectural 9,500 HPS**  
 Architectural 16,000 HPS  
 Architectural 30,000 HPS  
 Architectural 50,000 HPS  
 Architectural 14,000 MH  
 Architectural 21,000 MH  
 Architectural 36,000 MH  
 Architectural 8,000 LPS  
 Architectural 13,500 LPS  
 Architectural 22,500 LPS  
 Architectural 33,000 LPS  
**C. Cobra/Roadway 5,800 HPS**  
 Cobra/Roadway 9,500 HPS  
 Cobra/Roadway 16,000 HPS  
 Cobra/Roadway 30,000 HPS  
 Cobra/Roadway 50,000 HPS  
 Cobra/Roadway 14,000 MH  
 Cobra/Roadway 21,000 MH  
 Cobra/Roadway 36,000 MH  
 Cobra/Roadway 8,000 FL  
 Decorative Transit 9,500 HPS  
**D. Decorative Transit 30,000 HPS**  
 Flood 30,000 HPS  
 Flood 50,000 HPS  
 Flood 21,000 MH  
 Flood 36,000 MH  
 Post Top gray 8,000 FL  
 Post Top gray 9,500 HPS  
 Post Top black 9,500 HPS  
 Post Top Transit 9,500 HPS  
**G. FROZEN 4,000 INC**  
 FROZEN 20,000 MV  
 FROZEN 7,000 MV  
 FROZEN Brackets 8ft to 16ft  
**FIXTURES (Customer Owned)**  
 A. Acorn 9,500 HPS  
 Acorn 16,000 HPS

Supporting Schedules: N/A  
 Recap Schedules: N/A  
 Schedule H-3  
 Page 10 of 22

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**

Line No.	Rate Schedule	Description	Billing Designation	Season	Present Rates		Proposed Rates		Change (J) - (E)
					(E)	(F)	(H)	(I)	
339	E-47 (cont)	Dusk to Dawn Lighting Service (cont)		Sum & Win	\$	6.17 /mo	6.44 /mo	0.27 /mo	
340						8.28 /mo	8.62 /mo	0.34 /mo	
341						10.53 /mo	11.08 /mo	0.55 /mo	
342						15.16 /mo	15.93 /mo	0.77 /mo	
343						10.22 /mo	10.36 /mo	0.14 /mo	
344						12.53 /mo	12.78 /mo	0.25 /mo	
345						17.07 /mo	17.57 /mo	0.50 /mo	
346						7.80 /mo	8.62 /mo	0.82 /mo	
347						8.82 /mo	10.41 /mo	1.59 /mo	
348						11.17 /mo	12.70 /mo	1.53 /mo	
349						12.99 /mo	14.96 /mo	1.97 /mo	
350						5.27 /mo	4.54 /mo	(0.73) /mo	
351						6.17 /mo	5.56 /mo	(0.61) /mo	
352						8.28 /mo	7.75 /mo	(0.53) /mo	
353						10.53 /mo	10.07 /mo	(0.46) /mo	
354						14.60 /mo	14.39 /mo	(0.21) /mo	
355						7.97 /mo	8.97 /mo	1.00 /mo	
356						9.78 /mo	11.15 /mo	1.37 /mo	
357						13.32 /mo	15.50 /mo	2.18 /mo	
358						3.58 /mo	4.43 /mo	0.85 /mo	
359						5.00 /mo	9.76 /mo	4.76 /mo	
360						8.54 /mo	14.09 /mo	5.55 /mo	
361						10.94 /mo	11.26 /mo	0.32 /mo	
362						15.16 /mo	15.52 /mo	0.46 /mo	
363						9.78 /mo	11.89 /mo	2.11 /mo	
364						13.32 /mo	16.13 /mo	2.81 /mo	
365						3.58 /mo	4.60 /mo	1.02 /mo	
366						6.17 /mo	5.85 /mo	(0.32) /mo	
367						6.41 /mo	6.05 /mo	(0.36) /mo	
368						5.00 /mo	9.00 /mo	4.00 /mo	
369						5.09 /mo	3.10 /mo	(1.49) /mo	
370						5.09 /mo	6.38 /mo	1.29 /mo	
371						11.51 /mo	12.41 /mo	0.90 /mo	
372									
373									
374						\$	\$		
375						8.68 /mo	10.70 /mo	2.02 /mo	
376						9.80 /mo	12.04 /mo	2.24 /mo	
377						10.63 /mo	13.03 /mo	2.40 /mo	
378						12.25 /mo	14.97 /mo	2.72 /mo	
379						12.88 /mo	15.73 /mo	2.85 /mo	
380						9.27 /mo	11.40 /mo	2.13 /mo	
381						10.69 /mo	13.10 /mo	2.41 /mo	
382						11.16 /mo	13.67 /mo	2.51 /mo	
383						13.01 /mo	15.88 /mo	2.87 /mo	
384						13.90 /mo	16.95 /mo	3.05 /mo	
385						9.99 /mo	12.27 /mo	2.28 /mo	
386						8.90 /mo	10.96 /mo	2.06 /mo	
387						10.60 /mo	13.00 /mo	2.40 /mo	
388						11.68 /mo	14.29 /mo	2.61 /mo	
389						12.50 /mo	15.86 /mo	3.36 /mo	

