# OPEN MEETING ITEM



ORIGINAL

0000071828

**ARIZONA CORPORATION COMMISSION**

DATE: APRIL 27, 2007

DOCKET NOS: E-01345A-05-0816, E-01345A-05-0826 and E-01345A-05-0827

TO ALL PARTIES:

Enclosed please find the recommendation of Administrative Law Judge Lyn Farmer. The recommendation has been filed in the form of an Opinion and Order on:

ARIZONA PUBLIC SERVICE COMPANY
(RATES/PALO VERDE/FUEL AND PURCHASED POWER PRACTICES AND COSTS)

Pursuant to A.A.C. R14-3-110(B), you may file exceptions to the recommendation of the Administrative Law Judge by filing an original and ten (10) copies of the exceptions with the Commission's Docket Control at the address listed below by **4:00** p.m. on or before:

MAY 15, 2007

The enclosed is NOT an order of the Commission, but a recommendation of the Administrative Law Judge to the Commissioners. Consideration of this matter has tentatively been scheduled for the Commission's Working Session and Open Meeting to be held on:

TO BE DETERMINED

For more information, you may contact Docket Control at (602) 542-3477 or the Hearing Division at (602) 542-4250. For information about the Open Meeting, contact the Executive Secretary's Office at (602) 542-3931.

Arizona Corporation Commission
DOCKETED
APR 27 2007
DOCKETED BY

BRIAN C. McNEIL
EXECUTIVE DIRECTOR

AZ CORP COMMISSION
DOCUMENT CONTROL
2007 APR 27 P 2:56
RECEIVED

# BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

MIKE GLEASON, Chairman
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
KRISTIN K. MAYES
GARY PIERCE

| | |
|---|---|
| IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UILITY 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<br>DECISION NO. _______________<br>**OPINION AND ORDER** |

| | |
|---|---|
| DATES OF HEARING: | October 5, (Pre-Hearing Conference), December 6, (Procedural Conference), October 10, 11, 12, 13, 16, 19, 20, 23, 24, 25, 26, 30, November 3, 6, 7, 8, 9, 20, 27, 28, 30, December 1, 4, 5, 6, 11, 12, 13, and 15, 2006. |
| PLACE OF HEARING: | Phoenix, Arizona |
| ADMINISTRATIVE LAW JUDGE: | Lyn Farmer |
| IN ATTENDANCE: | Jeff Hatch-Miller, Chairman<br>Mike Gleason, Commissioner<br>Kristin K. Mayes, Commissioner<br>William A. Mundell, Commissioner<br>Barry Wong, Commissioner |
| APPEARANCES: | Mr. Thomas L. Mumaw, PINNACLE WEST CAPITAL CORPORATION, Ms. Deborah R. Scott, SNELL & WILMER, LLP, and Mr. William Maledon, OSBORN MALEDON, P.A., on behalf of Arizona Public Service |

Company;

Mr. Scott Wakefield, Chief Counsel, and Mr. Daniel Pozefsky, on behalf of the Residential Utility Consumer Office;

Mr. Bill Murphy, MURPHY CONSULTING, on behalf of Distributed Energy Association of Arizona;

Ms. Laura Sixkiller, ROSHKA, DeWULF & PATTEN, PLC, on behalf of UniSource Energy Services;

Mr. Timothy Hogan, ARIZONA CENTER FOR LAW IN THE PUBLIC INTEREST, on behalf of Southwest Energy Efficiency Project and Western Resource Advocates;

Mr. Gary L. Nakarado, on behalf of Vote Solar and Arizona Solar Energy Industry;

Mr. Michael Grant, GALLAGHER & KENNEDY, P.A., on behalf of Arizona Utility Investors Association;

Mr. Kurt J. Boehm, BOEHM, JURTZ & LOWRY, on behalf of the Kroger Company;

Mr. C. Webb Crocket, FENNEMORE CRAIG, P.C., on behalf of the Arizonans for Electric Choice and Competition and Phelps Dodge Mining Company;

Lieutenant Colonel Karen S. White, on behalf of the Federal Executive Agencies;

Mr. Jay I. Moyes, MOYES STOREY, on behalf of Az-Ag Group;

Mr. Andrew W. Bettwy, on behalf of Southwest Gas Corporation;

Mr. Douglas V. Fant, on behalf of the Interwest Energy Alliance and Distributed Energy Association of Arizona;

Mr. Lawrence V. Robertson, Jr., MUNGER CHADWICK, on behalf of Southwestern Power Group II, LLC, Bowie Power Station, LLC and Mesquite Power, LLC.

Mr. Christopher Kempley, Chief Counsel, Ms. Janet F. Wagner, Senior Staff Attorney, and Mr. Charles Hains, Staff Attorney, Legal Division, on behalf of the Utilities Division of the Arizona Corporation Commission.

# INDEX

**BY THE COMMISSION:**

## I. INTRODUCTION

On November 4, 2005, the Arizona Public Service Company ("APS" or "Company") filed an application with the Arizona Corporation Commission ("Commission") for a rate increase and to amend Decision No. 67744 (April 7, 2005).

On November 9, 2005, the Commission opened a docket to investigate the outages at Palo Verde Nuclear Power Generating Station ("Palo Verde") during 2005, and another docket was opened to audit APS' fuel and purchased power practices and costs.

On January 31, 2006, APS filed an amended application using an updated Test Year ("TY").

On February 24, 2006, the Utilities Division Staff ("Staff") of the Commission filed a letter stating that the application was found sufficient and classified the applicant as a Class A utility.

On September 1, 2006, Staff of the Commission filed Motions to Consolidate ("Motions") dockets E-01345A-05-0816, E-01345A-05-0827 and E-01345A-05-0826. The Motions were granted by Procedural Order issued September 18, 2006.

The following requested and were granted intervention: Jim Nelson; the Residential Utility Consumer Officer ("RUCO"); the Arizona Cogeneration Association dba Distributed Energy Association of Arizona ("DEAA"); Comverge, Inc.; UniSource Energy Services; Western Resource Advocates ("WRA"); Sun City Taxpayers Association, Inc. ("SCTA"); the Arizona Utility Investors Association, Inc. ("AUIA"); The Kroger Co., ("Kroger"); Phelps Dodge Mining Company and Arizonans for Electric Choice and Competition ("Phelps Dodge/AECC"); the City of Scottsdale ("Scottsdale"); Arizona Water Company ("AWC"); the Federal Executive Agencies ("FEA"); the Arizona Competitive Power Alliance ("Alliance"); Mesquite Power, LLC, Southwestern Power Group II, LLC and Bowie Power Station, LLC ("Power Group"); George Bien-Willner dba Glendale & 27th Investments, LLC; Ruth Properties, LLC; Solicito Investments, LLC and Combined Commercial, LLC; the Arizona Solar Energy Industries Association, the Vote Solar Initiative, the Greater Tucson Coalition for Solar Energy and the Annan Group (collectively "Solar Advocates"); the AzAg Group; the Southwestern Energy Efficiency Project ("SWEEP"); Southwest Gas Corporation ("SWG"); Interwest Energy Alliance ("Interwest"); Tammie Woody; the Arizona

Interfaith Coalition on Energy ("AZ-ICE"); the Jewish Community of Sedona; and AARP Arizona ("AARP").

The hearing was conducted as scheduled and continued into December, 2006, lasting 29 days. The record remained open to allow late-filed exhibits to be filed. Post hearing initial briefs were filed January 22 and 23, 2007 by APS, Staff, RUCO, Phelps Dodge/AECC, AUIA, Kroger, FEA, AZ-ICE, WRA/SWEEP, Interwest, Solar Advocates, and DEAA. Post hearing reply briefs were filed February 16, 2007 by APS, Staff, RUCO, Phelps Dodge/AECC, AUIA, Kroger, WRA/SWEEP, Interwest, Solar Advocates, and DEAA.

On February 28, 2007, Staff filed late-filed exhibit S-50, containing the final version of Staff's proposed Plan of Administration ("POA") for the Power Supply Adjustor ("PSA").

### A. Rate Application

The application as amended is based upon a test year ending September 30, 2005. The Company is requesting an increase in revenues of $425,847,000[1], or 16.73 percent over TY adjusted revenues of $2,545,020,000,[2] for a total revenue requirement of $2,970,867,000 (APS Exhibit No. 53). Staff is recommending an increase of $188,265,000 or 7.27 percent, over adjusted TY revenues of $2,591,008,000 for a total revenue requirement of $2,779,273,000. RUCO is recommending an increase of $212,163,000, or 6.16 percent,[3] over adjusted TY retail revenues of $3,445,400,000 for a total revenue requirement of $3,657,563,000.[4] Based upon adjustments to the Company's filing as set forth herein, we authorize an increase of $286,147,000; an increase of 11.06 percent over TY adjusted revenues of $2,587,363, for a total revenue requirement of $2,873,509,000.

## II. RATE BASE

APS proposed an adjusted jurisdictional original cost rate base ("OCRB") of $4,456,937,000; a reconstruction cost new depreciated rate base ("RCND") of $7,765,052,000; and a fair value rate base ("FVRB") of $6,110,995,000. (APS Exhibit No. 53) Staff proposed an adjusted OCRB of

---

[1] $425,847,000 plus $4,542,000 for environmental improvement charge and $4,250,000 for environmental portfolio standard, for a total of $434,639,000.

[2] 20.43 percent over total sales to ultimate retail customers.

[3] 3.5 percent incremental increase over current rates with interim adjustor.

[4] RUCO's TY revenue requirements are not comparable to Staff's and APS' due to differences in purchased power and fuel costs included in base rates.

$4,402,377,000; a RCND of $7,710,492,000; and a FVRB of $6,056,435,000. RUCO proposed an adjusted OCRB of $4,463,352,000; a RCND of $7,728,174,000; and a FVRB $6,095,763,000.

## A. <u>Contested Rate Base Adjustments</u>

### 1. Allowance for Working Capital

APS proposes an allowance for working capital of $148,089,000, including a negative $29,565,000 cash working capital component. Staff proposed an additional $57,018,405 negative cash working capital resulting in a negative $86,391,274 component. RUCO proposed a negative cash working capital of $107,344,000.[5]

The area of dispute is over the cost-of-service elements that are included in the cash working capital calculation. APS included both depreciation and deferred taxes, and excluded interest expense in the lead-lag study it conducted to determine the Company's cash working capital requirements. Staff did not include depreciation and deferred taxes, and included interest expense. Staff also excluded amortized expense of pre-paid insurance costs and nuclear fuel from its study. RUCO excluded depreciation and included interest expense.

#### a. Inclusion of Depreciation Expense

APS argues that unlike other rate base elements that can be derived from the Company's balance sheet, cash working capital is a "calculated number that identifies the additional cash investments made in the Company in order to operate and maintain its electric system on a daily basis." (APS Initial Brief, p. 41). APS cites *Accounting for Public Utilities*:

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

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

APS argues that 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),

[5] On a total company basis, or approximately $97,313,000 on an ACC jurisdictional basis. Exhibit R-24, MDC-5 and 2.

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 (sic) pay for these items ... 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." (APS Initial Brief, p. 42) (emphasis original). APS believes that excluding depreciation expense prevents it from earning a return on "over $32,000,000 of unrecovered capital" and $7,872,000 of rate base for deferred tax expense.

APS acknowledges that the Commission has not included depreciation and deferred taxes in past decisions, including Decision No. 55931 (April 1, 1988), but argues that other state commissions have included those items in lead-lag studies. In its Reply Brief, APS states that as an alternative to including these items in the calculation, the Commission could "make a downward adjustment of equal magnitude to the depreciation and deferred tax reserves." (APS Reply Brief, p 20, citing testimony by its witness, Balluff, in APS Exhibit No. 66).

Staff defines cash working capital as "the amount of cash needed by a utility to pay the day-to-day <u>expenses</u> incurred in providing service in relation to the timing of the utility's collection of revenues for those services." (Staff Exhibit No. 34, p. 33) (emphasis original). Cash working capital is an "allowance" that is included in rate base to reflect timing issues related to cash flow. It can be either positive or negative, depending upon the timing differences between the expense and the collection. Staff points out that APS did not prepare its lead-lag study in accordance with Commission precedent when it included depreciation and deferred tax expenses and failed to include interest expense. The rate base impact is to overstate cash working capital, and therefore APS' rate base, by approximately $43.9 million. (Id. at 39). According to Staff, the cash flows that are appropriate to include in a lead-lag study are those transactions that relate to the day-to-day payment of expenses incurred in providing utility service, and neither depreciation nor deferred income tax expenses require APS to make a cash outlay in order to meet its day-to-day expenses incurred in providing utility service. Staff argues that both "depreciation expense and deferred income tax expenses are non-cash expenses; both represent accrued expenses; both are recovered through utility rates; the cumulative recoveries of both expenses are recognized as zero cost capital and used to reduce rate base; neither involves current period payments to suppliers, vendors, or taxing authorities; and both provide a source of cash (in other words, positive cash flow) that can be used for investment in plant construction or other corporate activities." (Staff Initial Brief, p.17) Staff witness Dittmer testified that: "non-cash expense items are properly excluded from a lead lag study. Their inclusion would be inconsistent with the widely accepted view of cash working capital as the amount of invested capital required to bridge the gap between the payment of cash expenses and the collection of related revenues. When there is no expense payment, no cash working capital is required. Depreciation and deferred income tax expenses do not require current period cash payments. Since investors are not required to provide cash advances for these expense items prior to the collection in revenues, it would be improper to include such items in a study of cash working capital requirements." (Staff Exhibit No. 34, p. 42) (emphasis original). In response to APS' argument that not every dollar of recorded depreciation reserve would have been collected from ratepayers as of the end of the test year, Staff pointed out that not every dollar of construction recorded as plant in service would have been paid for by the Company as of the end of the test year, and that all of the depreciation reserve recorded at the end of the test year would be recovered from ratepayers by the time that rates become effective. Staff believes that APS should not selectively expand the lead-lag study to include "non-cash" expenses, unless it also considers "offsets."

RUCO agrees with Staff that depreciation expense should not be included in the cash working capital calculation. RUCO argues that the reason cited by APS for including those expenses is "based on the erroneous assumption that a lead lag study and the resulting cash working capital requirement is intended to measure regulatory lag" when in fact, "the purpose of a lead lag study is to measure the period of time between when service is rendered and when cash is received or dispersed." (RUCO Initial Brief, pp. 10-11, citing RUCO Exhibit No. 26, p. 9) (emphasis original). RUCO points out that APS' argument that rate base is reduced during the benefit period when depreciation expense is incurred but depreciation is recorded about 37 days before APS recovers the revenues, is flawed because rate base is not reduced each month when depreciation is booked. "[R]ate base is a purely regulatory concept, and is recomputed only at the time of a rate case." (RUCO Initial Brief, p. 11) Because rate base is not modified monthly, the rates that customers pay are not reduced due to the prior month's recording of depreciation expense. In fact, customers continue to pay depreciation expense based upon the undepreciated plant level at the end of the test year of the last rate case.

All the parties agree that working capital represents the amount of cash, materials and supplies, fuel inventories, and prepayments needed to meet current expenses. The cash working capital component represents the funds the utility must have on hand to cover expenses that must be paid before revenues are received to make the expense payments.

APS witness Mr. Balluff testified that the treatment of non-cash items can be difficult for non-accountants to understand, saying that there "may be too much of a focus on the fact that these items do not require a cash outlay when expensed. . . " (APS Exhibit No. 66, p. 10). According to the Company, the recording of depreciation occurs "before the Company recovers the revenues related to depreciation. Thus, investors would be prevented from earning a return on their investment between the time depreciation is expensed and the time that such depreciation is recovered in rates . . . ." *Id.*

The real issue comes down to whether the Commission should allow APS' rate base to be increased to reflect the timing of recording depreciation expense and accumulated depreciation in the Company's financial statements. There is no "cash expense" incurred by APS when it records depreciation. It does not have to find cash to pay to itself one month and then pay itself back the next. As pointed out by RUCO, an allowance for cash working capital is to address cash flow timing problems, not "regulatory lag" issues related to earnings. APS has not acknowledged that investors continue to earn a return on that rate base that was just "depreciated" on its books, even after it was depreciated.[6] Therefore, there is no rate base investment that is not being allowed a return. It appears that APS is really arguing that because of growth, it needs to generate cash to continue constructing new plant. (Tr. Vol. XIII pp. 2260-1) While it may be true that APS needs more cash, artificially increasing cash working capital to increase rate base and thereby operating income, is inappropriate. Deferred income tax expenses are also non-cash, deferred accounting transactions, meaning that the Company does not disburse cash in the current year to pay deferred income taxes to Federal or State

---

[6] Rate base is only set during a rate proceeding, and rates do not correspondingly decrease as APS plant is depreciated during the time between rate cases.

taxing authorities. We agree with Staff that deferred income tax expense should not be included in the cash working capital calculation.

b. Inclusion of Interest Expense

APS acknowledges that the Commission used interest expense in the cash working capital calculation in Decision No. 55931, but points out that the Commission had previously rejected its use. APS' witness Balluff testified that if it is appropriate, as Staff and RUCO have done, to include the "interest component of the return in the calculation of cash working capital, it is necessary to include the entire return on rate base (including the weighted cost of debt) in the calculation of working capital." (APS Exhibit No. 66, p. 11). However, the APS' witness did not recommend that both be included. *Id.* Citing *Accounting for Public Utilities*, APS argues that most jurisdictions either include both operating income lag and interest, or exclude both. APS believes that Decision No. 55931 is "out of step with what would appear to be the general treatment of cash working capital throughout the country." (APS Reply Brief, p. 21).

Staff believes that the Commission should continue to include interest expense in the calculation of cash working capital. Interest expense is the result of the Company's debt obligations and the Company must make periodic cash payments in known amounts to the debt holders. Because ratepayers pay for service on a monthly basis while the periodic cash payments are made on a quarterly or semi-annual basis, Staff believes that fairness requires the lead-lag study to recognize the Company's use of these funds for the extended period of time between their collection from ratepayers and the Company's payment of interest to the debt holders. In response to the Company's argument that if interest expense is included then equity should also be included, Staff stated that if the lead-lag study were expanded to include the payment of dividends, the result would be an even smaller rate base, not a larger one. Staff believes that including only interest expense is consistent with all Commission decisions on this issue for at least the last twenty years, is conservative and should be upheld.

RUCO agreed with Staff that the Commission should continue to require interest expense to be included in the calculation of working capital. RUCO believes that fairness requires that the lead-lag study recognize APS' use of the funds for the extended period of time between their collection from ratepayers and the payout of interest to the debt holders.

APS has not shown why the Commission should change its long-standing policy of including interest expense in the calculation of cash working capital. Although interest expense is a non-operating expense, the ratemaking formula provides for the recovery of the periodic payments to debt holders, and the evidence shows that the Company has use of these funds for an extended period of time before payments are required to be made. We will continue to include interest expense in the cash working capital calculation.

c. Other Non-Cash Expenses

Staff also excluded amortized prepaid insurance and amortized nuclear fuel expenses from the lead-lag study. APS notes that the impact of excluding the amortization of prepaid insurance cost ($500,000) and nuclear fuel amortization ($3,500,000) are relatively small, but argues that Staff provided no explanation other than they are "non-cash" expenses. In response, Staff explains that they should be excluded because they are non-cash expenses, and should be excluded for the same reason that other non-cash expenses are excluded. We agree that these non-cash expenses should also be excluded from the calculation of cash working capital for the reasons set forth above.

d. Other Working Capital Recommendations

Staff proposed several adjustments to the lead-lag study that APS did not oppose, including:

a. revised purchased power expense level to reflect the elimination of significant unregulated power marketing activity from the quantification of cash working capital;
b. recalculation of the composite revenue lag using test year revenues instead of 2004 revenues, and thereby adoption of a reweighting method that is consistent with the above purchased power expense adjustment;
c. restatement of APS' expense lag calculation regarding the Palo Verde lease to reflect a shift in semi-annual payment requirements that began in 2005; and
d. revision of the payment lag for Arizona state taxes to be consistent with the statutory payment due dates.

Accordingly, based upon the discussion above, we will adopt a negative $86,391,274 cash working capital component of the allowance for working capital.

2. Bark Beetle Regulatory Asset

In Decision No. 67744 (April 7, 2005), the Commission adopted the Settlement Agreement entered into by the parties, which provided:

> 110. APS is authorized to defer for later recovery the reasonable and prudent direct costs of bark beetle remediation that exceed the test year levels of tree and brush control. The deferral account established for this purpose shall not accrue interest.
>
> 111. In the Company's next general rate proceeding, the Commission will determine the reasonableness, the prudence, and the appropriate allocation between distribution and transmission of these costs. The Commission will also determine an appropriate amortization period for the approved costs.

In this proceeding, APS seeks to begin recovery of the deferred costs of the bark beetle remediation. The TY end deferral balance was $5,173,879.[7] APS initially proposed an adjustment of $6,115,000 to include the additional deferrals through December 2006, and later modified that amount to $4,360,000.[8]

Staff disagreed with the way APS calculated its bark beetle deferrals. Staff believes that costs from January 1, 2005 to March 31, 2005, (prior to the effective date of rates resulting from Decision, No. 67744) should not be included in rate base. Staff believes that APS' method will result in retroactive application of the Commission's Order.

RUCO opposed the adjustment to include post test year amounts, indicating that some costs were estimates, and therefore not known and measurable. RUCO also believes that inclusion of those costs would violated the matching principle. RUCO's recommendation would mean that any costs not addressed in this Decision would continue to be deferred for later recovery in a subsequent rate proceeding.

In the prior rate proceeding, the Commission could have set a level of tree and brush control expense that would be built into rates and that would recover the ongoing costs of bark beetle remediation, or it could have allowed the Company to defer those costs, for later recovery. The Settlement Agreement chose to adopt the latter treatment. If the tree and brush control expense level were reset in the rate case to include a new level of bark tree remediation, then the recovery of those costs would have begun when new rates were effective. However, the language of the Settlement Agreement allowing deferral of these expenses refers to costs "that exceed test year levels."

---

[7] LLR WP 7, p. 4

[8] Including $2,793,000 of Accumulated Deferred Income Tax Credits, a $705,000 correction, and a $333,000 addition for estimated costs through 2006. (APS Initial Brief, p. 44 footnote 25, and Initial Brief Exhibit 5, Schedule B-2, column 5)

Therefore, the only way to calculate what are the "reasonable and prudent direct costs" allowed to be deferred is to compare costs for the same length time period as the "test year levels," and to the extent that those costs exceed the test year level, then they should be deferred for recovery. APS' choice to use the calendar year that rates were implemented is reasonable, as the costs that were incurred early in the year are not likely to have exceeded the test year level, and so therefore would not have been deferred until they were in excess of the test year level.[9] Although the Commission does not generally prefer to use estimated levels of expense as pointed out by RUCO, to not allow APS to begin amortizing these costs from 2006 would push out even further the recovery of these prudent costs, and would require future customers to pay for past costs incurred. Accordingly, we will adopt APS' adjustment to rate base of $4,360,000.

3. Investment Tax Credit

APS retained Deloitte and Touche, LLP, ("Deloitte") to research whether prior federal income tax returns could be amended to claim additional Investment Tax Credits ("ITC") related to plant constructed in the mid-to-late 1980s. Initially, APS retained Deloitte on a contingency basis, and in 2003, APS accrued $2,385,468 in anticipation of paying Deloitte, and loaded a portion of the contingency fee into the direct-assigned production costs assessed to joint owners of production facilities under the operating agreement. After the joint owners contested the "loading," APS, in December 2004, credited the joint owners, ultimately resulting in the recording of incremental APS production expense during the TY in the amount of $1,224,795. APS renegotiated the payment for Deloitte to a fee-for-service basis, and during the TY, APS recorded $1,533,333 of outside services expense for additional ITC research by Deloitte.

APS expects a tax refund in the amount of $6,483,389. APS believes that the tax credits are non-recurring and unrelated to the TY, and therefore, should not be included in the regulated cost of service. According to APS, "[p]ursuant to Decision No. 58644, which adopted a 1994 Settlement Agreement, the remaining (as of 1994) unamortized ITCs from all of the years prior to 1991 were to be fully amortized below-the-line over five years" and so customers have no further claim to the

[9] *See* APS Exhibit No. 30, rebuttal testimony of APS witness Bischoff at p. 2.

ITCs. (APS Initial Brief, p. 45)

Staff recommended that some of the tax refund benefit should go to ratepayers. Staff explained that in APS rate cases prior to 1994, unamortized ITCs were reflected as a rate base offset which benefited ratepayers, and the ITCs benefited shareholders by amortizing or reducing income tax expense over the life of the facilities. In the 1994 Settlement Agreement, APS agreed to amortize its unamortized ITCs over five years. When APS objected to Staff's initial recommendation to share the revenue requirement saving 50/50 between shareholders and ratepayers because it would violate Internal Revenue Service Code normalization requirements, Staff modified its recommendation to avoid any such violation. Staff's modified recommendation is that the Commission recognize as a rate base offset, all of the unamortized ITC balance related to plant not depreciated. Staff's adjustment would allow the Company to retain all of the ITC savings associated with the 62 percent of its ITCs that are fully amortized, and one-half of the remaining 38 percent of ITCs savings realized. According to Staff, this treatment provides some benefit to ratepayers without causing normalization violations, and is quite generous for APS' shareholders. The Staff proposal would decrease rate base by $766,768. (Staff Revised Joint Accounting Schedule B-3)

We agree that the Staff recommendation is reasonable under the circumstances. The majority of the tax refund is going to the Company which can use the cash to help with the construction costs and reduce its borrowing. It is appropriate that some portion of the refund benefit ratepayers, as ratepayer supplied funds were used to pay the original tax expense. We do not find Decision No. 58644 to be dispositive of this issue, as the ITCs at issue here were not identified in 1994, and no "receipt of a favorable ruling from the Internal Revenue Service" occurred to initiate the five year amortization provision. We also note that the provision of the Settlement Agreement that sets out the treatment of the ITCs is under the heading "Improvement of APS' Equity Ratio" and states that in furtherance of the goal that APS make continuous progress toward a 40 percent common equity ratio, APS would be allowed the five year amortization of its ITCs.

Accordingly, we will reduce rate base by $766,768.

**B. <u>Uncontested Rate Base Adjustments</u>**

1. Sundance Units

APS is seeking a finding by the Commission that the acquisition of the Sundance Combustion Turbine Units ("Sundance") was prudent, that the assets are "used and useful," and that APS be accorded full cost recovery under traditional cost-of-service principles. APS acquired the Sundance units during the TY on May 13, 2005 for $189,500,000, and it seeks ratebase treatment in this case. Both Staff and RUCO have agreed that the acquisition was prudent, and do not oppose the inclusion of the Sundance Units in rate base. No adjustment to rate base is necessary.

2. Spent Fuel Storage

No party has disputed the Company's final adjustment to reduce rate base by $5,775,000, which represents the Company's ACC Jurisdictional portion of current, ongoing, and future activities to transfer spent nuclear fuel to an interim Spent Fuel Storage facility. (APS Initial Brief, Exhibit 5, Schedule B-2, column 3).

3. Palo Verde Unit 1 Steam Generators

No party has disputed the Company's final adjustment to increase rate base by $81,941,000 to reflect the Company's ACC Jurisdictional portion of the costs associated with the replacement and retirement of steam generators and related equipment for Unit 1 that occurred in 2005. (APS Initial Brief, Exhibit 5, Schedule B-2, column 4).

4. Long Term Disability (SFAS 112)

No party disputes the Company's final adjustment to reduce rate base by $3,661,000 to reflect the Company's ACC Jurisdictional portion of deferred credits for long term-disability (SFAS 112) related to expenses for employees on long-term disability. (APS Initial Brief, Exhibit 5, Schedule B-2, column 6).

5. Regulatory Disallowance of West Phoenix Unit 4

No party disputes the Company's final adjustment to reduce rate base by $11,155,000 to reflect the Total Company and ACC Jurisdictional regulatory disallowance required by Commission Decision No. 67744 for the West Phoenix Unit 4, which was not reflected on the Company's books per Generally Accepted Accounting Procedures ("GAAP"), and as adjusted for the actual transfer date from Pinnacle West Energy Company ("PWEC") to APS. (APS Initial Brief, Exhibit 5, Schedule B-2, column 2).

### C. Original Cost Rate Base Summary

Based on the foregoing, the following statement details the adjusted test year OCRB for ratemaking purposes:

| | |
|---|---|
| APS' Proposed Adjusted Rate Base | $4,456,937,000 |
| Commission Approved Adjustments | |
| Allowance for Working Capital[10] | ($52,674,405) |
| Investment Tax Credit | ($766,768) |
| **Commission Adjusted Rate Base** | **$4,403,495,827** |

## III. ORIGINAL COST RATE BASE

Based on the foregoing discussion, we adopt an adjusted OCRB of $4,403,496,000.

## IV. RECONSTRUCTION COST NEW RATE BASE

In Schedule B-1 of APS' Initial Brief, Exhibit 5, APS presents a jurisdictional reconstruction cost new rate base of $7,765,052,000. All of the adjustments reflected in our determination of the OCRB are equally applicable to the RCNRB. No change to the adjustments is necessary to restate them in terms of reconstruction cost new. Thus, our RCNRB is $7,711,611,000.

## V. FAIR VALUE RATE BASE

The Commission has traditionally determined the "fair value" rate base by taking the average of the OCRB and RCNRB. No party has recommended a different weighting be used in this proceeding.[11] Consequently, we find that APS' adjusted FVRB at September 30, 2005, is $6,057,554,000.

## VI. OPERATING INCOME

### A. Gross Annual Revenues

Actual unadjusted ACC Jurisdictional TY operating revenues were $3,303,455,000. APS proposed adjusted TY revenues of $2,545,020,000; Staff proposed an adjusted TY level of $2,591,008,000; and RUCO proposed an adjusted TY revenue level of $3,445,400,000. We find that TY adjusted revenues are $2,587,363,000.

---

[10] Staff's $57,018,405 cash working capital allowance less a $4,344,000 adjustment reflected in APS' proposed adjusted rate base.

[11] APS witness Wheeler's rebuttal testimony indicated that the Commission could give greater weight to RCNRB, however, it did not recommend that to the Commission. Consistent with our later discussion herein, we will not deviate from our established method of determining FVRB.

**B** **Annual Operating Expenses**

1. Contested Operating Expense Adjustments

a. Bark Beetle Remediation Cost Amortization

APS proposes to recover its allowed deferred bark beetle remediation costs over three years. No party objected to the proposed recovery period, and therefore we will allow recovery of the amount of reasonable and prudent costs as determined in the rate base discussion above. Accordingly, we will adjust TY bark beetle remediation expense by $1,437,983.[12]

2. Sundance Units

APS proposes to increase TY O&M expense by $4,804,000 ($2,086,000 to annualize the $1,550,000 actual expense representing only part of the test year at $3,636,000, and $2,718,000 for the overhaul maintenance expense) for the Sundance Units. The overhaul or "non-routine" maintenance expense was calculated by determining the average number of years between overhauls, and charging the expense over that number of years. Because the Sundance Units major overhaul cycle is twelve years, the Company is asking to include one-twelfth of the costs in operating expenses each year.

Although Staff "conceptually agrees" that it is appropriate to include Sundance O&M expenses in APS' rates, Staff disagrees with some of the estimated O&M expenses and opposes recovery of certain of those estimated non-routine expenses that will not actually be incurred for many years in the future. Staff is concerned that the overhauls will not occur during the period that the rates set in this Decision will be in effect, and that customers may end up paying for the same costs again in a later proceeding, especially since the average intervals between Hot Gas Path overhauls is twelve years and twenty-four years for Major overhauls. Staff recognizes that because these non-routine maintenance activities are related to hours of usage, there is conceptual support for allowing APS to begin accruing the costs that are expected to be incurred in the future but are related to today's usage. Staff recommended that if the Commission allows APS to begin recovery of the non-routine maintenance expenses, the Commission should require APS to recognize monies for non-

[12] LLR, WP 7.

routine maintenance collected within rates as a current period expense and to concurrently establish a regulatory liability on its balance sheet. When the costs are actually incurred, they would then be charged against the deferred liability account rather than being charged to maintenance expense where they might otherwise be used to develop future rates. In its Reply Brief, APS agreed to Staff's proposed treatment. (APS Reply Brief, p. 25)

RUCO recommends that the Sundance routine O&M should be reduced by $1,122,000 to reflect more recent 2006 forecasts that indicate that the average MWHs that Sundance will generate over the 2006-2008 period will be lower than the number of MWHs that APS used with its 2005 projection.

We find that the Company's proposal to normalize its non-routine Sundance O&M expenses is reasonable. It recognizes that today's usage is causing large maintenance expenses to be incurred in the future, and it collects those costs from the customers that are creating that future expense. However, we also agree with Staff that the potential may exist that many years in the future, the fact that the costs of these expenses have already been collected, will be forgotten. Accordingly, we will require APS to recognize as a current period expense the amounts collected in rates for Sundance's non-routine maintenance and to concurrently establish a regulatory liability on its balance sheet, in order to ensure that ratepayers will not be charged twice for the same expense.

We also agree with RUCO that the use of the Company's more recent forecasts of generation should be used to estimate the level of routine O&M expense that should be included in rates as this will more closely match costs with recovery level. Therefore, we will adopt RUCO's adjustment and will reduce APS' $4,804,000 pro forma adjustment to O&M expense by $1,122,000. Accordingly, we will adjust TY O&M for the Sundance Units by $3,682,000 and direct APS to accrue (recognize) a regulatory liability at the rate of $226,500 per month[13] for overhaul maintenance.

3. PWEC Units

APS proposes to increase TY O&M and Administrative and General ("A&G") expenses to annualize operating expenses for the PWEC Units[14] that were formally transferred to APS on July 29,

[13] $2,718,000 divided by 12 months.

[14] West Phoenix Combined Cycles No. 4 & 5, Redhawk Combined Cycles No. 1 & 2, and Saguaro Combustion Turbine No. 3.

2005, pursuant to Decision No. 67744. The adjustment includes annualized costs associated with A&G expense, depreciation, amortization, and property tax expenses. It also includes a revenue adjustment related to plant auxiliary power.

Staff does not oppose APS' adjustment, however RUCO recommends that the Commission approve an adjustment that corrects the actual expenses to those in the TY, and that uses more recent projections. APS' adjustment used actual expenses for 2004, and RUCO corrects that to use the TY amounts. APS' adjustment used projections made in 2005 for expected 2006-2011 usage levels and used the average generation projection for each PWEC Unit for the years 2006-2011. RUCO argued that pro forma adjustments from TY plant performance should be based on specific known and measurable information, and that a more near-term forecast and not "speculative forecasts of generating unit performance five or six years into the future" should be used as the basis for the adjustment. (RUCO Initial Brief, p. 17) Because the most recent forecast projects that the PWEC generation in years 2007 and 2008 will differ significantly from their 2006 performance, RUCO believes that 2006 is not a representative year upon which to base an adjustment. RUCO recommended O&M expense based on projected PWEC generating performance as forecasted in 2006, for the years 2006-2008. This adjustment decreases O&M expenses by $5,768,000.

APS' position on the RUCO adjustment is the same as its position on the adjustment with the Sundance Units. We find that the RUCO adjustment to O&M expenses for the PWEC Units should be adopted for the same reasons set forth in the discussion of the Sundance Units, above. Accordingly, we will reduce the $31,734,000 O&M portion of APS' proposed $53,021,000 O&M adjustment, by $5,768,000, and allow a $26,346,000 adjustment to increase O&M expense associated with the PWEC units.

Phelps Dodge/AECC proposed two adjustments concerning the PWEC Units. Phelps Dodge/AECC recommended reducing the proposed A&G expense for the PWEC Units by $5.1 million, in order to limit the A&G expense to the level depicted by APS in the previous APS rate case which approved the Settlement Agreement and allowed the PWEC units into rate base. According to Phelps Dodge/AECC, a major consideration in that case was evaluating whether there were net benefits to APS customers in allowing the PWEC Units into rate base, including an analysis of expense levels such as A&G expenses. Phelps Dodge/AECC cites testimony from APS that indicates that annual A&G costs associated with the PWEC Units was $8.797 million. Phelps Dodge/AECC argues that had the parties and Commission known that APS would seek to recover $15.3 million for A&G expense, it would have negatively impacted the final package negotiated by the parties and approved by the Commission.

In her direct testimony, APS witness Rockenberger testified that the "operating income pro forma for the PWEC A&G expenses represents the portion of 2004 actual A&G expenses charged to the PWEC that will now be charged to APS.... The $20,415,000 pro forma adjustment thus reflects ten months of A&G expense based on historical PWEC actual costs that were not included in the Test Year." (APS Exhibit No. 56, p. 15) APS has not explained why in late 2004 it told the Commission that $8.797 million was "a fair representation of the A&G costs for the plants" and now is telling the Commission that the "historical PWEC actual costs" for the late 2004 to end of September 2005 time period was over $15 million. Accordingly, we will adopt the Phelps Dodge/AECC proposed adjustment and reduce APS' pro forma adjustment to A&G expense by $6,285,000.[15]

Phelps Dodge/AECC also recommended that the O&M expense level authorized by the Commission not exceed the amount indicated by APS in the prior rate proceeding. This would reduce the PWEC Units O&M expense by $3,613,000.

In its Reply Brief, APS argues that APS should not be "bound to the level of O&M used for the former PWEC units in the last rate proceeding. That prior docket used a 2002 test period. The former PWEC Units operate in a different mode now that they are APS units." (APS Reply Brief, p. 25). We agree with the Company that the level of O&M will change over time and that the Company's O&M expenses should not be held to the same level as a prior test period. We distinguish O&M expenses from A&G expenses because APS did not represent that the proposed O&M expenses were historical costs. Accordingly, we will not adopt this Phelps Dodge/AECC adjustment.

4. Advertising and Business Meals

---

[15] APS proforma A&G Expense of $20,180,000, less $5,098,000 adjustment in Rockenberger Rebuttal p. 25 and Schedule LLR-4-8RB, less $8,797,000.

Staff and RUCO made several adjustments to APS' advertising and other expenses, and APS has not opposed all but $400,000 of RUCO's adjustment.[16] APS' final adjustment is to remove $6,264,000. APS continues to believe that $400,000 of "catered lunches" is an appropriate operating expense. According to the Company, the business lunches are provided by the Company when employees are expected to continue to work during their personal lunch break. APS argues that they are "legitimate business expenses that provide the Company the benefit of additional productive, non-interrupted, non-paid work time from our employees." (APS Exhibit No. 57, p. 24) RUCO believes that these types of discretionary expenses should not be recovered from ratepayers. APS witness Rockenberger testified that the business lunches were not a formal program, but up to the person organizing the meeting, and "when we talk about providing lunches, we have a cafeteria. They will have little sandwich bags with lunch and chips and a soft drink, which is generally what I'm familiar with in terms of the lunches that are provided." (Tr. Vol. XIII, pp. 2687-2689).