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**

Line No.	Rate Schedule	Description	Billing Designation	Season	Present Rates		Proposed Rates		Rates	Block	Rates	Change (J) - (E)	Line No.
					(E)	(F)	(G)	(H)					
389	E-47 (cont)	Dusk to Dawn Lighting Service (cont)		Sum & Win									389
390												\$ 2.31 /mo	390
391												\$ 6.28 /mo	391
392												\$ 5.36 /mo	392
393												\$ 5.23 /mo	393
394												\$ 9.87 /mo	394
395												\$ 1.95 /mo	395
396												\$ 2.17 /mo	396
397												\$ 2.33 /mo	397
398												\$ 2.66 /mo	398
399												\$ 2.78 /mo	399
400												\$ 2.07 /mo	400
401												\$ 2.28 /mo	401
402												\$ 2.44 /mo	402
403												\$ 2.81 /mo	403
404												\$ 2.98 /mo	404
405												\$ 3.39 /mo	405
406												\$ 2.21 /mo	406
407												\$ 2.25 /mo	407
408												\$ 2.33 /mo	408
409												\$ 2.54 /mo	409
410												\$ 15.44 /mo	410
411												\$ 2.90 /mo	411
412												\$ 3.42 /mo	412
413												\$ 0.57 /mo	413
414												\$ 0.66 /mo	414
415												\$ 1.49 /mo	415
416												\$ 9.68 /mo	416
417												\$ 0.61 /mo	417
418												\$ 1.10 /mo	418
419												\$ 0.60 /mo	419
420												\$ 0.64 /mo	420
421												\$ 3.67 /mo	421
422												\$ 5.34 /mo	422
423												\$ 0.50 /mo	423
424												\$ 0.59 /mo	424
425												\$ 2.00 /mo	425
426												\$ 0.48 /mo	426
427												\$ 1.85 /mo	427
428												\$ 8.71 /mo	428
429												\$ 10.38 /mo	429
430												\$ 1.71 /mo	430
431												\$ 1.97 /mo	431
432												\$ 8.25 /mo	432
433												\$ 3.08 /mo	433
434												\$ 2.46 /mo	434
435												\$ 5.31 /mo	435
436												\$ 0.88 /mo	436
437												\$ 2.95 /mo	437
438												\$ 0.00921 /kWh	438
439												\$ 0.05577 /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.