Although providing lunch for employees is surely a valuable benefit to APS employees, APS did not provide any evidence of the reasonableness of the costs. Based upon a TY expense level of $400,000, apparently APS is spending on average $33,333 per month on sack lunches and soda. APS has not indicated how many employees it is feeding lunch or how often employees must work during their lunch breaks, nor has it shown that its staffing level is insufficient for employees to routinely complete their work during their normal, paid work day. Accordingly, we will disallow the $400,000 of miscellaneous expense related to catered employee lunches. Therefore, we will adjust TY advertising and miscellaneous expense by $6,664,000.

5. Underfunded Pension Liability

APS proposed to adjust its underfunded pension account by $41,166,000. Staff, RUCO, and AECC oppose this adjustment.

Through its parent company, Pinnacle West Capital Corporation, APS has a pension plan that covers all of its employees. APS calculates that as of December 31, 2004, the projected benefit obligation was approximately $1,371,000,000, and the fair value of the plan's assets was

[16] RUCO's $565,555 adjustment to miscellaneous expense included removing a number of sponsorships and donations to community organizations, as well as expenses for martini glasses, strobe lights, balloons and other party supplies, and catered employee lunches. RUCO Exhibit No. 24, Schedule MDC-9.

approximately $982,000,000, leaving $389,000,000 as unfunded. APS' share of this is $218,000,000, which APS proposes to recover through an accelerated recovery period of five years. This results in a TY adjustment to increase pension expense by $41,166,000 (APS Initial Brief Schedule C-2, p. 7). Because this would be an accelerated recovery, APS would create a regulatory liability that would later be amortized as a reduction to pension expense over ten years.

APS argues that the Commission should adopt its proposal because the "amortization would reduce future costs by approximately $22,000,000 per year for ten years, thus entirely offsetting the accelerated recovery sought in this proceeding. In addition, the accelerated recovery of the current underfunding would itself reduce future pension costs independent of the creation of the aforementioned regulatory liability, thus providing additional benefits to APS customers in the future. The accelerated pension will also provide an ongoing benefit to customers by an estimated $10,000,000 per year in perpetuity, as a result of the higher fund balance at the end of the 15-year program. (Tr. Vol. XXIV at 4547 [Brandt])" (APS Initial Brief, p. 60). Mr. Brandt also testified that "[s]o over a total of a 15-year period, customers pay in over five years, they get it back over 10. They get a total return, a rate base return while APS is holding their money. And from that point forward, their pension expense will be reduced by about $10 million, 10 or $11 million in perpetuity, all else being equal." (Tr. Vol. XXIV, p. 4547).

APS identified several other reasons why it believes the Commission should approve the Company's proposal: 1) the liability exists today and should be reflected in current rates and not deferred for future customers to pay; 2) there is no reason to believe that the underfunding will go away or be reversed on its own; 3) APS must now account on a current basis for the projected benefit obligation ("PBO") rather than the smaller accumulated benefit obligation ("ABO") and must reflect a liability for any unfunded PBO-based pension obligation on its year-end balance sheet; 4) it has a levelizing impact on rates; and 5) it has a positive impact on the Company's overall cash flow and FFO/Debt ratio.

AECC argues that ratepayer revenue should not be used to fund the accelerated proposal. AECC opposes the adjustment because most of the rate increase would be funding a benefit obligation that is based on projected salary increases that have not yet occurred. AECC argues that it is inequitable, unjust, and unreasonable to require today's ratepayers to pay millions of dollars in current rate increases in order to recover a projected increase in pension benefits associated with projected future salary increases. AECC recommends that for ratemaking purposes, regulators should focus on the ABO, which is identical to PBO, except for the treatment of future salary increases. Because the ABO is adjusted each year to reflect actual salaries as they change, the measurement of underfunded pension liability for ratemaking purposes will appropriately reflect current, not future salaries, and avoid the problem of intergenerational inequity.

RUCO opposes the adjustment to pension expense and states that the fact that there is an underfunded pension liability today does not mean that APS retirees are in danger of losing their pension benefits, nor does it mean that the underfunded situation will not change without the Commission's authorization of the pre-funding proposal. RUCO argues that the calculation of the level of funding and the PBO is based on many assumptions, including interest rates, mortality rates, retirement ages and discount rates. In addition to being unnecessary, RUCO argues that the proposal would result in intergenerational inequities, since ratepayers who pre-fund the pension over the next five years may not be the same ones who receive reimbursement over the subsequent ten years.

Staff recommends that the Commission reject the proposed five-year amortization of the underfunded PBO. Staff's witness testified that while "it is not desirable that the Projected Benefit Obligation become significantly 'under' *or* 'over' funded relative to the current market value of the plan, the 'underfunded' position at December 31, 2004, is not highly unusual, nor a situation to become particularly alarmed about." (Staff Exhibit No. 34, pp 64-64.) According to Staff, the underfunded position is primarily due to: 1) under-performance of returns on plan assets over a short period, and 2) a significant increase in the calculated projected benefit obligation that is directly linked to FAS 87's requirement to use a conservative interest rate in discounting the future obligation. The difference between the market value of pension plan assets and the PBO may vary significantly over time, due to changing interest rates and the performance of the stock market.

Staff also argued that underfunded position of the PBO is already considered within the net periodic pension cost and TY pension expense, which are used to determine APS' cost of service and rates, and that to add an additional amortization expense such as APS proposed, could lead to a double collection of these expenses. Staff witness Dittmer testified that when the return on plan assets falls short of expectations or when the current estimate of the PBO exceeds prior projections, FAS 87 requires net periodic pension cost to include an amortization of significant shortfalls from earlier projections. Nearly a third of APS' 2005 net periodic pension cost was attributable to amortization from earlier projections. In the past, the Commission has developed the retail cost of service using the FAS 87 determined net periodic pension cost and related net pension expense. Such rates include the "catch up" amortization designed to correct for: 1) the impact of returns that differ significantly from prior projections; or 2) the growth or decline in the PBO that is either above or below prior projections.

Staff also believes that the Company's proposal "front loads" future pension costs to existing ratepayers, pointing out that if the Company's proposal is adopted, future ratepayers would pay little, if any, pension expense after completion of the five-year amortization period. The PBO accounts for future years of employment and future pay raises. APS' proposal requires today's ratepayers to pay for the FAS-87 determined pension expense (which includes "catch up" amortization) and the five year amortization of the PBO.[17] Because future ratepayers will benefit from the services yet to be provided, Staff believes that it is inequitable to impose those costs on today's ratepayers.

Staff further argued that it is not clear that funds collected from ratepayers on an accelerated basis would actually be contributed to the pension fund to reduce the current gap between the market value of the pension fund assets and the projected benefit obligation. Despite the Company's explanation that it would commit to funding $44 million more than it would have otherwise contributed as long as the resulting amount does not exceed the IRS maximum, Staff's concerns were not eliminated. Staff indicated that there would be no way to know what the Company might have otherwise contributed absent approval of accelerated recovery, pointing out that in recent years, APS' actual contributions to the pension fund have differed significantly from the actuary's calculation of net periodic pension costs, and were always less than the maximum contributions allowed by the IRS. Staff believes that it would be reasonable to expect APS to make contributions to the pension trust

[17] TY actual pension expense of $23,482,000 plus PBO amortization of $41,166,000.

that are at least equivalent to the net periodic pension cost used to establish retail rates before asking ratepayers to fund an accelerated recovery.

According to Staff, APS' proposal is inconsistent with regulatory precedent, and APS could not cite a single instance in any jurisdiction where a regulatory commission adopted an amortization proposal similar to APS' proposal. Further, Staff argues that implementation of APS' requested amortization will lead to intergenerational equity issues because some of the underfunding is related to payroll dollars being capitalized as well as expensed.

Finally, Staff argues that there is no evidence to suggest that the significant increase in costs will eventually lead to long-term savings for ratepayers, and that the proposal will tend to worsen APS' cash flow position both now and into the future. Because APS has committed to funding its pension trust with the incremental rate recovery generated from its proposal, its short term cash flow will not improve, and because after five years APS must begin refunding the regulatory liability without withdrawing the funds from the trust, its cash flow position in the long term will worsen. In its Reply Brief, Staff states that none of APS' arguments convincingly explains how APS will address the regulatory liability that its proposal creates.

We agree with AECC, RUCO, and Staff that APS' proposed five-year amortization of the underfunded projected benefit obligation should not be adopted.

We agree with Staff that this proposal will not help APS' cash flow problems, and that it will potentially create additional cash flow problems, when after five years, APS must find the funds internally to "refund" or reduce pension expense cost paid by customers. When APS argues that accelerated contributions to the pension fund would substantially reduce the need for future pension fund contributions (while at the same time lowering the expense borne by APS customers) and thereby improve the Company's FFO/Debt ratio and assist the Company maintain its bond ratings, it does not state where the revenues would come from to "refund" or amortize the accelerated payments. The lower pension cost of service will decrease the Company's revenue requirement and therefore its required operating income in its next rate case, directly affecting its FFO levels. Although in its Initial Brief, APS stated that a benefit of the proposal is the "positive impact that it has on the Company's overall cash flow and its FFO/Debt ratio," Mr. Brandt testified that Staff's proposal to disallow this proposed adjustment would not have an effect on the Company's FFO to debt ratio in the first five years. (Tr. at 547)

APS has not explained how a PBO (which reflects a future liability) affects FFO/Debt and bond ratings but a pension fund regulatory liability (which reflects a future liability) of the same or higher amount, would not. Essentially, APS is seeking to borrow money from ratepayers for five years and pay it back over 10 years.[18] APS did not present any evidence that this "forced loan" by ratepayers was more beneficial than other investment opportunities that ratepayers may choose to invest in. If the accelerated recovery reduces future pension costs independent of the creation of the regulatory liability, under APS' proposal, the regulatory liability would be amortized "as a reduction to pension expense over ten years." APS has not provided evidence of what the annual pension expense would be once the underfunding is eliminated in five years. To the extent that it decreases as APS says it will, there is a potential that the amortization offset amount may be greater than the annual pension expense,[19] in which case, not only will APS need to find the funds internally to cover the pension expense, but other operating expenses as well. This would be exacerbated if the pension fund performed better than projected. According to Staff's witness, Mr. Dittmer, APS is not allowed to withdraw funds from the trust to make the refunds. In a future rate case, it would be inappropriate to increase rates to amortize the millions of dollars collected from and owed to ratepayers,[20] and APS' ability to incur debt is limited by its need to fund construction and other restrictions. It is not clear what or whether other Company operations in 2012 would be compromised by the decrease in operating income resulting from amortization. Further, if APS does not have a rate case pending in five years, around the time the "refunding" should commence, there is no mechanism to insure that ratepayers actually will be refunded or credited for those accelerated payments, or that the reduction in pension expense cost of service built into base rates would be realized by ratepayers.

Accordingly, we are not convinced that there is a current problem with pension funding that needs to be addressed in this proceeding. Although there currently is a "gap" between the PBO and

---

[18] Tr. p. 4547.
[19] APS expects the amortization would be $22,000,000 per year, and approximately $25,253,000 is being included in annual pension expense.
[20] Ratepayers would be paying for the same costs twice.

the current market value of plan assets, we believe (and can see historically) that the difference in the values of these will vary, even significantly, over time. The current method of addressing any differences through the use of the FAS 87 calculation of net periodic pension cost, including an amortization of significant shortfalls from earlier projections, sufficiently addresses any underfunding to insure the pension obligations will be met. APS has shown no need for requiring its customers to essentially finance or pre-fund projected shortfalls in the future that may never happen. We agree with Staff that adopting APS' proposal may result in double recovery of these costs, and no "benefits" will accrue to APS customers until a subsequent rate proceeding recognizes rate base treatment and the amortization. APS' proposal has not been demonstrated to improve its cash flow, now or in the future, and would certainly put off "payments," potentially exacerbating cash flow problems in the future.

We do not adopt APS' pro forma adjustment to increase pension expense by $41,166,000.

6. SERP Expense

APS offers a Supplemental Executive Retirement Plan ("SERP") to its highest-ranking executives which is in addition to the regular retirement plan available for all APS employees. RUCO believes that these individuals who receive SERP benefits are "already generously compensated for their work, and provided with a wide array benefits and that the cost of providing supplemental benefits to high-ranking employees is not a necessary cost of doing business, and customers should not be required to pay for those costs." RUCO cited Decision No. 68487 where the Commission recently disallowed SERP costs for Southwest Gas Company ("SWG") as support for its position. RUCO's adjustment would remove $4.7 million in TY SERP costs from operating expenses.

APS opposes RUCO's adjustment consistent with its position that the associated operating expense should be recognized in cost of service. APS argues that SERP provides a layer of pension benefit not otherwise available under the qualified pension plan to senior management employees as a result of their compensation levels. According to APS, a SERP "cures the inequity these employees would otherwise suffer as a result of the IRC-imposed compensation limitation[21] applicable to the 'qualified' pension plan." (APS Exhibit No. 5, Brandt Rebuttal, p. 66) APS states that it could not compete for executive and management talent without offering a SERP, unless it were to substantially increase base compensation.

As we recently stated in Decision No. 68487 (February 23, 2006):

> We believe that the record in this case supports a finding that the provision of additional compensation to SWG's highest paid employees to remedy a perceived deficiency in retirement benefits relative to the company's other employees is not a reasonable expense that should be recovered in rates. Without the SERP, the Company's officers still enjoy the same retirement benefits available to any other SWG employee and the attempt to make these executives "whole" in the sense of allowing a greater percentage of retirement benefits does not meet the test of reasonableness. If the Company wishes to provide additional retirement benefits above the level permitted by IRS regulations applicable to all other employees it may do so at the expense of its shareholders. However, it is not reasonable to place this additional burden on ratepayers. Decision No. 68467, p. 18.

APS has not demonstrated any reason to treat the SERP expense for its SERP eligible employees any differently than our determination of SERP expenses associated with SWG employees. Accordingly, we find that the SERP expense should not be recovered from APS ratepayers, and accordingly, will reduce operating expense in the amount of $3,391,467.[22]

RUCO's adjustment also included removing a $50 million deferred credit and $19 million in accumulated deferred income taxes ("ADIT") related to SERP, which would result in a net increase to rate base of $30,582,000. (RUCO Exhibit No. 24, Schedule MDC-3) We disagree with this portion of the RUCO adjustment because the deferred credits and ADIT are for past periods and remain valid, and our resolution of SERP expense in this matter will only mean that no new SERP deferred credits or related ADITs will be created in the future.

7. Annualize Property Tax Expense

APS proposed adjusting its property tax expense by $16,719,000 to annualize the PWEC Units' property taxes, one full year of property taxes for the Sundance Units, estimated taxes for the

[21] Currently the IRS caps at $220,000 the amount of an employee's annual earnings that can be included in the benefit calculation formula under a qualified plan. APS Exhibit No. 5, Brandt Rebuttal, pp 63-64.
[22] $4,173,000 Total Company with 94.212% ACC Jurisdictional Allocator.

full Maricopa Community College Bond, and a 2007 increase in property taxes that will result when the PWEC units have passed the statutory "phase-in" period.

Staff recommended reducing the Company's property tax expense by $1,689,000 to eliminate the APS proposed inclusion of the 2007 statutory phase-in of increased property taxes associated with the PWEC Units. APS agreed to Staff's property tax recommendation, and revised its adjustment to $15,159,000 total company, or $15,031,000 ACC jurisdictional.

RUCO recommended that the Company-proposed level of property tax be reduced by $5,976,491 to reflect the temporary suspension of the county education tax rate as recently enacted by A.R.S. § 41-1276(I).[23] The suspension of the county education tax rate will reduce property taxes in 2006, 2007, and 2008. In its Closing Brief, Staff agreed with RUCO's adjustment. APS disagrees with RUCO's adjustment, arguing that other significant issues that RUCO did not account for will also impact the property tax expense, including net increases in assessed valuation that are known and measurable. APS witness Rockenberger testified that if all these factors were considered in RUCO's adjustment, the adjustment would be $2.4 million, rather than approximately $6 million. APS also argues that RUCO's adjustment is based upon a temporary suspension of the tax rate, and that APS' projected 2007 property tax expense is anticipated to be $128,000,000,[24] while if RUCO's adjustment is adopted, it would recover at most, $124,000,000 in property tax expense in the first year, leaving APS with a shortfall of $4,000,000 in revenues.

We find that APS' proposed adjustment to property tax expense of $15,031,000 is appropriate and should be adopted. This level reflects as closely as possible the level of plant-in-service at the end of the TY. Although RUCO's adjustment is based upon a known and measurable event after the TY, the event is temporary and the adjustment does not include the other known and measurable component, increased plant-in-service, that goes into calculating property tax expense. To adopt a temporary lower tax rate but not apply that new rate to known, increased plant levels, will result in a net negative cash flow situation from the date the rates are implemented, and is not reasonable. Therefore, we will not adopt RUCO's recommended adjustment and will adopt APS' adjustment that

---

[23] Passed during the 2006 legislative session and signed into law June 21, 2006.
[24] Including the reduction for the suspension of the county education tax rate. TR. Vol. XIII p. 2686.

includes Staff's recommended adjustment, for a total adjustment of $15,031,000.

8. Annualized Depreciation and Amortization

APS proposed a pre-tax adjustment to depreciation and amortization expense of $20,276,000 based upon the results of a technical update to the depreciation rates previously authorized in Decision No. 67744. The Company is not requesting any change to the amortization rates authorized in that Decision, but is requesting approval for two new rates to provide for the amortization of leased vehicles that are subsequently purchased by the Company. No party has objected to the new rates for the leased autos.

RUCO proposed a $6,991,000 reduction in amortization expense based upon its use of a composite amortization rate. RUCO proposed its adjustment because it believes APS did not demonstrate how a 35 percent increase in annual amortization expense was reasonable when there was only a 5.5 percent increase in the account balances.

APS argues that RUCO's methodology does not have sufficient analysis or detail to properly normalize amortization expense noting that RUCO's method is a high level general estimating process that may be appropriate to use when all assets have similar estimated lives, but because APS' intangible assets have a wide range of useful lives, and because each asset is individually amortized, the RUCO calculation does not properly normalize amortization expense. (APS Exhibit No. 57, Rockenberger Rebuttal, p. 18) APS' witness explained that the APS calculation is based on the "actual individual costs and lives at September 30, 2005, multiplied by the actual amortization rates for each individual asset. By using the actual assets at September 30, 2005, the calculation would exclude recent retirements and include recent additions for a full year calculation of amortization expense. Fully amortized assets were properly excluded from the calculation. The amortization rates in effect today were approved by the Commission in Decision No. 67744. The pro forma adjustment is the difference between the normalized annual amortization expense and the actual test year amortization expense." (*Id.* at pp. 18-19). In cross-examination, the APS witness indicated that it was "really a function of the level of assets by asset category" (Tr. Vol. XII, p. 2026). During cross-examination of RUCO's witness, the Company demonstrated how individual costs applied to different balances affect expense levels. (Tr. Vol. XVII, pp. 3426-9.)

We find that APS' proposed adjustment to annual depreciation and amortization is reasonable and will adopt it. APS has adequately explained RUCO's perceived inconsistency with the expense related to account balance change. Accordingly, we will adopt APS' adjustment of $20,276,000.[25]

9. Demand Side Management

APS proposed a Demand Side Management ("DSM") adjustment increasing TY operating expenses by $2,989,000 for program costs, and an adjustment to reduce TY revenues by $4,907,000 to reflect Commission approved DSM programs. Both Staff and RUCO objected to the pro-forma $4,907,000 revenue adjustment, which reflects a "net lost revenue" or "conservation" adjustment.

In the Settlement Agreement approved in 2005, APS committed to spending an average of $16 million per year, for three years, on DSM programs. In August 2005, APS obtained approval of its consumer products DSM program, and received approval of its non-residential programs in February 2006. The remaining residential programs were approved in April 2006. APS recovers $10 million per year of DSM funding in its base rates and has the opportunity to recover its other DSM expenses through a DSM adjustor mechanism.

Staff recommended that the Company be compensated for its efforts to make DSM available and for the savings achieved by successful DSM programs through a performance incentive mechanism. A performance incentive and an adjustment for net lost revenues are two separate, mutually exclusive, approaches to compensating the utility. Staff noted that Decision No. 67744 adopted the Settlement Agreement that provides for a performance incentive. Staff prefers the performance incentive approach because conceptually it rewards the Company only when its DSM programs are successful and result in energy or demand savings. Staff also believes that APS' proposed adjustment is not sufficiently known and measurable to merit inclusion in rates. Staff believes that DSM spending for the remainder of the Portfolio Plan is very much in question, and that the resulting energy savings would be even more difficult to quantify with certainty.

RUCO argues that the APS adjustment is inappropriate for the following reasons: the adjustment seeks to recover estimated lost revenues and expenses that have not actually been realized

---

[25] *See* APS Initial Brief Exhibit 5, p. 16, column 18. The adjustment includes a $452,000 adjustment to revenues and a $20,276,000 adjustment to depreciation and amortization.

and are therefore not known and measurable; the net lost revenue adjustment results in an improper mismatch of the time period over which the revenues are measured due to post test year load growth; and because the Settlement Agreement adopted in Decision No. 67744 specifically precludes the recovery of net lost revenues that were not reflected in the test year of a future rate application.

In response to Staff and RUCO's objections, APS argues that its adjustment "merely captures the impact of DSM expenditures made during the Test Year and in 2006" and is "simply a normalization adjustment for the 'known and measurable' effect of the recently approved DSM programs based upon expenditures in 2005-2006." (APS Initial Brief, p. 68) The Company argues that it is appropriate to set rates on conditions that will be present when the new rates go into effect. APS did not respond to the argument that pursuant to the Settlement Agreement, that "except to the extent reflected in a test year used to establish APS rates in future rate proceedings . . . APS shall not recover or seek to recover net lost revenues on a going-forward basis." APS admits that the revenues it seeks to recover were not reflected in the test year, and that is why it is proposing a pro-forma adjustment.

We agree with Staff and RUCO that APS' pro-forma conservation, or net lost revenue, adjustment to increase revenues should not be adopted. As testified to by Staff, a mechanism exists for APS to recover a portion of the actual energy efficiency savings from its successful DSM programs. We also agree that neither the adjustment nor its amount is sufficiently known and measurable to reasonably change the cost of service. Further, under the terms of the Settlement Agreement as approved by the Commission, APS is not allowed to recover net lost revenues in this case on a going forward basis. Accordingly, we will allow APS' adjustment to increase TY operating costs by $2,989,000 for program costs, and will not adopt APS' net lost revenue adjustment.

10. Base Fuel and Purchased Power

APS proposed a pro forma adjustment to reflect the Company's proposed Base Fuel Cost. The ACC Jurisdictional adjustment includes an increase in revenues of $17,212,000 and an increase in purchased power and fuel costs of $276,724,000, to include 2007 base fuel and purchased power expense and off-system revenues in cents/kWh at adjusted TY usage levels, for a net adjustment of $259,512,000. (APS Initial Brief, Exhibit 5, Schedule C-2, column 24). APS argues that its proposed cost is the only number in this case that represents fuel prices and the conditions that will be in effect when the rates set in this case go into effect. Further, it recommends that regardless of which PSA is adopted by the Commission (either a retrospective reconciliation of already incurred fuel costs or a prospective mechanism to recover fuel costs as incurred), the base fuel cost should be set as close as possible to current expectations of fuel and purchased power costs during the period it first becomes effective. Therefore, APS recommends that its base fuel cost of 3.2491¢, and its pro forma adjustment of $259,512,000 should be adopted irrespective of any changes to the PSA.

RUCO proposed that the Commission adopt a base cost of fuel of 3.1202¢, the amount of APS' original base cost of fuel proposal adjusted for the withdrawal of the proposed sharing of hedging gains and losses. RUCO noted that APS' original proposal was based on conditions the Company expected to experience in 2006, whereas the rejoinder position was based on estimates of 2007 prices and loads and included a reduced margin credit for off-system sales. RUCO argues that because the Company modified its request mid-case, the parties were prevented from having "sufficient time to review the 2007 forecasts in sufficient depth to rely on them as being accurate." (RUCO Reply Brief, p. 19) RUCO, therefore, did not recommend the Commission accept APS' rejoinder proposal.

Staff proposed that the calendar year 2006 be used as an appropriate period from which to establish the fuel and energy portion of APS' base rates. Staff proposed several adjustments to the 2006 data in reaching its calculation for net retail fuel costs of $824.4 million, which results in an average fuel cost of 2.8104 cents/kWh. Staff recommended that the cost of fuel and purchased power should be reduced by $111.6 million (with the APS sharing proposal) or $111.4 million (without the APS sharing proposal); by $3,702,501 to reflect 2006 margins for transactions involving non-utility use of an APS transmission asset; and should be reduced to account for the removal of non-fuel and energy costs associated with non-utility marketing and trading activity. Staff rejected APS' substituted 2007 forecasts as the means for determining the base cost of fuel and purchased power. The 2007 forecasts were provided late in the rate case examination process and have not undergone the same level of analysis and scrutiny as the 2006 forecast. Because these forecasts are difficult and result in errors,[26] Staff recommends that the Commission adopt its recommended base cost of fuel and purchased power to determine APS' base rates.

AECC recommends that the Commission reduce fuel expense by $83 million relative to the Company's final position. AECC's recommendation for setting base fuel costs is based on APS' analysis for 2006, and not the 2007 test year that APS adopted later in its rebuttal testimony. AECC argues that fuel prices in 2006 did not change significantly from the projections used by the Company in its rebuttal, which resulted in a $67 million reduction from the Company's direct filing.

We agree with Staff, RUCO, and AECC that we should not use APS' forecasted 2007 test year for setting the base cost of fuel and purchased power in this case. The parties did not have a sufficient opportunity to scrutinize the 2007 proposal that APS offered late in the proceeding to form basis for its use as the base cost of fuel and purchased power. APS argues that the other parties' recommendations do not take into account "the higher utilization of gas generation and purchased power in 2007, including the recently executed contracts resulting from the RFP referenced in the 2004 APS Settlement and Decision No. 67744, as well as other contractual price changes in 2007." (APS Initial Brief, p. 35) In setting the base cost of fuel and purchased power, we strive to set a rate that will reflect the ongoing and expected level of costs. When the utility also has a fuel and purchased power adjustor, that base level becomes the measure of whether and how much the adjustor rate should change. To the extent that the base cost is set too high, ratepayers will pay higher rates now, with the promise of a credit later. To the extent that the base cost is set too low, the ratepayers will pay lower rates now, with the promise of an increase later. We believe that based upon all the recommendations, the appropriate base cost of fuel and purchased power to use in this case is 3.1202¢kWh.

11. Lobbying Costs

APS requests $1,763,994 be included in operating expenses for lobbying costs. These costs were incurred by the Federal Affairs and Public Affairs Departments and reflects the amount that APS has allocated as "above-the-line" cost of activities that it believes has "directly benefited

[26] *See* Staff Exhibit No. 29, p. 9, Antonuk Sur-Rebuttal testimony discussion of errors, including the Company's original presentation of its TY fuel and purchased power costs where the presentation mistakenly included $849 million of revenue and $856 million of costs pertaining to APS' unregulated power-trading operations.

regulated operations." APS cites as examples of customer benefits the waiver of tariff importation fees for the Palo Verde replacement steam generator ($10 million savings), support of provisions in the Energy Transportation Act of 2005 on tax incentives for new transmission investment ($1.4 million savings per $50 million of eligible new transmission), support of the Production Tax Credit provisions of the American Jobs Creation Act ($3 million benefit), and support of state property tax legislation ($1.7 million annual savings).

Staff recommends that all lobbying expenses should be disallowed as a matter of regulatory policy. Staff argued that ratepayers could potentially be harmed by allowing cost recovery of lobbying expenses, stating that with a utility's unique monopoly status there is a potential for abuse by promoting unfair or unnecessary legislation. Even when utility-supported legislation has benefited ratepayers, it is "virtually impossible" to know the cost of that achievement. Staff recommends that the Commission should refrain from involving itself in the process of discerning "good" from "bad" lobbying.

Staff's witness testified that pursuant to the Federal Energy Regulatory Commission ("FERC") Uniform System of Accounts ("USOA") utilities are required to record lobbying costs below-the-line, where there is a presumption of non-recovery. However, contrary to the specific USOA guidelines, APS charged some of its lobbying costs above the line to administrative and general expense accounts, thereby including them in the proposed TY cost of service. Staff found this disturbing, and recommends that the Commission order APS to appropriately comply with the USOA requirements. Staff notes that recording expenses properly below-the-line does not prevent APS from seeking cost of service recovery of them in rate cases, but will "ensure that expenses that are presumed to fall outside of the Company's cost-of-service are not hidden within inappropriate accounts, thereby placing the burden upon Staff auditors to uncover them." (Staff's Reply Brief, p. 23)

RUCO proposed an adjustment to reduce APS' requested lobbying expenses by $785,654. RUCO recommended that the $137,686 paid by the Federal Affairs department to an outside lobbyist be completely disallowed and that the remaining expenses of the Federal Affairs department ($696,629) should be split between ratepayers and shareholders because the work benefits both.

Additionally, RUCO reduced the payroll expense of the Public Affairs department by fifty percent. In response to APS' argument that it had demonstrated that customers received benefits from the lobbying efforts, RUCO pointed out that APS did not claim that customers received the benefit from all the lobbying efforts for which it seeks cost recovery, and that shareholders also benefited.

We agree with Staff that it is disturbing that APS was not complying with USOA in recording its lobbying costs. When APS is concerned about timely recovery of its costs, and the time necessary to process its rate cases, it certainly does not speed up the process or instill confidence in APS' filings when the Commission learns that Staff auditors must expend extra time and effort to make sure all costs have been appropriately accounted for by the Company. Although APS now says that it agrees with Staff that all future lobbying expenses should be recorded below-the-line and that any recovery should in the future be expressed as a pro forma adjustment, and that it has made this change to its accounting system on a going-forward basis, we will order the Company to comply and expect Staff and other parties to monitor the Company's continued compliance with this requirement.

We agree with RUCO's adjustment to reduce lobbying expense by $785,654. APS did demonstrate some customer benefits that resulted from its lobbying activities, and with the APS allocated below-the-line costs together with those excluded in the RUCO adjustment, we find that the remaining costs are reasonable. However, we agree with Staff that it is not desirable to have to distinguish between "good" and "bad" lobbying activities. To the extent that in future rate cases APS proposes pro forma adjustments to recover its below-the-line lobbying expenses, APS must provide the itemized lobbying costs associated with each benefit it alleges resulted from the specific lobbying activity. Accordingly, we will reduce operating expense by removing $785,654 of lobbying expenses.

12. Incentive Compensation

a. Stock-Based Incentive Compensation

APS requests $4.8 million in TY operating expense related to its employee stock incentive program, which it asserts is integral in attracting and retaining high quality management personnel. Staff recommended eliminating costs associated with APS' stock-based incentive plans, but allowing recovery of TY expenses for APS' cash-based incentive compensation, approximately $17.8 million.

Staff recommends the costs of the stock-based incentive plan not be included in rates because that compensation program is driven by the financial performance of Pinnacle West Capital Corporation ("Pinnacle West"), rather than the operational performance of APS as a public utility.[27] Staff recommends the costs of the cash-based incentive plan be included in rates because the TY level of those costs was tied to performance measures that benefit APS' customers.

APS argues that the issue is whether APS compensation, including incentives, is reasonable. APS does not believe that the Commission should look at how that compensation is determined or its individual components, but rather should just look at the total compensation. The Company argues that the interests of investors and consumers are not in fundamental conflict over the issue of financial performance, because both want the Company to be able to attract needed capital at a reasonable cost.

We agree with Staff that APS' stock-based based incentive compensation expense should not be included in the cost of service used to set rates. Contrary to APS' argument that we should not look at how compensation is determined, we do not believe rates paid by ratepayers should include costs of a program where an employee has an incentive to perform in a manner that could negatively affect the Company's provision of safe, reliable utility service at a reasonable rate. As testified to by Staff witness Dittmer and set out in Staff's Initial Brief, "[e]nhanced earnings levels can sometimes be achieved by short-term management decisions that may not encourage the development of safe and reliable utility service at the lowest long-term cost. . . . For example, some maintenance can be temporarily deferred, thereby boosting earnings.. . . But delaying maintenance can lead to safety concerns or higher subsequent 'catch-up' costs." (Staff Initial Brief, pp. 31-31) To the extent that Pinnacle West shareholders wish to compensate APS management for its enhanced earnings, they may do so, but it is not appropriate for the utility's ratepayers to provide such incentive and compensation. Accordingly, we will reduce operating expense by $4,487,657.[28]

b. Cash-Based Incentive Compensation

---

[27] "Awards are based on the Company's compound annual growth rate in Earnings Per Share over a three-year performance period relative to the S&P Electric Utilities Super Composite EPS growth rate over the same period." APS Exhibit No. 51, Gordon Rebuttal, p. 21.

[28] ACC Jurisdictional amount, Staff Initial Brief, Revised Joint Accounting Schedule, Schedule C-13.

APS incurred approximately $17.8 million of cash-based (variable) incentive expense during the TY.[29] APS' variable incentive program is an "at risk" pay program where a part of an employee's annual cash compensation is put at risk and expectations are established for the employee at the start of the year. If certain performance results are achieved, a predictable award will be earned based upon objective criteria. The actual amount of the award depends upon the achieved results. The intent of the plan is to: link pay with business performance and personal contributions to results; motivate participants to achieve higher levels of performance; communicate and focus on critical success measures; reinforce desired business behaviors, as well as results; and to reinforce an employee ownership culture. (APS Exhibit No. 51, Gordon Rebuttal, p. 8) Staff did not oppose inclusion of the TY variable incentive expense in cost of service, noting that although corporate earnings serve as a threshold or precondition to the payout, the TY level of expense is tied primarily to performance measures that directly benefit APS customers. (Staff Exhibit No. 43, Dittmer Direct, p. 110)

RUCO proposed an adjustment reducing APS' cash-based incentive program expense by approximately 20 percent, or $4,563,000. The adjustment is based on a policy recommendation that ratepayers should not be expected to shoulder the entire incentive program that allows APS employees to earn additional compensation when APS ratepayers have experienced repeated rate increases over the past two years. APS opposes RUCO's adjustment as arbitrary and without analysis or justification. In its Reply Brief, RUCO indicates that it is not recommending adoption of both the RUCO and the Staff adjustment to incentive pay, and that Commission adoption of either one would be appropriate. We adopted the Staff adjustment for the reasons set forth above, and believe that adjustment will reflect an appropriate level of incentive compensation. Therefore we will not adopt RUCO's adjustment.

## C. Uncontested Operating Adjustments

### 1. Spent Fuel Storage

No party has disputed APS' final adjustment to increase purchased power and fuel costs by

[29] Total expense was $21,727,033, but the Company voluntarily eliminated Officers' cash-based compensation in the amount of $3,895,147, leaving $17,831,886 in the proposed TY cost of service. Staff Exhibit S-34, Dittmer Direct p. 107, footnote 31.

$10,653,000 to reflect the Company's ongoing ACC Jurisdictional costs for interim storage of spent nuclear fuel from Palo Verde and an amortized portion of deferred amounts. This amount also reflects Staff's recommended adjustment to reflect reduction in costs related to post-shut down activities. APS requests that this Decision include the "Schedule of Amounts to Be Deposited in the Decommission Trusts," which is attached hereto as Attachment A. (APS Initial Brief, Exhibit 5, Schedule C-2, column 14).

2 Nuclear Decommissioning

No party has disputed APS' final adjustment of $3,820,000 to annualize its ACC Jurisdictional contributions to the nuclear decommissioning trust funds to the amount authorized in Decision No. 67744. The Company requests that this Decision specifically provide for approval of the $19,211,000 annual level of decommissioning funding and that Attachment LLR-3 from APS Exhibit No. 56, be attached to this Decision. The requested exhibit is attached hereto as Attachment B. (APS Initial Brief, Exhibit 5, Schedule C-2, column 13).

3. Four Corners Coal Reclamation

No party disputes the Company's final adjustment to increase purchased power and fuel expense by $1,284,000 to reflect the Company's ACC Jurisdictional annual expense for coal reclamation at the Four Corners Power plant based upon the 2004 Marston study. (APS Initial Brief, Exhibit 5, Schedule C-2, column 17).

4. Annualize Payroll

No party disputes the Company's final adjustment to increase payroll by $8,717,000 to reflect annualized payroll, benefits, and payroll tax expense to December 2005 employee levels; December 2005 wage levels for performance review employees; and April 2006 wage levels for union employees. (APS Initial Brief, Exhibit 5, Schedule C-2, column 20).

5. Regulatory Disallowance for West Phoenix Unit 4

No party disputes the Company's final adjustment to decrease depreciation expense by $227,000 to reflect an annual reduction in depreciation expense associated with the write-off associated with West Phoenix Unit 4. (APS Initial Brief, Exhibit 5, Schedule C-2, column 10).

6. Regulatory Assessments and Franchise Fees

No party disputes the Company's final adjustment to decrease operating revenues and expenses by $15,723,000 to remove the Company's ACC Jurisdictional assessments and franchise fees. (APS Initial Brief, Exhibit 5, Schedule C-2, column 1).

7. Base Rate Component for EPS

No party disputes the Company's final adjustment to increase revenues by $6,779,000 and expenses by $6,000,000 to reflect the authorized System Benefits Charge to fund the Electric Portfolio Standard ("EPS"). (APS Initial Brief, Exhibit 5, Schedule C-2, column 2).

8. Interest on Customer Deposits

No party disputes the Company's final adjustment of $2,400,000 which reflects the increase in annualized interest costs associated with customer deposits (interest expense). (APS Initial Brief, Exhibit 5, Schedule C-2, column 4).

9. Amortization of Regulatory Assets

No party disputes the Company's final adjustment of $381,000 to increase amortization to reflect the amortization of Palo Verde Unit 2 Sale/Leaseback rent levelization regulatory asset over the remaining life of the lease. (APS Initial Brief, Exhibit 5, Schedule C-2, column 5).

10. PWEC Loan

No party disputes the Company's final adjustment of $3,292,000 to decrease amortization to reflect the amortization over five years the deferred net interest income from the APS loan to PWEC which was repaid in April 2005. (APS Initial Brief, Exhibit 5, Schedule C-2, column 6).