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

**ATTACHMENT E**

Line No.	Rate Schedule	Description	Billing Designation	Season	Present Rates		Proposed Rates		Change (J) - (I)	Line No.
					Block	Rates	Block	Rates		
440	E-51	Optional Electric Service for Qualified Cogeneration and Small Power Production Facilities over 100 KW	Basic	Sum & Win	Basic Service Charge	\$ 0.276 /day	Basic Service Charge	\$ 0.276 /day	\$ -	440
441					Generator Meter Charge	0.828 /day	Generator Meter Charge	0.828 /day	-	441
442					Reservation Charge per KW	2.08 /KW	Reservation Charge per KW	2.4980 /KW	0.41 /KW	442
443					Initial Reservation Charge	20.78 /KW	Initial Reservation Charge	24.88 /KW	4.10 /KW	443
444					All On-Peak kWh	0.04602 /KWh	All On-Peak kWh	0.05722 /KWh	0.01120 /KWh	444
445					All Off-Peak kWh	0.02142 /KWh	All Off-Peak kWh	0.03262 /KWh	0.01120 /KWh	445
446					All On-Peak kWh	0.03271 /KWh	All On-Peak kWh	0.04391 /KWh	0.01120 /KWh	446
447					All Off-Peak kWh	0.02142 /KWh	All Off-Peak kWh	0.03262 /KWh	0.01120 /KWh	447
448					All On-Peak kWh	0.02142 /KWh	All On-Peak kWh	0.03262 /KWh	0.01120 /KWh	448
449					All Off-Peak kWh	0.02142 /KWh	All Off-Peak kWh	0.03262 /KWh	0.01120 /KWh	449
450	E-52	Electric Service for Partial Requirements Service of less than 3000 KW	Basic	Sum & Win	Basic Service Charge	\$ 3.51 /day	RATE E-52 CANCELLED NO CURRENT CUSTOMERS			450
451					Generator Meter Charge	0.561 /mo				451
452					Res Charge per KW 90% and above	\$ 5.01 /KW				452
453					Res Charge per KW 80-89%	6.59 /KW				453
454					All On-Peak kWh	0.02961 /KWh				454
455					All Off-Peak kWh	0.01574 /KWh				455
456					All On-Peak kWh	0.02537 /KWh				456
457					All Off-Peak kWh	0.01006 /KWh				457
458					All on-peak kWh	\$ 0.02537 /KWh				458
459					All off-peak kWh	0.01006 /KWh				459
460					C.F. less than 75%	\$ 18.79 /KW				460
461					C.F. less than 75% @ xmsn	14.39 /KW				461
462					Billed on Rate Schedule E-32 or Rate Schedule E-32TOU		NO CHANGE			462
463	E-53	Electric Service for Athletic Stadiums and Sports Fields	Rate	Sum & Win						463
464			Minimum	Sum & Win	No bills rendered when no usage		NO CHANGE			464
465			Rate	Sum & Win	Billed on Rate Schedule E-32 or Rate Schedule E-32TOU					465
466	E-54	Seasonal Service	Rate	Sum & Win	"Floor" Annual Minimum	\$ 603.49 /yr	NO CHANGE			466
467			Minimum	Sum & Win	Monthly Minimum	50.29 /mo				467
468										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.

**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.	Rate Schedule	Description	Billing Designation	Season	Present Rates		Proposed Rates		Change (J) - (I)	Line No.
					(E)	(F)	(G)	(H)		
469	E-55	Electric Service for Partial Requirements Service of 3000 KW or greater	Basic Service	Sum & Win	\$ 54.95 /day					469
470			Generator Meter Charge		2.055 /day					470
471			Res Charge per KW 95% abv		\$ 4.21 /mo					471
472			Res Charge per KW 90-94%		5.14 /mo					472
473			Res Charge per KW 80-89%		6.77 /mo					473
474			All On-Peak kWh	Summer (Jun-Oct)	0.03040 /kWh					474
475			All Off-Peak kWh	Winter (Nov-May)	0.01616 /kWh					475
476			All On-Peak kWh		0.02605 /kWh					476
477			All Off-Peak kWh		0.01033 /kWh					477
478										478
479			Maint. Service	Sum & Win	\$ 0.02605 /kWh					479
480					0.01033 /kWh					480
481			C.F. penalty	Sum & Win	\$ 21.28 /KW					481
482					18.94 /KW					482
483		Above 69 KV	Standby Service	Sum & Win	\$ 1.45 /mo					483
484					2.30 /mo					484
485					4.11 /mo					485
486			C.F. penalty	Sum & Win	\$ 18.94 /KW					486
487					18.11 /KW					487
RATE E-55 IS FROZEN, NO CHANGE IN CHARGES										
488	E-58	Street Lighting Service	Rate	Sum & Win	\$ 19.86 /mo					488
489					22.04 /mo					489
490					11.28 /mo					490
491					13.18 /mo					491
492					15.64 /mo					492
493					19.29 /mo					493
494					15.79 /mo					494
495					17.92 /mo					495
496					22.41 /mo					496
497					16.40 /mo					497
498					19.34 /mo					498
499					22.09 /mo					499
500					26.58 /mo					500
501					6.41 /mo					501
502					7.54 /mo					502
503					9.45 /mo					503
504					11.39 /mo					504
505					15.45 /mo					505
506					10.98 /mo					506
507					12.84 /mo					507
508					16.90 /mo					508
509					12.62 /mo					509
510					27.22 /mo					510
511					31.16 /mo					511
512										512