11. Tax Consulting Fees

No party disputes the Company's final adjustment of $2,746,000 to decrease operating expense to reflect the elimination of non-recurring tax research consulting fees that was recorded during the TY, but was incurred prior to the beginning of the TY and is not an on-going expense. (APS Initial Brief, Exhibit 5, Schedule C-2, column 32).

12. Out of Period Income Tax Adjustments

No party disputes the Company's final adjustment of $243,000 to decrease income tax to reflect added income tax true-up items related to the test year, and to remove income tax expense recorded during the test year period related to non-recurring income tax items. (APS Initial Brief,

Exhibit 5, Schedule C-2, column 7).

13 Miscellaneous Adjustments

No party disputes the Company's final net adjustment of $1,720,000 to reflect the elimination of non-recurring or out-of-period expenses or credits from the test year, including financial data warehouse costs, Four Corner severance reserve true-up, FERC audit reserve, APS corporate offices rent expense, and bill estimation refund. (APS Initial Brief, Exhibit 5, Schedule C-2, column 23).

14. Pension Expense

No party disputes the Company's final adjustment of $2,119,000 to increase pension expense to reflect actual 2006 pension expense. (APS Initial Brief, Exhibit 5, Schedule C-2, column 36).

15. Post Retirement Medical Benefits

No party disputes the Company's final adjustment of $3,006,000 to decrease post retirement medical benefits to reflect the actual 2006 post retirement medical expenses. (APS Initial Brief, Exhibit 5, Schedule C-2, column 37).

16. Administrative and General

No party disputes the Company's final adjustment of $8,422,000 to reduce administrative and general operating expense to reflect out-of-period costs related to depreciation and rent expense, including out-of-period adjustments for the PWEC Units and legal costs properly chargeable to PWEC and related to the sale of Silverhawk. (APS Initial Brief, Exhibit 5, Schedule C-2, column 35).

17. Unregulated APS Marketing and Trading

No party disputes the Company's final adjustment to remove revenues ($835,567,000), purchased power and fuel costs ($841,847,000), and operating expenses ($8,637,000) related to APS unregulated marketing and trading activities. (APS Initial Brief, Exhibit 5, Schedule C-2, column 33).

18. Palo Verde Unit 1 Steam Generators Depreciation

No party disputes the Company's final adjustment of $1,764,000 to increase depreciation expense to reflect one full year of depreciation on the new Unit 1 steam generators and to exclude the actual test year depreciation on the replaced steam generators. (APS Initial Brief, Exhibit 5, Schedule C-2, column 15).

19. Normalize Non-Nuclear Maintenance Expense

No party disputes the Company's adjustment to increase maintenance expense by $1,435,000 to reflect the normalization of fossil production maintenance expense and to include operation and maintenance costs of renewable generation acquired in compliance with the EPS. (APS Initial Brief, Exhibit 5, Schedule C-2, column 25).

20. Normalize Nuclear Maintenance Expense

No party disputes the Company's final adjustment of $718,000 to decrease maintenance expense to reflect the normalization of nuclear production maintenance expense. (APS Initial Brief, Exhibit 5, Schedule C-2, column 26).

21. Annualize Customer Levels to Year End 2004

No party disputes the Company's final adjustment to increase revenues ($44,663,000), fuel and purchased power costs ($13,890,000) and operating expenses ($2,455,000) to reflect the annualization of customer counts at December 31, 2004. (APS Initial Brief, Exhibit 5, Schedule C-2, column 27).

22. Normalize Weather Conditions

No party disputes the Company's final adjustment to increase revenue ($10,938,000), fuel and purchased power costs ($4,224,000), and operating expenses ($747,000) to reflect normal weather conditions for the ten years ended December 31, 2004. (APS Initial Brief, Exhibit 5, Schedule C-2, column 28).

23. Annualize 4/1/05 ACC Rate Levels

No party disputes the Company's final adjustment to increase revenues by $17,136,000 to reflect the annualization of ACC rate levels for the April 1, 2005, rate increase authorized in Decision No. 67744. (APS Initial Brief, Exhibit 5, Schedule C-2, column 29).

24. E-3/E-4 Promotional Expense

No party disputes the Company's final adjustment of $62,000 to increase promotional expense to reflect the increased promotional expense for low income rate options that were required by Decision No. 67744. (APS Initial Brief, Exhibit 5, Schedule C-2, column 30).

25. Schedule 1 Changes

No party disputes the Company's final adjustment to increase revenues by $127,000 and reduce expense by $38,000 to reflect revenue-related changes to the Company's Rate Schedule 1 that were authorized by Decision No. 67744. (APS Initial Brief, Exhibit 5, Schedule C-2, column 31).

26. Federal and State Income Tax

There is no dispute between the Company and Staff as to the Company's additional adjustment to the Company's original cost of service income tax expense to reflect a top-down calculation including permanent tax items to reduce test year income tax expense by $4,588,000. (APS Initial Brief, Exhibit 5, Schedule C-2, column 34).

**D. Adjustments dependent upon final levels**

1. Income Tax/ Interest Synchronization

There is no dispute as to the methodology to be used to reflect the synchronization of interest expense using the adjusted September 30, 2005 test year capital structure and the cost of long-term debt, as well as the use of the statutory income tax rate. Using the OCRB and cost of debt as determined herein, the appropriate adjustment is a $607,000 increase to test year income tax expense.[30]

2. Generation Production Income Tax Deduction

This adjustment reflects the tax benefits associated with the American Jobs Creation Act and reflects the cost of capital as determined herein. The appropriate adjustment is ($2,915,000).

**E. Summary of Net Operating Income**

Based on the foregoing, the following statement details the adjusted test year net operating income for ratemaking purposes:

Operating Income Summary

| | |
|---|---|
| Operating Revenues | $2,587,363,000 |
| Operating Expenses (per APS) | $2,415,481,000 |
| Total Adjusted Operating Expenses | $2,395,397,000 |
| **Net Operating Income** | **$ 191,966,000** |

## VII. COST OF CAPITAL

The cost of capital compensates investors for the use of their capital to finance the plant and equipment necessary to provide utility service. There are generally three steps to determining the

[30] Reflecting a $1,555,000 decrease to interest expense.

appropriate cost of capital in a rate case proceeding: establishing the appropriate capital structure; determining the appropriate cost of the utility's debt; and estimating a reasonable cost of equity for the utility.

### A. Capital Structure

In estimating the cost of capital for a utility, the appropriate capital structure of the company must be determined. APS proposed using a capital structure consisting of 45.5 percent debt and 54.5 percent equity. Staff accepted APS' proposed capital structure, and RUCO recommended a capital structure of 50 percent debt and 50 percent equity.

RUCO recommends that the Commission adopt its proposed capital structure because it is similar to that of APS' parent and is therefore sound for the lower-risk utility; it has more common equity than APS has utilized in the past, which will provide additional financial security for the Company during its construction period; and it will provide a better balance of the interests of ratepayers and stockholders because it is a more economically efficient and less costly capitalization than requested by the Company.

The capital structure recommended by APS and accepted by Staff is the Company's adjusted September 30, 2005 capital structure of 45.5 percent long-term debt and 54.5 percent common equity. In response to RUCO's recommendation, APS argues that RUCO's witness improperly included short-term debt and financial ratios of companies with "junk" credit ratings, which distort the results. APS also believes that use of RUCO's proposed capital structure would result in a financially weaker APS with non-investment grade credit metrics.

We agree with APS and Staff that a 46/54 percent debt/equity capital structure is appropriate for determining cost of capital in this proceeding. It is the capital structure existing at the end of the test year[31] and will continue to support the Company's existing financial profile and maintain its investment grade profile.

### B. Cost of Debt

All parties agree that a cost of long-term debt of 5.41 percent is the appropriate cost of debt.

[31] Staff Exhibit No. 8, Parcell Direct, p. 3.

## C. Cost of Equity

APS, Staff, and RUCO all presented expert witnesses to evaluate cost of equity. Their recommendations are as follows:

| Party | Range | Recommendation |
|---|---|---|
| APS - Avera | 11.00 - 12.00% | 11.50% |
| Staff - Parcell | 9.50 - 10.75% | 10.25 % |
| RUCO - Hill | 9.25 - 9.75% | 9.25% |

The cost of equity cannot be observed directly because it is a function of the returns available from other investment alternatives and the risks to which the equity capital is exposed. The cost of equity must be estimated by analyzing information about capital market conditions, assessing company specific risks, and using various qualitative methods to find investors' required rate of return. Because APS is not a publicly traded company and because the cost of capital is an opportunity cost and is prospective, the cost of equity must be estimated. All of the expert witnesses agreed that no one single method or model should be used to determine a utility's cost of equity. All witnesses testified as to their understanding of the economic, financial, and legal principles that underlie the concept of a fair rate of return for a public utility.

All the expert witnesses conducted a Discounted Cash Flow Analysis ("DCF"). It is one of the oldest, as well as the most commonly used models for estimating the cost of common equity for public utilities.[32] DCF models used to essentially replicate the market valuation process that sets the price that investors are will to pay for a share of a company's stock. The DCF model is based upon the "dividend discount model" of financial theory, which maintains that the price of a commodity or security is the discounted present value of all future cash flows. The constant growth DCF model recognizes that the return expected or required by investors consists of two factors: the dividend yield (current income) and growth (future income).

APS' witness, Dr. Avera, applied the DCF model, risk premium methods, and the comparable earnings method to a proxy group of other electric utilities operating in the western United States.

[32] The Commission has long used the DCF model, as was indicated in APS' 1986 rate case: "As has been stated by the Commission on previous occasions, market measures of common equity costs are generally preferable to comparative analyses. Although both require the exercise of considerable subjective judgment, methodologies such as DCF entail fewer unproved (and sometimes unprovable) assumptions." Decision No. 55228 (October 9, 1986).

Dr. Avera's DCF analysis resulted in a cost of equity of 9 percent. Dr. Avera did not believe that his constant growth DCF results should be used as a reasonable cost of equity for APS, stating that it is a "blunt tool" that should never be used exclusively. He testified that the short-term growth rates used with the DCF model may be overly cautious, and that therefore, the DCF does not necessarily capture investors' long-term expectations for the industry. Dr. Avera also employed a risk premium analysis where the cost of equity is estimated by determining the additional return investors require to forego the relative safety of bonds and accept the greater risks associated with common stock, and then adding this "equity risk premium" to the current yield on bonds. He based his estimates of equity risk premiums on: surveys of previously authorized rates of return on common equity (10.7 - 11.4 percent); realized rates of return (9.8 - 11.0 percent); and alternative applications of the Capital Asset Pricing Model ("CAPM") (Forward-looking: 12.5 - 12.6 percent; and Historical: 10.9 - 11.9 percent). Dr. Avera also evaluated cost of equity using the Comparable Earnings Method ("CEM"). This method refers to rates of return available from alternative investments of comparable risk. In his direct testimony, Dr. Avera testified that the most recent edition of *Value Line* reports that its analysts expect an average rate of return on common equity for the electric utility industry of 10.5 percent in 2005 and 2006, and increasing to 11.0 percent over its three-to-five year forecast horizon. When Dr. Avera used a proxy group from the unregulated sector of the economy, the expectations averaged 15.7 percent. He concluded that the comparable earnings approach implied a fair rate of return on equity of 11.0 to 12.0 percent.

Dr. Avera concluded, based upon the results of his quantitative analyses and his assessment of the relative strengths and weaknesses inherent in each model, that the cost of equity for the electric proxy group ranges between 10.8 percent and 11.8 percent. He also added a "flotation cost" for the costs associated with issuing common stock of 20 basis points, for a range of equity of 11.0 percent to 12.0 percent, with a midpoint of 11.5 percent.

Dr. Avera criticized Staff's witness Parcell's use of the "spot dividend yield" instead of the end-of-period yield, which Dr. Avera says understates the cost of equity and leads to a "downward-bias" result. Dr. Avera testified that constant growth assumptions are not likely to be representative of real-world circumstances for utilities and he employed a multi-stage form of the DCF using Mr.

Parcell's reference group and calculated a 10.8 percent cost of equity.[33]

Staff's witness, Mr. Parcell, employed three recognized methodologies to estimate the cost of equity for APS. He used the DCF, the CAPM, and the CEM. He applied each of these methodologies to two proxy groups: his group of comparison electric utilities with similar operating and risk characteristics to APS and Pinnacle West; and to Dr. Avera's proxy electric companies. Mr. Parcell used five indicators of growth in his DCF analysis, including: five year earnings retention, or fundamental growth; average historic growth in earnings per share ("EPS"), dividends per share ("DPS"), and book value per share ("BVPS"); 2006-2010 projections of earnings retention growth; 2004-2010 projections of EPS, DPS, and BVPS; and 5-year projections of EPS growth. As a result of his DCF analysis, Mr. Parcell concluded the current DCF cost of equity for APS is between 9 and 10 percent. Mr. Parcell explained that the CAPM is a version of the risk premium method, but is generally superior because it specifically recognizes the risk of a particular company or industry. The CAPM is designed to describe and measure the relationship between a security's investment risk and its market rate of return. Mr. Parcell's CAPM analysis resulted in a cost of equity range of 10.5 to 10.75 percent. Mr. Parcell also conducted a CEM examination which is designed to measure the returns expected to be earned on the original cost book value of similar risk enterprises. He conducted the CEM by examining realized returns on equity for several groups of companies and evaluated the investor acceptance of these returns by reference to the resulting market-to-book ratios. According to Mr. Parcell, it is generally recognized that utilities with a market-to-book ratio of greater than one (100 percent) reflect a situation where a company is able to attract new equity capital without dilution. His analysis was based upon market data and used prospective returns. The results indicated that historic returns of 9.9 - 11.7 percent have been adequate to produce market-to-book ratios of 139-161 percent. The projected returns on equity for 2006, 2007 and 2009-2011 ranged from 8.2 percent to 10.4 percent for the two proxy groups. Mr. Parcell concluded that based upon the recent earnings and market-to-book ratios, the cost of equity for APS using the CEM is no greater than 10 percent.

[33] APS Exhibit No. 42, Avera Rebuttal, p. 21, 28.

Staff's witness testified that although Arizona is a fair value state, he took into consideration the *Bluefield* and *Hope* decisions and considered the additional risk factor of APS' current bond rating and investor expectations in making his recommendation. (Tr. Vol. XVII, pp. 3259-60) Based on all of his cost of equity analyses, Mr. Parcell concluded that APS' cost of equity falls within a range of 9.5 percent to 10.75 percent, and he recommended a rate of 10.25, the approximate mid-point of the range. Staff recommends that the Commission not allow flotation costs because APS has not demonstrated that it has incurred any issuance costs, and an $8 million adjustment paid annually is excessive.

RUCO's witness, Mr. Hill, also conducted a DCF analysis using market data from a sample of electric utility companies similar in risk to APS. His DCF resulted in a cost of equity of 9.44 percent. He also used three other methods to corroborate his DCF results – the Modified Earnings-Price Ratio ("MPER") Analysis, the Market-to-Book Ratio ("MTB") Analysis, and the CAPM. The CAPM produced results that ranged from 9.23 percent to 10.56 percent; the MPER ranged from 9.13 percent to 8.79 percent; and the MTB ranged from 9.31 percent to 9.38 percent. Mr. Hill's estimate of the cost of equity for the sample group ranged from 9.25 percent to 9.75 percent, and because APS has a higher equity component in its capital structure than the sample group, Mr. Hill recommends an appropriate cost of equity of 9.25 percent. In response to Company criticism as to his reliance on the DCF model, Mr. Hill noted that the DCF is now and has been for over thirty years, the pre-eminent equity cost estimation methodology used in regulation because it works well. RUCO also criticized APS for placing primary emphasis on a method its witness has previously discounted, the risk premium method. Mr. Hill argues that the volatility inherent in the historical data used in Dr. Avera's risk premium analysis indicates that the determination of the historical period effectively determines the outcome of the analysis. Mr. Hill testified that the primary flaw in Dr. Avera's CAPM analysis is the risk premium, because APS used two estimates that are well above the current forward-looking risk premium as evidenced by the Company's own pension fund equity return expectations and current academic research.

Mr. Hill took into account not only the financial risks that the Company faces, but also the current economic environment, including anticipated interest rate increases by the Federal Reserve

Bank and the effect it would have on utility stock. RUCO argues that if the multi-stage DCF analysis is properly applied to restate RUCO's analysis, the result is an 8 percent return on equity, not the 10.7 percent claimed by APS.

AUIA supports the APS recommended 11.5 percent return on equity, with a 1.7 attrition allowance. It argues that Dr. Avera has provided a "current and real-world assessment of what investors expect given the depressed credit ratings, low earnings, growth challenges and dangers faced by APS." (AUIA Initial Brief, p. 5) AUIA's witness, Ms. Cannell, testified that investor expectations support the 11.5 percent recommendation. AUIA notes that since the Commission's Decision No. 67744 less than two years ago, "APS' business profile has increased, all three rating agencies have downgraded the Company, APS' critical FFO to Debt metric remains in non-investment grade territory, the Company sits one notch above a junk bond rating and it has a negative outlook from Moody's." (AUIA Initial Brief, p. 6) AUIA argues that investors cannot expect the same or less risk compensation as they did two years ago, contrary to Staff and RUCO recommendations.

The DCF model has long been favored by this and other Commissions as the appropriate way to estimate a regulated utility's cost of equity. As Staff witness Parcell explained, capital costs are currently low in comparison to the levels that have prevailed over the past three decades and it reasonably can be expected that DCF models currently produce returns that are lower than in previous years.

While the Company criticized RUCO's return on equity as "completely outside a reasonable range and is entirely inconsistent with mainstream benchmarks", RUCO argued that the Company placed its reliance on the market-based models that yielded the highest costs of equity, and placed no reliance on the model which RUCO believes provides the best indication of the cost of equity, the DCF. RUCO also criticized Dr. Avera's use of the CEM, stating that the updated CEM analysis highlights the inherent flaws of including companies that are unregulated and have substantially different risk from APS. They are not monopolies operating in a franchised service area and have much different market positions than APS, and it is unknown whether the returns used in the study are equal to the cost of capital, unless a market based analysis like the DCF is performed. RUCO believes that Staff's recommendation is also inflated because Mr. Parcell used the upper range results from his models, and because Staff's common equity ratio recommendation indicates that APS has less financial risk than the others in the sample group, the recommended cost of equity should be in the lower range of the estimate results.

The cost of equity recommendations from the parties vary from a low of 9.25 percent to a high of 11.5 percent. We continue to believe that market measures of common equity costs are generally preferable to comparative analyses, and we note that the DCF results from all witnesses tend to the lower end of the range. However, we compare those results with the results from the other methods, and believe that the DCF results alone would not result in an appropriate cost of equity in this case for APS. We are cognizant of APS' current bond rating as well as the Company's continued growth and the capital costs associated with that growth. After considering all the rate of return testimony, the legal and policy arguments how to determine cost of equity and its relationship to just and reasonable rates, we conclude that the appropriate cost of equity to be used to determine the cost of capital is 10.75 percent. We do not agree that a flotation adjustment or additional "attrition adjustment" to the cost of equity is reasonable or appropriate.

### D. Cost of Capital Summary

| | Percentage | Cost | Weighted Cost |
|---|---|---|---|
| Long-Term Debt | 45.5% | 5.41% | 2.46% |
| Common Equity | 54.5% | 10.75% | 5.86% |
| Cost of Capital | | | 8.32% |

## VIII. AUTHORIZED INCREASE

### A. APS' Revenue Enhancement Proposals

APS believes that the entire rate relief it requests is necessary and appropriate because according to the Company, the current rates: substantially under-collect the costs of providing electric service (particularly fuel and purchased power costs); do not adequately reflect certain non-fuel costs; and do not provide APS an opportunity to earn a reasonable rate of return on its invested equity. According to APS, it is the non-fuel cost recovery and return on equity issues that have led to "chronic under-earning by APS" and "have driven the Company and its customers to the very brink of 'junk' credit status, with the attendant problems of even higher costs and limited access to critically needed capital to meet the growing demands of this State." (APS Initial Brief, p. 2) APS proposed several "alternative and innovative options for addressing APS' cost recovery and return on equity" ("ROE") needs, including allowing Construction Work in Progress ("CWIP") into rate base, accelerating depreciation expense, adding an attrition allowance to its ROE, or by authorizing a "return on 'fair value' in excess of APS' cost of capital." (Id. at 4)

1. APS' Proposals

a. Credit Ratings/Cash flow

APS argues that its current credit ratings and cash flow problems are the result of inadequate rates. APS states that its cash flow problem began in 2005 and that it continues to suffer from a "severe cash flow problem." (APS Initial Brief, p. 2) According to the Company, because its service area is experiencing significant growth, APS' need for cash to fund capital expenditures has also grown and with it the required return on the investment. APS argues that this cash flow pressure from both operations and new construction and the delay in recognizing cost recovery and a return on the new investment, have left it "in a perilous credit-rating position that threatens to plunge APS into 'junk' credit status for the first time in its more than 100-year history." (*Id.*)

APS currently has a Standard & Poor's ("S&P") credit rating of BBB-minus and a negative outlook from Moody's Investors Service ("Moody's") and APS cautions the Commission that S&P and Moody's and the broader investment community are looking to see whether the Commission will "obtain the rate relief and further regulatory support that will be required for APS to fully recover its costs in a timely manner, earn a reasonable ROE, and improve its lagging credit metrics." (*Id* at 3).

APS argues that its credit metrics and other financial indicators are important and relevant factors for the Commission to consider. APS believes that the impact of the Commission's determination on the level of rates set in this case on "APS's projected financial condition and on future customer rates not only **can** be considered by the Commission, but **must** be considered by the Commission in order to ensure that the rate relief granted by the Commission is adequate **at the time it becomes effective** and, thus is consistent with applicable constitutional and regulatory principles." (emphasis original) (APS Initial Brief, pp 3-4)

APS argues that although the concept of "just and reasonable rates" can be achieved through a variety of different approaches, the constitutional principles set forth in the United States Supreme Court case, *Bluefield Water Works & Improvement Co. v. Public Serv. Comm'n of West Virginia,* 262 U.S. 679 (1923) and *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1942) must be met.

The *Bluefield* case states:

> What annual rate will constitute just compensation depends upon many circumstances, and must be determined by the exercise of a fair and enlightened judgment, having regard to all the facts. . . . The return should be reasonably sufficient to assure confidence in the financial soundness of the utility, and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market and business conditions generally. *Bluefield*, 262 U.S. at 692-93.

APS also cited the *Hope* case:

> The rate-making process under the Act i.e., the fixing of "just and reasonable" rates, involves a balancing of the investor and consumer interests. Thus we stated in the Natural Gas Pipeline Co. case that 'regulation does not insure that the business shall produce net revenues.' 315 U.S. at page 589, 62 S.Ct. at page 745, 86 L.Ed. 1037. But such considerations aside, the investor interest has a legitimate concern with the financial integrity of the company whose rates are being regulated. From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. . . . By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital. Hope, 320 U.S. at 603.

According to APS, these constitutionally mandated principles of ratemaking cannot be adequately addressed without the Commission considering the projected impact of a rate decision on the utility's financial criteria – including its ability to "maintain and support its credit" and to "raise the money" necessary for the operation of its business. APS argues that *Scates v. Arizona Corporation Comm'n*, 118 Ariz. 531 578, P. 2d at 612 (Ariz. App. 1978) "requires that rates be just and reasonable when they are in effect, which necessitates some forward looking and not just rigid adherence to a hypothetical and stale Test Year that has been demonstrated to be unrepresentative of present conditions." (APS Initial Brief, p. 10)

To support its argument that there is a substantial risk that APS will be downgraded to "junk bond" credit status if its full requested rate increase is not approved, APS presented testimony from two witnesses. APS witness Donald Brandt testified that in his opinion, if RUCO's proposal were adopted by the Commission there was a 95 percent risk of a downgrade to junk; an 85 percent risk with Staff's proposal (including Staff's forward-looking PSA); and a 15 percent risk with the Company's proposal. Mr. Brandt testified that he based these estimates on financial forecasts that he prepared using the same forecasting methodology the Company uses in the ordinary course of business and in its regular dealings with rating agencies and financial analysts. Mr. Brandt also testified that his calculation showed that under RUCO's proposal, the Company's FFO/Debt ratio would be 15.1 percent at year end 2007 and 12.9 percent at year-end 2008; under Staff's proposal, the ratio would be 16.4 percent at year-end 2007 and 15.1 percent at year-end 2008; and under the Company's proposal, the ratio would be 19.2 percent at year-end 2007 and 17.5 percent at year-end 2008. Mr. Brandt testified that the reason why the ratio trends down in 2008 is because "near-term costs of customer growth are greater than the increased revenues generated by that growth by about $86,000,000 per year at present." (APS Initial Brief, p. 13) Mr. Brandt also testified that the Staff and RUCO ratios are below the 18 percent minimum for an investment grade rating under S&P criteria and the comparable Moody's criteria.

Mr. Fetter, a former rating agency executive and former Chairman of the Michigan Public Service Commission, testified the recent instability in the financial markets has created challenges to an extent that had not existed in the past, and that he believes that utilities operating in today's more stressful environment, as well as the regulatory authorities, should strive to minimize regulatory uncertainties that can affect a utility's financial profile, its credit ratings, and its access to capital on favorable terms.

APS also argued that "quality of regulation" is a factor in a credit rating agency's assessment of the financial and business risks of a regulated monopoly and its debt offerings. APS says this means that the rating agencies are closely and carefully assessing the extent of regulatory support and the consistency of treatment that will be provided to the Company by the Commission in this proceeding. (APS Initial Brief, p. 16). The Company believes that although the Commission's actions in the past twelve months have been constructive, "the Company is far from safe from having its credit rating slip into 'junk' status if the Commission were to reverse course in this proceeding and reject the Company's rate proposal in favor of something more closely approximating the Staff or RUCO proposals. Such action by the Commission would demonstrate a lack of regulatory support and would produce the very sort of regulatory uncertainty that the rating agencies have said would carry negative rating implications for APS, even apart from APS' quantitative credit metrics." (APS Initial Brief, p. 17)

APS argues that its current credit ratings and related cash flow problems are the result of inadequate rates, and that even with an improved, forward-looking PSA, the Company's current rate level is insufficient for the Company to recover its costs and to even maintain, much less improve, its current credit rating.

APS also argues that the adverse consequences of APS having its credit rating downgraded to "junk bond" status would be severe and long term. Mr. Brandt testified that should the Commission reject or substantially reduce the Company's rate request, "the resultant downgrade to junk status would cause an initial annual increase in interest expense in the range of $15 million to $30 million. From 2007 through 2016, APS will go to the capital markets to issue several billion dollars of debt to fund its required infrastructure additions and improvements. The amount of additional annual interest expense would reach $115 million to $230 million by 2016. On a cumulative basis, this amounts to an additional $675 million to $1.3 billion in interest expense between 2007 and 2016 – an increase the customers would eventually shoulder." (APS Exhibit A-4, Brandt Direct, p. 4) Mr. Brandt also testified that APS' marketing and trading function would suffer if APS was downgraded to a non-investment grade rating.

APS proposed two adjustments to its cost of service that would improve its cash flow, but not affect its earnings. APS' Construction Work in Progress accounts included $261 million of generation and distribution plant expenditures as of June 30, 2006. APS witness Brandt testified that if this amount were to be put in rate base, the Company would obtain cash revenues to pay the financing costs it incurs on the expenditures. Because the Company would stop accruing Allowance for Funds Used During Construction ("AFUDC"), earnings would be offset and no additional earnings would be realized, only improved cash flow. Placing $261 million of CWIP into rate base would generate $33 million of additional revenue, or $20 million after income taxes, of additional cash flow annually. Mr. Brandt testified that the Company's FFO/Debt ratio would improve by an additional five-tenths of a percent in each of the next several years. (APS Exhibit 5, pp. 26-27.) In addition to improving the Company's credit metrics, moving the CWIP into rate base would also reduce future revenue requirements from customers.

APS also proposed that, similar to CWIP, increasing depreciation expense would improve the Company's credit metrics, reduce future revenue requirements from customers, and not increase the Company's earnings. According to APS witness Brandt, a $50 million across-the-board increase in depreciation expense would generate $30 million after taxes of additional positive cash flow and improve the FFO/Debt ratio by approximately seven-tenths of a percent in each of the next several years.

b. Return on Equity/Attrition

APS argues that it is being deprived of a reasonable opportunity to earn its allowed return on equity because of attrition of earnings stemming from the lag in recovering capital expenditures. APS cites its decrease from a return of 8.4 percent for the twelve months ending March 31, 2003, to 5.7 percent for the twelve months ended June 30, 2006. APS says the reason for the earnings shortfall is the need to fund a huge capital expenditure program in recent years, coupled with the regulatory lag in recovering those expenses as part of rate base. APS argues that the "constitutional requirement that APS be given a reasonable opportunity to earn a fair return on its invested equity" is undermined, citing the *Bluefield* case. APS argues that it is not enough that it can file a rate case, because it may take a year or two for a new rate order to be implemented. Therefore, APS argues that the Commission should take measures to limit the impact of earnings attrition and afford the Company a reasonable opportunity to earn its allowed ROE. The Company proposed that the Commission grant it an "attrition allowance" of between 1.7 percent to 4.1 percent, to be added to the Company's allowed ROE, depending on the amount of the rate increase granted by the Commission.

The Company cites the following quote from the *Scates* case as support for its opinion that "setting an allegedly 'reasonable' ROE that the Commission knows (or reasonably should know) cannot actually be earned under present circumstances fails the constitutionally-mandated 'reasonableness' standard":

> Thus, the rates established by the Commission should meet the overall operating costs of the utility and produce a reasonable rate of return. It is equally clear that the **rates cannot be considered just and reasonable if they fail to produce a reasonable rate of return...** *Scates* at 533-34.

APS offers this justification for its proposed earnings attrition allowance of 1.7 percent to 4.1 percent: "In other words, simple math determines that, under present circumstances, APS will not have an opportunity to earn its allowed ROE unless the Commission adds the attrition allowances discussed above. Moreover, adding such an attrition allowance does not increase the Company's ROE to a level higher than the cost of capital, as found by the Commission, but rather allows the Company the opportunity to earn the cost of capital to which it is entitled." (APS Initial Brief, p. 31)

APS also proposed the Commission consider adopting a return on "fair value" rate base that is a higher return than the Company's weighted cost of capital. APS cites Decision No. 53537 (April 27, 1983) as support for the position that a return on "fair value" is the minimum reasonable return under Arizona's Constitution. APS witness Wheeler also testified that the Commission could "increase the allowed return on 'fair value' rate base to a level above that necessary to reflect the bare bones of capital. . . . In that vein, the Commission could give a greater weighting to reproduction cost new in establishing 'fair value' rate base while keeping the allowed return on that rate base treatment." (APS Exhibit 2, Wheeler Rebuttal, p. 19)

2. Parties' Positions

a. AUIA's Position

The AUIA recommended that the Commission adopt the Company's requests for CWIP and an across-the-board annual increase of $50 million in allowed depreciation expense, and also recommended an additional 1.7 percent attrition adjustment.

b. RUCO's Position

In response to APS' assertion that case law requires the Commission to consider projected impacts of rates to insure that rates will produce a reasonable rate of return, RUCO noted that the Commission has used the traditional rate making approach to determine rates based upon an examination of the expenses, revenues, and investment in a twelve month period historical test year. RUCO further noted that it was unaware of any Arizona case that overturned a Commission rate decision on the basis that the historical test year approach inevitably fails to satisfy constitutional requirements. RUCO pointed out that in one way, the Commission's analysis of cost of equity does look to the future to determine future returns. To the extent that there is a requirement that the Commission consider future impacts, RUCO asserts this analysis satisfies that requirement. RUCO argues that Commission Decision No. 53537 (April 27, 1983)[34] does not support for APS' position that rates should be set on financial projections. RUCO argues that APS' witness Wheeler quoted a portion of the discussion which explained why both non-recurring revenues and expenses should ordinarily be deleted from test year operations, not that rates should be set on unknown estimates of future events.

RUCO explains that projected financial results would be a poor basis upon which to set rates, because financial forecasts can be easily biased based on the assumptions on which they are established. RUCO cited "future customer levels, consumption levels, conservation, weather, plant operation efficiency, generation resource mixes, fuel and purchased power prices, management decisions, employee productivity, and costs of debt financing" as some of the assumptions that must be made in order to project a utility's financial results. (RUCO Initial Brief, pp. 5-6) RUCO stated that the Company's calculated credit rating metrics are based on the same types of projections and are only as reliable as the assumptions and guesswork on which they are built. According to RUCO, such a projection is no more appropriate as a basis for setting rates merely because it may be used by debt rating agencies. RUCO urges the Commission to continue to establish rates on an evaluation of results achieved in a recent test year, an approach which both the Arizona courts and the Commission

[34] RUCO Exhibit No. 1

have found to be reasonable and constitutional, and not accept APS' offer to set rates based on a "shaky foundation of assumptions and projections of unknown, and unknowable, future events."

RUCO argues that CWIP is routinely excluded from rate base because it does not meet the used and useful rate making standard, which requires assets to actually be in service and providing a benefit to customers before they are included in rates. RUCO agreed that rate base treatment does not change a utility's level of earnings, but argued that utility regulators rarely allow CWIP to be included in rate base, and then, only in extraordinary circumstances, which RUCO does not believe exists.

RUCO argues that APS' proposal for accelerated depreciation is asymmetrical because it automatically increases rates for depreciation on new assets, but does not decrease rates for asset retirements. It also does not decrease rates for the decline in rate base or look at deferred income tax impacts, changes in debt or equity costs.

RUCO opposes the Company's proposed attrition adjustment to increase the authorized return on equity because it is biased against customers, looking only at the aspects of regulatory lag that are disadvantageous to the Company and ignoring other aspects that benefit the Company. Further, RUCO argues that because it is based on estimates of future events, it has the same problems as the financial projections.

c. Phelps Dodge/AECC's Position

Phelps Dodge/AECC recommends that the Commission deny APS' request for an attrition adjustment. It believes that the proposed adjustment would "effectively ignore the massive efforts the Company undertook to prepare a historical test year analysis and neutralize any revenue adjustments made by Staff or Intervenors to APS's proposed revenue requirements." (Phelps Dodge/AECC Initial Brief, p. 16) Phelps Dodge/AECC also opposes APS' requested depreciation adjustment because it is not based on detailed and systematic depreciation rate studies and would not necessarily be FERC-account specific. It stated that the request appears to be a "gratuitous attempt to increase near-term cash flow without an underlying basis corresponding to the true life expectancy of the plant being depreciated. As such, it gives rise to serious inter-generational equity concerns". (*Id.* at 17)

d. Staff's Position

Staff argues that the Commission should reject the Company's proposed "attrition adjustments" as both meritless and untimely raised. The Company's initial testimony and exhibits were not developed upon financial integrity issues, but upon an historic test year ending September 30, 2005, and the majority of Staff's analysis was focused on rising fuel and purchased power costs and issues concerning the PSA and timely recovery of those costs. Because of the timing of APS' assertion and request for an attrition adjustment, the parties had very little time to conduct discovery and analyze the Company's financial projections and forecasts. Staff urges the Commission not to allow or encourage APS to undermine the rate case examination and hearing process by adopting adjustments that have not been subjected to scrutiny.

Staff urges the Commission not to adopt APS' request for an attrition adjustment because outside of fuel and purchased power costs, Staff's analysis shows that APS' cost of providing service has been, and continues to be, adequately recovered through existing base rates. Staff believes that its recommendations to significantly modify the PSA, including eliminating the 90/10 sharing and the recommendation for a forward component, as well as other modifications, will significantly diminish the likelihood of cash flow constraints from delayed recovery of fuel and purchased power expense.

Staff believes that any "attrition" that may have occurred was related to the delay in the recovery of APS' fuel and purchased power costs, and that if Staff's PSA recommendations are adopted, "attrition caused by such delay should be virtually eliminated." (Staff's Initial Brief, p. 5)

As evidence against the need for APS' claimed earnings attrition, Staff points out that the existing PSA includes demand charges. Decision No. 67744 contained a self-build moratorium and until that expires, Staff states that APS will probably meet the need for new generation capacity and energy caused by growth through purchased power agreements. The purchased capacity paid for through the demand charges replaces the need to build generating capacity that would otherwise be required to meet customer growth. Staff stated that "demand charges are often excluded from such clauses because growth in retail sales will often be available to offset or 'pay for' the incremental demand costs incurred to serve new load." Staff argues that because the existing PSA allows demand charges to be passed through the adjustor, any attrition related to production costs is significantly addressed through the recovery of demand charges, making the growth in retail margins available to a much larger extent to meet cost increases related to growth in distribution plant and to recover cost increases caused by inflation over time. (Staff Initial Brief, p. 4)

Staff recommended that if the Commission were to adopt an attrition adjustment, it should adopt either the CWIP or the accelerated depreciation proposal, as they both result in accounting changes that will eventually yield reductions in rates for future ratepayers. According to Staff, the other attrition adjustments would not produce direct benefits for ratepayers, but would increase earnings for shareholders.

In its Reply Brief, Staff states that APS' argument that the Commission must grant the entire rate relief requested or it will face "financial ruin" is based on three main assertions: 1) That the Commission is required as a matter of law to consider the projected impact of a rate decision on APS' financial criteria; 2) the forecasts show that, from a quantitative view, that APS will not meet the required credit metrics to maintain an investment grade rating under either Staff or RUCO's proposals; and 3) that customer growth is greater than the revenues generated by that growth, thereby causing the rates to be inadequate.

Staff argues that the Commission is not required, as a matter of law, to consider the projected impact of a rate decision on APS' financial criteria. Staff argues that the *Hope* and *Bluefield* cases do not support APS' position, but rather conclude that for purposes of deciding whether a rate decision is confiscatory for purposes of federal due process, it is the end result that is significant, not the specific method. (Staff Reply Brief, pp. 1-2.)

According to Staff's analysis, the cases identify three factors that determine whether rates satisfy federal constitutional standards: The return should be reasonably sufficient to assure confidence in the financial soundness of the utility, and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. *Bluefield*, 262 U.S. at 693.

Staff states that the courts did not identify any one method for satisfying the factors, but indicated that what constitutes just compensation "depends upon many circumstances and must be determined by the exercise of a fair and enlightened judgment, having regard to all relevant facts . . . ." *Id.* at 692.