Recap Schedules: N/A

Schedule H-3  
Page 14 of 22

Supporting 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**

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	(E) Present Rates	(F) Rates	(G) Block	(H) Proposed Rates	(I) Rates	(J) Block	(K) Change (J) - (E)	(L) Line No.
513	E-58 (cont)	Street Lighting Service	Rate	Sum & Win	FIXTURES (Investment by Company) (cont)	FIXTURES (Investment by Company) (cont)	E. Flood 30,000 HPS	E. Flood 30,000 HPS	\$ 18.11 /mo		\$ 2.99 /mo	513
514					Flood 50,000 HPS	Flood 50,000 HPS	Flood 50,000 HPS	Flood 50,000 HPS	\$ 22.46 /mo		\$ 3.71 /mo	514
515					Flood 21,000 MH	Flood 21,000 MH	Flood 21,000 MH	Flood 21,000 MH	\$ 19.33 /mo		\$ 3.19 /mo	515
516					Flood 36,000 MH	Flood 36,000 MH	Flood 36,000 MH	Flood 36,000 MH	\$ 23.57 /mo		\$ 3.89 /mo	516
517					Post Top gray 9,500 HPS	Post Top gray 9,500 HPS	Post Top gray 9,500 HPS	Post Top gray 9,500 HPS	\$ 16.29 /mo		\$ 2.69 /mo	517
518					Post Top black 9,500 HPS	Post Top black 9,500 HPS	Post Top black 9,500 HPS	Post Top black 9,500 HPS	\$ 9.32 /mo		\$ 1.54 /mo	518
519					Post Top Transit 9,500 HPS	Post Top Transit 9,500 HPS	Post Top Transit 9,500 HPS	Post Top Transit 9,500 HPS	\$ 28.54 /mo		\$ 4.71 /mo	519
520					FROZEN 4,000 INC	FROZEN 4,000 INC	FROZEN 4,000 INC	FROZEN 4,000 INC	\$ 8.60 /mo		\$ 1.42 /mo	520
521					FROZEN 7,000 MV	FROZEN 7,000 MV	FROZEN 7,000 MV	FROZEN 7,000 MV	\$ 11.14 /mo		\$ 1.84 /mo	521
522					FROZEN 11,000 MV	FROZEN 11,000 MV	FROZEN 11,000 MV	FROZEN 11,000 MV	\$ 13.95 /mo		\$ 2.30 /mo	522
523					FROZEN 20,000 MV	FROZEN 20,000 MV	FROZEN 20,000 MV	FROZEN 20,000 MV	\$ 21.91 /mo		\$ 3.62 /mo	523
524												524
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559												559
560												560
561												561
562												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**  
**CHANGES IN REPRESENTATIVE RATE SCHEDULES**  
**COMPARISON OF PRESENT AND PROPOSED RATES**  
**TEST YEAR ENDING SEPTEMBER 30, 2005**

**ATTACHMENT E**

Line No.	Rate Schedule	Description	Billing Designation	Season	Present Rates		Proposed Rates		Change (J) - (E)	Line No.
					(E)	(F)	(G)	(H)		
563	E-58 (cont)	Street Lighting Service	Rate	Sum & Wfm	POLES (Investment by Company)					
564					A. Anchor Flush, Round, 1X, 12ft	8.93 /mo	10.70 /mo	\$	1.77 /mo	563
565					Anchor Flush, Round, 1X, 22ft	10.05 /mo	12.04 /mo	\$	1.99 /mo	564
566					Anchor Flush, Round, 1X, 25ft	10.88 /mo	13.03 /mo	\$	2.15 /mo	565
567					Anchor Flush, Round, 1X, 30ft	12.50 /mo	14.97 /mo	\$	2.47 /mo	566
568					Anchor Flush, Round, 1X, 32ft	13.13 /mo	15.73 /mo	\$	2.60 /mo	568
569					Anchor Flush, Round, 2X, 12ft	9.52 /mo	11.40 /mo	\$	1.88 /mo	569
570					Anchor Flush, Round, 2X, 22ft	10.94 /mo	13.10 /mo	\$	2.16 /mo	570
571					Anchor Flush, Round, 2X, 25ft	11.41 /mo	13.67 /mo	\$	2.26 /mo	571
572					Anchor Flush, Round, 2X, 30ft	13.26 /mo	15.88 /mo	\$	2.62 /mo	572
573					Anchor Flush, Round, 2X, 32ft	14.15 /mo	16.95 /mo	\$	2.80 /mo	573
574					Anchor Flush, Square, 5", 13ft	10.24 /mo	12.27 /mo	\$	2.03 /mo	574
575					Anchor Flush, Square, 5", 15ft	9.15 /mo	10.96 /mo	\$	1.81 /mo	575
576					Anchor Flush, Square, 5", 23ft	10.85 /mo	13.00 /mo	\$	2.15 /mo	576
577					Anchor Flush, Square, 5", 25ft	11.93 /mo	14.29 /mo	\$	2.36 /mo	577
578					Anchor Flush, Square, 5", 28ft	13.24 /mo	15.86 /mo	\$	2.62 /mo	578
579					Anchor Flush, Square, 5", 32ft	13.17 /mo	15.78 /mo	\$	2.61 /mo	579
580					Anchor Flush, Concrete, 12ft	30.51 /mo	36.54 /mo	\$	6.03 /mo	580
581					Anchor Flush, Fiberglass, 12ft	25.84 /mo	30.95 /mo	\$	5.11 /mo	581
582					Anchor Flush, Dec Transit Ped, 4", 16ft	25.19 /mo	30.17 /mo	\$	4.98 /mo	582
583					Anchor Flush, Dec Transit, 6", 30ft	48.64 /mo	58.26 /mo	\$	9.62 /mo	583
584					B. Anchor Pedstl, Round, 1X, 12ft	8.59 /mo	10.29 /mo	\$	1.70 /mo	584
585					Anchor Pedstl, Round, 1X, 22ft	9.71 /mo	11.63 /mo	\$	1.92 /mo	585
586					Anchor Pedstl, Round, 1X, 25ft	10.53 /mo	12.61 /mo	\$	2.08 /mo	586
587					Anchor Pedstl, Round, 1X, 30ft	12.16 /mo	14.57 /mo	\$	2.41 /mo	587
588					Anchor Pedstl, Round, 1X, 32ft	12.78 /mo	15.31 /mo	\$	2.53 /mo	588
589					Anchor Pedstl, Round, 2X, 12ft	9.18 /mo	11.00 /mo	\$	1.82 /mo	589
590					Anchor Pedstl, Round, 2X, 22ft	10.25 /mo	12.28 /mo	\$	2.03 /mo	590
591					Anchor Pedstl, Round, 2X, 25ft	11.07 /mo	13.26 /mo	\$	2.19 /mo	591
592					Anchor Pedstl, Round, 2X, 30ft	12.92 /mo	15.48 /mo	\$	2.56 /mo	592
593					Anchor Pedstl, Round, 2X, 32ft	13.80 /mo	16.53 /mo	\$	2.73 /mo	593
594					Anchor Pedstl, Round, 3 Bolt, 32ft	15.86 /mo	19.00 /mo	\$	3.14 /mo	594
595					Anchor Pedstl, Square, 5", 13ft	9.90 /mo	11.86 /mo	\$	1.96 /mo	595
596					Anchor Pedstl, Square, 5", 15ft	10.13 /mo	12.13 /mo	\$	2.00 /mo	596
597					Anchor Pedstl, Square, 5", 23ft	10.51 /mo	12.59 /mo	\$	2.08 /mo	597
598					Anchor Pedstl, Square, 5", 25ft	11.59 /mo	13.88 /mo	\$	2.29 /mo	598
599					Anchor Pedstl, Square, 5", 28ft	12.89 /mo	15.44 /mo	\$	2.55 /mo	599
600					Anchor Pedstl, Square, 5", 32ft	13.38 /mo	16.03 /mo	\$	2.65 /mo	600
601					C. Direct Bury, Round, 19ft	13.52 /mo	16.19 /mo	\$	2.67 /mo	601
602					Direct Bury, Round, 30ft	10.55 /mo	12.64 /mo	\$	2.09 /mo	602
603					Direct Bury, Round, 38ft	12.88 /mo	15.43 /mo	\$	2.55 /mo	603
604					Direct Bury, Self-Support, 40ft	15.86 /mo	19.00 /mo	\$	3.14 /mo	604
605					Direct Bury, Stepped, 49ft	47.89 /mo	57.12 /mo	\$	9.43 /mo	605
606					Direct Bury, Square, 4", 34ft	11.65 /mo	13.95 /mo	\$	2.30 /mo	606
607					Direct Bury, Square, 5", 20ft	11.06 /mo	13.25 /mo	\$	2.19 /mo	607
608					Direct Bury, Square, 5", 30ft	11.52 /mo	13.80 /mo	\$	2.28 /mo	608
609					Direct Bury, Square, 38ft	12.51 /mo	14.98 /mo	\$	2.47 /mo	609
610					Direct Bury, Steel Dist Pole, 35ft	17.27 /mo	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.