Staff argues that instead of urging the Commission to consider all the relevant facts, APS asserts that the Commission should disregard the evidence presented by Staff and RUCO, and rely only upon the financial projections. Staff argues that this is the complete opposite of the holdings in the *Hope* and *Bluefield* cases. Staff believes that APS' argument implies that federal constitutional standards require the use of a future test year, but APS not only fails to cite any federal cases to support this theory but also fails to reconcile it with Arizona law.

Staff argued that the Commission should not rely on forecasts as a basis of determining rates. Arizona is an historic test year jurisdiction and case law supports Commission decisions setting rates using the historic test year examination. Staff cites Arizona cases that suggest that rates should be set in reference to an historic test year, and that the utility's rate base must be established by reference to the fair value of its property that is "used and useful" in providing public service. *See,* Ariz. Const. art. XV, § 14.

Staff points to language of the Arizona Supreme Court:

> It is clear, therefore, that under our constitution as interpreted by this court, the *Commission is required to find the fair value of the company's property and use such finding as a rate base for the purpose of calculating what are just and reasonable rates.* The *Hope* case cannot be used by the Commission. To do so would violate our constitution. The statute under consideration in that case prescribed no formula for establishing a rate base. While our constitution does not establish a formula for arriving at fair value, it does require such value to be found and used as the base in fixing rates. *The reasonableness and justness of the rates must be related to this finding of fair value.*
> *Simms. v. Round Valley Light and Power Co.*, 80 Ariz. 145, 151, 294 P.2d 378, 382 (1956) (emphasis added).

Staff noted that the *Simms* case indicated that "'fair value' focuses the Commission's analysis on the 'time of inquiry.'" *Id.* at 151, 153, 294 P.2d at 382, 382. Staff also cites other Arizona cases finding that the fair value concept is related to the time of inquiry: *Arizona Corp. Comm'n v. Arizona Public Service Co.*, 113 Ariz. 368, 370, 555 P.2d 326, 328 (1976); *Arizona Corp. Comm'n v. Arizona*

*Water Co.*, 85 Ariz. 198, 202, 335 P.2d 412, 414 (1959); *Consolidated Water Utils., Ltd. v. Arizona Corp. Comm'n*, 178 Ariz. 478, 482-83, 875 P.2d 137, 141-42 (App. 1993).

Staff believes that there are both legal and policy reasons for using the historic adjusted cost-of-service test year as the basis for establishing rates. Staff believes that if the APS projections were helpful, the Commission might justifiably consider them. Staff, however, believes that they are not helpful and should be disregarded.

Staff points out that the projections were prepared on a total company basis, not on the ACC Jurisdictional basis used to set rates. Thus, they include APS' FERC regulated transmission operations. APS is planning on filing a transmission rate case at FERC and Staff concludes that APS believes that it is currently under-earning on its transmission investment. Staff's witness Dittmer roughly calculated that at least a part of the "total company" earnings shortfall is apparently caused by under-earnings on the Company's FERC regulated transmission assets. Staff argues that "reliance on 'total company' financial metrics that are known to include an earnings shortfall from 'non-jurisdictional' business operations is not an accurate measure by which to set rates." (Staff Reply Brief, p. 5). If the Commission were to use an attrition adjustment and unintentionally remedy earnings shortfalls on the Company's FERC assets, the result would likely be a 'double recovery' with Arizona ratepayers paying for the same alleged earnings shortfalls once through retail rates and once again through FERC transmission rates via the transmission adjustor. Staff argues that transmission cost recovery is a matter regulated by FERC, and any rate relief related to transmission should be addressed at FERC.

Staff's audit of the Company's current rates shows that the non-fuel costs are being recovered, contrary to APS' claim that the cost of customer growth is greater than the revenues generated by that growth. In response to APS' November 28, 2006, letter to Chairman Hatch-Miller, Staff notes that it was produced after the cut-off date for discovery and Staff has not had the opportunity to review the data, calculations, or assumptions underlying the letter. Staff's witness did note some shortcomings with the document, however. According to Staff, the document seems to have examined growth in gross plant in service amounts to serve customers, and fails to capture the fact that net production plant has actually been declining, and fails to account for the growth in depreciation reserve that offsets the higher costs of new gross plant added to serve new customers. No economies of scale were considered; other offsets to serving new customers were not considered; the assumption of the marginal cost of debt underlying the new plant is significantly overstated; and the document does not distinguish which gross plant additions are being added to achieve operational savings. Staff notes these concerns but emphasized that it has not had the opportunity to conduct discovery and analysis, and that the document should be subjected to scrutiny before it is relied upon.

Staff believes that APS' need for rate relief is driven by under-recovery of fuel costs, and its audit shows that, except for fuel costs, rates have been adequate to cover non-fuel items. Staff argues that any attrition related to production (generation) costs is significantly addressed through the recovery of demand charges in the PSA, and growth in retail margins is available to a much larger extent to meet cost increases related to growth in distribution plant and to recover cost increases from inflation. According to Staff, the existence of this PSA feature significantly undermines APS' claim that it will suffer attrition.

Staff believes that fuel costs have been generously addressed through the use of a forecast of calendar year 2006 to establish the base cost of fuel and purchased power, the changes recommended by Staff to the PSA, including the elimination of the 90/10 sharing, the $776 million cap; and the 4 mil bandwidth. Staff believes that these modifications, together with other recent Commission decisions concerning APS, show regulatory support for APS.

3. Analysis

APS argues that it needs nothing less than the total amount of its requested increase for two reasons: to improve its cash flow so that its credit metrics (specifically its FFO/Debt ratio) are high enough to keep it from being downgraded to "junk" status; and to enable it to actually earn the return on equity that the Commission uses to set rates for electric service. Essentially, APS' position is that it does not matter what revenues the cost of service ratemaking analysis indicates APS needs to collect to provide just and reasonable rates for electric service. APS argues that using an historical test year approach will not provide adequate revenues and to support that argument, APS uses projected financial information and assumptions about events that may or may not occur in the future.

In his rebuttal testimony, APS witness Brandt testified about what measures the Commission could take to help APS gradually improve its creditworthiness. He indicated that "timely recovery of costs sits atop the list." (APS Exhibit No. 4, Brandt Rebuttal, p. 22) We believe that APS' cash flow problems will be sufficiently addressed through our adoption of Staff's forward looking PSA and the higher base cost of fuel and purchased power that we are adopting in this Decision. )See discussion below) APS' recent cash flow problems resulted from the implementation of a PSA that did not have mechanisms available to timely address recovery of the dramatic increase in fuel and purchased power costs after hurricane Katrina. The PSA mechanism adopted in this Decision uses a higher base cost of fuel and purchased power, and it also incorporates a forward-looking cost of fuel and purchased power that is based upon projected costs that are expected to be experienced during the time that PSA adjustor is in effect. It does not contain a "cap" on the total amount of costs, it does not have an annual or lifetime 4 mil bandwidth limit, and the 90/10 sharing provision was modified per APS' request to exclude certain types of costs. This new PSA will have a dramatic effect on APS' ability to timely recover its costs, and upon its cash flow.[35] Essentially, APS will collect more of its costs sooner. APS' projected financial information failed to properly account for this effect and is not reliable[36] for this and other reasons discussed herein.[37] Accordingly, we will not adopt APS' proposed adjustments to increase its cash flow.

Although APS argues that it has not been allowed to earn a reasonable return on its equity, we note that for over at least the past fifteen years, the rates that APS charges are rates to which it has agreed. The use of a historical test year is designed to examine a defined time period and examine the costs, revenues and plant associated with providing the utility service. This "snapshot" of a

---

[35] The fuel and purchased power costs are two thirds of APS' operating costs. Tr. Vol. IV, pp. 712-12.

[36] APS has not clearly demonstrated how its financial projection model handles growth in sales and revenues throughout the year and how PSA collections are included. Tr. Vol. III, pp 531-35 (PSA reconciliation) and Tr. Vol. V. pp 1154-57.

[37] Contrary to the statement in the APS brief that Mr. Fetter "independently analyzed APS' financial forecasts," Mr. Fetter merely relied on the Company's forecasts and agreed, upon cross examination by RUCO's counsel, that he relied on the Company's inputs and did not review them; agreed that if the inputs were wrong, then the forecasts would be wrong; and agreed that with forecasted data, the further you go out, the less reliable the forecast would be. (Tr. Vol. IV, p. 1254-55; 1297). Mr. Fetter did use the Company's forecasts and the S&P methodology to independently analyze the likely credit rating impact of the parties' proposals, and concluded that if the Commission were to adopt either the Commission Staff or RUCO proposals, APS' credit ratings would likely suffer a rating downgrade to below investment-grade. (APS Exhibit No. 24, Fetter Rebuttal, p.14)

utility's operations establishes the relationship between the company's customers and the cost of providing service to those customers, and therefore, the level of revenues that is necessary to provide safe, reliable and adequate service as well as provide the company an opportunity to earn a reasonable rate of return. The results of an historic test year analysis are useful in setting rates because they are representative of ongoing operations. Once rates are set and customers start paying the new rates, those costs of service established in the rate case can change. They can increase and they can decrease. It is the Company's responsibility to monitor its financial condition and seek approval for new rates when the relationship established in the prior rate case no longer allows it to provide the appropriate level of service or earn a reasonable return.

APS argues that it will not earn its allowed return because of the growth that it will experience when the new rates are in effect. In order to determine whether the cost of providing service to new customers outpaces the expenses, we would need to evaluate and compare the cost of providing service to an existing customer during the TY to the cost of providing service to the same customer at some point in the future. Rates established by the Commission are not discriminatory, so a residential customer, no matter how "new" or "old" that customer may be, pays the same rate for service. APS has not provided such a breakdown comparing the cost of providing service to a specific class of customer now and at some future point. To compare the cost of providing residential service during the test year to the projected or actual construction costs incurred over a defined period of time divided by the number of new customers does not provide us with the all of the information necessary to determine whether, or how much, the costs exceed the expense.[38]

After reviewing and analyzing all the testimony and evidence, we find that the evidence presented by APS does conclusively show that the costs of growth will exceed the revenues accompanying the growth. The exhibits presented by APS in support of its argument are very general and do not include an analysis of offsetting economies of scale or other efficiencies that will occur as fixed costs are spread over more customers.[39] APS' analysis is also skewed by including total company construction costs in its analysis, and including not only the costs for new customers, but

---

[38]See, e.g. APS Exhibit No. 59.

[39] See, e.g. APS Exhibit No. 77, which does not include O&M expense.

also ongoing refurbishments and replacements of plant and equipment.[40] The Company did not respond to Staff's argument that including demand charges in the PSA significantly addresses any attrition costs and that the growth in the retail margins would be available to a much larger extent to meet cost increases related to growth in distribution plant and to recover cost increases caused by inflation.[41] APS failed to demonstrate that the near-term costs of customer growth are greater than the increased revenues generated by that growth.

APS defined attrition as "the tendency of the utilities rate of return to diminish over time because of operating costs that increase faster than revenue, capital costs growing faster than earnings or a combination of both." However, just because the rate of return may diminish over time, it does not mean that the rates and charges for service are no longer just and reasonable. According to the *Bluefield* court: "A rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market and business conditions generally." (*Bluefield*, at 693) The Commission uses a return on equity, cost of capital, and eventually a rate of return on FVRB to set rates and charges that are just and reasonable – it is not the rate of return or the level of revenues received that must be just and reasonable, but the rates and charges. (Arizona Constitution Article 15, §3) Although it may be difficult to understand the distinction, the approved rates and charges reflect the underlying cost-based relationship between the cost of providing service and the revenues needed to provide that service. As the number of customers increases over time, total revenues will increase, but whether total expenses will increase proportionally, is unknown and unknowable. This is because some "fixed" expenses built into existing rates and charges can be spread over more customers before the expense level increases. Another unknown variable is that the total level of expenses may increase or decrease due to factors that are unrelated to the number of customers. Plant in service and rate base amounts will also change over time. Furthermore, the fair

[40] See, e.g. APS Exhibit No. 27

[41] We also note Decision No. 55118 (July 24, 1986), which re-examined APS' Purchased Power Fuel Adjustment Clause (PPFAC) included the following findings of facts: "18. The inclusion of demand or capacity costs in APS's PPFAC, when such inclusion would bring the total-per-Kwh costs of purchased power above that of APS's alternative fuel cost, results in a partial "double charging" of ratepayers for generating capacity. 19. The inclusion of demand or capacity in APS's PPFAC for purchased power contracts in excess of ninety (90) days is unnecessary and might result in a partial "double charging" of APS's ratepayers for capacity. Decision No. 55118, p. 25.

value rate base rate of return used to set rates and charges for service does not equate to the total company's earned returns. The concept of rate base includes only the reasonable and prudent investments that are necessary to provide service and may or may not be the same as the total company's plant.

Therefore, "attrition" in and of itself, is not especially significant.[42] It is a normal, expected, and to some degree, necessary, component of the rate setting process. It serves as a "trigger mechanism" for a utility, a way of determining at what point the existing rates and charges are no longer "just and reasonable." It is at that point that the utility must make a determination to file a rate application, where that "relationship" between costs and service can be re-established to provide rates and charges that are just and reasonable. The newly established just and reasonable rates and charges may result from a rate of return that is higher or lower that the rate of return used to set rates in the previous rate case. Granting APS' request would artificially increase a rate of return that would set just and reasonable rates and charges, would modify the meaning of fair value rate base, and would distort the relationship between cost and revenues. This attempt to account for unmeasureable and unknown future actions and events would necessarily create unjust rates and charges immediately in order to possibly achieve just and reasonable rates at some unknown point in the future.

Further, to accept APS' position that it should be allowed revenues over and above the amount that is necessary under an historical test year approach would render meaningless our all of our findings of prudency and reasonableness of APS' operating expenses and plant, and ultimately, the concept of a fair value rate base.[43] As discussed by RUCO's witness, regulators "seek to set the allowed return equal to the cost of equity capital for the same reason they set the return allowed on utility debt equal to the cost of that type of capital. Utility rates should be cost-based. That includes the cost of money – equity and debt. Investors understand that utility returns are allowed and earned on the book value (original cost less depreciation) of the utility's plant investment. That long-standing regulatory paradigm has been in existence for many, many years and, through

---

[42] Because the utility's rates are set on a jurisdictional basis and it is allowed to earn a return on FVRB, the moment that rates are established, there will be "attrition" if one applies the fair value rate of return to Total Company plant in service instead of FVRB.

[43] Tr. Vol. III, pp 536-7.

informationally efficient markets, utility investors are aware of that fact." (RUCO Exhibit No. 11, Hill Direct, pp 19-20.)

4. Resolution

The parties have expended a lot of effort arguing over what the Commission must consider when establishing rates. Upon review of the constitution, statutes, and case law, it is clear to us that we must "consider" all the relevant facts and circumstances, and that our constitutional duty is to prescribe "just and reasonable rates and charges" after ascertaining the fair value of the public service corporation's property within the state.[44]

The Commission has used the historical test year cost-of-service analysis for many years as a way to analyze what rates and charges are just and reasonable when setting rates for regulated utilities. We use the application of a return on fair value to establish a level of revenues that is just and reasonable. The end is not to achieve a certain, prescribed return, but to set just and reasonable rates and charges. Our duties under the constitution also require us to ascertain the fair value of the property, and according to *Simms*, such value is required to be "used as the base in fixing rates" and the "reasonableness and justness of the rates must be related to this finding of fair value." Thus, it would not be constitutional for us to set rates based upon the achievement of certain targeted financial credit metrics or return on equity.

We believe that the rates and charges that we adopt herein are just and reasonable, and will assure confidence in the financial soundness of APS, and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. In support of this conclusion, we specifically note the increase in rates, including the large increase in the base cost of fuel and purchased power, the

[44] APS' uses a partial quote of *Scates* as support for its opinion that "setting an allegedly 'reasonable' ROE that the Commission knows (or reasonably should know) cannot actually be earned under present circumstances fails the constitutionally-mandated 'reasonableness' standard." APS inappropriately omitted the entire sentence as set forth in the complete quote: "Thus, the rates established by the Commission should meet the overall operating costs of the utility and produce a reasonable rate of return. It is equally clear that the rates cannot be considered just and reasonable if they fail to produce a reasonable rate of return **or if they produce revenue which exceeds a reasonable rate of return**." *Scates v. Arizona Corporation Comm'n*, 118 Ariz. 531, 578 P.2d 612 at 533-34. (emphasis indicates omitted portion of quote). The "equally clear" language does not apply to the fact that rate actually must be earned, as APS argues, but that when setting just and reasonable rates and charges, those rates and charges must not over- or under-produce a reasonable rate of return.

allowance for demand charges in the PSA, the forward looking component to the PSA adjustor, the elimination of the cap on total fuel and purchased power costs, the elimination of the bandwidth limit on increases in the adjustor,[45] our determination concerning the level of Palo Verde outage costs that were imprudent, the implementation of an EIC, and the fair value rate of return used in our calculation of just and reasonable rates.

We believe that APS should also continue its efforts to increase its creditworthiness by improving its performance at its nuclear power plants and avoiding outages while maintaining safety; seeking rate relief from FERC for its under-recovery of transmission costs; and by seeking rate relief from the Commission when necessary and assisting in processing applications expeditiously and without errors.

Based upon the discussion contained herein, we find that no additional adjustments or modifications to our traditional ratemaking method are necessary or appropriate to set just and reasonable rates.

### B. Authorized Increase

With the adjustments adopted herein, the adjusted test year operating income is $191,966,000. Applying the fair value rate of return to the FVRB results in a required operating income of $366,371,000. This is $174,405,000 more than the adjusted TY income under existing rates. The required increase in gross annual revenues is $286,147,000 or an 11.06 percent increase over TY revenues.

## IX. COST ALLOCATION AND RATE DESIGN

### A. Cost Allocation

Once the required revenue level has been established, the next step in the rate setting process is to determine the appropriate rates to be charged to each class of customers. The starting point in the rate design process is the cost-of-service study ("COSS") which is designed to allocate the costs of providing service to customers. Other considerations are also taken into account in designing rates, including rate stability and continuity, customer understandability, and ease of administration.

---

[45] APS Exhibit No.7, Robinson January 31, 2006, Direct testimony, p. 20. "S&P has characterized the Company's PSA as 'relatively weak' due to the Total Fuel Cost Cap, the four mill limit on the PSA Factor, and the length of time needed to actually recover fuel and purchased power costs. Other analysts have made similar observations."

APS prepared a COSS with the twelve-month period ending September 30, 2005 as the test period, to perform jurisdictional allocations to separate the retail portion of APS' operations from the non-retail portion and to determine the overall retail revenue requirements and to further allocate costs among customer classes. Staff recommended one modification to the COSS retail class allocation factors. Staff's modification concerned the proper method for allocating production demand costs – the costs associated with the nuclear, coal, and gas-fired generation facilities. APS used the Four Coincident Peak ("4CP") method which allocates demand-related production and transmission costs to major customer classes using the average of its four test year monthly summer (June, July, August, September) coincident system peaks.[46] This is the method that APS has used in its previous rate cases. According to Staff, the theory assumes that meeting hourly peak demand is the sole planning criteria APS uses to determine whether to incur generation fixed costs. Staff disagrees because costs are also incurred for its generation facilities to provide service during all the non-peak hours of the year.

Staff believes that the Company should use a Four Coincident Peak and Average ("4CP & Average") method instead of the 4CP method. The 4CP & Average method uses an energy-weighted approach to allocate production costs and considers the fact that electric production facilities are designed and operated to meet both peak and non-peak demands. Staff's 4CP & Average approach uses a weighted combination of the peak demand allocation factor used by APS along with an average demand (or energy-based) allocation. In the last APS rate case, Staff and RUCO opposed the 4CP method. Other Arizona utilities with summer peaking characteristics, such as Tucson Electric Power, have used a 4CP & Average method.

Parties analyzing APS' cost-of-service reached the following conclusions:

| Cost of Service Category | Rate of Return (percent) | | |
|---|---|---|---|
| | APS | Staff | AECC |
| Residential | 1.52 | 4.25 | 1.04 |
| General Service | 3.91 | 6.51 | 4.49 |

[46] Coincident peak demands are the measured maximum combined loads of all customers on the system in the single hour when overall system demand is the highest during the year.

| | | | |
|---|---|---|---|
| Water Pumping | 9.3 | 8.3 | 10.18 |
| Street Lighting | 2.05 | 2.18 | 3.27 |
| Dusk to Dawn | 5.78 | 5.98 | 6.26 |

APS witness Rumolo testified that because of "the magnitude of the requested revenue increase in this case, I was concerned that adopting an alternative demand allocation method for customer class allocations could introduce a higher degree of rate shock to some customers." (APS Exhibit No. 70, p. 3) Using the 4CP & Average approach to the COSS results in retail cost allocations shifting between customer classes, with more costs being shifted to general service, irrigation, and lighting service customers, and reduced allocation to residential customers.

AECC and the FEA oppose Staff's proposed modification to the COSS and recommend that the Commission use APS' 4CP method. AECC witness Higgins testified that "APS's retail demands are driven by summer usage" and that the Company's average peak in the four summer months is 50 percent greater than its average peak in the non-summer months. (PDM/AECC Exhibit No. 5, p. 3). AECC and the FEA argue that because the 4CP method allocates fixed production costs based on the average of system peak demands in the summer months, which is when APS' production capacity requirements are determined, the allocation of fixed costs is properly aligned with cost causation. AECC argues that the peak and average method used by Staff is conceptually flawed because average demand is already included in peak demand and is therefore counted twice in the allocation of costs. The FEA also argued that Staff's method produced an asymmetrical allocation of production plant and fuel costs, because although the 4CP & Average method allocated a higher percentage of fixed production costs to higher load factor classes, it did not allocate a similar higher percentage of the fuel-cost savings from baseload plants to these classes. The AECC recommended that if the Commission were to order that an energy-weighted method be used to allocate fixed production costs, then the Average and Excess Demand method should be used because it avoids the double counting of average demand.

We agree with Staff that an energy-weighting method for allocating production plant is appropriate for APS. However, we are not convinced that the method recommended by Staff is the method that should be adopted. AECC's recommended Average and Excess Demand method would eliminate the criticism that the average demand is being counted twice. We do note that the results of the energy-weighting method will shift costs and agree with APS that adopting it now may affect rates significantly. We will order that APS, in its next rate application, to propose an energy-weighting method that addresses the concerns raised in this case, and that will also consider the likely cost shifting that will be necessary as we determine the appropriate rate design in this case.

AECC proposed a modification to the COSS to allocate fuel and purchased power costs on the basis of each customer class' energy cost responsibility, taking into account the hourly costs of fuel and purchased power costs and hourly loads by customer class. APS agreed to this modification and no other party objected to its use.

In its rebuttal testimony, APS modeled the recommendations of Staff and AECC. (APS Exhibit No. 70, Rumolo Rebuttal, p. 9, and Attachment DJR-1RB). The results showed that on a class basis, the two recommendations tended to offset one another and produced results similar to APS' original filing. Essentially, we note that although the individual percentage numbers may differ, all of the COSS results have generally similar findings.

### B. Rate Design

APS proposes to spread the revenue increase on a roughly equal basis to the major classes of customers: Residential, General Service, Irrigation, Street Lighting, and Dusk to Dawn. Each would receive a percentage increase that is approximately the same result as the overall increase, even though the COSS results indicate that higher increases are supportable. APS also designed individual rate schedules to depart from strict cost-of-service when necessary so that the differences in individual customers' increases will be moderated to the extent that APS found reasonable. Phelps Dodge/AECC recommends that it is important to align rates with cost causation to the greatest extent possible, because it is fair to minimize cross subsidies among customers, and it sends the proper price signals which improves efficiency in resource utilization. AECC also recognizes that the concept of gradualism is appropriate to mitigate the impact of moving immediately to cost based rates. It recommends adopting a long-term strategy of moving in the direction of cost causation, and avoiding schemes that result in permanent cross-subsidies from other customers. The AECC proposed the following objectives:

1. Set residential rates midway between system average percentage increase and residential cost-of-service, as modified to include an hourly energy allocation:

2. Set the percentage increase for Street Lighting equal to Residential;

3. Set Rates E-34 and E-35 equal to cost-of-service, as modified to include an hourly energy allocation;

4. Set the percentage increase for Rate E-32, Water Pumping, and Dusk-to-Dawn equal to the respective cost-of-service for each, as modified to include an hourly energy allocation, plus the same percentage point increase necessary to fund the Residential rate mitigation. (PDM/AECC Exhibit No. 5, pp 15-18).

The FEA witness recommended that the interclass subsidies should be reduced by half, subject to no class receiving either a rate reduction or in increase greater than 150 percent of the average system rate increase.

Intervenor Kroger argues that although the results of the APS' COSS show large interclass subsidies are being paid from the General Service class to the Residential Class,[47] APS does not use the results in its rate allocation proposal and does not attempt to mitigate the cost disparities in this case. Kroger proposed that the Commission reduce class subsidies by 25 percent as an incremental step towards the objective of setting rates based on cost-of-service, or adopt the AECC proposal.

Kroger argues that APS' rate design proposal unreasonably penalizes high-load factor E-32 customers. The Company's proposed rate design includes an overall increase to E-32 at about the average retail increase, but within the class, the high-load factor customers will experience a larger increase. The proposed percentage increase in the demand charge for demands in excess of 100 kW is 18.1 percent, and the increase in demands below 100 kW is 4.9 percent. Kroger also believes that the Company's proposed percentage increase to the generation energy charge is not reasonable. Kroger recommends that the E-32 delivery charges and generation charges be increased by an equal percentage amount.

RUCO recommended that as far as is possible, the rate increase should be spread evenly

[47] Kroger's witness testified that APS' COSS showed that the residential class is paying less than 60 percent of its allocated cost-of-service, and general service customers are paying approximately 150 percent of the system average. Kroger Exhibit No. 1, pp. 11-12.

across all rate schedules. RUCO noted that although some parties are recommending that rates be moved toward cost-of-service, rates were moved toward cost-of-service in the rate case two years ago and since then there have been numerous increases due to fuel costs. RUCO believes that rate stability and continuity are necessary now more than ever.

Staff in general favors a rate spread that reflects the results of the COSS, as opposed to an across the board increase. Staff's COSS indicated that the Residential and Street Lighting customer classes are earning a return less than the system average, while the General Service, Water Pumping and Dusk to Dawn classes are earning greater than the system average rate of return.[48]

In designing its proposed residential rates, APS proposed maintaining the current basic service charge, increasing differentials between on- and off-peak periods, and increasing the differential between summer and winter. Staff's approach was the same as APS', but Staff's proposed rates reflected the difference in the parties' recommended revenue requirement and Staff's proposed revenue spread. Staff recommended an increase for the residential class as a whole that is greater than the system average. Staff recommended that Residential rates EC-1, ET-1, and ECT-1 receive a greater than average increase because these rate classes are underperforming relative to the rest of the residential class as well as to the system average, and that E-12 receive an increase that is less than the system average because this rate class is earning slightly more than the system average. Staff recommended that the rate designs for ET-2 and ECT-2 remain revenue neutral compared to ET-1 and ECT-1's respective adopted rates. Staff also recommends that ET-2 incorporate off-peak kilowatt-hour winter rates that are less than off-peak summer rates.

Commission Decision No. 67744 "froze" rate schedules E-10 and EC-1, and Staff proposed two scenarios to use in determining the proper rate spread for the interclass Residential cost-of-service categories, but only recommended the scenario that complied with Decision No. 67744. Staff's recommended customer transition plan for Residential customers on E-10 and EC-1 modified APS' proposal by giving customers on these schedules one year instead of one month to choose a new rate schedule. Staff believes that a one year transition period is appropriate because the increase

[48]COSS Residential ROR Index 0 .81; General Service 1.25; Water Pumping 1.59; Street Lighting 0.42; and Dusk-to-Dawn 1.15. Staff's proposed revenue spread resulting ROR index: Residential 0.86; General Service 1.19; Water Pumping 1.34; Street Lighting 0.44; Dusk-to-Dawn 0.89. (Staff Exhibit No. 22, Andreasen Direct, pp. 3-5.)

is fairly significant and customers are likely to need more time to evaluate all other available rate options, including time-of-use ("TOU") and demand options. Staff recommended that APS continue to educate the customers during the transition period. Staff agreed with APS' proposal to move customers to default rates if they fail to elect a new rate during the transition period. APS agreed with Staff's Residential rate design recommendations, and we will adopt them.

Staff recommended an increase for the General Service class as a whole that is less than the system average increase. Because rate schedules E-34 and E-35 are underperforming relative to the rest of the General Service class and the system average, Staff recommends a higher than average increase for those schedules.

Although Staff recommended an increase less than the system average for the E-32 category as a whole, Staff believes that the E-32 (1,000 kW or greater) category should receive a greater increase than the other E-32 categories (0-20 kW), (21-100 kW), (101-400 kW) and (401-999 kW) because it is underperforming in comparison to the others. Staff recommends that in its next rate case, APS should propose to replace general service rate schedule E-32 with alternate General Service schedules that divide E-32 usage into small, medium, and large categories or other appropriate divisions. Staff believes that multiple size-based categories for General Service customers would make it easier to tailor rate structures to different size customers with similar usage characteristics. APS and DEAA agreed with this recommendation. Staff agreed with DEAA that E-32 TOU should be replaced with size sensitive rates and recommends that APS file tariffs for the E-32 TOU that are consistent with the E-32 rate structure that it proposes in the next rate case. Staff agrees with AECC that the same rate increase that is applied to E-32 should also be applied to E-32 TOU in order to maintain the same relationship between the two schedules that was established in the last rate case.

Staff recommended that general service customers on the experimental TOU rates E-21, E-22, E-23, and E-24 not be automatically switched to the default rate of E-32 TOU, but that the customers would 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. APS has agreed to Staff's recommendation.

Staff noted that in the last rate case, general service rate E-32 was completely redesigned to remove the demand charge for customers under 20 kW and to significantly increase the demand rate for customers above 20 kW. The change was intended to move generation distribution capacity rates closer to cost and resulted in some lower load factor customers with rate increases significantly greater than average due to the higher demand rate. Therefore, Staff is concerned about raising demand rates significantly in this case and recommends that the proposed demand rates for E-32 not be raised significantly over the levels proposed by APS. We agree with the Staff recommendations for General Service.

During the hearing, APS agreed with AECC that transmission rate design should maintain the same character in terms of demand or energy as reflected in Schedule 11 of APS' Open Access Transmission Tariff ("OATT"), with the smallest E-32 customers (billing demands less than 20 kW) being billed in accordance with the OATT energy charge, and the E-32 customers with billing demands of 20kW or greater billed in accordance with the corresponding OATT demand charge. In its Reply Brief, Staff opposed AECC's proposal to pass through the transmission charge in the demand portion of Rate E-32 because Staff is concerned that it will result in a substantial rate increase to a segment of APS' customers who have recently experienced rate increases that are significantly greater than the system average. However, it appears that AECC modified its proposal to use the OATT energy charge, not the demand charge, to set the rates for the smallest E-32 customers, and thereby somewhat alleviate Staff's concerns. With this understanding, and to the extent reasonable considering Staff's concerns, we will start the move toward the AECC proposal.

APS increased the voltage discounts for customers served at transmission voltages from $4.30 per kW to $4.52 per kW. The FEA requests that the Commission also authorize an increased voltage discount for customers served at primary substation and primary lines. The FEA recommended that the Commission adopt a discount of $4.72/kW for transmission customers, $4.04/kW for customers served from a primary substation, and $0.79 for customers served from primary lines. The proposed discounts are cost-based and do not impact the revenue requirement of any other rate class. No party opposed the voltage discounts as proposed by the FEA and we will adopt them.

It is clear from the results of all cost-of-service studies that there are subsidies in APS' current rate structure. This means that some classes of customers are providing a subsidy to others[49] and that some customers in a class subsidize others in the same class. Several parties have recommended that the Commission begin to close that gap, and move rates closer to the class' cost-of-service now. We agree that some movement should be made in that direction, but given the fact that current rates have been in effect for only two years and they were designed to move rates closer to cost-of-service, we do not want to modify the current rate structure dramatically. Accordingly, given the level of revenues that we authorize herein, we will generally adopt the Company's rate design as modified by Staff and with the AECC proposal for transmission rate design as agreed to by APS, and the voltage discounts as proposed by the FEA.

### C. <u>Schedules</u>

Staff made some recommendations to APS' Schedule 1 which is the rate schedule that sets forth APS' terms and conditions of service. APS proposed some clarifying changes and it also changed the way its after-hours charge for other services is assessed, to include a charge of $75 per crew person per hour. Staff opposes this APS change, noting that it has the potential to create customer confusion and customers will not have advance knowledge of the charge. Staff recommends that the after-hours charge remain at $75 per trip. APS objected to Staff's recommendation because the special services charged for under Section 2.2.4 are being performed outside of normal work hours and usually require a crew with more than one person. The Company believes that if Staff's recommendation is adopted, the Company will not recover its costs for the service and other customers will pick up the costs. Also, the Company argued that Staff's proposal does not send the correct price signal to customers as to the true cost of requesting extensive types of after-hours work. We believe that APS should be able to collect the costs of the work performed for special services, but are concerned that customers may not know the cost prior to requesting such service. Accordingly, we will allow APS to make this change in its Schedule 1, as long as it includes a provision requiring customers to be given notice of the charges prior to the customer incurring any such charge. The proposed notice language should be in a form reviewed and found acceptable by

---

[49] Having an energy-weighted allocator for production costs in the next rate case will give us better information as to exactly how much classes such as Residential need to move toward cost-of-service.

Staff. Staff also recommended that the wording for Sections 4.3.2.3.4, 5.4, and 6.4 on Schedule 1 included in APS document number 10679 be adopted[50] and that APS include a definition of Multi-Unit Residential High-Rise Development on Schedule 1. We will adopt these Staff recommendations. No party objected to the other changes to Schedule 1, and therefore we will adopt them.

Staff also made recommendations concerning APS' Schedule 3, which sets forth APS' line extension policy. Pursuant to Schedule 3, APS can collect the costs of installing distribution-related facilities necessary for the development of new homes and businesses in APS' service area. APS proposed to move away from a free-footage-based allowance to a dollar-based allowance. Staff believes that this will improve APS' ability to recover its distribution costs associated with new growth. In its rebuttal testimony, APS agreed with the Staff recommendations and provided a redlined exhibit showing the changes. Staff requested further clarifications and in rejoinder testimony, APS accepted those as well.[51] We will approve the modifications to Schedule 3.

APS proposed changes to Schedule 4 which addresses the practice of totalizing meter readings when customers at a single premise receive service through multiple service points. APS proposed language to address the emergence of new metering technology that allows for electronically totalized demand and energy, in addition to physical wire interconnections. No party objected to these changes, and we will adopt them.

AZ-ICE recommends that APS be required to retain E-20 as a permanent rate, in an "unfrozen" state. This would allow movement to the E-20 rate for existing Houses of Worship currently on other rates and would allow new Houses of Worship to use the E-20 rate also. AZ-ICE also requests that the Commission keep the experimental rates E-22 through E-24 in an unfrozen status so that they are available to current and future Houses of Worship. In the alternative, AZ-ICE urges the Commission to retain E-20 in an unfrozen status and either E-23 or E-24 unrestricted for present and future Houses of Worship. AZ-ICE believes that Houses of Worship should not be forced onto E-32 or E-32 TOU as the Company proposes, as it would defeat the creation of the

[50] Staff Exhibit S-23, Andreasen Surrebutal, Exhibit A.
[51] In response to questions during the hearing from Commissioner Mayes, the Company's provided late-filed Exhibit No. 105 which included an analysis of the impact of alternative equipment allowances.

Houses of Worship rates established by the Commission in earlier years.

APS is not proposing to eliminate Schedule E-20, which is available only to Houses of Worship. E-20 was frozen as part of the Settlement Agreement in the previous rate case, and it would remain frozen under APS and Staff's proposals. The Settlement Agreement also provided for the elimination of other already frozen, experimental, time of use rate Schedules E-21, E-22, E-23, and E-24. These rates were limited participation rates established several years ago on an experimental basis. In their place, APS now offers "an improved" Schedule E-32 TOU which is open to all customers who want to take advantage of lower off-peak prices. APS states that new "Houses of Worship" and other general service customers that have primary hours of operation in the evening or weekend can benefit from the new schedule. Historically, APS has had administrative problems determining what classifies a customer for a house of worship rate. APS witness Rumolo testified as to the difficulties trying to fairly classify a mixed use facility and whether it is eligible for the E-20 rate.

While we understand that some Houses of Worship are not longer able to get on the E-20 rate, we agree with APS and Staff that there is now a good alternative to that rate that can be beneficial. APS has articulated a valid reason for not allowing additional customers to go on rate schedule E-20 and has offered an attractive and fair alternative to all of its customers, including members of AZ-ICE. We encourage APS to meet with the members and representative of AZ-ICE to educate and assist them in choosing appropriate rate schedules.

Partial Requirements rates are applicable to customers who use distributed generation to self-provide a portion of their electric load. APS currently has the following partial requirements service rate schedules: EPR-2, EPR-3, EPR-4, E-32-R, E-51, E-52, E-55, EQF-S, and EQF-M.

APS is proposing some modifications and new proposals concerning partial service offerings:

- Eliminate existing rate Schedules EPR-3, EQF-S, EQF-M, and E-52, which are currently frozen;
- Close (freeze) existing rate Schedules E-32R and E-55 to new customers and eliminate them in the next rate case;
- Eliminate Schedule E-51, which is currently frozen, in the next rate case;
- Consolidate Schedule EPR-4 into the revised Schedule EPR-2;

- Modify the existing EPR-2 to update the buyback rate to incorporate the avoided costs filing made on June 20, 2006.

Additionally, the Company made minor wording changes to be able to use these schedules with the new residential TOU rates ET-2 and ECT-2; eliminated the monthly service charge which was dependent on the customer's type of service; changed the summer and winter billing cycle months to match APS' other rate schedules; eliminated the requirement for the customer to share in the cost of bi-directional metering; and removed a provision that allowed the customer to pay the incremental metering costs over a five year period. (APS Exhibit No. 38, DeLizio Rebuttal, p. 25).