**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.	Rate Schedule	Description	Billing Designation	Season	(A)	(B)	(C)	(D)	Present Rates		Proposed Rates		(K)	(L)
									(E)	(F)	(G)	(H)		
Line No.	Rate Schedule	Description	Billing Designation	Season	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
611	E-58 (cont)	Street Lighting Service		Sum & Win										
612					\$				25.73 /mo				\$	30.82 /mo
613									8.92 /mo					10.68 /mo
614									9.84 /mo					11.79 /mo
615									1.09 /mo					1.31 /mo
616									6.56 /mo					7.86 /mo
617									6.56 /mo					7.86 /mo
618														
619									1.23 /mo					1.47 /mo
620									1.38 /mo					1.65 /mo
621									1.50 /mo					1.80 /mo
622									1.72 /mo					2.06 /mo
623									1.74 /mo					2.08 /mo
624									1.31 /mo					1.57 /mo
625									1.51 /mo					1.81 /mo
626									1.87 /mo					2.19 /mo
627									1.53 /mo					1.88 /mo
628									1.95 /mo					2.34 /mo
629									1.41 /mo					1.69 /mo
630									1.26 /mo					1.51 /mo
631									1.49 /mo					1.78 /mo
632									1.64 /mo					1.96 /mo
633									1.82 /mo					2.18 /mo
634									1.81 /mo					2.17 /mo
635									4.20 /mo					5.03 /mo
636									3.56 /mo					4.26 /mo
637									3.47 /mo					4.16 /mo
638									6.70 /mo					8.03 /mo
639									1.18 /mo					1.41 /mo
640									1.34 /mo					1.61 /mo
641									1.45 /mo					1.74 /mo
642									1.68 /mo					2.01 /mo
643									1.76 /mo					2.11 /mo
644									1.26 /mo					1.51 /mo
645									1.41 /mo					1.69 /mo
646									1.52 /mo					1.82 /mo
647									1.78 /mo					2.13 /mo
648									1.90 /mo					2.28 /mo
649									2.18 /mo					2.61 /mo
650									1.36 /mo					1.63 /mo
651									1.39 /mo					1.66 /mo
652									1.45 /mo					1.74 /mo
653									1.60 /mo					1.92 /mo
654									1.78 /mo					2.13 /mo
655									1.84 /mo					2.20 /mo

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**

Line No.	Rate Schedule	Description	Billing Designation	Season	(A)	(B)	(C)	(D)	Present Rates		Proposed Rates		(K)	(L)
									(E)	(F)	(G)	(H)		
656	E-58 (cont)	Street Lighting Service	Rate	Sum & Win										
657									POLES (Investment by Others) (cont)					
658									C. Direct Bury, Round, 19ft					
659									Direct Bury, Round, 30ft					
660									Direct Bury, Round, 38ft					
661									Direct Bury, Self-Support, 40ft					
662									Direct Bury, Stepped, 49ft					
663									Direct Bury, Square, 4", 34ft					
664									Direct Bury, Square, 5", 20ft					
665									Direct Bury, Square, 30ft					
666									Direct Bury, Square, 38ft					
667									Direct Bury, Steel Dist Pole, 35ft					
668									D. Post Top, Dec Transit, 16ft					
669									Post Top, Gray Steel/Fiberglass, 23ft					
670									Post Top, Black Steel, 23ft					
671									E. Existing Distribution Pole					
672									F. FROZEN, Wood Poles, 30ft					
673									FROZEN, Wood Poles, 35ft					
674									ANCHOR BASE (Investment by Company)					
675									Flush, 4ft					
676									Flush, 6ft					
677									Pedestal, 8ft					
678									Pedestal, 32' round steel pole, 4ft 6"					
679									ANCHOR BASE (Investment by Others)					
680									Flush, 4ft					
681									Flush, 6ft					
682									Pedestal, 8ft					
683									Pedestal, 32' round steel pole, 4ft 6"					
684									OPTIONAL EQUIPMENT					
685									Per foot of cable under paving					
686	E-59	Energy Services for Government Owned Streetlighting Systems	Rate	Sum & Win					Service Charge					
687									Energy Charge					
688	E-66	Share the Light	Rate	Sum & Win					Billed on Rate Schedule E-58					
689														
690	E-67	Municipal Lighting Service - City of Phoenix	Rate	Sum & Win					All kWh					
691														
692	E-114	Share the Light	Rate						Billed on Rate Schedule E-58					
693	E-116	Share the Light	Rate						Billed on Rate Schedule E-58					