APS is proposing two new partial requirement rate schedules: E-56 and E-57. E-56 would be applicable to general service customers having distributed generating equipment 100 kW or greater capable of supplying all or a portion of its power requirements. The main components of rate schedule E-56 include:

1. A Basic Service component which is comprised of the unbundled monthly Basic Service and Revenue Cycle Service charges included in the customer's applicable General Service rate schedule;
2. Supplemental Service is defined as the demand and energy needs contracted by the customer to augment the power and energy generated by the customers' generation facility. Supplemental Service will be provided in accordance with the monthly rate levels contained in the customers' applicable General Service rate schedule excluding the monthly Basic Service and Revenue Cycle Service Charges (included in the above Basic Service component); and
3. Standby and Maintenance Service, which is the sum of the demand and energy charges, derived as follows:

   Demand Charge: The Demand Charge is the unbundled transmission charge, if applicable, contained in the Customer's General Service rate schedule, plus the unbundled delivery charge contained in the Customer's General Service rate schedule. This summation is then multiplied by the amount of Contract Standby Capacity. Contract Standby Capacity is defined as the greater of: a) the measured kW output of each customer self-generation unit at the time of start-up testing; or b) the highest 15 minute measured kW output of each generating unit, however, not to exceed the Customer's actual load.

   Energy Charge: Defined as the electric energy supplied by the Company to replace the power normally supplied by the Customer's generator(s) during unscheduled full outages, unscheduled partial outages, and scheduled maintenance periods. The unbundled transmission charge, if applicable, contained in the Customer's General Service rate schedule plus the per kWh monthly firm power purchase rates shown in the rate schedule EPR-2.

Rate Schedule E-57 would be applicable to general service customers having solar/photovoltaic generating equipment greater than 100 kW but less than 1,000 kW capable of supplying all or a portion of its power requirements. The main components of rate schedule E-57 include:

1. A Basic Service component that is comprised of the unbundled monthly Basic Service and Revenue Cycle Service charges included in the customer's applicable General Service rate schedule;
2. Supplemental Service is defined as the demand and energy needs contracted by the customer to augment the power and energy generated by the customers' generation facility. Supplemental Service, to include 100 percent of the customer's energy requirements, will be provided in accordance with the monthly rate levels contained in the customer's applicable General Service rate schedule excluding the monthly Basic Service and Revenue Cycle Service Charges (included in the above Basic Service component);
3. A monthly Standby Service component is derived by multiplying the unbundled delivery charge contained in the Customer's applicable General Service rate schedule by the 15 minute integrated kW measured on the customer's generator meter(s) during the customer's monthly peak demand; and
4. The Company will pay the customer for any excess energy produced by the distributed generator at the purchase rates specified in the Schedule EPR-2 that are based on the Company's avoided cost.

The Company will install at the customer's expense, a generator meter(s) at the point(s) of output from each of the customer's generators, allowing the Company to accurately meter customers taking service under this rate schedule.

The DEAA recommended the following solutions for partial requirements:

A. For partial requirement customers below 3,000 kW, SRP rate E-32 is fairer to DG than any of the APS proposed rates, and is also easier to understand and apply. Above 3,000 kW the similar SRP E-60 type rates would be implemented. We suggest simplifying APS rates along those guidelines.

B. The Commission should consider taking the following list of actions in order to solve the "Revenue Stability" vs. "Clear Price Signals" issue for partial requirements customers:

   1. Provide a rate design that is at least neutral to customer use of DG
   2. Provide a rate that offers DG customers significant seasonal TOD energy (kWh) price signals.
   3. This new proposed rate should be designed with clarity, simplicity, and along with the appropriate TOD (energy) pricing signals.

C. For DG customers, APS' rates should begin to reflect the new market reality, i.e., higher fuel (energy) prices, and lower capital costs (demand). This is the basis of the recommendation for general service DG customers to use a rate similar to the SRP E-32TOU. DEAA also recommends that APS partial requirement rates begin to truly reflect

> the differences in system costs between summer and winter, day and night, the peak seasonal hours. The DEAA also recommends the Commission review the trend that greater energy usage results in lower cents/kWh. The current rates appear to reflect that the capital/fuel cost relationship that existed in the early 1990s is no longer applicable today for partial requirements customers.

Staff indicated that it had not fully analyzed the APS proposed modifications and new rate schedules proposed, and was unable to offer a recommendation. In its Closing Brief, the Solar Advocates objected to the use of non-time-differentiated measurement of peak demand recorded at any time during the month. The Solar Advocates argued that APS' method could result in a solar generation customer that peaks at midnight paying the same demand based charge as a customer that peaks sometime in the afternoon. The Solar Advocates believes that there is no reason to create such misleading and discriminatory rate structures which send the wrong price signals to the market. Solar Advocates urge the Commission to order the Company to revise the E-56 and E-57 tariffs to better match the actual costs incurred to serve the customer, through more precise metering and costing information. Although it is not clear from its brief, it appears that DEAA does not believe that APS' proposed partial requirements tariffs address its concerns. APS believes that DEAA's general rate design is fundamentally flawed and its proposed partial requirements rate design philosophy has no basis in cost causation. The Company agreed that its partial requirement rates were complicated and that is why it proposed the above modifications and new rate schedules. 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. APS should then submit its proposed tariffs for our approval within 60 days.

## X. <u>MISCELLANEOUS ISSUES</u>

### A. <u>EPS Uniform Credit Purchase Program</u>

Decision No. 68668 required APS to set aside $4.25 million for additional funding for the Environmental Portfolio Standard Uniform Credit Purchase Program ("UCPP"). Staff recommended that the EPS adjustor rate and caps be increased to recover an additional $4.25 million through the Company's adjustment Schedule EPS-1. APS believes that a reconciliation provision should be provided to true up this $4.25 million with the actual UCPP costs for 2006, or that there be authorization to carry-forward any unspent funds from 2006 to subsequent years. In its Reply Brief, Staff stated that it has not fully analyzed this proposed creation of a regulatory asset/liability in connection with the $4.25 million incremental EPS surcharge and could not offer an opinion. We agree that APS should be allowed to true-up the $4.25 million with the actual UCPP costs for 2006.

**B. Systems Benefits Charge**

Staff recommends that the System Benefits Charge be $49,191,690, (including $6,000,000 for renewables) and that the System Benefits Charge for all applicable APS rate schedules be set at $.001850 per kWh. No party opposed this level or charge, and we will adopt it.

**C. Environmental Improvement Charge**

In its Initial Brief, APS stated that to remain successful in the future it must address the ongoing challenge of meeting Arizona's growing energy demands efficiently, with limited rate impacts, while minimizing the impact of its generating plants. (APS Initial Brief, pp. 99-100) APS has three coal burning plants that provide a significant part of APS' generation capacity. The plants are located near one or more large national parks and wilderness areas designated as mandatory "Class I Areas" under the Clear Air Act. (APS Exhibit No. 34, Fox Direct, pp 3-4) APS is seeking an Environmental Improvement Charge ("EIC"), an adjustment mechanism that would provide for "a timely recovery of the cost for a substantial capital investment necessary for adding or improving environmental controls in the Company's coal generation facilities. (*Id.* at 2) The EIC is designed to collect the expected return, associated tax, depreciation, and other carrying costs associated with the proposed environmental projects. APS proposed an initial request of $243,000,000 for environmental improvements to the Cholla Power Plant for the next five years to be recovered through the EIC. This would be a monthly charge for both the actual and forecasted expenditures required for the proposed environmental improvement projects. APS proposes to set the EIC at $0.00016 per kWh for all kWh used by Standard Offer customers except those customers on Schedules SP-1 (Solar Partners), Schedule GPS-2 (Green Power Percent) and Schedule Solar-2. The impact to an average residential customer using 1163 kWh monthly would be an increase in the customer's monthly bill of approximately 19 cents in 2007. The average impact on total Company revenues (based on the EIC plan for 2007) would be 0.19 percent.[52] APS proposed that it would prepare subsequent EIC requests for Commission review and approval on an annual basis by March 15th. The requests would include a true-up of the EIC revenues approved and collected, and a proposal of EIC revenue to be collected during the next year. If the EIC were over-collected or costs were found to be imprudent, those costs plus interest would be used to offset the EIC calculation going forward. APS believes that this true-up method would assure that customers only pay for actual and prudent costs. Under APS' proposal, once APS' EIC filing is made, Staff would prepare a Staff Report within 60 days, and if the Commission did not take action at an Open Meeting within 30 days after issuance of the Staff Report, then the EIC filing would be deemed approved, subject to true-up the following year. The Commission could review the prudency of the EIC expenditures and revenues during the annual review or during a general rate case. According to APS, the EIC allows the Company to comply with existing environmental laws and engage in long-term planning of providing service in one of the fastest growing service territories in the county. Without the EIC, APS says that environmental projects are just another capital need in a very long line of competing needs, which will mean that capital will not be allocated to environmental improvement projects until they are mandated, by which time APS expects the costs to be higher.

AUIA recommends that the Commission adopt the proposed EIC. The AUIA believes that it is clear that the Company's fleet of fossil fuel plants provides very cost-efficient power, but it is equally clear that environmental improvements to the plants will require considerable capital investments that will add to the pressure on APS' financial performance.

WRA supports the concept of the EIC because by making cost recovery more timely and more certain, it encourages APS to either accelerate programs to comply with existing or anticipated environmental standards early or undertake voluntary environmental improvements that are not required by law. WRA argues that these actions would benefit Arizona and the environment and may reduce APS' exposure to potential compliance costs in the future. WRA's witness Berry testified that the EIC is beneficial because:

[52] Approximately $4,542,000.

- It makes the environmental impacts of resource choices more apparent to APS, the Commission, and ratepayers;
- Utilities should not be discouraged from complying with environmental regulations or pursuing beneficial environmental goals through fear of disallowances for doing the right thing; and
- Utilities should be encouraged to take actions that reduce environmental damages caused by power generation, including compliance with regulations, actions taken in anticipation of future regulation, or societally beneficial responses to environmental issues for which no regulation is imminent.

(WRA Initial Brief, pp 11-12, WRA Exhibit No. 1, Berry Direct, p.19)

WRA recommends approval of the EIC or a similar concept. In response to Staff and RUCO concerns about compliance with traditional regulatory ratemaking concepts, WRA notes that the Commission has been innovative while still protecting ratepayers from imprudent utility actions, citing the DSM charge and the surcharge for the Environmental Portfolio Standard and the Renewable Energy Standard. WRA recommends that Schedule EIC be modified to explicitly include voluntary environmental improvements and exclude penalties assessed for non-compliance with environmental regulations. If the Commission accepts RUCO's argument that no special treatment should be afforded for compliance with mandatory environmental regulations, WRA proposes that the Commission apply the EIC only to cases where APS demonstrates it is accelerating compliance by at least one year, or is voluntarily reducing environmental impacts beyond those required by law.

RUCO opposes approval of the EIC. RUCO argues that the Commission does not need to "foster" environmental improvements because there are a number of laws and regulations that have recently been enacted that require the Company to make environmental improvements. RUCO believes that the EIC proposal is completely contrary to the normal rate making process for plant additions and improvements, and does not meet the criteria for being recovered through an adjustor mechanism.

Staff also opposed the EIC. Staff's witness Rowell identified the following reasons to reject the proposed EIC:

1) The EIC would include costs that will not be incurred for several years beyond the test

year;

2) The EIC would include funding for projects before they are mandated to be installed on APS' system;
3) Regulatory mandates typically build in construction lead times to provide industry sufficient time to comply with mandated regulatory requirements;
4) The EIC is derived based upon multiple year revenue requirements that increase the complexity of auditing the charge in the context of future general rate cases and annual EIC reset proceedings;
5) The effect of the EIC on APS' interest expense is unclear;
6) The annual reset of the EIC could be implemented without Commission approval under APS' proposal;
7) The EIC does not address the fundamental financial challenges that APS has identified *i.e.* customer growth and rising fuel costs;
8) The environmental impact of implementing the EIC is unclear.

(Staff Exhibit No. 19, Rowell Direct, pp 14-15)

Staff highlighted two points in its recommendation to reject the proposed EIC: it would collect revenues from ratepayers based upon predominately estimated, rather than actual, incurred costs; and it is unique and has not been used in any other jurisdiction. Staff disagrees with APS' characterization that the EIC is analogous to CWIP. Staff argues that the EIC is designed to recover many of APS' costs, including capital costs, in advance, thereby eliminating the need for APS to actually make an investment before recovering the costs of the investment. Staff believes that the proposal is similar to ratepayer supplied capital, but without any recognition of this principle. There is no provision to recognize the ratepayers' capital contribution and to deduct it from rate base.[53] Staff concluded that the EIC is one-sided and that the design is not equitable.

We agree that APS should be proactive rather than reactive on issues of environmental improvement. APS has presented testimony that the cost of mandated improvements rises once those improvement become mandatory, and that implementing the improvements earlier may be less costly and also bring environmental benefits sooner. Unfortunately, the method by which APS proposes to seek recovery of those costs is unusual and outside the normal ratemaking process, making it difficult for us to adopt. We decline to adopt an adjustor that includes forecasted costs, and will only allow APS to recover actual costs. We agree with WRA that no penalties should be recovered through the EIC and that voluntary improvements should also be included. Therefore, APS is authorized to make

[53] Essentially, the ratepayers would be paying a return on an investment that may or may not have been made by the Company.

its first EIC adjustor request within 30 days of the date of this Decision, to include only costs for actual capital investment already made. WRA also proposed that the Commission direct APS to undertake a climate change management plan, carbon emission reduction study, and commitment and action plan with public input and Commission review. No party objected to this proposal, and we will adopt it, noting, however, that the Commission may or may not choose to formally approve or take action on any plan submitted.

**D. Net Metering**

APS is seeking Commission approval of its proposed Rate Schedule EPR-5 which creates a three year "pilot" net metering program for customers that have renewable resource generation facilities of 10 kW or less, where the customer's generator and load are located at the same premise. EPR-5 has a cap of 15 MW on aggregate participation, and renewable resources eligible to participate in the program include solar and other renewable resources as defined in the Commission's Environmental Portfolio Standard. Qualifying standard retail rate schedules for service are limited to Rate Schedules E-12, ER-1, ET-2, ECT-1R, and ECT-2 for Residential customers and Rate Schedules E-32 and E-32 TOU for General Service customers with a monthly maximum demand of 20 kW or less.

According to APS, EPR-5 is designed to be a limited offering to give an incentive for small customers to participate in APS' Solar Partners Incentive Program (credit purchase program). The Company is targeting customers with renewable energy facilities that primarily meet their own needs, but who occasionally have excess energy to provide to the Company. As part of the program, the Company would install the necessary bi-directional meters to measure power flow both to and from the customer. During the year, the excess power would be credited against power that the customer purchases from the Company in future billing periods and so would be compensated at the full retail rates. Although EPR-5 allows excess energy to be carried from month to month, the excess supply would be zeroed out at the end of each calendar year.

The Company proposes that the "incremental cost for net metering will be funded through revenues collected through the current EPS surcharge. In addition, infrastructure costs, such as changes to the customer billing systems, will be funded through the EPS surcharge. Revenue associated with transmission and distribution, as well as non-avoidable costs that are not recovered from EPR-5 customers would also be funded by the EPS surcharge." (APS Exhibit No. 37, DeLizio Direct, p. 10). APS believes it is appropriate to recover its "uncollected fixed costs" under EPR-5 which offers a special financial subsidy to customers in order to promote small renewable distributed generation systems. Under the proposed program, the uncollected fixed costs would be netted against the associated avoided generation costs that the Company would not incur as the result of the distributed generation. APS proposed that both the generation energy and capacity cost savings from net metering would be based on the Company's PURPA avoided costs.

The Solar Advocates strongly opposes recovery of "lost revenues" as a result of a net metering tariff, and recommended increasing the cap on individual system size to 2 MW. Solar Advocates argue that no other state has allowed such recovery using the proposed mechanism; APS' calculation has only considered the cost, and none of the system benefits; that APS has failed to establish any credible grounds for recovery of the "so-called lost revenues;" and that the recent Commission Decision adopting the RES rules specifies clearly the methodology that is to be used to calculate any cost recovery and APS has not complied with the requirements of that rule.

Staff recommended approving the EPR-5 with the following modifications:

1) Staff would not require a bidirectional meter;
2) Staff recommends that the facility size limit be increased to 100 kW;
3) Customer participation should not be limited by rate schedule;
4) The schedule should be modified to indicate that all changes to the schedule will require Commission approval; and
5) APS should be required to clarify the tariff to indicate that ratepayers will be responsible for the cost of the meter.

Staff's witness recommended that APS be permitted to recover revenue loss associated with its proposed net metering tariff, but disagreed with APS' proposal for measuring revenue loss. Staff believes that the revenue loss is the difference between the retail rate and APS' avoided cost, and that the proposed lost revenue should apply only to excess generation, not to total capacity. Further, Staff recommended that actual retail rates should be applied, not annual average; that avoided costs should reflect seasonal on-peak and off-peak rates; and that all metered rates schedules should be eligible, not just those proposed by APS.

APS did not agree with Staff's recommendations, stating that the Company's proposal was an attempt to strike a delicate balance between providing incentives to promote distributed renewable resources and the amount of the incentive being paid for by others who are not participants in the program. APS believes that Staff's position would upset the balance and provide an even greater subsidy to program participants. APS argues that the 10 kW cap on the generator size is appropriate for net metering, "even in light of an expanded RES program because the Company already offers net billing rate options for distributed generation systems up to 100 kW, which do not have any cap on aggregate participation." (APS Exhibit No. 38, DeLizio Direct, p. 13) However, as clearly pointed out by the Solar Advocates, APS customers do not find those net billing options a substitute for net metering. We agree with Staff's recommendations and will adopt them, however, we believe that APS should be able to require the use of a bidirectional meter. APS should file its revised tariff consistent with this Decision within 30 days of the effective date of this Decision. This is a pilot program and we expect APS to provide clear, quantifiable and verifiable information using actual results as to what are, if any, the net costs (after calculating all benefits) of net metering.[54] We further note that this tariff is not being filed pursuant to the RES rules, and that APS will be required to comply with the RES rules when they become effective.

### E. Demand Side Management

Pursuant to Decision No. 67744 and the Settlement Agreement, APS committed to spend $48 million on demand-side management programs ("DSM") by year-end 2007. Base rates include $10 million per year of funding, and expenditures above that are deferred and collected through a DSM adjustor mechanism. This level of spending will continue at the current level until APS files, and the Commission approves, modifications to the program design and budget requirements. According to APS, as a result of delayed DSM approvals, the time it takes to ramp up DSM spending, and the lag inherent with spending on energy efficient new construction projects, APS will not spend the $48 million by the end of 2007. APS and SWEEP propose that any unspent funds should be carried over

[54] APS' use of "total uncollected fixed costs at $0.04/kWh" in APS No. Exhibit 73 and in APS Exhibit No. 105, Appendix C is based on ballpark approximations. Tr. Vol. VIII, p. 1784.

and spent in subsequent years. Staff opposes the "carry over" and cites to Decision No. 67744 which requires that any unspent amount should be credited to the balance of the Demand Side Management Adjustment Clause ("DSMAC") account if APS does not spend at least $30 million of the base rate allowance for approved and eligible DSM-related items during 2005-2007. According to Staff, this "under-funding" is returned to ratepayers. We agree that to the extent that APS has not spent at least $30 million by year end, the DSMAC should be credited, as required by Decision No. 67744.

RUCO recommended that the Commission expand APS' DSM spending requirement beginning in 2008, by requiring total annual spending of at least $20 million ($10 million in base rates and $10 through the DSM adjustor mechanism). RUCO argues that increasing the required spending by $4 million will encourage more new programs and savings to customers. APS opposes requiring additional spending at this time. APS agreed with RUCO that the DSM programs have been successfully rolled out, but disagreed that they are "up and running" and noted that the DSM adjustor has flexibility to allow APS to spend more than the required amount. We agree with Staff and APS that the current required level of $16 million should not be increased at this time.

APS requests that it be allowed to accrue interest on the unrecovered DSM adjustor balance. Staff did not oppose the request, but recommended that the applicable interest rate be the one-year Nominal Treasury Constant Maturities rate that is contained in the Federal Reserve Statistical Release H-15 or its successor publication. RUCO opposed APS' request to accrue interest, citing no provision in the Settlement Agreement that would allow such accrual. RUCO argues that it would be inappropriate to begin permitting APS to earn interest on uncollected DSM expenditures now, when for the past several years APS has pre-collected funds from customers and no interest was credited to customers. We agree with APS and Staff that APS should be allowed to accrue interest on the unrecovered DSM adjustor balance, at the rate recommended by Staff. It is not inequitable to allow interest to accrue now, because prior to approval of its DSM programs, APS was unable to use the funds in the adjustor balance.

Staff concurred with APS' proposed performance incentive in its Portfolio Plan of DSM programs which set the performance incentive at 10 percent of the net benefits achieved and capped it at 10 percent of total DSM spending. Staff also recommended that APS include its request for a performance incentive in each semi-annual DSM report, and that APS provide Staff with backup workpapers and input data to substantiate the numbers for net benefits and performance incentives included in its semi-annual DSM reports. Staff further recommends that APS use the most recent and regionally similar energy savings data available, and not the program-filed savings numbers from 2005; that a time limit should be placed on energy use measurements from other regions; that APS use measured savings obtained from APS customers by the Measurement, Evaluation, and Research ("MER") contractor beginning no later than July 1, 2007; and that the averages of actual measured usage, for both standard and upgraded equipment, should be recalculated by the MER from usage samples for each prescriptive measure based on new measurements from the field no less frequently than every two years. (Staff Exhibit No. 16, Anderson Direct) APS agreed with Staff's recommendations and we will adopt them.

SWEEP believes that cost-effective energy efficiency DSM programs reduce total costs for customers and are in the public interest. It proposed changes to APS' DSM programs, including the adoption of Energy Efficiency Standards ("EES") to set DSM energy efficiency program goals; the development of an implementation plan; and increases in funding to achieve the EES goals. SWEEP argues that it is "important to focus primarily on the *effects and impacts* of energy and utility policies for setting goals, not primarily on the funding or spending levels. . . . . Simply spending money, even cost-effectively, should not be the primary focus of future goals." (emphasis original) (SWEEP Exhibit No. 2, Schlegel Surrebuttal, pp. 3-4). APS argued that its DSM programs have only recently been approved and APS needs time to get its DSM programs up to speed, to gauge the progress, and to evaluate what is actually being achieved. APS and Staff believe that it is premature to make substantial changes by implementing the EES or a savings target. In response to the SWEEP recommendation of a 12 year implementation plan, APS suggested that the DSM Portfolio Plan's required biennial updates be used. While we see merit in the position that targets or goals, and not just spending, is what should be important and driving DSM programs, we agree with APS and Staff that we need time to evaluate our current DSM structure before we make such substantial changes as recommended by SWEEP.

APS and WRA agree that urban heat island reduction measures should be taken. The large concentration of pavement and buildings in urban areas such as Phoenix has created an urban heat island effect and increasing temperatures, which strain the electric grid and require increased generation from intermediate and peaking power plants. APS is a founding lifetime sponsor of the Arizona State University Global Institute for Sustainability, which is designated as the EPA Center for Excellence in working towards solutions to this problem. APS agrees that it should study the benefits of a heat island reduction program but disagreed with WRA's recommendation that APS be directed to move forward with developing and implementing a cost-effective urban heat island program now. APS indicated that it was willing to hold a DSM Collaborative Working Group meeting to further analyze the issues, and that using the DSM custom project option is a viable way to address the urban heat island effect. Although APS and WRA do not agree on whether there is sufficient research and information today to implement a program, we agree that APS should take steps to address the urban heat island effect. We will require APS to convene a Collaborative Working Group Meeting within the next 60 days and to present where APS believes the research stands and what additional information is needed before a reduction plan can be implemented, and when that information will be obtained.

**F. Renewable Procurement**

WRA made several recommendations concerning APS' procurement of renewables. WRA argues that APS and its ratepayers face virtually unlimited cost exposure over the long run because of APS' heavy reliance on natural gas. Natural gas prices over the next 20 to 30 years are unpredictable, but the recent high prices are the major reason for APS' recent and proposed rate increases and WRA believes that it is in the public interest to cap APS' exposure to high cost natural gas and replace it with low cost, stably priced renewable energy. WRA witness Berry testified that wind energy projects installed in 2006 or 2007, and geothermal energy contracts signed in 2005 or 2006, have prices that are cost competitive with natural gas fired power production at recent prices for natural gas. (WRA Exhibit No. 1, Berry Direct, DB-3) WRA's witness testified that "low cost, stably priced renewable energy is best viewed as a hedge against high gas prices in an uncertain world" where price forecasts cannot be used to effectively manage gas price risk over the long run.[55] To implement such a long term hedge, WRA recommends that the Commission require APS to seek to acquire 1,300 GWH per year of low cost, stably priced renewable energy under long term contracts starting between 2008 and 2010, and continuing for at least 15 years. WRA also recommended that the Commission require APS to file a renewable energy acquisition plan that incorporates input from interested parties through a collaborative process, within four months of this Decision, for Commission review and approval, and that APS should file reports with the Commission by March 1 of 2009, 2010, and 2011 describing its progress in meeting the goals and proposing how to make up any deficiencies. WRA noted that no party testified against using renewable energy as a hedge against high natural gas prices, or that increasing the amount of renewable energy would compromise system reliability. WRA recommended that the costs of the additional renewable energy should be recovered through the power supply adjustor. WRA disagrees with APS that the RES rules alone are adequate to provide a significant hedge against high natural gas prices, noting that the outcome of the RES rules is unknown and that the quantity of renewable energy to be obtained pursuant to the RES rules does not provide an adequate hedge against high natural gas prices.

APS argues that there is a cost premium for any "hedge" and that careful consideration of that cost is required. APS states that the "critical questions are whether additional amounts of renewable energy (additional to the RES and that required by Decision No. 67744) constitutes the most effective hedge in most applications, and, if not, whether such additional cost is reasonable for APS customers." (APS Reply Brief, pp 36-37).

We agree with WRA that APS should be seeking low cost, stably priced renewable energy under long term contracts to hedge against and to limit APS' and the ratepayers' exposure to high natural gas prices over the next 15 years or longer. APS' recent rate increase requests were prompted by rising fuel and purchased power costs, and APS ratepayers have little insulation against the price of natural gas. We note that APS currently is able to flow the high cost natural gas through the PSA, and has little incentive to replace natural gas costs with the cost of renewables. We also agree that

[55] The Energy Information Administration has stated that "natural gas generally has been the fuel with the least accurate forecasts" with a reported average absolute percent error for forecasts of natural gas wellhead prices from 1982 to 2004 of 67.7 percent. (WRA Exhibit No. 2, Berry Surrebuttal, pp 9-10)

the costs of the renewable energy should be recovered through the PSA, as otherwise, APS would have no incentive to replace natural gas produced electricity with electricity produced from renewable resources. We note that WRA's recommended 1,300 GWH per year level of renewables is only a goal, not a requirement. We have recently adopted requirements for renewables in our Decision adopting the RES rules, and we find that the record in this case supports a finding that the requirement contained in the RES rules is appropriate for APS at this time. Accordingly, we decline to adopt a specific target in this proceeding in addition to what is contained in our RES rules. This does not mean that APS should look no further at acquiring additional low cost, stably priced renewable resources. The evidence from this hearing indicates that the cost of renewables is very much in the ballpark for prices of electricity generated using natural gas, and APS has a duty to obtain or generate power that is reliable, cost-efficient, and reasonably priced. Even though we have not set a target, we believe that WRA's recommendation for APS to file a renewable energy acquisition plan as discussed in WRA's testimony, is appropriate and will insure that APS maintains a focus on the long term use of renewables. We also believe that during those collaborative meetings, as recommended by Interwest, interested parties should also discuss and evaluate how performance-based incentives and decoupling of rates from revenues might encourage APS to procure more renewable energy resources.

Interwest recommends that the Commission require an Independent Evaluator be included in future Request For Proposals ("RFP") processes for the procurement of renewable energy resources to ensure that a fair market reference price is created and that additional costs are not assigned to specific renewable energy projects. APS opposes the recommendation and believes that an Independent Evaluator is unwarranted. APS argues that the RES rules require utilities to have procedures for selecting resources and also require certification by an independent auditor that the procedures are fair and unbiased, and have been appropriately applied. APS also plans to commission a Wind Integration Study to assist in establishing guidelines to be used for RFP evaluations of wind projects.[56] According to APS, the cost to hire an Independent Evaluator to

[56] Interwest Energy Alliance and WRA raised concerns about APS' methodology for calculating wind integration costs in its renewable RFPs, and APS is in discussion with Northern Arizona University for the coordination of the wind study. The wind study will develop experience with actual renewable resources so APS can understand the impact of integrating

review an RFP is $90,000 to $125,000 and APS notes that the RES rules do not mandate an RFP. APS believes that the cost of an Independent Evaluator is an unnecessary use of customers' money. We find that a requirement to include an independent evaluator in every future RFP for renewables is not necessary at this time.[57] If in the future problems develop in the RFP process, the affected parties should bring that to the attention of Staff and/or file a complaint with the Commission.

Interwest also recommends that the Commission mandate procurement schedules for APS to solicit bids for 150 MW of renewable energy. Interwest believes that regularly scheduled bids will provide notice to the industry for project development, and the use of an all-renewable source RFP will create a competitive process to drive down prices. (Interwest Energy Alliance Initial Brief, p. 16) APS opposed the recommendation because it believes that determinations about how and when to procure renewable energy should be left to the Company so that it can have the flexibility it needs to best serve its customers. APS committed to "engaging the market in an open and fair manner, and anticipates conducting additional renewable energy RFPs in the future. . . ." (APS Initial Brief, p. 116) Given APS' commitment, the requirement in the RES rules and our adoption of that requirement in this Decision, and our intent to hold APS to that commitment, it is not necessary to mandate additional procurements or a specific procurement schedule at this time.

## G. <u>Renewables</u>

In its Initial Brief, APS stated that it supports the intent of the RES and the development and integration of renewable energy into its energy portfolio. APS believes that renewable energy diversifies the Company's energy supplies and provides many benefits to APS customers and helps manage the environmental impacts of electricity generation.

APS has proposed to offer Green Power to customers who want to buy renewable energy at a surcharge cost of $0.01 per kWh. The proposed rate is based on the actual costs of renewable energy from three projects APS has under contract. The energy provided under the Green Power rates will be in excess of the EPS/RES and Decision No. 67744 requirements. APS agreed with the following WRA recommendations: 1) to provide reports on customer participation, kWh sales, and revenue in

---

specific renewable resources like wind and solar into its system.

[57] We note that Staff is conducting workshops on procurement.

its annual EPS/RES filings; 2) that the green schedules should be based on actual project costs; 3) to pursue green-e certification for its Green Power products; 4) to change the minimum block size in GPS-1 to 100 kWh/month; and 5) to change the 30 percent option in GPS-2 to 35 percent to better coincide with recent changes to the Leadership in Energy and Environmental Design (LEED) standard for new buildings.

Staff recommends approval of APS GPS-1A and 2A tariffs because APS is offering more energy from renewable sources at a lower price than APS' current program, and because customers will have the opportunity to determine the percentage of their electricity that will come from renewable resources.

WRA believes that Green Power is in the public interest. WRA recommended two modifications to the proposed tariff: the Green Power premium should reflect the stable cost of renewable energy minus the fluctuating cost of conventional generation instead of being fixed as APS proposes; and instead of APS submitting multiple Green Power tariffs with varying prices which can be confusing to customers, APS should have a single tariff with a single set of rates that are set each year based upon APS' yearly filing of revisions to the premium. WRA also recommended that the green power percent schedule should be modified to apply the 10 percent option only to non-residential customers, so that APS can qualify for Green-e certification. We agree with these recommendations and will approve the Green Power tariffs as modified herein.

APS is aware that its customers are interested in renewable energy and in particular, solar energy. APS currently has approximately 4,400 customers enrolled in its Solar Partners Rate Program, which allows customers to purchase 15 kilowatt hour blocks of solar energy, and 835 customers are participating in its Solar Partners Incentive Program, having installed their own solar energy systems. Because many of APS' customers may not be able to own and operate their own systems, APS is proposing to offer a new Total Solar Rate (Solar-3) as part of a pilot program. Under this program, customers could support solar energy by purchasing APS-generated solar energy to offset either 50 or 100 percent of their energy consumption. Several parties raised concerns about the cost of the Total Solar Rate, and APS subsequently issued an RFP for solar energy for the Total Solar Rate. APS did not receive any bids for the RFP, but did enter into a Memorandum of Understanding and term sheet for a 50 percent interest in a total solar project associated with the Gila River Indian Community that will provide about one-half a megawatt of solar power to serve a portion of its current Solar Partners Rate Program as well as the solar energy for the Total Solar Rate program. On December 22, 2006, APS filed its revised Total Solar Rate of $.0225 per kWh, which is lower than its initial rate. No party has opposed this tariff and we will approve it.

## I. Other Issues

### 1. Hook-up Fees

Staff researched the feasibility of establishing a hook-up fee for APS. Staff believes that there are many unanswered questions that need to be addressed before the Commission decides this issue, and so does not recommend the adoption of hook-up fees for APS at this time. Staff recommends that if the Commission wants to continue looking into the feasibility of hook-up fees for electric and gas utilities, a generic docket should be opened where parties can provide information and feedback. Staff notes that if the Commission were to adopt hook-up fees in this case, then Schedule 3 should be modified to remove the free allowance and to account for specialized distribution related costs in excess of what is included in the hook-up fee.

### 2. Demand Response and Load Management

Demand Response programs are mechanisms designed to provide incentives to customers to reduce their load in response to prices, market conditions, or threats to system reliability. Demand Response can result in savings of variable supply costs during times when wholesale prices and demand are high. It can displace the need to build additional capacity including generation, transmission, and distribution, and it can improve system reliability. Load Management is a utility's deliberate action to reduce peak demand or improve system operating efficiency. Staff recommended that APS conduct a study to identify what types of Demand Response and Load Management programs would be most beneficial to APS' system. The study should rely on a cost-benefit analysis based on the Societal Cost Test and should be filed with the Commission within eight months of this Decision. Staff further recommended that APS should file with the Commission for approval, one or more cost effective Demand Response or Load Management programs that the Company believes would be most beneficial to its system and its ratepayers. Staff recommended this filing be made concurrently with the study.

The Company agreed with Staff and RUCO that Demand Response programs have the ability to benefit the system, and that a study group should be assembled to evaluate various Demand Response options. These programs are distinct from APS' DSM programs, and they rely on market conditions and tiered pricing to reduce peak load. To create a reliable, efficient, and effective Demand Response program, APS will need to consider implementation costs, benefits, infrastructure needs, and the complexity of administration. APS believes that a thorough study is necessary to determine which programs would most likely produce the most cost effective benefits, and thinks that Staff's recommended eight month study would not be sufficient time. Accordingly, we will adopt Staff's recommendations; however, we will require the study and the program filing to be made within one year from the date of this Decision.

3. Rate Stabilization Fund

In response to inquiries from the Commission, Staff analyzed whether a rate stabilization fund was appropriate for APS. Staff testified that although it is a novel idea with potential benefits, Staff does not recommend establishing such a fund at this time. According to Staff, a rate stabilization fund would require a large amount of up-front funding from ratepayers to achieve any meaningful impact, and would essentially be front-loading the costs.

4. Depreciation

Staff recommended that the depreciation rates proposed by APS be adopted for use in this case. Staff found them to be developed in a manner consistent with the Commission's rules for depreciation rates and that they are consistent with a "technical update" approach to the depreciation rates approved in Decision No. 67744. Staff recommended that APS should be required to clearly break out each new depreciation rate between a service life and a net salvage rate, similar to the rates shown in Appendix A to Decision No. 67744. This will allow depreciation expense related to the estimated future cost of removal to be tracked and accounted for by plant account. Staff also recommended that the Commission consider amending A.A.C. R14-2-102, the Commission's depreciation rule, to allow alternative treatment for the cost of removal.

5. Reliability and Service Quality

Staff conducted an engineering inspection to determine whether APS' 2005 capital improvements were used and useful and to evaluate APS' plant for quality of service purposes. Staff concluded that the plant improvements were appropriate and necessary to provide reliable, efficient, and cost effective service to retail customers and to the wholesale market. On March 21, 2007, Staff filed a late-filed exhibit which included additional information about APS' plant, in response to questions from Commissioner Mayes.

6. Advanced Metering Infrastructure

As part of its Advanced Metering Infrastructure ("AMI"), APS is rolling out approximately 1,000 "smart meters" a week, and it expected to have installed approximately 12,000 by the end of 2006. The initial distribution has taken place in APS' denser service segments, apartment complexes and condominium projects. One advantage of the AMI program is reduced labor costs, both from the ability to connect and reconnect customers without sending a crew to conduct two separate meter reads, and from not having to physically reprogram meters with TOU rates. APS suggests that the Commission look at permitting APS to continue to provide metering services to all direct access customers.

7. Critical Peak Pricing

The Energy Policy Act of 2005 identified several time-based rate options, including critical peak pricing that utilities should consider offering to customers. Critical peak pricing is a time-based rate schedule where time-of-use prices are in effect except for certain peak days when prices may reflect the costs of generating and/or purchasing electricity at the wholesale level, and when consumers may receive additional discounts for reducing peak period energy consumption. APS has started looking at critical peak pricing but has not proposed this option in this case. We encourage APS to submit such a proposal in its next rate case.

8. Low Income Plans

APS has made modifications to the Low Income Plan of Administration in order to promote further enrollment in the Company's Energy Support Programs. ("E-3" and "E-4"). The E-3 program offers discounts up to 40 percent off the cost of electricity for customers who meet certain income guidelines and exempts them from PSA charges. The E-4 program adds another discount for use of durable medical equipment. APS stated that its new enrollment techniques, including pre-paid postage for applications and an electronic application pilot program, have been successful. APS proposes to modify the Plans of Administration for Schedules E-3 and E-4 in order to facilitate the automatic enrollment process. No party objected to these modifications and we will adopt them.

## XI. FUEL AUDIT

Staff engaged The Liberty Consulting Group ("Liberty") to conduct an examination and audit of the management and operations of the fuel and purchased power functions at APS, and to formulate recommendations. The audit included issuing data requests, in-person and telephone interviews, and on-site work observations and inspections. During the period of the audit, APS was responsible for managing 10,400 MW of capacity, including 6,415 MW of capacity that it owned.

Liberty made the following conclusions and recommendations:[58]

### A. Organization and Staffing

Liberty made thirteen conclusions about organization and staffing, primarily finding that fuel and power procurement work groups have the necessary skills and experience, operate under adequate job descriptions, communicate effectively, have access to appropriate training, use generally adequate procedures and decision processes, document decisions sufficiently, operate under established procurement approval limits, and undergo regular internal auditing. Liberty made three recommendations concerning organization and staffing: 1) develop a complete set of procedures related to the management and administration of coal contracts; 2) audit and revise procedures for acceptance of offers for gas supply; and 3) secure an understanding with APS that Commission auditing includes access to members of the board of directors.