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**

Line No.	Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	(E) Present Rates		(F) Proposed Rates		(H) Block	(I) Rates	(J) - (E) Change	Line No.
					(F) Rates	(G) Rates	(I) Rates	(J) - (E) Change				
694	E-145	Share the Light										694
695	E-221	Water Pumping Service	Rate	Sum & Win								695
696		All kW	Rate		\$ 0.493 /day					\$ 0.493 /day		696
697		First 240 kWh	Rate		1.66 /kW					1.66 /kW		697
698		Next 275 kWh per kW	Rate		0.09726 /kWh					0.10104 /kWh		698
699		All additional kWh	Rate		0.06612 /kWh					0.06869 /kWh		699
700		Time of Week Option	Rate	Sum & Win								700
701		Based on Measured kWh in Control Period:										701
702		2 kWh per kW or less			\$ (0.00693) /kWh					\$ (0.00693) /kWh		702
703		Greater than 8 kWh/kW			0.00347 /kWh					0.00347 /kWh		703
704		Minimum Basic Service Charge			\$ 0.493 /day					\$ 0.493 /day		704
705		Minimum Demand Charge			1.66 /kW					1.66 /kW		705
706		Minimum Annual kW Charge			19.92 /kW					24.00 /kW		706
707	E-221-8T	Water Pumping Service	Rate	Sum & Win								707
708		Time Of Use	Rate									708
709		All On-Peak kW	Rate		\$ 0.851 /day					\$ 0.851 /day		709
710		All Off-Peak kWh	Rate		3.95 /kW					3.95 /kW		710
711		Minimum Basic Service Charge			2.36 /kW					2.360 /kW		711
712		Minimum Demand Charge			0.07975 /kWh					0.082850 /kWh		712
713		Minimum Annual kW Charge			0.04289 /kWh					0.044460 /kWh		713
714	E-249	Share the Light	Rate	Sum & Win								714
715	EPR-2	Purchase Rates	Rate	Sum & Win								715
716		0-200 amps, 1-phase	Rate		\$ 7.34 /mo					\$ (7.340) /mo		716
717		0-200 amps, 3-phase	Rate		8.87 /mo					(8.870) /mo		717
718		200-400 amps, 3-phase	Rate		18.31 /mo					(18.310) /mo		718
719		Non-Firm On-Peak	Rate	Summer	0.03551 /kWh					0.04486 /kWh		719
720		Non-Firm Off-Peak	Rate		0.02257 /kWh					0.04531 /kWh		720
721		Firm On-Peak	Rate		0.05433 /kWh					0.07630 /kWh		721
722		Firm Off-Peak	Rate		0.03453 /kWh					0.05330 /kWh		722
723		Non-Firm On-Peak	Rate	Winter	0.02552 /kWh					0.06384 /kWh		723
724		Non-Firm Off-Peak	Rate		0.01871 /kWh					0.04905 /kWh		724
725		Firm On-Peak	Rate		0.03904 /kWh					0.07510 /kWh		725
726		Firm Off-Peak	Rate		0.02862 /kWh					0.05770 /kWh		726

Supporting Schedules:  
N/A

Recap Schedules:  
N/A

**NOTES TO SCHEDULE:**

- Proposed rates are shown on a bundled basis. See tariff sheets for unbundled components.
- 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**