### B. Fuel Management

Liberty made twelve conclusions about coal and natural gas management. Liberty concluded that APS has effectively managed inventory levels and variance analysis, administered coal contracts, measured supplier performance, carried out sampling processes, automated its coal-sampling systems and made economical use of combustion by-products. APS' historical approach to gas-supply

[58] Staff Exhibit No. 33, pp 6-13; Staff Exhibit No. 28 Antonuk Direct, pp 7-21.

management has been typical and effective. Liberty made three recommendations concerning fuel management: 1) streamline the procedures for handling of information on coal weights; 2) revise the inventory target for Regular Coal at the Cholla Station from 25 days of supply to 35 days of supply; 3) conduct a comprehensive analysis of gas purchasing and management under El Paso's revised rate structure, and report to the Commission within one year.

**C. Fuel Contracts**

Liberty made six conclusions about fuel contracts, primarily finding that APS' long-term and short-term coal supply agreements are effective and appropriate and that APS used an appropriate process in its recent solicitation of new long-term coal supplies. Liberty found that APS uses a sound process to contract for gas commodity and fuel oils. Liberty made no recommendations concerning fuel contracts.

**D. Hedging and Risk Management**

Liberty made four conclusions about hedging and risk management, primarily finding that APS has designed and operates a sound hedging program that has been successful in meeting its primary objective of price stability. Liberty found that the hedging program will prevent costs from falling, and that the segregation of utility and non-utility activities is not as complete as it should be. Liberty made two recommendations concerning hedging and risk management: 1) engage stakeholders in a discussion of hedging program objectives; and 2) report to the Commission on the future plans for non-utility activities.

**E. Forecasting and Modeling**

Liberty made four conclusions concerning forecasting and modeling, primarily finding that APS uses sufficiently accurate modeling to predict fuel and purchased power volume and cost; APS has taken appropriate actions to ensure it achieves least-cost total dispatch; APS uses outside reviews appropriately to improve management and operations; and APS maintains adequate documentation to support regulatory oversight and review. Liberty made no recommendations concerning forecasting and modeling.

**F. Plant Operations**

Liberty made twelve conclusions about plant operations, primarily that the performance metrics of the base-loaded coal units demonstrate effective operation; the large gas units have experienced representative outage frequency and duration given the recent in-service dates, generic problems, and the change in mode of operation; boiler leaks account for "a conspicuously high percentage of net replacement power costs" associated with some units. (*Id.* p. 19); and that the use of a 50/50 load forecast combined with fast growth and system constraints in the Phoenix load pocket make achievement of targeted reserves less certain. Liberty made five recommendations concerning plant operations: 1) prepare and execute an action plan that will improve economic evaluations related to minimization of outage time; 2) analyze system reserve calculations using both a 50/50 and 90/10 load forecast, incorporating the constraints of the Phoenix load pocket; 3) evaluate the replacement of boiler sections at Four Corners #5, Navajo #2, and Navajo #3 in light of current high net replacement power costs; 4) conduct a centralized review of operator and maintenance errors at APS base-loaded coal plants and at Navajo, in order to assure that root causes are being correctly identified and addressed, and determine the reasons why such errors appear to be concentrated at Four Corners Unit #3 and Navajo Unit #3; and 5) implement for West Phoenix #5 the requirement for root cause analysis when generation is lost.

**G. <u>Purchased Power and Off-System Sales</u>**

Liberty made eight conclusions about purchased power and off-system sales, primarily finding that APS bases its marketing and trading activities on sound hedging policies and procedures, and conducts electricity sales and purchases consistently with least-cost dispatch guidelines. Liberty found that the primary reason that off-system sales have produced smaller margins is because of APS' "short" position in low-cost generation.[59] Liberty also found that PWCC made some inappropriate commitments to trades using utility assets in 2005 which APS discovered, corrected and for which APS received the margins the transactions produced. Liberty also found that APS does not separate utility and non-utility activities sufficiently. Liberty made two recommendations concerning purchased power and off-system sales: 1) clearly segregate utility and non-utility trading in all operations and reporting to ensure that utility trading is conducted to maximize utility

[59] APS does not have excess coal and nuclear generation available for substantial portions of the year because its system load has grown beyond its coal and nuclear resources. Staff Exhibit No. 28, Antonuk Direct, p. 17.

operations; and 2) complete the process of preventing future affiliate use of utility assets and examine means for continuing transmission optimization transactions through some form of sharing mechanism.

**H. Nuclear Fuel**

Liberty made three conclusions concerning nuclear fuel: APS conducts nuclear fuel procurement and management through an effective organization; it has developed and used effective procedures to procure nuclear fuel; and it uses an appropriate basis to account for its nuclear fuel costs for ratemaking purposes. Liberty made no recommendations concerning nuclear fuel.

**I. Financial Audit of PSA Costs**

Liberty made eight conclusions about APS' handling of PSA costs, primarily that APS' accounting systems are adequate and reasonably maintained to collect, report, and audit the PSA filings, and to conduct testing; that the monthly PSA filings were in general compliance with filing requirements and the sum total of costs were reasonably accurate; and that detailed testing of August 2005 PSA data showed the supporting information to be well documented and reasonably consistent with the values APS reported. Liberty made five recommendations concerning the PSA: 1) Conduct periodic internal audits of the PSA filings to verify the soundness, completeness, and accuracy of the activities that produce them, with the first such audit to be conducted as part of the next audit plan; 2) Develop a written policy and procedure for the preparation of the confidential PSA filings; 3) Correct PSA reporting methods to assure more accurate classification and reporting of coal, oil, and gas generation information; 4) Revise the PSA confidential filing format to provide a sufficient level of detail to support the calculation of the components contained within the PSA non-confidential filings; and 5) Closely review and monitor adjustments to fuel costs to assure that supplemental charges and refunds appropriately consider the impact on inventory values and fuel expenses for financial reporting purposes.

**J. Discussion**

APS is in general agreement with the findings of the Liberty audit, and testified that some of the changes recommended by the audit have already been undertaken. Staff believes that a reasonable way to address audit findings is for the Company to prepare an implementation plan for each recommendation that it accepts, and for each recommendation it does not accept, APS should be required to provide a detailed explanation of the reasons why the recommendation need not be implemented. Staff would then identify the best method for monitoring the Company's implementation plan and for resolving any issues in dispute.

We agree with Staff's recommendation and will order APS to prepare and file an implementation plan and explanation within sixty days of the date of this Decision.

## XII. PURCHASED POWER AND FUEL ADJUSTOR

Decision No. 67744 established a Power Supply Adjustor ("PSA") mechanism to collect fuel and purchased power costs that exceeded the base fuel costs that were included in base rates. APS proposed modifications to the existing PSA, including the following:

1) Elimination of the Total Fuel Cost Recovery Cap of $776.2 million established by Decision No. 67744 (and which has been effectively suspended by Decision Nos. 68437 and 68685 pending the resolution of this case);

2) Elimination of the four mil cumulative "lifetime" cap on the Annual PSA Adjustor and its replacement with a four mill annual cap;

3) Elimination of the 90/10 cost sharing mechanism established by Decision No. 67744 for the following elements of fuel and purchased power costs:

   a) the costs of renewable energy acquired from third parties and not otherwise recoverable under the Environmental Portfolio Standard/Renewable Energy Standard; and

   b) the demand component of any long-term purchased power agreement acquired via a competitive procurement process;

4) Removal of 10 percent of hedging gain/losses from the 90/10 sharing, thus effectively increasing the sharing of such gains/losses to 80/20;

5) Elimination of the requirement for mandatory PSA surcharge applications whenever the level of deferrals reaches $100,000,000.

### A. Total Fuel Cost Recovery Cap; Four Mill Cap; Hedging Gains and Losses; Mandatory Surcharge Applications

No party objected to APS' proposal to modify the existing PSA to eliminate the Cap on Total Fuel Cost Recovery; to eliminate the four mill "lifetime" cap and replace it with a four mill annual cap; or to eliminate the requirement for mandatory PSA surcharge applications when deferrals reach $100,000,000. The Company withdrew its original proposal concerning hedging, and now proposes to treat hedging gains and losses just like other fuel and purchased power costs. RUCO and AECC agreed with this position, and it is not inconsistent with Staff's recommendation.

We agree with the parties that these provisions of the existing PSA are unnecessary and should no longer be part of the PSA.

**B. <u>90/10 Sharing</u>**

RUCO accepted APS' proposal to modify the sharing to exclude both the costs of renewable energy acquired from third parties and not otherwise recoverable under the Environmental Portfolio Standard/Renewable Energy Standard, and the demand component of any long-term purchased power agreement acquired via a competitive procurement process. Staff's proposed PSA does not contain a 90/10 or any other sharing mechanism. AUIA recommends that the Commission eliminate the 90/10 sharing component of the existing PSA. The Phelps Dodge/AECC opposed any modification to the 90/10 sharing provision.

We believe that maintaining an incentive mechanism with the opportunity for some "sharing" of the savings or costs of the purchased power and fuel costs is appropriate. Although the 90/10 sharing may be a "blunt instrument," apparently it did hit the mark and has worked to insure that APS is diligent in its fuel procurement.[60] As pointed out by RUCO, it is not a "penalty provision" but an incentive mechanism to align APS' interest in acquiring fuel with the interests of APS' customers who pay the costs that APS incurs. However, we do agree with APS' recommendations to modify which costs are subject to the sharing requirement. We agree with APS that the fixed or demand element of long-term Purchase Power Agreements acquired through competitive procurement and renewable energy purchases not otherwise recoverable through the EPS/RES should be excluded from the sharing requirement.

---

[60] See discussion in Fuel Audit section above.

C. **Broker Fees**

In addition to the changes to the existing PSA, APS wants the Commission to include the Federal Energy Regulatory Energy Commission ("FERC") Fuel Account No. 557 – Broker Fees, to the costs that can be recovered through the PSA. According to APS, in Decision No. 68437, the Commission denied recovery of broker fees through the PSA because it believed that broker fees were not included in the base rates. APS argues that there is no dispute that they are included in the base fuel costs in this proceeding, that they are legitimate and necessary costs of fuel and purchased power procurement, and that their exclusion from the PSA would result in a complete disallowance of such costs.

Decision No. 68437 found that wheeling costs were included in the PSA, but that brokerage costs were not.[61] APS argues that broker fees are included in the determination of base costs of fuel and purchased power, and that they should also be recovered in the adjustor. APS has not demonstrated any reason why we should change the costs that are allowed to be recovered in the adjustor, and we find that the level of broker fees that APS will collect in its base rates is reasonable. Accordingly, the broker fees in excess of the level already included in base rates will not flow through to the adjustor.

D. **PSA Proposals**

The current PSA structure compares one year of historical, actual fuel and purchased power costs with the actual fuel and purchased power costs recovered though the Company's base rates, and then collects/refunds the allowed costs over the next year through an adjustor mechanism set once a year.

Staff believes that prices for fuel and energy remain volatile and therefore, it is appropriate for the Commission to continue to approve some type of PSA mechanism for APS. Staff proposed several changes to the PSA as discussed above, and also proposed the use of a forecasted year for setting the PSA rate in the future and a new Plan of Administration to replace the existing Plan of Administration. Staff noted that the existing PSA mechanism, in combination with the increase in

[61]Decision No. 68437, pp. 17, 25, and the October 17, 2005, testimony of Barbara Keene in Docket No. E-01345A-03-0437, p. 8. "Staff continues to believe that broker fees are not allowable PSA costs."

fuel and purchased power prices after Hurricanes Katrina and Rita, led to the build-up of substantial undercollections in 2005-06. This build-up of deferrals caused concern with rating agencies, who threatened to downgrade APS' ratings. Staff believes that the public interest would be served by modifying aspects of the existing PSA that may have contributed to the build-up of significant deferrals, and that the changes Staff proposes will allow more timely recovery of APS' fuel and purchased power costs, thereby addressing the concerns of rating agencies.

On February 28, 2007, Staff filed its final version of its proposed Plan of Administration ("POA") for the PSA and a final version of the schedules that accompany the POA.[62] On March 26, 2007, APS filed its Comments on the Staff's final version of those documents.

Staff's proposed new PSA uses a forward-looking estimate of fuel and purchased power costs to set a rate that is then reconciled to actual costs experienced. The PSA rate will consist of three components, that working together, are designed to provide for the recovery of actual, prudently incurred fuel and purchased power costs that exceed the base cost of fuel and purchased power embedded in base rates. The "Forward Component" recovers or refunds differences between expected PSA Year (each February 1 through January 31 period shall constitute a PSA Year) fuel and purchased power costs and those embedded in base rates.[63] The "Historical Component" tracks the differences between the PSA Year's actual fuel and purchased power costs and those recovered through the combination of base rates and the Forward Component, and also provides for their recovery during the next PSA Year. The "Transition Component" provides for: a) the refund or recovery of balances arising under the provision of the old PSA, prior to its replacement by the new PSA; b) the opportunity to seek a mid-year change in the PSA rate in cases where variances between recovery of fuel and purchased power costs under the combination of base rates and Forward Component become so large as to warrant recovery, should the Commission first deem such an adjustment to be appropriate; and c) the tracking of balances resulting from the application of the Transition Components, in order to provide a basis for the refund or recovery of any such balances.

[62] Staff Late-Filed Exhibit S-50.

[63] The forecasted costs used to set the "Forward Component" are the costs for a calendar year (i.e. Jan-Dec 2007) but the recovery year (or "PSA Year") begins a month later, starting February 1, 2007 to collect those forecasted costs and continues to collect them through the end of the following January 2008. Essentially there is a one month lag. Staff Exhibit No. S-30, Antonuk Supplemental, p. 3.

The PSA Year begins on February 1 and ends on the ensuing January 31, with the first PSA Year in which the new PSA rate applies beginning on February 1, 2007 or the date the Commission approves the adoption of the new PSA. The first PSA Year will end on January 31, 2008, regardless of the start date, and succeeding PSA Years will begin on each February 1 thereafter.

On or before September 30 of each year, APS will submit a PSA Rate filing that includes a proposed calculation of the three components of the PSA rate, together with the necessary supporting data and information.[64] APS will supplement this September filing with Historical Component and Transition Component filings by December 31 in order to replace estimated balances with actual balances.

Although Staff did not accept the Company's 2007 forecast as the basis for setting the base cost of fuel and purchased power, Staff does not object to using APS' 2007 forecast proposed in APS rejoinder testimony to determine the "forward component" for 2007.

AUIA believes that Staff's PSA is the best way to address the issue of timely recovery of fuel and purchased power costs and that by allowing recovery of costs on the most current basis, it markedly improves cash metrics and offers the best insurance policy against further negative rating agency actions. If the Commission decides to maintain the current PSA mechanism, AUIA strongly urges the Commission to set the base fuel rate at $0.032491/kWh and eliminate the 90/10 sharing.

Phelps Dodge/AECC believes that Staff's proposal to include a prospective component to the PSA is a dramatic change to the current form of the PSA that alters the balance of equities struck when the PSA was first negotiated. According to AECC, it has implications for the 90/10 sharing and the incentive for APS to control its costs, and may require a "doubling-up" of the adjustor in the first year. AECC believes that the change is not in the public interest and should be denied.

RUCO believes that Staff has proposed a radically different form of a PSA than either the existing PSA or the PSA with the APS proposed modifications. RUCO recommends that the Commission reject the Staff PSA because it would be premature to discard a PSA and its POA that were extensively analyzed and developed in past proceedings and adopt a PSA that is based upon

---

[64] Including a forecast for upcoming calendar year fuel and purchased power costs and a forecast of kWh sales for the same calendar year.

completely different philosophical underpinnings. RUCO believes that it is more appropriate to tweak the existing PSA to better address fuel cost recovery than to start over. RUCO also opposes Staff's PSA because it omits the 90/10 sharing feature of the exiting PSA. RUCO argues that the "art in establishing a fuel adjustor mechanism is striking the appropriate balance between timely collection of costs and appropriate consumer safeguards, especially protections against undue volatility in customer rates." (RUCO Initial Brief, p. 41) RUCO is concerned that it may be difficult for the Commission to adopt a Forward Component thirty days after APS files its final proposal in late December because proceedings with prospective adjustors become more complicated than proceedings involving only retrospective adjustors.

APS agreed that Staff's proposed "prospective" PSA ensures that APS recovers its full fuel and purchased power costs better than APS' existing PSA with the modifications recommended by APS. That agreement is based upon the following factors:

1) The "forward component" must be set in **this** proceeding and become effective **at the same time** base rates are made effective.
2) The "forward component" must be set at the difference between the Base Fuel Cost established in this case by the Commission and 3.2491¢kWh (which would make the "forward component" zero under the Company's proposed Base Fuel Cost).
3) The 90/10 penalty provision would be abolished.
4) The charges authorized under the current PSA structure (the February 1, 2007 Annual Adjustor, the Step 1 PSA Surcharge, and the Step 2 PSA Surcharge [to the extent authorized] must be allowed to run their course and not be terminated and rolled into a 2008 "historic component," as was suggested in Staff's original Plan of Administration ("POA"). This is consistent with Staff witness Antonuk's testimony at the hearing. (Tr. Vol. XXI at 3870-75 [Antonuk]).
5) Some provision must be made for broker fees. The most obvious solution would be to include them in the recoverable costs under the PSA. A second, but less preferable, option would be to treat them as a separate line item in the Company's non-fuel operating expenses. (APS' Initial Brief at 37, emphasis original).

With these conditions, APS supports Staff's PSA proposal and its POA.

No party has suggested that a PSA is no longer necessary or appropriate for APS. We agree with RUCO that there is an "art" to developing a PSA, and that it must balance timely recovery of costs with safeguards to customers for extreme volatility in costs. The existing PSA has deficiencies that have been identified by the parties, but with the modifications recommended in this proceeding, it can be improved to provide more timely recovery of costs. A PSA that has: a 4 mill annual cap; a provision for 90/10 sharing of costs, except the costs of renewable energy acquired from third parties and not otherwise recoverable under the EPS/RES and the demand component of any long-term purchased power agreement acquired via a competitive procurement process; no Cap on Total Fuel Cost Recovery; and no requirement for mandatory PSA surcharge applications when deferrals reach $100,000,000 would go a long way toward making the PSA more responsive to changes in fuel and purchased power costs. However, a prospective PSA would make the recovery even timelier, thereby improving the Company's cash flow significantly, and it would still provide safeguards to customers to make sure that the costs recovered were prudent. However, such a prospective adjustor should also contain a sharing provision to provide an incentive for the Company to keep its fuel and purchased power costs as close to base rates as possible. The resolution concerning sharing above, which excludes the costs of renewable energy acquired from third parties and not otherwise recoverable under the EPS/RES and the demand component of any long-term purchased power agreement acquired via a competitive procurement process should apply to the prospective PSA as well.

Accordingly, while we believe that either PSA described above is reasonable, because a prospective PSA will significantly improve APS' cash flow, we will adopt Staff's proposed PSA as modified to include the sharing mechanism above. Staff has agreed to APS' calculation of the "Forward Component" for 2007, and accordingly, we will adopt a "Forward Component" that is the difference between the 3.1202¢ base cost of fuel and purchased power adopted herein, and the 2007 forecast cost of 3.2491¢.[65] The Plan of Administration for Staff's PSA addressed the transition from

[65] .1289¢

the old PSA to the new PSA. We agree with Staff and APS that the appropriate way to address any PSA charges currently authorized is to allow them to continue to run their course as originally set. Any residual amounts remaining can be handled in the 2008 PSA Year.[66]

Subsequent to Staff filing its Late-Filed Exhibit No. 50, APS filed comments and suggested modifications to the Plan of Administration. Staff has not filed any objections to APS' suggestions, and except for the language APS changed to allow broker fees in excess of the amounts included in base rates into the PSA, we will adopt them and order Staff to file the final, conformed Plan of Administration that is consistent with this Decision, within 30 days of this Decision.

## XIII. PALO VERDE ISSUES

The Palo Verde Nuclear Generating Station ("Palo Verde") is jointly owned by seven companies: APS (29.1 percent); Salt River Agricultural Improvement and Power District (17.5 percent); Southern California Edison Company (15.8 percent); El Paso Electric Company (15.8 percent); Public Service Company of New Mexico (10.2 percent); Southern California Public Power Authority Association (5.9 percent); and Department of Water and Power City of Los Angeles (5.9 percent). APS is the licensed operator and the operating agent for Palo Verde on behalf of its owners. APS manages the employees and contractors working at Palo Verde and makes all decisions regarding the safe and reliable operation of the station. APS confers with and receives approval from the other owners on some issues, including all major capital projects such as steam generator replacements and turbine upgrades. (APS Exhibit No. 94, Levin Rebuttal, p. 7). Palo Verde is a vital component of APS' generation resources, providing 18.9 percent of APS' total generating capacity. (Staff Exhibit No. 46, GDS Associates, Inc. Report, p. 6)

In 2005, Palo Verde had more outages than normal and the capacity factor and generation were lower than expected. (*Id.*) APS agrees that it fell about ten percent shy of its production and capacity factor targets for 2005, and that the decrease in performance was directly related to the greater than typical number and duration of plant outages. (APS Exhibit No. 94, Levin Rebuttal, p. 10).

[66] Tr. Vol. XXI, pp. 3870-72.

Operating performance of the Palo Verde nuclear power plants directly affects the costs of fuel and purchased power that ratepayers are required to pay though an adjustor mechanism. Nuclear power plants have the highest capital costs of any central power station, but have low fuel and variable costs. This offset enables nuclear power to be an economic source of electrical generation. Because both the high capital costs and low operating costs are built into base rates, ratepayers pay the high capital costs, even when the plants are not operating. When the plants are out of service, that low cost lost generation has to be replaced by higher cost generation and the additional costs are recoverable through the PSA. However, the fuel and purchased power costs recoverable under the PSA are subject to a prudency review and may be disallowed by the Commission if the costs are found not to be prudently incurred. In response to the eleven Palo Verde outages in 2005, Staff issued a Request for Proposals to engage a consultant to investigate the reasons for the lower performance and to make recommendations to improve performance and reduce the likelihood of more unplanned outages in the future.

On February 2, 2006, APS filed an application for approval of a PSA surcharge to recover $44.6 million[67] plus accumulated interest in replacement power costs that were a result of outages at Palo Verde during 2005.[68] APS believes that none of the outages were the result of imprudence and that all the replacement power costs should be recovered from ratepayers through implementation of a "Step 2 PSA Surcharge" in this Decision. Staff's witness, Dr. William Jacobs, Vice President of GDS Associates, Inc. ("GDS") testified that of the eleven planned and unplanned outages in 2005, he identified four that resulted from imprudence. Dr. Jacobs recommended that the Commission disallow recovery of $16.186 million, including $13.757 million of replacement power costs during the period the PSA was in effect, and the cost of reduced margins on off-system and opportunity sales.

Staff's consultant, GDS, made the following seven conclusions:

1) Performance of the Palo Verde Plant has declined significantly over the past three years.

---

[67] 90 percent of $49,516,000.
[68] Docket No. E-01345-05-0826.

2) The number of outages was much higher than normal and the capacity factor and generation were lower than should be expected.
3) APS acknowledges the decline in performance and has implemented an aggressive Performance Improvement Plan ("PIP") to return the Plant to its former level of performance.
4) Four of the 2005 outages were avoidable and the result of imprudence.
5) Some of the unplanned outages were caused by faulty or defective vendor supplied equipment. We have evaluated APS' actions related to these specific outages and have concluded that APS' actions were not imprudent.
6) It is too soon to determine the prudence of the Unit 1 shutdown associated with the shutdown cooling line vibration. This is a unique problem. It appears that APS has made a concerted effort to resolve the vibration problem, which continued into 2006. Additional investigation will be needed to determine the cause of and responsibility for this outage.
7) Although APS received a yellow finding from NRC[69] in 2004 regarding safety related issues of substantial importance, it is GDS' conclusion that there is no evidence or indication that operation of the plant in 2005 has compromised safety.

GDS made the following six recommendations:

1) The Commission should disallow the additional costs resulting from outages identified as avoidable and imprudent in this report. The resulting disallowance is $17.373 million (see Table 5). The amount of $1.623 million incurred before April 1, 2005 should not be eligible for consideration in establishing base fuel costs in the pending rate case.[70]
2) An issue related to the unplanned Palo Verde outages attributable to faulty or defective vendor-supplied equipment is the degree to which APS has sought appropriate legal or other remedies. This report does not address this issue, but instead recommends that the Commission address it in the pending rate case. APS should be given the opportunity to demonstrate the steps that it has taken in this regard, and the Commission should evaluate APS' action.
3) The Commission should establish a Nuclear Performance Standard that would establish minimum acceptable levels of performance for Palo Verde and penalties for periods during which the performance of Palo Verde falls below the minimum levels. The Nuclear Performance Standard should be considered in APS' pending rate case.
4) The Commission should order APS to submit a semi-annual report to the Commission's Docket Control, describing plant performance, explaining any negative regulatory reports by the NRC or INPO,[71] and providing details of corrective actions taken. APS should submit this report semi-annually until the Commission decides that it is no longer necessary.
5) The Commission should order APS to evaluate its programs to deal with aging equipment at Palo Verde. This evaluation should consider industry experience with aging equipment, programs established at other nuclear plants that have been

[69] Nuclear Regulatory Commission
[70] This recommendation was later modified to a total of $16.186 million as set out above.
[71] "Institute of Nuclear Power Operations"

successful in managing aging equipment issues, and recent experience at Palo Verde. APS should submit a report to the Commission within 120 days of the Commission's order in this matter describing the findings of the evaluation and the actions taken to improve APS' management of aging equipment issues.

6) The Commission should order APS to evaluate its programs for receipt inspection and verification of parts prior to installation. This evaluation should consider industry experience, programs established at other nuclear plants that have been successful in avoiding outages due to installation of incorrect parts, and experience at Palo Verde. APS should submit a report to the Commission within 120 days of the Commission's order in this matter describing the findings of the evaluation and the actions taken to improve receipt inspection and pre-installation verification of parts at Palo Verde.

**A. Conclusions #1, #2, #3, and Recommendation #3 – Performance, Performance Improvement Plan, Nuclear Performance Standard**

APS' witness, Levine, testified that safe operation of the Palo Verde units is the overriding priority and that Palo Verde has operated safely. He disagreed with the GDS conclusion that the plant's 2005 capacity factor shows that performance in 2005 was "poor" and testified that "over the last 10 years, Palo Verde has performed well in comparison to other nuclear plants." (APS Exhibit No. 94, Levine Rebuttal, p. 4) In response, Staff's witness testified that he believed that the comments of Palo Verde's top executive, Mr. Levine, and the other Company witnesses are:

> . . . quite ironic and misplaced given that their failure to recognize the decline in Palo Verde performance and take appropriate corrective action was due in part to their reliance on past performance. Their recommendation that the Commission focus on the prior 10 years of Palo Verde performance is exactly the management mindset that allowed the decline in Palo Verde to continue for several years without corrective action and led to Palo Verde residing at the bottom of the nuclear industry. The Palo Verde Performance Improvement Plan states: 'Site leadership did not fully accept that the Palo Verde performance indicators reflected actual performance until mid 2005. Management's mindset resulted in part from ten previous years of Palo Verde top quartile levels of performance.' By focusing on prior good performance, Palo Verde management failed to recognize the declining performance until several years after the trend began. (Staff Exhibit No. 48, Jacobs Surrebuttal, p. 4)

Dr. Jacobs also disagreed with Mr. Levine's assertion that the decrease in performance was related to the greater number and duration of plant outages, citing the APS Performance Improvement Plan's statement:

> In late 2002 or early 2003 performance indicators at Palo Verde began a downward trend relative to the sustained high performance levels in previous years. A cause of

> this trend appears to have been the realignment of key site leadership that in turn caused the team to be more focused on day-to-day tactical matters, and less focused on strategic planning, standards and accountability. Additionally, in 2004, two significant events occurred at Palo Verde. They are the three unit trip in June 2004 that resulted from a grid disturbance and, the discovery, in July 2004, of the absence of water in portions of Emergency Core Coolant System piping ("RAS[72] Sump Event"). These events also revealed issues with regard to various Palo Verde programs and processes that are in need of improvement.[73]

Dr. Jacobs concluded that APS determined that the declining performance was due to APS' loss of focus by key site leadership and programs and processes that needed improvement.

APS agreed that its PIP is a comprehensive plan with substantial resources and the commitment of APS management to return Palo Verde's performance to the sustained level of excellent performance it previously enjoyed. After making his initial conclusions about APS' PIP and expressing optimism for its success, Dr. Jacobs expressed less optimism in his surrebuttal testimony filed later in 2006. Dr. Jacobs noted that both the NRC inspection report on the area of problem identification and resolution issues in May 2006, and the August 31, 2006. NRC Midcycle Review and Inspection Plan for Palo Verde were not encouraging, and testified that the "NRC is not convinced and results to date have not demonstrated that the corrective actions implemented to date are sufficient to resolve the problems in human performance and problem identification and resolution." (Staff Exhibit No. 48, Jacobs Surrebuttal, p. 13)

Staff Recommendation #3, implementation of a Nuclear Performance Standard ("NPS") included the following features to be considered in designing an NPS:

- The method of setting targets and evaluating actual versus target performance should be clearly defined and consistently applied;
- Plant performance should be evaluated in terms of its impact on the "bottom line" system production cost in order to ensure that system cost savings remains the primary operating goal;
- Disallowances should be based on the change in system production costs which is related to the difference between actual and target plant performance;

[72] "RAS" stands for Recirculation Actuation Signal, the signal that allows the Emergency Core Cooling Systems to take suction from the Containment Sump during a Loss of Coolant Accident.
[73] Palo Verde Nuclear Generating Station Performance Improvement Plan, October, 15, 2005, page 1.

- Disallowances should closely correlate with the actual change in system production costs which is related to the difference between actual and target plant performance;

- The range for disallowances should be capped at a level which prevents severe financial penalty and above which detailed reviews of extended outages or other extraordinary events can be conducted; and

- The Nuclear Performance Standard should be relatively easy to administer and not overly burdensome on the Company or Commission Staff. (Staff Exhibit N. 47, Jacobs Direct, pp 6-7)

Staff's witness testified that the following specific details should be part of the NPS for Palo Verde:

- Palo Verde's performance will be measured by the capacity factor achieved, calculated every 3 years;

- The capacity factor target value is the average capacity factor achieved over the 3-year period by similar U.S. nuclear power plants. Similar nuclear power plants are defined to be all pressurized water reactors ("PWR") operating in the United States with generating capacity greater than 600 MW;

- U.S. PWRs with a 3-year capacity factor of less than 60% should be excluded from calculation of the target value;

- If the 3-year capacity factor achieved by Palo Verde is greater than the target value, there would be no action resulting from the NPS;

- It the 3-year capacity factor achieved by Palo Verde is less than the target value, APS will determine the additional fuel or replacement power costs incurred by comparing actual system costs to system costs that would have resulted if Palo Verde had operated at the target value capacity factor. APS should submit the calculation of Palo Verde performance, the target value and the cost impact if Palo Verde performance is below the target value within 90 days of the end of each 3-year period;

- Treatment of these additional costs, if any, will be determined by the Commission; and

- At the Commission's discretion, detailed reviews may be conducted of extended outages or other extraordinary events that would significantly impact Palo Verde's capacity factor during the 3-year period. (Staff Exhibit N. 47, Jacobs Direct, pp 7-8)

APS' witnesses testified that an NPS is unnecessary, inappropriate, and that Staff's proposed NPS is lacking key elements. APS believes that a NPS is unnecessary because the existence of one would not affect how APS operates Palo Verde. In a recent proceeding in Georgia, upon Dr. Jacobs' recommendation, the Georgia Commission terminated an NPS because the utility indicated that the

NPS had no impact on how it operated the plant. APS also argues that the NRC has expressed concern about the effect that penalty-only, capacity factor-only NPSs have on safety. Further, APS argues that Staff's proposal did not include enough information and detail to adopt an NPS in this proceeding. APS pointed out that further development on the issue of a "cap" on the penalty is necessary; that the differences in refueling cycles would have to be addressed; whether the mean or median capacity factor should be used for the target value needs to be determined; that details of how a financial penalty would be calculated would need to be included; that plant specific characteristics of Palo Verde should be included; that consideration should be given to a "dead band" or "null zone;" that the comparison group includes plants greater than 1000 MW; and that additional safety-related attributes to offset any of the potential negative effects of the capacity factor-only proposal should be considered and included. APS also argues that a performance standard should include equal opportunities for rewards and penalties as expressed by the NRC and as the Commission concluded in a Decision in 1984,[74] and that a performance standard should apply to the entire system, including baseload coal plants.

In response, Staff's witness testified that he does not believe that any reward provided by a symmetrical program results in better plant performance and is merely additional expense borne by ratepayers for what the Company should already be doing; that nuclear and coal-fired generation are fundamentally different, having different capital costs and fuel and production costs, and different issues and regulations affecting the operations of the plants; that he agreed that either his or APS' comparison group is appropriate; that the three-year evaluation cycle was proposed to allow for differing refueling cycle lengths among the comparison group plants, but that he would consider a different evaluation cycle if APS proposed a reasonable one; that many nuclear power plants operate under a performance standard and that there is no indication that it has resulted in unsafe operation and that the compensation of the plant's senior managers and executives is tied to plant performance; that the cap on the amount of the penalty is a reasonable request; and that although his testimony provides sufficient detail to implement the NPS, additional details can be added.

---

[74] Decision No. 54247.

Clearly, the evidence shows that the Commission should be concerned about Palo Verde's recent performance and should be monitoring APS' operation of the Palo Verde plants. Staff has proposed a Nuclear Performance Standard, but many of the details remain to be either agreed upon or determined by us. We do not believe that we have sufficient evidence or detail in this proceeding to adopt and implement an NPS at this time. We direct Staff and APS to work out a detailed NPS,[75] together with a Plan of Administration, that we can consider in a separate proceeding. In the meantime, we believe that for all future planned or unplanned outages at Palo Verde, APS should identify all replacement power costs, as well as the amount of reduced off-system sales and lost opportunity sales margins associated with each outage, and file documentation with the Commission explaining the reasons for the outage and the associated costs, within 60 days of the conclusion of the outage. This will assist us in monitoring and evaluating APS' operational performance with the Palo Verde plants, and help determine which costs are prudent when setting the PSA adjustor.

### B. Conclusion #4, Recommendation # 1 - 2005 Palo Verde Outages

GDS analyzed the eleven planned and unplanned Palo Verde outages that occurred during 2005. It concluded that four of the outages were imprudent. According to the GDS Report, the analysis "evaluated APS' performance by comparison to the reasonable decisions and actions of a qualified and experienced utility manager given what was known or should have been known at the time without the benefit of hindsight. Thus, the actions and decisions of Palo Verde personnel 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." (Staff Exhibit No. 4, GDS Report, p. 19)

APS cites A.A.C. R14-2-103(A)(3)(1) which is the definition of "prudently invested." The rule provides that all investments "shall be presumed to have been prudently made, and such presumptions may be set aside only by clear and convincing evidence that such investments were imprudent, when viewed in the light of all relevant conditions known or which in the exercise of reasonable judgment should have been known, at the time such investments were made." As pointed out by Staff's legal counsel in opening arguments, this rule applies to rate base and investments, not

[75] Not including baseload coal or other non-nuclear plants.

to operating expenses such as replacement power costs.[76] APS witness Levine testified that "[p]rudence only requires that reasonable actions be taken based on information that was or should have been known at the time of an action, without the use of hindsight." (APS Exhibit No. 94, Levine Rebuttal, p. 11)

Staff and APS generally agree on the prudence standard, but take different points of view on its application. APS believes that there is a presumption of prudence that can only be overcome by clear and convincing evidence, and Staff believes that APS bears the burden to demonstrate that its costs are reasonable, appropriate and not the result of imprudence.

We agree that the rule cited by APS does not apply to the operating expenses at issue here, and we also agree with the prudence standard as agreed upon by both APS and Staff. Regardless of who has the initial burden or presumption, 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.

APS criticizes GDS' use of NRC and Company documents, INPO reports and INPO grades arguing that such documents use hindsight and are not contemporaneous reflections of what management knew or should have known at the time. We are cognizant of the danger of using hindsight to evaluate the reasonableness of past decisions and actions, and are careful to use only the facts that were known or reasonably should have been know at the time, to make our determinations. The use of NRC, Company, or other documents that describe events, actions, decisions, and what was known at the time is appropriate, and is not using "hindsight" just because the documents were created after the time or event involved. As pointed out by counsel for Staff, it would be impossible to use documents that were created prior to such events. Further, APS had the opportunity to call as witnesses any person who had actual knowledge of the event that might contradict the descriptions or information contained in those documents, and APS chose not to present or offer such a rebuttal.

### C. <u>Outages Not Due to Imprudence</u>

---

[76] "Secondly, please look at the cited rule. I won't quote it, but bear in mind that it is designed to apply to rate base elements. It talks in terms of investments. What we are discussing now is operations related expenses. And with operations related expenses, the utility has the burden of showing that its operating expenses are reasonable in order to recover them." Tr. Vol. XXVI, p. 4901.

GDS concluded that APS had acted prudently in connection with both 2005 refueling outages and with Unit 1's February 9-19, 2005, outage; Unit 1's August 11-28, 2005, outage (except for the 2 days of that outage due to a reactor trip on August 26, 2005 – see below); Unit 2's August 22-26, 2005, outage; Unit 3's May 22 to June 24, 2005, outage; Unit 3's July 6-13, 2005, outage; and Unit 3's October 2-7, 2005, outage.

**D. Unit 1 March 2005 Outage Due to Failure of Diesel Generator Governor**

On March 17, 2005, Palo Verde Unit 1's Diesel Generator "A" or emergency diesel generator ("EDG") failed to achieve full speed during a post-maintenance test. APS determined that the generator's governor needed to be replaced, and it replaced the governor. The technical specifications required the unit to be shut down to perform the retests required following the governor replacement. APS conducted a root cause investigation and determined that the direct cause was "contamination of the lube oil in the governor actuator." (Exhibit No.94 Levine Rebuttal, p. 26) APS was unable to determine for certain what led to the problems with the governor, but the investigation identified the "three most probable root causes as water introduced during refurbishment that was not completely drained, governor storage drained of oil in the Palo Verde warehouse, and water introduced during oil change." (Id.)

GDS concluded that this outage was the result of imprudence and was avoidable by ensuring that the storage conditions and pre-installation inspection of the re-furbished governor were commensurate with the importance of the equipment. Staff pointed out that the governor was stored in a non-climate controlled warehouse, drained of oil, and argues that if the governor had been stored with oil in it, it could have prevented the outage. Staff believes that because each unit requires both EDGs to be operable if off-site power is lost and because the loss of an EDG for an extended period requires the shut-down of the affected unit, it is clear that APS did not treat the EDGs with the level of care that would be appropriate to the significance of this equipment.