Line No.	Rate Schedule	Description	Billing Designation	Season	Present Rates		Proposed Rates		Change (J) - (I)	Line No.
					(E)	(F)	(G)	(H)		
726	EPR-3	Purchase Rates	Rate	Summer		0.03551 /kWh				726
727		Non-Firm On-Peak				0.02257 /kWh				727
728		Non-Firm Off-Peak				0.05433 /kWh				728
729		Firm On-Peak				0.03453 /kWh				729
730		Firm Off-Peak				0.02552 /kWh				730
731		Non-Firm On-Peak		Winter		0.01871 /kWh				731
732		Non-Firm Off-Peak				0.03904 /kWh				732
733		Firm On-Peak				0.02862 /kWh				733
734		Firm Off-Peak				0.02862 /kWh				734
735	EPR-4	Purchase Rates	Rate	Summer		0.03551 /kWh				735
736		Non-Firm On-Peak				0.02257 /kWh				736
737		Non-Firm Off-Peak				0.05433 /kWh				737
738		Firm On-Peak				0.03453 /kWh				738
739		Firm Off-Peak		Winter		0.02552 /kWh				739
740		Non-Firm On-Peak				0.01871 /kWh				740
741		Non-Firm Off-Peak				0.03904 /kWh				741
742		Firm On-Peak				0.02862 /kWh				742
743		Firm Off-Peak								743
744	EQF-M	Scheduled Maintenance Electric Service for Qualified CoGenerators and Small Power Production Facilities								744
745	EQF-S	Standby Electric Service for Qualified CoGenerators and Small Power Production Facilities								745
746										746
747										747
748	Solar-1	Photovoltaic Service Pilot Program	Rate	Sum & Win		\$ 20.00 /mo				748
749						1.6% /mo				749
750						3.1% /mo				750
751	Solar-2	Individual Solar Electric Service	Initial Fee	Sum & Win		5% one time				751
752						10% one time				752
753										753
754										754
755										755
756										756
757										757
758										758
759										759
760										760
761										761
762										762
763										763
764	SP-1	Solar Partners	Rate	Sum & Win		\$ 2.84 /mo				764
	Solar-2	Solar Service Premium Power Rate	Rate	Sum & Win						
	GPS-1	Green Power Block	Rate	Sum & Win						

RATE EPR-3 CANCELLED;  
NO CURRENT CUSTOMERS

RATE EPR-4 CANCELLED;  
CUSTOMERS TRANSFERRED TO EPR-2

RATE EQF-M CANCELLED;  
NO CURRENT CUSTOMERS

RATE EQF-S CANCELLED;  
NO CURRENT CUSTOMERS

RATE SOLAR-1 CANCELLED;  
NO CURRENT CUSTOMERS

NO CHANGE

RATE SP-1 IS FROZEN, NO CHANGE TO CHARGES

Solar Power Premium Rate \$ 0.1660 /kWh

Green Power Block Rate \$ 1.00 /100 kWh block

**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) Block	(F) Present Rates	(G) Rates	(H) Block	(I) Proposed Rates	(J) Rates	(K) Change	(L) (J) - (I)	Line No.
GPS-2	Green Power Percent	Rate	Sum & Win					Green Power Additional Charge	\$ 0.0100 /kWh				
								100% Green Power	\$ 0.0050 /kWh				
								50% Green Power	\$ 0.0035 /kWh				
								35% Green Power	\$ 0.0010 /kWh				
								10% Green Power					
EPR-5	Net Metering	Rate	Sum & Win					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					Partial Requirement Services are billed on customer's otherwise applicable rate schedule					
E-57	Solar Partial Requirements	Rate	Sum & Win					Partial Requirement Services are billed on customer's otherwise applicable rate schedule					

Supporting Schedules:  
N/A

Recap Schedules:  
N/A

**NOTES TO SCHEDULE:**

- Proposed rates are shown on a bundled basis. See tariff sheets for unbundled components.
- 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**

Line No.	Rate Schedule	Description	Billing Designation	Season	(E)		(F)		(G)		(H)		(I)		(J)		Change (J) - (E)	Line No.
					Block	Present Rates	Block	Proposed Rates	Block	Proposed Rates	Block	Proposed Rates	Block	Proposed Rates	Block	Proposed Rates		
765	EPS-1	Environmental Portfolio SurchARGE	Adjustment	Sum & Win	All kWh	\$0.000875 /kWh	All kWh	\$0.001392 /kWh	Cap for all Residential Services	0.35 /service	Cap for all Residential Services	0.58 /service	Cap for General Services under 3MW	13.00 /service	Cap for General Services under 3MW	20.68 /service	\$ 0.001	765
766					Cap for General Services 3MW and above	39.00 /service	Cap for General Services 3MW and above	62.04 /service									\$ 0.210	766
767																	\$ 7.680	767
768																	\$ 23.040	768
769	CRCC-1	Competition Rules Compliance Charge	Adjustment	Sum & Win	All kWh	\$0.000338 /kWh												769
770																		770
773	EIC	Environmental Improvement Charge	Adjustment	Sum & Win														773
774																		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.