APS witness Levine testified that the governor was stored according to the manufacturer's recommendations, and that the manufacturer recommends examination of the governor every five years. According to Mr. Levine, the governor at issue was rebuilt and shipped to Palo Verde in July 2000, and installed in April 2001, which is much shorter than the five year recommendation. Mr.

Levine also testified that the governor was inspected as it was installed and that no rust could have been detected because the rust was only detected after it underwent a "disassembly inspection" during the post-failure examination. He testified that it is not reasonable to require Palo Verde personnel to disassemble a component before installation and that such a disassembly would only increase the possibility of contaminating equipment.

This outage occurred prior to the implementation of the PSA, so no recommendation was made to disallow any costs associated with the outage. We agree with APS that this outage was not the result of imprudence. At the time of the event, APS had no way of knowing that there was rust in the governor, it had maintained the equipment in conformance with the manufacturer's recommendations, and a pre-installation disassembly would not have been reasonable.

**E. Unit 1 August 2005 Reactor Trip**

On August 9, 2005, Unit 1's EDG "B" failed to maintain proper steady state output voltage during performance of a routine monthly surveillance test. (Staff Exhibit No. 46, GDS Report, p.24). When the problem was not correctable within 72 hours, Unit 1 was shut down on August 12, 2005. On August 26, 2005, during the startup, the unit tripped due to an operator error in controlling the feedwater to the steam generator. GDS found that the initiating event, the failure of the automatic voltage regulator diode, could not have reasonably been foreseen and was unavoidable, but that the delay in the completion of the outage and resulting cost due to the reactor trip of August 26, 2005, is due to imprudence.

APS' witness Levine testified to the following description of the event:

> The operator did not believe the automatic control was adequately maintaining the level in the steam generator, so the operator switched the system to manual control. However, as GDS acknowledges, the operator failed to request concurrence from the Control Room Supervisor when he shifted to manual operation. In attempting to maintain the proper level in the steam generator, the operator altered the level setpoint and switched between manual and automatic control several times. The attempts, combined with the expansion of the water in the steam generator due to rising temperatures, were unsuccessful, and the reactor tripped due to a high level in the steam generator." (APS Exhibit No. 94, Levine Rebuttal, pp. 21-22).

APS' position on this reactor trip is that it occurred because of the failure of the secondary control room operator to follow procedures, and it was not the result of imprudent actions by APS management. APS cites three factors in support of its position: 1) Palo Verde management was not involved in the cause of the reactor trip, as it was the operator's individual actions that were contrary to procedures that caused the trip; 2) if the operator had followed procedures, the reactor would not have tripped; and 3) Palo Verde provided the appropriate amount of training to the operators on this system as evidenced by the fact that the issue had never caused an earlier reactor trip. (APS Initial Brief, p. 161).

The root cause investigation of this event identified the following direct, root and contributing causes:[77]

> **Direct Cause #1:** The assigned dayshift licensed operator for Steam Generator feedwater control failed to request CRS [Control Room Supervisor] concurrence when placing the digital feedwater control system[78] in manual when level was lower than desired under automatic control. This communication failure isolated the individual from supervisory oversight and the crew's ability to assess the overall plant condition. Subsequently, the feedwater flow was increased by operator action at a rate in excess of the rate required to compensate for the steaming rate at that power level and resulted in a high steam generator level and subsequent MSIS [Main Steam Isolation Signal] and reactor trip.
>
> **Direct Cause #2:** Crew members failed to provide the team support needed to ensure individual errors are promptly identified and corrected.
>
> **Root Cause #1:** Consistent Standards of Performance by Unit 1 Operations Crew C were not sufficiently anchored.
>
> **Root Cause #2:** Feedwater control system performance issues at low power levels have not been effectively resolved since the digital upgrade. This has led to acceptance of operational strategies to cope with system instability at low power levels.
>
> **Contributing Cause #1:** Procedures 40DP-9FT01&2, *Feedwater Pump Turbine A(B)* are not sufficiently human factored for all users, making them susceptible to performance error and resultant system perturbations.
>
> **Contributing Cause #2:** Common belief existed among licensed operators that the DFWCS [Digital Feedwater Control System] cannot reliably control SG

[77] Staff Exhibit No. 45, GDS Report, Attachment 11.
[78] ("DFWCS")

> [Steam Generator] level well at low power. This belief was not based on actual performance data and led to acceptance of the condition and mitigating strategies.
>
> **Contributing Cause #3:** Training was not commensurate with the unidentified difficulty of putting DFWCS into auto operation given the current procedure detail and system design. This resulted in mis-operation of DFWCS components while in single element control.

Staff's witness, Dr. Jacobs, testified that the outage clearly reflects the cross-cutting issues identified by the NRC[79] and that the outage was the result of a human performance error and failure of APS to resolve a known problem in a timely manner. Dr. Jacobs testified that the operator's failure to follow procedures and to communicate with his shift management is closely related to the INPO's finding of a lack of consistent standards, lack of accountability, and a willingness to accept longstanding equipment problems. (Staff Exhibit No. 45, GDS Report, pp 26-27.)

Dr. Jacobs testified that this reactor trip is also an example of APS' failure in the cross-cutting areas of problem identification and resolution. Root Cause #2 explained that performance issues since the digital upgrade were not effectively resolved, which led to acceptance of operational strategies to cope with perceived system instability. The accompanying note indicated that deficiencies with effective problem resolution extend throughout the Palo Verde organization as previously identified by the NRC as cross-cutting issues. The supporting facts to Contributing Cause #2 include: "*Many licensed operators believed DFWCS was not reliable* in maintaining stable feedwater levels when at low power levels"; "Reliance on individual experience and unconfirmed anecdotal accounts influenced operator opinion of low power DFWCS stability. *This was not an isolated, single occurrence, but rather a common mindset (culture) regarding expected system performance at low power levels;*" "*Past evaluations of system performance have not resulted in actions (procedures or training) to address how the system is operated.*" (Staff Exhibit No. 45, GDS Report, Attachment 11, p. 11) (emphasis added) The supporting facts to Contributing Cause #3 include: "Performance issues associated with this evolution have not been forwarded to training for analysis"; "Training was conducted in 2004 on the procedure change . . . Since the training was

---

[79] "A cross-cutting issue is an issue or concern that affects several areas of the plant organization. The NRC identifies cross-cutting issues in the areas of human performance, problem identification and resolution, and safety conscious work environment." Staff Exhibit No. 45, Jacobs Surrebuttal, pp 11-12.

conducted there have been at least five instances where SG[80] levels were difficult to control"; "Following the training in 2004 for transferring from manual to auto DFWCS, no formal feedback was provided noting procedure ambiguity of step 4.3.13. Anecdotal instructor recollection is the Operators had concerns with the wording"; "The training conducted in 2004 was provided in the simulator was to the entire crew with only one crew member actually performing the task." (Id. p. 12) Further, the supporting facts to Contributing Cause # 1 included the following statement: "Simulator instructor recalls operators informally reported some difficulty with step 4.3.13 during training on the procedure change." (Staff Exhibit No. 45, GDS Report, Attachment 11, p. 10)

Dr. Jacobs concluded that "even though the concern with the ability of the digital feedwater control system to maintain steam generator level at low power was well known in the operations department, training of the operators was not commensurate with the difficulty encountered putting the control into automatic mode." (Staff Exhibit No. 45, GDS Report, p. 27)

Although 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"[81] he would have answered "yes", 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. These facts and the existence of the operators' opinions concerning the reliability of system procedures were known and knowable at the time of the startup. Unit 1 had been shut down for two weeks when APS began the startup and it should have used that time to insure that the operators were adequately trained on the startup procedure, even if the procedure was long, as testified to by Mr. Levine. Although Mr. Levine testified that APS did not conduct just-in-time training on the steam generator level control systems because there had not been significant difficulties in the past,[82] the APS root cause investigation stated that since the training was conducted, there had been at least five instances where SG levels were difficult to control. APS' argument that there wasn't a problem with the procedures, just a *perception* that there was a problem, does not help. APS should ask and know what the concerns are of the operators, especially when

[80] "Steam Generator"
[81] Tr. Vol. XXVII, p. 5133
[82] Tr. Vol. XXVII, p. 5232

those operators have a "common mindset" that there is a problem in a system or procedures that can trip a reactor. While APS cannot control every individual action, it can and should know when there is a widespread perception that the process or procedure is not working well, and take immediate steps to address and resolve it. Accordingly, we find that the outage associated with the reactor trip on August 26, 2005 was the result of APS' imprudence and will disallow recovery of the costs associated with the outage via the PSA.

**F. <u>Unit 2 and Unit 3 October 2005 Outages</u>**

In August 2004, the NRC identified a violation at all three Palo Verde units involving a failure to adequately control the designed configuration of the containment sump safety injection suction piping. This violation was subsequently determined by the NRC to be of substantial safety significance ("Yellow Finding") and caused plant performance for Palo Verde to be categorized within the Degraded Cornerstone Column of the NRC's Manual Chapter 0305 "Operating Reactor Assessment Program" Action Matrix. A supplemental inspection was conducted to obtain information so the NRC could determine if the licensee (APS) could provide reasonable assurance that the problems associated with the degraded Mitigating Systems cornerstone were thoroughly understood, the cause and effects were properly evaluated, and whether sufficient corrective actions had been taken to prevent recurrence.

During this supplemental inspection, the NRC inspectors identified a (Green) noncited violation related to the potential air entrainment into the emergency core cooling system ("ECCS") suction header from the refueling water tank ("RWT"). The inspectors determined that "the water level in the RWR could fall below the level of the tank discharge pipe and associated vortex breaker during the transfer from the RWT to the containment sump after an accident. As a result, air could enter the ECCS piping system under accident conditions. This issue was applicable to both trains of all three units." (Staff Exhibit No. 45, GDS Report, Attachment 3 (January 27, 2006 letter and report from Bruce Mallet, NRC Regional Administrator, p. 7))s ("January 2006 NRC Report").

In preparation for the inspection, the inspectors reviewed APS' report on the extent of condition and extent of cause evaluations for the ECCS sump issue (Yellow Finding) and noted that the report included the RWT in it scope, but that it did not address the RWT as a potential source of air entrainment into the ECCS. According to the January 2006 NRC Report, the inspectors also noted that the Palo Verde design did not include automatic closure of the RWT isolation valves with a recirculation actuation signal ("RAS"). During their review, the inspectors noted "*that the licensee did not fully understand the plant design basis and the dynamics of the system at the time of a RAS. Based on these observations, the inspectors questioned the licensee personnel further on the potential of air entrainment from the RWT into the ECCS.*" (Id. at 8) (emphasis added).

The design calculation applicable to this issue included an analysis to demonstrate that the "final RWT level following a RAS was adequate, relative to the minimum water level in containment, to ensure that the suction piping would not void and gas-bind the ECCS pumps" and was based on a minimum containment pressure of 23 psia or approximately 8.5 psig. When questioned by the inspectors whether the 23 psia value was conservative, APS' engineering staff indicated that more recent "'best-estimate' analyses had indicated that the actual minimum containment pressure was 17.5 to 18.5 psia (approximately 3 to 4 psig)." (*Id.*) In response, APS engineering personnel initiated a CRDR[83] on October 6, 2005, that raised the concern whether the original Combustion Engineering design interface requirements would "preclude the possibility of drawing air from the RWT to the safeguards pump suction during recirculation." The interface requirement stated: "the piping for each safeguards train is designed such that the piping junction of the suction pipe, that runs to the refueling water tank and the containment recirculation sump, is located at least 16 feet below the top of the recirculation containment sump, which is 4 feet below the minimum water level in the containment during recirculation. This provides adequate static hydraulic head margin for the minimum containment pressure of -3.5 psig, . . . to preclude the possibility of drawing air from the RWT to the safeguards pump suction during recirculation." (Id.) According to the January 2006 NRC Report, the NRC inspectors "were concerned that while this was a design interface requirement, it was intended to be a bounding design consideration for the ECCS, especially during dynamic flow conditions." (*Id.*) On October 6, 2005, an operability determination was initiated to address this issue. APS determined that the ECCS was operable and stated that "further evaluation will

[83] "Condition Report Disposition Request"

demonstrate that with appropriate assumptions for the containment pressure and water inventory in the RTW/containment, the minimum water level will remain above the vortex breaker in the RWT which eliminates the potential for air entrainment. Based on this information, reasonable assurance exists that the ECCS is capable of performing its specified design function and therefore remains operable." (Id.) However, a subsequent containment pressure analysis performed by Westinghouse showed that the maximum RWT temperature was nonconservative for determining the minimum containment pressure under accident conditions, and that the minimum containment pressure required to prevent uncovering the RWT vortex breaker was 4.3 psig. Given APS' recent containment modeling showing containment pressure could be 3 to 4 psig, it was determined that the ECCS of both trains of all three units were outside the design bases and were declared inoperable. On October 17, 2005, APS determined that the ECCSs were operable and approved restarts for Units 2 and 3. This determination was based upon conclusions in a report from Fauske & Associates, Inc., ("Fauske Report') including that the design of the safety injection system ("SIS") and containment spray system ("CSS") suction piping meets the subject interface requirement and supports operability of the SIS and CSS. After a detailed review of APS' operability determination and design calculation, the inspectors questioned APS' conclusion that "a degraded or nonconforming condition did not exist" because the Fauske Report "predicted that the RWT level would fall below the RWT vortex breaker and that some air would enter the piping system. Although this report concluded that the air would not reach the pump suctions, air entrainment in the piping system was not consistent with the design basis." (Id. at 10) APS agreed and undertook additional actions to correct the condition.

According to the January 2006 NRC Report, in addition to the above noncited violation, the NRC inspectors noted other performance deficiencies and found that this issue had cross-cutting aspects of human performance. Importantly, the NRC inspectors found that "the licensee's attention to detail was lacking and there was poor inter- and intra-group coordination." (*Id.*) Some of the deficiencies included:

- The inspectors determined that the licensee extent of cause and extent of condition reviews were narrowly focused. The licensee defined very extensive design criteria and features that could be pertinent to the original (Yellow) violation. However, if some design document or interface document addressed the design criteria, the licensee performed no further review. There was not a thorough effort by the licensee to validate the design criteria. This was clearly demonstrated in the RWT voiding issue. Examples include the licensee's misunderstanding of the maximum RWT temperature, and their reliance on a Combustion Engineering interface requirement, for piping elevations, to meet all dynamic thermal-hydraulic design criteria for ECCS piping.

- The inspectors determined that the licensee's evaluation of the technical issues was iterative, which demonstrated a lack of thoroughness in reviews. The inspectors noted that engineering personnel would address one particular aspect or consideration when a design problem was presented. However, when questioned by the inspectors or engineering management, more discrepancies would be identified by the engineering personnel. The inspectors determined that design engineering personnel were making broad assumptions of criteria in their reviews, and in several cases, were using unverified or unstated assumptions from other groups. An example was the stroke times for the containment sump isolation valves used by design engineers in their RWT required volume calculations. There was no stated basis for the times used, and design engineers could not explain to the inspectors where the values came from. Additionally, other engineering personnel were not challenging these assumptions in peer or supervisory reviews.
- The inspectors noted a lack of communication between organizations, and a lack of attention to detail when coordinating critical design evaluations between organizations.
- The inspectors determined that the licensee had a very limited use of operating experience for the RWT issue. The licensee had previously identified that ineffective use of operating experience was a contributor to the (Yellow) ECCS violation. . . . However, during the review of the RWT issue, the licensee did not consider all relevant operating experience. (*Id.* at 10-12)

The NRC inspectors concluded that the potential for air entrainment into the ECCS suction header from the RWT was a performance deficiency, it did not conform to the plant design basis, and had not been analyzed. This finding affected the Mitigating Systems cornerstone because of the potential for the safety injection and containment spray systems to be degraded due to air reaching the pump suctions under accident conditions. The NRC inspectors determined that the specific accident conditions that could have challenged the ECCS have not existed and APS also determined that although potentially degraded, the SIS and CSS remained operable. The inspectors determined the issue was Green because there was no actual loss of safety function, and because of its Green finding and because it has been entered into the corrective action program, the violation was treated as a noncited violation.

The GDS Report concludes that the October 2005 outages for Units 2 and 3 were avoidable and imprudent. The issue of air entrainment and damage to safety-related pumps was originally identified by the NRC in July 2004, and was the subject of a Yellow Finding, a significant event for APS. The GDS Report states that the "RWT air entrainment issue is closely related to the 2004 yellow finding in that the fundamental concern of both issues is the possible damage to safety-related pumps due to air entrainment either from the empty sump piping or from the drain down of the RWT." (Staff Exhibit No. 45, GDS Report, p. 32) The GDS Report notes that APS' analyses of problems have been found to be too narrow previously, and the RWT is another example. "Even though the RWT was within the boundary of the evaluation of the yellow finding event, and the primary concern was the potential for damage to safety related pumps due to air entrainment, APS personnel did not identify the RWT concern until it was pointed out by NRC inspectors. . . ." (*Id.*) According to the GDS Report, Palo Verde's NRC Senior Resident Inspector stated that he believed the outage was avoidable. (*Id.*)

According to APS' witness Dr. Mattson, the October 2005 outages at Palo Verde Units 2 and 3 were not the result of APS' imprudence. He testified that Palo Verde personnel responded reasonably to a "new question" the NRC raised, one that he believes APS should not have anticipated. Dr. Mattson testified that the question went to the "adequacy of the original licensing basis, and thus was outside the scope of an extent of condition review for the problem found in 2004 with voiding in the sump suction lines, which was a design basis implementation issue; i.e. the question went to whether the design the NRC had approved back before the plant operated was adequate rather than whether APS had properly implemented the NRC-approved design." (APS Exhibit No.87, Mattson Rebuttal, pp. 48-49) According to Dr. Mattson, just before the supplemental inspection in October 2005, one of the inspectors told APS that the inspection team would look at the refuel water tank and other water sources to determine if the design had been implemented. (*Id.* at 53). He testified that APS and its contractors "assembled 35 volumes of documentation on the RWT and five other safety systems in preparation for the inspection to demonstrate how the original designs of these systems had been implemented. (*Id.*) Dr. Mattson testified that the October 6, 2005 response to the NRC inspector's question said that "there was sufficient margin in the design to assure that these dynamic effects could be overcome and the intent of the design would be met. The revised response also provided evidence that Combustion Engineering had been aware of the potential for air entrainment when the interface requirements related to the design had been established." (*Id.*) APS' consultant, Westinghouse, was requested to confirm that the margin in the static design basis was sufficient to accommodate what APS calls the "dynamic effect." They were unable confirm the margin if there were "low temperatures in the RWT at the time of a loss of coolant accident,[84] temperatures that were allowed by the plant's technical specifications, and so the plants were shut down. Dr. Mattson, a former Director at the NRC in the early 1980s, expressed his opinion that the NRC inspectors imposed a "backfit" on Palo Verde by raising the issue of the switchover of ECCS suction in PWRs[85] from the RWT to the sump and that this "backfit" was not done in accord with NRC procedures.[86]

APS also argues that NRC Region IV Administrator Bruce Mallet told the Commission at a Special Open Meeting on January 26, 2006, that it was a "new question" and that the "NRC determined that APS should not have raised the question before the NRC did so" citing pages 45 and 46 of the transcript from the Special Open Meeting. According to APS, "[a]lthough Dr. Mallet was

[84]("LOCA")

[85] Pressurized water reactors.

[86] According to Dr. Mattson, it would have been required to be technically justified as being required for assurance of adequate protection of public health and safety, and would have had to be approved by senior management in NRC's Office of Nuclear Reactor Regulation. APS Exhibit No. 87, Mattson Rebuttal, pp. 63-64.

not making a prudence determination when he conducted his analysis, his conclusion that APS should not have raised the new question before it was raised by the NRC nonetheless demonstrates that APS was not imprudent." (APS Initial Brief, p. 155).

Dr. Jacobs believes that APS' characterization of the issue raised by the NRC as a "new question" is an attempt to shift responsibility for the design of Palo Verde to the NRC. He believes that the question should have been raised during review of the 2004 Yellow Finding event, and that APS should have paid more attention to the handling of design basis information, been thorough in its review of technical issues, and that APS should have undertaken a broader review of operating experience.[87] In addition to the opportunity raised by the Yellow Finding review, he cites several other opportunities when APS could have identified this issue previously, including the development of the Design Basis Manual, the Conduct of the Design Basis validation of the Safety Injection system, the Conduct of a Safety System Functional Inspection; the Conduct of DRDR 2726509[88] in sufficient depth to identify the issue; and a more thorough and detailed review of similar operating experience.

APS cannot have it both ways, either Dr. Mallet was making a prudence determination or he was not. According to APS witness Levine "the NRC does not focus on prudence" (APS Exhibit No. 94, p. 17) and Dr. Mattson testified that the "safety standards that the NRC applies and those applicable to prudence cases such as this are markedly different." (APS Exhibit No. 87, Mattson Rebuttal, p. 7).

Although APS characterizes the Mallet testimony to affirmatively state that the NRC determined that APS should not have first asked the question, a review of the transcript when Mr. Mallet was asked whether it was a question that APS should have asked itself earlier, he answered: "Only if they are inspecting and reviewing that system in depth. Okay? And other licensees have

[87] The January 27, 2006, NRC report stated that APS did not consider relevant operating experience including a similar finding in 2003 at the Brunswick Nuclear Power Station, and a 2001 engineering study that detailed flow modeling of the same system and partly refuted the original operability determination by stating air would enter the suction piping.

[88] "CRDR 2726509 addressed the fact that the ECCS suction piping from the containment sumps was maintained unfilled since plant licensing despite the fact that several design documents indicate the pipe must be filled. In reviewing this CRDR, **APS concluded ' . . . the evaluation of CRDR 2726509 involved the same system and components and presented a missed opportunity for PVNGS personnel to challenge the design basis similar to how it was subsequently done by the NRC team.'"** Staff Exhibit No. 48, Jacobs Surrebuttal, p. 30.

similar systems where we go out and look and ask a question that was not found in the past. And we do evaluate whether they should have found it before us. In this instance, we didn't determine that they should have found it beforehand, I don't believe, Troy, unless you correct me on that, since I have stuck you in this one. But the issue, I think, was it was a new question that was asked. If they were investigating and looking at that system, you would expect them to find out, but I am not sure we would expect them to go in and look at that system at the time we were looking at it. Does that make sense?" (APS Exhibit No. 104. Transcript of January 26, 2006 Special Open Meeting, p. 46)

This statement is not a "determination" that from a prudency review standpoint, that APS should not have identified the issue and looked into it in its review of the air entrainment issue. Neither do we believe that the statement of the resident NRC inspector interviewed by GDS is dispositive on the issue of prudency. We believe that the written description of the events that occurred during the NRC inspection, found in Dr. Mallet's January 27, 2006, letter and report to APS' Executive Vice President of Generation, James Levine, and which are not disputed by APS,[89] are helpful and should be used to determine from a regulatory, cost recovery, perspective whether APS' actions were prudent.

The question to be asked is not should APS have anticipated the NRC's question, but why did the NRC inspector feel the need to ask the question. From the description of the inspection that is contained in the January 2006 NRC Report, it is clear that the inspectors did not believe that the APS personnel understood the plant design basis and the dynamics of the system and felt the need to question the personnel further on the potential of air entrainment from the RWT into the ECCS.

Not only had APS known since July 2004 that the NRC was concerned about air entrainment and damage to pumps affecting the safety systems, APS had already itself included the RWT in the scope of the response to the Yellow Finding <u>and</u> APS had been given a "heads up" by the inspector that the RWT would be looked at during the supplemental inspection.[90] APS knew that the NRC was interested in the RWT issue and that it would be asking questions about it and making sure that APS understood the system and how and why the design was to work. Instead of focusing on how the

[89] Dr. Mattson does dispute the conclusions but not the description of events.
[90] APS had already itself included the RWT in the scope of the response to the Yellow Finding, but it was not included as a potential source of air entrainment into the ECCS. Staff Exhibit No. 48, Jacobs Surrebuttal, p. 25.

RWT system related to the concerns identified in the Yellow Finding that was the subject of the upcoming supplemental inspection, apparently APS' only preparation was to assemble documents to show that the design had been implemented.

And yet APS was unable to demonstrate a good understanding of the issue of air entrainment and how it was addressed in the design when questioned by the NRC. If APS had initially demonstrated knowledge, competency, and experience in how the design was intended to address the air entrainment issue, and had studied relevant operating experience, it is entirely possible that the NRC would not have felt the need to ask the question about performance under "dynamic conditions." This was not a question "out of the blue" about some issue or related type system that was not the subject of a previous NRC finding, and APS personnel had the time and opportunity to thoroughly study, analyze, and familiarize themselves with the problem identified in 2004 and how it related to the RWT.

We find that the actions taken by APS prior to and during the supplemental inspection related to the RWT issue were not reasonable based upon the knowledge and information that APS had and should have had at the time. Accordingly, we will disallow recovery of the replacement power costs associated with this outage.

### G. PSA Surcharge for Palo Verde Prudent Outage Costs

Staff calculated that $16.186 million, including $13.757 million of replacement power costs during the period the PSA was in effect, and the cost of reduced margins on off-system and opportunity sales represents the costs associated with the outages caused by imprudence. 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 those lost sales. Although the methodology has been used by the Commission in the past, Staff disagreed with APS' use of two significant assumptions that APS used in its analysis: that lost sales would only occur during the times when Palo Verde was shutdown due to an imprudent outage; and that APS was not buying power in the wholesale market. Staff believes that neither assumption is reasonable because the outages may be the events that cause APS to purchase wholesale power. We agree with Staff that APS has not demonstrated that the results of its production model produce reliable estimates of lost sales, and will use the Staff recommended level.

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 should be shared between ratepayers and shareholders, and accordingly, we will reduce the amount of nonrecoverable replacement power by $2,550.000. APS also argued that improved performance of its coal generation should offset losses of generation at Palo Verde. We agree with Staff that improved coal performance has nothing to do with the Palo Verde outages, and that the outages did not cause improved operations at the Company's various coal-fired plants, nor did they produce lower coal prices. APS should always strive for good performance from all of its generation plants.

Based on our discussion above, the amount of $16,186,000, which includes lost margins for off-system sales and opportunity sales, less $2,250,000, for a total of $13,936,000[91] should be deducted from the balance of unrecovered Palo Verde replacement costs to be recovered through a surcharge.[92]

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 as adjusted for our determination herein, and submit the proposed surcharge level to Commission Staff for approval, within 30 days of the date of this Decision.

### H. <u>Conclusion #5, Recommendation #2 & #6 – Outages and Vendor Supplied Equipment</u>

---

[91] As modified by the interest as discussed by Dr. Jacobs.
[92] There is approximately $47.6 million unrecovered as of May 1, 2007.

GDS concluded that some of the unplanned outages were caused by faulty or defective vendor supplied equipment. GDS evaluated APS' actions related to these specific outages and concluded that APS' actions were not imprudent. APS witness Levine testified to the Company's efforts to pursue vendors for remedies resulting from equipment failures, and no party disputed that testimony or recommended additional action be taken. GDA also recommended that the Commission order APS to evaluate its programs for receipt inspection and verification of parts prior to installation and that it should submit a report to the Commission within 120 days of the Commission's Order in this matter describing the findings of the evaluation and the actions taken to improve receipt inspection and pre-installation verification of parts at Palo Verde. APS did not object to this recommendation and we will adopt it.

### I. Conclusion #6 – Unit 1 Shutdown, Line Vibration

GDS concluded that it is too soon to determine the prudence of the Unit 1 shutdown associated with the shutdown cooling line vibration but that it appears that APS has made a concerted effort to resolve the vibration problem. GDS concluded that additional investigation will be needed to determine the cause of and responsibility for this outage. We will require Staff to provide an update within 90 days of this Decision.

### J. Conclusion #7 – Safety

GDS concluded that there is no evidence or indication that operation of the plant in 2005 compromised safety. APS agreed with this conclusion.

### K. Recommendations #4 & #5 – Reports

GDS recommended that the Commission should order APS to submit a semi-annual report to the Commission's Docket Control, describing plant performance, explaining any negative regulatory reports by the NRC or INPO, and providing details of corrective actions taken. GDA recommended that APS submit this report semi-annually until the Commission decides that it is no longer necessary. APS did not oppose this recommendation, but noted that it may be necessary to provide some information confidentially.

GDA recommended that the Commission order APS to evaluate its programs to deal with aging equipment at Palo Verde and should submit a report to the Commission within 120 days of this

Decision describing the findings of the evaluation and the actions taken to improve APS' management of aging equipment issues. APS testified that it was willing to file the reports to the extent that it was possible.

We will adopt these recommendations concerning reports and require APS to file them to the extent possible as compliance items in this Docket.

* * * * * * * * * *

Having considered the entire record herein and being fully advised in the premises, the Commission finds, concludes, and orders that:

## XIV. FINDINGS OF FACT

1. APS is a public service corporation principally engaged in furnishing electricity in the State of Arizona. APS provides either retail or wholesale electric service to substantially all of Arizona, with the major exceptions of the Tucson metropolitan area and about one-half of the Phoenix metropolitan area. APS also generates, sells and delivers electricity to wholesale customers in the western United States.

2. On November 4, 2005, APS filed with the Commission an application for a $405 million rate increase and to amend Decision No. 67744 (April 7, 2005).

3. On November 9, 2005, the Commission opened a docket to investigate the outages at Palo Verde Nuclear Power Generating Station during 2005, and another docket was opened to audit APS' fuel and purchased power practices and costs.

4. On January 31, 2006, APS filed an amended application using an updated TY consisting of the twelve months ending September 30, 2005. The Amended Application requested a permanent base rate increase of $449.6 million on annualized test year sales, or 21.1 percent, on average, for its jurisdictional electric operations. The Amended Application also requested that the Commission permanently modify or eliminate the $776.2 million "cap" placed on total annual net fuel and purchased power costs by Decision No. 67744, and to make certain changes to the PSA mechanism.

5. On February 24, 2006, Staff filed a letter stating that the application was found sufficient and classified the applicant as a Class A utility.

6. By Procedural Order issued March 28, 2006, a hearing date and testimony deadlines were established.

7. On March 30, 2006, RUCO filed a Motion to Modify the Procedural Schedule.

8. By Amended Procedural Order issued April 5, 2006, new dates for processing the application were established, setting the hearing to commence on October 10, 1006.

9. On September 1, 2006, Staff of the Commission filed Motions to Consolidate dockets E-01345A-05-0816, E-01345A-05-0827 and E-01345A-05-0826, which were granted by Procedural Order issued September 18, 2006.

10. During the course of this matter, intervention was granted to Jim Nelson, RUCO, DEAA, Comverge, Inc., UniSource Energy Services, WRA, SCTA, AUIA, Kroger, Phelps Dodge/AECC, Scottsdale, AWC, FEA, Alliance, Power Group, George Bien-Willner dba Glendale & 27th Investments, LLC; Ruth Properties, LLC; Solicito Investments, LLC and Combined Commercial, LLC, Solar Advocates, AzAg Group, SWEEP, SWG, Interwest, Tammie Woody, AZ-ICE, the Jewish Community of Sedona, and AARP.

11. Counsel for APS, FEA, Kroger and Solar Advocates were granted Admission Pro Hac Vice and participated in the hearing.

12. Notice of the application was provided in accordance with the law.

13. The hearing commenced as scheduled on October 10, 2006 and continued for 29 days, concluding on December 15, 2006.

14. Late-filed exhibits were filed by APS and Staff.

15. Post-hearing Initial Briefs were filed by APS, Staff, RUCO, Phelps Dodge/AECC, AUIA, FEA, Kroger, Interwest, DEAA, WRA/SWEEP, Solar Advocates, and Interfaith Coalition.

16. On January 23, 2007, Staff filed its Motion to Extend Due Date for Responsive Briefs.

17. On January 23, 2007, Staff filed its Supplement to Motion to Extend Due Dates for Responsive Briefs, stating that APS, RUCO, WRA/SWEEP, and AUIA did not oppose the Motion and AECC and the Power Group supported the Motion.

18. On January 24, 2007, Phelps Dodge/AECC filed a Motion in Support of Staff's Motion.

19. On January 30, 2007, a Procedural Order was issued granting the Motion and extending the time for filing Reply Briefs to February 16, 2007, and extending the timeclock accordingly.

20. Reply Briefs were filed by APS, Staff, RUCO, Phelps Dodge/AECC, AUIA, Kroger, Interwest, DEAA, WRA/SWEEP, and Solar Advocates.

21. On February 28, 2007, Staff filed its late-filed Exhibit S-50 which contained a final version of Staff's proposed Plan of Administration for the PSA; a final version of the schedules that accompany the POA; a red-lined version of Staff's proposed POA showing the changes to Exhibit S-30 that were discussed by Staff witness Antonuk during the hearing; and hypothetical schedules for 2007, 2008, and 2009 that provide sample calculations pursuant to the POA.

22. On March 12, 2007, APS filed a letter in the docket stating that it did not have an objection to the late-filed Exhibit S-50, but indicating that it planned to file written comments on the Exhibit on or before March 26, 2007, and requesting that other parties be allowed, as well, to file written comments.

23. By Procedural Order issued March 19, 2007, all parties desiring to comment on the late-filed Exhibit S-50, were ordered to file comments by March 26, 2007.

24. On December 12, 2006, the Commission issued Decision No. 69184[93] which authorized APS to continue the interim PSA adjustor of seven mills for 2007 costs until rates become effective in this docket.

25. On March 21, 2007, Staff filed a late-filed exhibit of its witness, Prem Bahl. The exhibit contained a response to Commissioner Mayes' questions concerning APS' quality of service.

26. APS' OCRB, RCNRB, and FVRB are determined to be $4,403,496,000; $7,711,611,000; and $6,057,554,000, respectively.

27. APS' adjusted TY revenues, operating expenses, and net operating income were $2,587,363,000; $2,395,397,000; and $191,966,000, respectively.

28. A fair and reasonable rate of return on APS' FVRB is 6.05 percent.

[93] In Docket No. E-01345A-06-0009, APS' emergency interim rate application filed in January, 2006.

29. The rate increase proposed by APS would produce an excessive return on fair value and would not result in just and reasonable rates and charges.

30. Operating income of $366,371,000 is necessary to reach a 6.05 percent rate of return on the fair value rate base.

31. APS must increase operating revenues by $286,147,000 to produce operating income of $366,371,000.

32. Based upon the COS studies, rate continuity, and simplicity and stability, the revenue distribution as set forth herein is appropriate in this case.

33. The Company's rate design as modified by Staff, together and with the voltage discounts as proposed by the FEA, and the move towards the AECC proposal for transmission rate design to the extent consistent with Staff's concerns, is appropriate for designing rates. [94]

34. APS should file its revised schedule of rates and charges and proof of revenues for Staff review and confirmation prior to their implementation.

35. It is not appropriate or necessary to adopt any of APS' revenue enhancement proposals.

36. No additional adjustments or modifications to our traditional ratemaking method are necessary or appropriate to set just and reasonable rates.

37. APS failed to demonstrate that the near-term costs of customer growth are greater than the increased revenues generated by that growth.

38. The existence of attrition does not necessarily mean that rates are no longer just and reasonable.

39. The rates and charges adopted herein will assure confidence in the financial soundness of the Company, and should be adequate, under efficient management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its duties.

---

[94] This will result in an increase in base rates set in Decision No. 67744 for commercial of approximately 13.32 percent and for residential of approximately 13.6 percent, however, the "actual rate increase experienced" will be less due to the adoption in Decision No. 68685 (May 5, 2006) of the interim 7 mill adjustor (which will no longer exist). For example, a residential customer on E-12 at 800 kWh in the summer will have an increase of approximately 5.62 percent ($5.15); and in the winter will have an increase of 3.44 percent ($2.67).

40. APS should continue its efforts to increase its creditworthiness by improving its performance at its nuclear power plants and avoiding outages while maintaining safety; seeking rate relief from FERC for its under-recovery of transmission costs; any by seeking rate relief from the Commission when necessary and assisting in processing applications expeditiously and without errors.

41. APS' approved annual level of nuclear decommissioning funding is $19,211,000.

42. APS should conduct a study to identify what types of Demand Response and Load Management programs would be most beneficial to APS' system, relying on a cost-benefit analysis based on the Societal Cost Test and should be filed with the Commission within one year of the date of this Decision.

43. APS should file with the Commission for approval, one or more cost effective Demand Response or Load Management Programs that the Company believes would be most beneficial to its system and its ratepayers, within one year of the date of this Decision.

44. APS should include an energy-weighting method for allocating production plant as discussed herein in the cost-of-service study presented in its next rate application.

45. APS' proposed changes to Schedule 1 as modified herein and by Staff's other recommendations are reasonable and therefore approved.

46. APS' proposed changes to Schedule 3 and 4 as modified by Staff's recommendations are reasonable and therefore approved.

47. Schedule E-20 should remain "frozen" as established in the Settlement Agreement, as other viable schedules are available to Houses of Worship.

48. APS' proposed Partial Requirement Schedules E-56 and E-57 need further discussion and revision and APS should meet with Staff and the interested parties and submit a revised E-56 and E-57 tariffs within 60 days of the date of this Decision.

49. APS' proposed modification to other schedules as set forth herein were unopposed and should be approved.

50. APS should be allowed to true-up the $4.25 million with the actual UCPP costs for 2006.

51. The System Benefits Charge for all applicable APS rate schedules should be set at $.001850 per kWh.

52. APS should be authorized to implement an EIC adjustor as set forth herein.

53. APS' "pilot net metering" proposed Rate Schedule EPR-5 as modified herein should be approved and APS should file its revised tariff within 30 days of the date of this Decision.

54. Pursuant to Decision No. 67744 and the Settlement Agreement, unspent DSM funds should be credited to the balance of the DSMAC.

55. No increase beyond the current DSM spending requirement is appropriate at this time.

56. APS should be allowed to accrue interest on the unrecovered DSM adjustor balance at the rate recommended by Staff.

57. Staff's recommendations to APS' proposed performance incentive in its Portfolio Plan of DSM programs are reasonable and should be approved.

58. APS should convene a Collaborative Working Group Meeting within the 60 days of this Decision and make a presentation showing where APS believes the research stands and what additional information is needed before a reduction plan can be implemented, and when that information will be obtained.

59. APS should be seeking low cost, stably priced renewable energy under long term contracts to hedge against and to limit APS' and the ratepayers' exposure to high natural gas prices over the next 15 years or longer.

60. The record in this case supports a finding that the requirement contained in the RES rules is appropriate for APS at this time, and accordingly, it is not necessary to adopt a specific target in this proceeding in addition to what is contained in our RES rules.

61. During the collaborative meetings APS and interested parties should also discuss and evaluate how performance-based incentives and decoupling of rates from revenues might encourage APS to procure more renewable energy resources.

62. Staff is currently conducting procurement workshops and a requirement to include an independent evaluator in every future RFP for renewables is not necessary at this time.

63. Given APS' commitment to procure renewable energy, the requirement in the RES rules and our adoption of that requirement in this Decision, and our intent to hold APS to that commitment, it is not necessary to mandate additional procurements or a specific procurement schedule at this time.

64. APS' Green Power and Total Solar Rate tariffs, as modified herein, should be approved.

65. A generic docket should be opened to investigate the feasibility of hook-up fees for electric and gas utilities.

66. APS' proposed depreciation rates are appropriate to use in this case and APS should clearly break out each new depreciation rate between service life and a net salvage value, similar to the rates shown in Appendix A to Decision No. 67744.

67. Staff should consider initiating a docket to amend A.A.C. R14-2-102, the Commission's depreciation rule, to allow alternative treatment for the cost of removal.

68. APS' 2005 plant improvements were appropriate and necessary to provide reliable, efficient, and cost effective service.

69. APS should submit a critical peak pricing proposal in its next rate application.

70. APS' proposed modifications to the Low Income Plan of Administration to promote the low income programs and to facilitate the enrollment process are reasonable and should be approved.

71. Staff's examination and audit of the management and operations of the fuel and purchased power functions at APS resulted in numerous conclusions and recommendations as set forth in the Discussion and APS indicated general agreement with the findings.

72. APS should prepare an implementation plan for each recommendation that it accepts and for each recommendation that it does accept, APS should provide a detailed explanation of the reasons why the recommendation should not be implemented.

73. APS should file its Fuel Audit Implementation Plan within 60 days of the date of this Decision and then within 45 days after the plan is submitted, Staff should identify how it will monitor the plan and resolve disputes.

74. No party objected to APS' proposal to modify the existing PSA to eliminate the Cap on Total Fuel Cost Recovery; to eliminate the four mill "lifetime" cap and replace it with a four mill annual cap; or to eliminate the requirement for mandatory PSA surcharge applications when deferrals reach $100,000,000.

75. Maintaining an incentive mechanism in the PSA with the opportunity for some "sharing" of the savings or costs of the purchased power and fuel costs is appropriate, but the fixed or demand element of long-term Purchase Power Agreements acquired through competitive procurement and renewable energy purchases not otherwise recoverable through the EPS/RES should be excluded from the sharing requirement.

76. Broker fees in excess of the level already included in base rates should not flow through to the PSA.

77. No party has recommended that a PSA is no longer necessary or appropriate for APS.

78. Staff's proposed new PSA uses a forward-looking estimate of fuel and purchased power costs to set a rate that is then reconciled to actual costs experienced.

79. RUCO and Phelps Dodge/AECC opposed adoption of Staff's Prospective PSA; AUIA supported adoption of Staff's PSA; and APS supported it with modifications.

80. Developing a PSA is an "art" because it must balance timely recovery of costs with safeguards to customers for extreme volatility in costs.

81. The existing PSA has deficiencies that have been identified by the parties, but with the modifications recommended in this proceeding, it can be improved to provide more timely recovery of costs.

82. A PSA that has: a 4 mill annual cap; a provision for 90/10 sharing of costs, except the costs of renewable energy acquired from third parties and not otherwise recoverable under the EPS/RES and the demand component of any long-term purchased power agreement acquired via a competitive procurement process; no Cap on Total Fuel Cost Recovery; and no requirement for mandatory PSA surcharge applications when deferrals reach $100,000,000 would go a long way toward making the PSA more responsive to changes in fuel and purchased power costs.

83. A prospective PSA would make the recovery of fuel and purchased power costs more timely, thereby improving the Company's cash flow significantly, and it would also provide safeguards to customers to make sure that the costs recovered were prudent.

84. A prospective adjustor should also contain a sharing provision to provide an incentive for the Company to keep its fuel and purchased power costs as close to base rates as possible.

85. A sharing incentive that excludes the costs of renewable energy acquired from third parties and not otherwise recoverable under the EPS/RES and the demand component of any long-term purchased power agreement acquired via a competitive procurement process should apply to the prospective PSA as well.

86. Either PSA described above is reasonable but because a prospective PSA will significantly improve APS' cash flow while still allowing APS to only recover prudently incurred costs, Staff's proposed PSA, as modified to include the 90/10 sharing mechanism above, should be adopted.

87. Staff agreed to APS' calculation of the "Forward Component" for 2007, and accordingly, we will adopt a "Forward Component" that is the difference between the 3.1202¢ base cost of fuel and purchased power adopted herein, and the 2007 forecast cost of 3.2491¢.

88. Staff and APS recommend that the appropriate way to address any PSA charges currently authorized is to allow them to continue to run their course as originally set, with any residual amounts remaining can be handled in the 2008 PSA Year, and we find this is reasonable.

89. APS filed comments and suggested modifications to Staff's Plan of Administration, and except for the language APS changed to allow broker fees in excess of the amounts included in base rates into the PSA, we will adopt them and order Staff to file the final, conformed Plan of Administration that is consistent with this Decision, within 30 days of this Decision.

90. APS is the licensed operator and the operating agent for Palo Verde on behalf of its seven owners.

91. APS manages the employees and contractors working at Palo Verde and makes all decisions regarding the safe and reliable operation of the station.

92. APS confers with and receives approval from the other owners on some issues, including all major capital projects such as steam generator replacements and turbine upgrades.

93. Palo Verde is a vital component of APS' generation resources, providing 18.9 percent of APS' total generating capacity.

94. In 2005, Palo Verde had more outages than normal and the capacity factor and generation were lower than expected.

95. Operating performance of the Palo Verde nuclear power plants directly affects the costs of fuel and purchased power that ratepayers are required to pay though an adjustor mechanism.

96. The fuel and purchased power costs recoverable under the PSA are subject to a prudency review and may be disallowed by the Commission if the costs are found not to be prudently incurred.

97. In response to the eleven Palo Verde outages in 2005, Staff issued a Request for Proposals to engage a consultant to investigate the reasons for the lower performance and to make recommendations to improve performance and reduce the likelihood of more unplanned outages in the future.

98. On February 2, 2006, APS filed an application for approval of a PSA surcharge to recover approximately $44.6 million plus accumulated interest in replacement power costs that were a result of outages at Palo Verde during 2005.

99. APS believes that none of the outages were the result of imprudence and that all the replacement power costs should be recovered from ratepayers through implementation of a "Step 2 PSA Surcharge" in this Decision.

100. Staff's witness, Dr. William Jacobs, Vice President of GDS Associates, Inc. testified that of the eleven planned and unplanned outages in 2005, four resulted from imprudence.

101. Dr. Jacobs recommended that the Commission disallow recovery of $16.186 million, including $13.757 million of replacement power costs during the period the PSA was in effect together with the cost of reduced margins on off-system and opportunity sales.

102. Dr. Jacobs concluded that there is no evidence or indication that operation of the Palo Verde plant in 2005 compromised safety.

103. APS' witness, Levine, testified that safe operation of the Palo Verde units is the overriding priority and that Palo Verde has operated safely.

104. Staff recommended that the Commission implement a Nuclear Performance Standard for APS' Palo Verde nuclear power plants.

105. APS' witnesses testified that an NPS is unnecessary, inappropriate, and that Staff's proposed NPS is lacking key elements.

106. The evidence shows that the Commission has reason to be concerned about Palo Verde's recent performance and should be monitoring APS' operation of the Palo Verde plants, however, we do not have sufficient evidence or detail in this proceeding to adopt and implement an NPS at this time.

107. Staff and APS are directed to work together to prepare a detailed NPS, together with a Plan of Administration that can be considered in a separate proceeding.

108. Until that until a Plan of Administration for the NPS is in place, for all planned or unplanned outages at Palo Verde, APS should identify all replacement power costs, as well as the amount of reduced off-system sales and lost opportunity sales margins associated with each outage, and file documentation with the Commission explaining the reasons for the outage and the associated costs, within 60 days of the conclusion of the outage. This will assist us in monitoring and evaluating APS' operational performance with the Palo Verde plants, and help determine which costs are prudent when setting the PSA adjustor.

109. During a prudency review, the actions and decisions of Palo Verde personnel 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.

110. 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.

111. The use of NRC, Company, or other documents that describe events, actions, decisions, and what was known at the time is appropriate, and is not using "hindsight" just because the documents were created after the time or event involved.

112. APS acted prudently in connection with both 2005 refueling outages and with Unit 1's February 9-19, 2005, outage; Unit 1's August 11-28, 2005, outage (except for the 2 days of that outage due to a reactor trip on August 26, 2005); Unit 2's August 22-26, 2005, outage; Unit 3's May 22 to June 24, 2005, outage; Unit 3's July 6-13, 2005, outage; and Unit 3's October 2-7, 2005, outage.

113. The Unit 1 March 2005 Outage Due to Failure of Diesel Generator Governor was not the result of imprudence because at the time of the event, APS had no way of knowing that there was rust in the governor; it had maintained the equipment in conformance with the manufacturer's recommendations; and a pre-installation disassembly would not have been reasonable.

114. The delay in the completion of the Unit 1 outage and resulting cost due to the reactor trip of August 26, 2005, was due to imprudence.[95]

115. We find that the actions taken by APS prior to and during the NRC supplemental inspection related to the RWT issue were not reasonable and prudent based upon the knowledge and information that APS had and should have had at the time and resulted in the Unit 2 and Unit 3 October 2005 Outages.[96]

116. It was appropriate for APS to perform other needed maintenance during the October 2005 outage, and the $5,100,000 amount of offset requested by APS should be shared equally between ratepayers and shareholders.

117. Improved performance of coal generation should not be used to offset losses of generation at Palo Verde.

118. APS should always strive for good performance from all of its generation plants.

119. APS should not be allowed to recover the costs of outages that resulted from imprudence, and accordingly, approximately $13,936,000, which includes lost margins for off-system sales and opportunity sales, should be deducted from the balance of unrecovered Palo Verde replacement costs to be recovered through a surcharge, and not recovered from ratepayers.

---

[95] See discussion in Section XIII.E for description of underlying facts and event.
[96] See discussion in Section XIII.F for description of underlying facts and event.

120. APS' application for a Step 2 surcharge should be approved and implemented concurrently with the implementation of rates in this proceeding.

121. APS shall calculate the correct amount as adjusted for our determination herein, and submit the proposed surcharge level to Commission Staff for review and approval, within 30 days of the date of this Decision.

122. Some of the unplanned outages were caused by faulty or defective vendor supplied equipment and APS has taken appropriate actions to pursue vendors for remedies resulting from equipment failures.

123. APS is directed to evaluate its programs for receipt inspection and verification of parts prior to installation and to submit a report to the Commission within 120 days of this Decision, describing the findings of the evaluation and the actions taken to improve receipt inspection and pre-installation verification of parts at Palo Verde.

124. It is too soon to determine the prudence of the Unit 1 shutdown associated with the shutdown cooling line vibration and Staff is directed to provide an update on this outage 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, and providing details of corrective actions taken, until further Order of the Commission.

126. APS shall evaluate its programs to deal with aging equipment at Palo Verde and submit a report to the Commission within 120 days of this Decision describing the findings of the evaluation and the actions taken to improve APS' management of aging equipment issues.

127. APS testified that no light rail costs are included in this rate increase.

## XV. CONCLUSIONS OF LAW

1. Arizona Public Service Company is a public service corporation within the meaning of Article XV of the Arizona Constitution and A.R.S. §§ 40-222, 250, 251, 321, 322 and 331.

2. The Commission has jurisdiction over Arizona Public Service Company and the subject matter of the rate application, the Inquiry into Unplanned Outages at Palo Verde, and over the Audit of the Fuel and Purchased Power Practices and Costs of APS.

3. Notice of the application was provided in accordance with the law.

4. The rates and charges for electric services proposed by APS are not just and reasonable.

5. The rates, charges, and conditions of service established herein are just and reasonable.

6. The fair value of APS' rate base is $6,057,554,000, and applying a 6.05 percent rate of return on APS' fair value rate base will produce rates and charges that are just and reasonable.

7. It is not appropriate or necessary to adopt any of APS' revenue enhancement proposals.

8. No additional adjustments or modifications to our traditional ratemaking method are necessary or appropriate to set just and reasonable rates.

9. Arizona law requires just and reasonable rates to be set and such rates must be related to our finding of fair value.

10. The rates and charges adopted herein will assure confidence in the financial soundness of the Company, and should be adequate, under efficient management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its duties

11. The PSA adopted herein will significantly improve APS' timely recovery of its fuel and purchased power costs and will positively impact its current cash flow.

12. The costs associated with the outages caused by imprudence at the Palo Verde Nuclear Power Plants should not be recovered from ratepayers.

13. APS should be directed to file revised schedules and tariffs consistent with the findings contained in this Order.

## XVI. ORDER

IT IS THEREFORE ORDERED that Arizona Public Service Company is hereby directed to file with the Commission, on or before May 31, 2007, revised schedules of rates and charges for electric service consistent with the Discussion, Findings of Facts, and Conclusions of Law herein and shall also file a proof of revenues showing that the revised rates will produce the authorized revenue increase

IT IS FURTHER ORDERED that the revised schedules of rates and charges shall be effective for all service rendered on and after June 1, 2007.

IT IS FURTHER ORDERED that Arizona Public Service Company shall notify its affected customers of the revised schedules of rates and charges authorized herein by means of an insert in its next regularly scheduled billing and by posting on its website, in a form approved by the Commission's Utilities Division Staff.

IT IS FURTHER ORDERED that Arizona Public Service Company shall recognize the amounts collected in rates for Sundance's non-routine maintenance as a current period expense and shall concurrently establish and maintain a regulatory liability on its balance sheet for use when the costs are eventually incurred.

IT IS FURTHER ORDERED that Arizona Public Service Company's approved annual level of nuclear decommissioning funding is $19,211,000.

IT IS FURTHER ORDERED that Arizona Public Service Company shall set forth each new depreciation rate between a service life and a net salvage rate in a similar manner as found in Appendix A to Decision No. 67744.

IT IS FURTHER ORDERED that Staff shall initiate a docket to consider amending A.A.C. R14-2-102, the Commission's depreciation rule, to allow alternative treatment for the cost of removal.

IT IS FURTHER ORDERED that in its next rate proceeding Arizona Public Service Company shall include an energy-weighting method for allocating production plant as discussed herein, in its cost-of-service study.

IT IS FURTHER ORDERED that Arizona Public Service Company is authorized to implement an Environmental Improvement Charge adjustor as set forth herein.

IT IS FURTHER ORDERED that Arizona Public Service Company shall file with Docket Control as a compliance item in this Docket, its revised pilot net metering proposed Rate Schedule EPR-5 as modified herein within 30 days of the date of this Decision.

IT IS FURTHER ORDERED that Arizona Public Service Company shall credit any unspent DSM funds to the balance of the DSMAC, as provided in Decision No. 67744 and the Settlement

Agreement.

IT IS FURTHER ORDERED that the unrecovered DSM adjustor balance shall accrue interest at the rate recommended by Staff herein.

IT IS FURTHER ORDERED that Arizona Public Service Company's performance incentive in its Portfolio Plan of DSM programs, with Staff's recommendations, is hereby approved.

IT IS FURTHER ORDERED that Arizona Public Service Company shall convene a Collaborative Working Group Meeting within the 60 days of this Decision and make a presentation showing where APS believes the research stands and what additional information is needed before a reduction plan can be implemented, and when that information will be obtained.

IT IS FURTHER ORDERED that Arizona Public Service Company shall seek low cost, stably priced renewable energy under long term contracts to hedge against and to limit exposure to high natural gas prices over at least the next 15 years.

IT IS FURTHER ORDERED that requirement contained in the RES rules for Arizona Public Service Company is appropriate at this time, and therefore, it is not necessary to adopt a specific target in this proceeding in addition to what is contained in the RES rules.

IT IS FURTHER ORDERED that given Arizona Public Service Company's commitment to procure renewable energy, the requirement in the RES rules and our adoption of that requirement in this Decision, and our intent to hold Arizona Public Service Company to that commitment, it is not necessary to mandate additional procurements or a specific procurement schedule at this time.

IT IS FURTHER ORDERED that Arizona Public Service Company shall use the collaborative meetings to discuss with interested parties and evaluate how performance-based incentives and decoupling of rates from revenues could encourage the procurement of more renewable energy resources.

IT IS FURTHER ORDERED that a generic docket shall be opened to investigate the feasibility of hook-up fees for electric and gas utilities.

IT IS FURTHER ORDERED that Arizona Public Service Company's proposed depreciation rates are appropriate to use in this case and Arizona Public Service Company should clearly break out each new depreciation rate between service life and a net salvage value, similar to the rates shown in

Appendix A to Decision No. 67744.

IT IS FURTHER ORDERED that Staff should consider initiating a docket to amend A.A.C. R14-2-102, the Commission's depreciation rule, to allow alternative treatment for the cost of removal.

IT IS FURTHER ORDERED that Arizona Public Service Company shall true-up the $4.25 million with the actual UCPP costs for 2006.

IT IS FURTHER ORDERED that Arizona Public Service Company shall submit a critical peak pricing proposal in its next rate application.

IT IS FURTHER ORDERED that Arizona Public Service Company shall prepare and file with Docket Control as a compliance item in this Docket, a Fuel Audit Implementation Plan as set forth herein, within 60 days of the date of this Decision.

IT IS FURTHER ORDERED that within 45 days after the plan is submitted, Staff shall identify how it will monitor the Fuel Audit Implementation Plan and resolve disputes, and shall make an appropriate filing with Docket Control as a compliance item in this Docket.

IT IS FURTHER ORDERED that Arizona Public Service Company and Staff shall work to prepare a detailed Nuclear Performance Standard, together with a Plan of Administration that can be considered in a separate proceeding.

IT IS FURTHER ORDERED that until a Plan of Administration for the Nuclear Performance Standard is in place, for all planned or unplanned outages at Palo Verde, Arizona Public Service Company shall identify all replacement power costs, as well as the amount of reduced off-system sales and lost opportunity sales margins associated with each outage, and file with Docket Control as a compliance item in this Docket, documentation with the Commission explaining the reasons for the outage and the associated costs, within 60 days of the conclusion of the outage.

IT IS FURTHER ORDERED that Arizona Public Service Company's application for a Step 2 surcharge should be approved as determined herein and verified by Staff, and effective concurrently with the implementation of rates in this proceeding.

IT IS FURTHER ORDERED that the Step 2 surcharge shall not include the costs resulting from imprudent outages at Palo Verde as determined herein.

IT IS FURTHER ORDERED that Staff shall file with Docket Control as a compliance item in this Docket, the final, conformed Plan of Administration for the Power Supply Adjustor consistent with this Decision, within 30 days of this Decision.

IT IS FURTHER ORDERED that Arizona Public Service Company shall evaluate its programs for receipt inspection and verification of parts prior to installation and to submit a report as described herein, to the Commission's Docket Control as a compliance item in this Docket, within 120 days of this Decision.

IT IS FURTHER ORDERED that Staff shall file with Docket Control as a compliance item in this Docket, an update of the Unit 1 shutdown associated with the shutdown cooling line vibration within 90 days of this Decision.

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, and providing details of corrective actions taken, until further Order of the Commission.

. . .

. . .

. . .

. . .

. . .

. . .

. . .

. . .

. . .

. . .

. . .

. . .

. . .

. . .

IT IS FURTHER ORDERED that Arizona Public Service Company shall a report with the Commission' Docket Control as a compliance item in this docket, within 120 days of this Decision describing the findings of the evaluation and the actions taken to improve Arizona Public Service Company's management of aging equipment issues at Palo Verde.

IT IS FURTHER ORDERED that this Decision shall become effective immediately.

BY ORDER OF THE ARIZONA CORPORATION COMMISSION.

CHAIRMAN COMMISSIONER

COMMISSIONER COMMISSIONER COMMISSIONER

IN WITNESS WHEREOF, I, BRIAN C. McNEIL, Executive Director of the Arizona Corporation Commission, have hereunto set my hand and caused the official seal of the Commission to be affixed at the Capitol, in the City of Phoenix, this _____ day of _________, 2007.

BRIAN C. McNEIL
EXECUTIVE DIRECTOR

DISSENT ______________________

DISSENT ______________________

SERVICE LIST FOR: ARIZONA PUBLIC SERVICE COMPANY

DOCKET NOS.: E-01345A-05-0816, E-01345A-05-0827 and E-01345A-05-0827

Jana Van Ness
ARIZONA PUBLIC SERVICE COMPANY
400 N. 5th Street, MS 8695
Phoenix, AZ 85004

Brian Brumfeld
ARIZONA PUBLIC SERVICE COMPANY
P.O. Box 5999, MS 9708
Phoenix, AZ 85072

Thomas L. Mumaw
Karilee S. Ramaley
PINNACLE WEST CAPITAL CORPORATION
P.O. Box 53999
Phoenix AZ 85072-3999

Deborah R. Scott
Kimberly A, Grouse
SNELL & WILMER
One Arizona Center
400 E. Van Buren Street
Phoenix AZ 85004-2202

Dan Austin
Comverge, Inc.
6509 W. Frye Road, Ste. 4
Chandler, AZ 85226

Jim Nelson
12621 N. 17th Place
Phoenix, AZ 85022

Scott S. Wakefield
RUCO
1110 W. Washington, Ste. 220
Phoenix, AZ 85007

Bill Murphy
Murphy Consulting
5401 N. 25th Street
Phoenix, AZ 85016

Douglas V. Fant
3655 W. Anthem Drive, Ste. A109
PMB 411
Anthem, AZ 85086

Amanda Ormond
INTERWEST ENERGY ALLIANCE
7650 S. McClintock, Ste. 103-282
Tempe, AZ 85284

Michael W. Patten
ROSHKA, DeWULF & PATTEN
One Arizona Center
400 East Van Curen Street, Ste. 800
Phoenix, AZ 85004

Michelle Livengood
UniSource Energy Srevices
One South Church Street, Ste. 200
Tucson, AZ 85702

Timothy M. Hogan
Arizona Center for Law in the Public Interest
202 E. McDowell Road, Ste. 153
Phoenix, AZ 85004

Tracy Spoon
Sun City Taxpayers Association
12630 N. 103rd Avenue, Ste. 144
Sun City, AZ 85351

Gary Yaquinto
Arizona Utility Investors Association
2100 N. Central Avenue, Ste. 210
Phoenix, AZ 85004

Michael L. Kurtz
Kurt J. Boehm
BOEHM, JURTZ & LOWRY
36 East Seventh Street, Ste. 1510
Cincinnati, OH 45202
Attorneys for The Kroger Co.

C. Webb Crockett
Patrick J. Black
FENNEMORE CRAIG
3003 North Central Avenue, Ste. 2600
Phoenix, AZ 85012-2913
Attorneys for Phelps Dodge Mining Company and Arizonans for Electric Choice and Competition

Steven B. Bennett
Deputy City Attorney
City of Scottsdale
3939 N. Drinkwater Blvd.
Scottsdale, AZ 85251

Robert W. Geake
ARIZONA WATER COMPANY
P.O. Box 29006
Phoenix, AZ 85038

Lieutenant Colonel Karen S. White
Chief, Air Force Utility Litigation Team
AFLSA/JACL-ULT
139 Barnes Drive
Tyndall AFB, FL 32403

Greg Patterson
916 West Adams, Ste. 3
Phoenix, AZ 85007

Lawrence V. Robertson, Jr.
MUNGER CHADWICK
P.O. Box 1448
Tubac, AZ 85646
Attorneys for Mesquite Power, LLC,
Southwestern Power Group, II, LLC and
Bowie Power Station, LLC

George Bien-Willner
3641 N. 39th Avenue
Phoenix, AZ 85014

Sean Seitz
3008 N. Civic Center Plaza
Scottsdale, AZ 85251
Arizona Solar Energy Industries Association

Jay I. Moyes
MOYES STOREY
1850 N. Central Avenue, Ste. 1100
Phoenix, AZ 85004

Kenneth R. Saline
K.R. SALINE & ASSOCIATES, PLC
160 N. Pasadena, Ste. 101
Mesa, AZ 85201

Andrew W. Bettwy
Karen S. Haller
Debra S. Jacobson
Legal Affairs Department
SOUTHWEST GAS CORPORATION
5241 Spring Mountain Road
Las Vegas, NV 89150

Tammie Woody
10825 W. Laurie Lane
Peoria, AZ 85345

David Kennedy
818 E. Osborn Road, Ste. 103
Phoenix, AZ 85014
Attorney for Arizona Interfaith Coalition on Energy

Joseph Knauer, President
Jewish Community of Sedona
100 Meadowlark Drive
P.O. Box 10242
Sedona, AZ 86339

Michael F. Healy
MORGAN, LEWIS & BOCKIUS
1111 Pennsylvania Avenue, NW
Washington, DC 20004

Gary L. Nakarado
24657 Foothills Drive N
Golden, CO 80401

Jon Poston
AARP Electric Rate Project
6733 E. Dale Lane
Cave Creek, AZ 85331

Coralette Hannon
AARP Govt Relations & Advocacy
6705 Reedy Creek Road
Charlotte, NC 85331

Christopher Kempley, Chief Counsel
Legal Division
ARIZONA CORPORATION COMMISSION
1200 West Washington Street
Phoenix, AZ 85007

Ernest G. Johnson, Director
Utilities Division
ARIZONA CORPORATION COMMISSION
1200 West Washington
Phoenix, AZ 85007

ARIZONA PUBLIC SERVICE COMPANY
SCHEDULE OF AMOUNTS TO BE DEPOSITED IN THE
DECOMMISSIONING TRUSTS INCLUDED IN COST OF SERVICE
PALO VERDE TOTAL
(Thousands of Dollars)
(APS Share)

| LINE | YEAR | POST SHUTDOWN ON-GOING ISFSI ANNUAL CONTRIBUTION REQUIRED | POST SHUTDOWN ISFSI REGULATORY ASSET AMORTIZATION ANNUAL CONTRIBUTION REQUIRED | DECOMMISSIONING ANNUAL CONTRIBUTION REQUIRED | TOTAL ANNUAL CONTRIBUTION REQUIRED | ACC JURISDICTIONAL AMOUNT /1/ |
|---|---|---|---|---|---|---|
| 1 | 2004 | $ 376 | $ 396 | $ 15,328 | $ 16,100 | $ 15,865 |
| 2 | 2005 | 752 | 792 | 19,211 | 20,755 | 20,452 |
| 3 | 2006 | 752 | 792 | 19,211 | 20,755 | 20,452 |
| 4 | 2007 | 752 | 792 | 19,211 | 20,755 | 20,452 |
| 5 | 2008 | 752 | 792 | 19,211 | 20,755 | 20,452 |
| 6 | 2009 | 1,816 | 792 | 19,211 | 21,819 | 21,500 |
| 7 | 2010 | 4,481 | 792 | 19,211 | 24,484 | 24,127 |
| 8 | 2011 | 4,481 | 792 | 19,211 | 24,484 | 24,127 |
| 9 | 2012 | 4,481 | 792 | 19,211 | 24,484 | 24,127 |
| 10 | 2013 | 4,481 | 792 | 19,211 | 24,484 | 24,127 |
| 11 | 2014 | 4,481 | 792 | 19,211 | 24,484 | 24,127 |
| 12 | 2015 | 4,481 | 792 | 19,211 | 24,484 | 24,127 |
| 13 | 2016 | 1,920 | 404 | 11,139 | 13,463 | 13,266 |
| 14 | 2017 | 1,920 | 404 | 11,139 | 13,463 | 13,266 |
| 15 | 2018 | 1,920 | 404 | 11,139 | 13,463 | 13,266 |
| 16 | 2019 | 1,920 | 404 | 11,139 | 13,463 | 13,266 |
| 17 | 2020 | 1,920 | 404 | 11,139 | 13,463 | 13,266 |
| 18 | 2021 | 1,920 | 404 | 11,139 | 13,463 | 13,266 |
| 19 | 2022 | 1,920 | 404 | 11,139 | 13,463 | 13,266 |
| 20 | 2023 | 1,920 | 404 | 11,139 | 13,463 | 13,266 |
| 21 | 2024 | 1,920 | 404 | 11,139 | 13,463 | 13,266 |
| 22 | 2025 | 960 | 190 | 6,017 | 7,167 | 7,062 |
| 23 | 2026 | 1,004 | 238 | 6,017 | 7,259 | 7,153 |
| | | $ 51,330 | $ 13,172 | $ 338,934 | $ 403,436 | $ 397,546 |

/1/ ACC Jurisdictional share is approximately 98.54%.

DOCKET NO. E-01345A-06-0816 ET AL.

ARIZONA PUBLIC SERVICE COMPANY
SCHEDULE OF AMOUNTS TO BE DEPOSITED IN THE
DECOMMISSIONING TRUSTS INCLUDED IN COST OF SERVICE
PALO VERDE UNIT 1
(Thousands of Dollars)
(APS Share)

| LINE | YEAR | POST SHUTDOWN ON-GOING ISFSI ANNUAL CONTRIBUTION REQUIRED | POST SHUTDOWN ISFSI REGULATORY ASSET AMORTIZATION ANNUAL CONTRIBUTION REQUIRED | DECOMMISSIONING ANNUAL CONTRIBUTION REQUIRED | TOTAL ANNUAL CONTRIBUTION REQUIRED | ACC JURISDICTIONAL AMOUNT /1/ |
|---|---|---|---|---|---|---|
| 1 | 2004 | $ 125 | $ 107 | $ 4,077 | $ 4,309 | $ 4,246 |
| 2 | 2005 | 251 | 214 | 5,122 | 5,587 | 5,505 |
| 3 | 2006 | 251 | 214 | 5,122 | 5,587 | 5,505 |
| 4 | 2007 | 251 | 214 | 5,122 | 5,587 | 5,505 |
| 5 | 2008 | 251 | 214 | 5,122 | 5,587 | 5,505 |
| 6 | 2009 | 605 | 214 | 5,122 | 5,941 | 5,854 |
| 7 | 2010 | 960 | 214 | 5,122 | 6,296 | 6,204 |
| 8 | 2011 | 960 | 214 | 5,122 | 6,296 | 6,204 |
| 9 | 2012 | 960 | 214 | 5,122 | 6,296 | 6,204 |
| 10 | 2013 | 960 | 214 | 5,122 | 6,296 | 6,204 |
| 11 | 2014 | 960 | 214 | 5,122 | 6,296 | 6,204 |
| 12 | 2015 | 960 | 214 | 5,122 | 6,296 | 6,204 |
| 13 | 2016 | 960 | 214 | 5,122 | 6,296 | 6,204 |
| 14 | 2017 | 960 | 214 | 5,122 | 6,296 | 6,204 |
| 15 | 2018 | 960 | 214 | 5,122 | 6,296 | 6,204 |
| 16 | 2019 | 960 | 214 | 5,122 | 6,296 | 6,204 |
| 17 | 2020 | 960 | 214 | 5,122 | 6,296 | 6,204 |
| 18 | 2021 | 960 | 214 | 5,122 | 6,296 | 6,204 |
| 19 | 2022 | 960 | 214 | 5,122 | 6,296 | 6,204 |
| 20 | 2023 | 960 | 214 | 5,122 | 6,296 | 6,204 |
| 21 | 2024 | 960 | 214 | 5,122 | 6,296 | 6,204 |
| 22 | 2025 | | | | | |
| 23 | 2026 | | | | | |
| | | $ 16,134 | $ 4,387 | $ 106,517 | $ 127,038 | $ 125,183 |

/1/ ACC Jurisdictional share is approximately 98.54%.

DECISION NO. ____________

DOCKET NO. E-01345A-06-0816 ET AL.

ARIZONA PUBLIC SERVICE COMPANY
SCHEDULE OF AMOUNTS TO BE DEPOSITED IN THE
DECOMMISSIONING TRUSTS INCLUDED IN COST OF SERVICE
PALO VERDE UNIT 2
(Thousands of Dollars)
(APS Share)

| LINE | YEAR | POST SHUTDOWN ON-GOING ISFSI ANNUAL CONTRIBUTION REQUIRED | POST SHUTDOWN ISFSI REGULATORY ASSET AMORTIZATION ANNUAL CONTRIBUTION REQUIRED | DECOMMISSIONING ANNUAL CONTRIBUTION REQUIRED | TOTAL ANNUAL CONTRIBUTION REQUIRED | ACC JURISDICTIONAL AMOUNT /1/ |
|---|---|---|---|---|---|---|
| 1 | 2004 | $ 126 | $ 194 | $ 6,153 | $ 6,473 | $ 6,378 |
| 2 | 2005 | 250 | 388 | 8,072 | 8,710 | 8,583 |
| 3 | 2006 | 250 | 388 | 8,072 | 8,710 | 8,583 |
| 4 | 2007 | 250 | 388 | 8,072 | 8,710 | 8,583 |
| 5 | 2008 | 250 | 388 | 8,072 | 8,710 | 8,583 |
| 6 | 2009 | 606 | 388 | 8,072 | 9,066 | 8,934 |
| 7 | 2010 | 2,561 | 388 | 8,072 | 11,021 | 10,860 |
| 8 | 2011 | 2,561 | 388 | 8,072 | 11,021 | 10,860 |
| 9 | 2012 | 2,561 | 388 | 8,072 | 11,021 | 10,860 |
| 10 | 2013 | 2,561 | 388 | 8,072 | 11,021 | 10,860 |
| 11 | 2014 | 2,561 | 388 | 8,072 | 11,021 | 10,860 |
| 12 | 2015 | 2,561 | 388 | 8,072 | 11,021 | 10,860 |
| 13 | 2016 | | | | | |
| 14 | 2017 | | | | | |
| 15 | 2018 | | | | | |
| 16 | 2019 | | | | | |
| 17 | 2020 | | | | | |
| 18 | 2021 | | | | | |
| 19 | 2022 | | | | | |
| 20 | 2023 | | | | | |
| 21 | 2024 | | | | | |
| 22 | 2025 | | | | | |
| 23 | 2026 | | | | | |
| | | $ 17,098 | $ 4,462 | $ 94,945 | $ 116,505 | $ 114,804 |

/1/ ACC Jurisdictional share is approximately 98.54%.

DECISION NO. ____________

DOCKET NO. E-01345A-06-0816 ET AL.

ARIZONA PUBLIC SERVICE COMPANY
SCHEDULE OF AMOUNTS TO BE DEPOSITED IN THE
DECOMMISSIONING TRUSTS INCLUDED IN COST OF SERVICE
PALO VERDE UNIT 3
(Thousands of Dollars)
(APS Share)

| LINE | YEAR | POST SHUTDOWN ON-GOING ISFSI ANNUAL CONTRIBUTION REQUIRED | POST SHUTDOWN ISFSI REGULATORY ASSET AMORTIZATION ANNUAL CONTRIBUTION REQUIRED | DECOMMISSIONING ANNUAL CONTRIBUTION REQUIRED | TOTAL ANNUAL CONTRIBUTION REQUIRED | ACC JURISDICTIONAL AMOUNT /1/ |
|---|---|---|---|---|---|---|
| 1 | 2004 | $ 125 | $ 95 | $ 5,098 | $ 5,318 | $ 5,240 |
| 2 | 2005 | 251 | 190 | 6,017 | 6,458 | 6,364 |
| 3 | 2006 | 251 | 190 | 6,017 | 6,458 | 6,364 |
| 4 | 2007 | 251 | 190 | 6,017 | 6,458 | 6,364 |
| 5 | 2008 | 251 | 190 | 6,017 | 6,458 | 6,364 |
| 6 | 2009 | 605 | 190 | 6,017 | 6,812 | 6,713 |
| 7 | 2010 | 960 | 190 | 6,017 | 7,167 | 7,062 |
| 8 | 2011 | 960 | 190 | 6,017 | 7,167 | 7,062 |
| 9 | 2012 | 960 | 190 | 6,017 | 7,167 | 7,062 |
| 10 | 2013 | 960 | 190 | 6,017 | 7,167 | 7,062 |
| 11 | 2014 | 960 | 190 | 6,017 | 7,167 | 7,062 |
| 12 | 2015 | 960 | 190 | 6,017 | 7,167 | 7,062 |
| 13 | 2016 | 960 | 190 | 6,017 | 7,167 | 7,062 |
| 14 | 2017 | 960 | 190 | 6,017 | 7,167 | 7,062 |
| 15 | 2018 | 960 | 190 | 6,017 | 7,167 | 7,062 |
| 16 | 2019 | 960 | 190 | 6,017 | 7,167 | 7,062 |
| 17 | 2020 | 960 | 190 | 6,017 | 7,167 | 7,062 |
| 18 | 2021 | 960 | 190 | 6,017 | 7,167 | 7,062 |
| 19 | 2022 | 960 | 190 | 6,017 | 7,167 | 7,062 |
| 20 | 2023 | 960 | 190 | 6,017 | 7,167 | 7,062 |
| 21 | 2024 | 960 | 190 | 6,017 | 7,167 | 7,062 |
| 22 | 2025 | 960 | 190 | 6,017 | 7,167 | 7,062 |
| 23 | 2026 | 1,004 | 238 | 6,017 | 7,259 | 7,153 |
| | | $ 18,098 | $ 4,323 | $ 137,472 | $ 159,893 | $ 157,559 |

/1/ ACC Jurisdictional share is approximately 98.54%.

DECISION NO. ______________

## ARIZONA PUBLIC SERVICE COMPANY

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

**PRO FORMA ADJUSTMENT: SPENT FUEL STORAGE**

Adjustment to Test Year operations to amortize deferred Spent Fuel Storage expenses consistent with Decision No. 67744.

| Line No. | Description | Amount |
|---|---|---|
| 1. | **EXPENSES:** | |
| 2. | Fuel Expenses | $ 11,092 |
| 3. | Other Operating Expenses | |
| 4. | Operations Excluding Fuel Expenses | |
| 5. | Maintenance | |
| 6. | Total Pro Forma Adjustment to Expenses | $ 11,092 |
| 7. | **OPERATING INCOME (before income tax)** | **$ (11,092)** |
| 8. | Interest Expense | (144) |
| 9. | **Taxable Income** | **$ (10,948)** |
| 10. | Income Tax at 39.05% | (4,275) |
| 11. | **OPERATING INCOME AFTER TAX** | **$ (6,817)** |