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BEFORE THE ARIZONA CORPORATION COMM

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

RUCO'S INITIAL CLOSING BRIEF

INTRODUCTION

The Arizona Corporation Commission's ("Commission") traditional method of setting rates for a regulated utility such as the Arizona Public Service Company ("APS" or "Company") is grounded in the rate setting requirements established by the Arizona Constitution and elucidated by the Arizona courts. Those requirements include the determination of a rate base at the time rates are set.[1] Contrary to the Commission's practice of basing rates on a historic test year, APS suggests that the Commission consider future financial results, based on estimates of what revenues and expenses might be in future periods. APS is also advocating a number of other rate setting approaches that differ from those historically relied on by the Commission, including

- a near total disregard of the discounted cash flow methodology to set return on equity
- recovery of certain plant not only before it is in service, but before the Company begins to spend construct it
- recovery of the previously-authorized bark beetle deferral amounts that reach beyond the test year, including estimates of amounts that had not yet been spent by the date of the hearing
- including in the cash working capital allowance the non-cash expense of depreciation
- recovery of estimated net lost revenues attributable to demand side management
- pre-funding of pension expense
- including construction work in progress in rate base
- accelerating the recovery of depreciation
- including post-test year plant in rate base, and
- increasing return on equity as an attrition adjustment.

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[1] A.R.S. Constitution Article XV, § 14; *Simms v. Round Valley Light & Power Co.*, 80 Ariz. 145, 153, 294 P.2d 378, 383 (1956).

The Commission should decline APS' invitation to stray from the traditional rate making principles on which it has relied for nearly a hundred years. The Commission has relied on those principles because they result in just and reasonable rates, and they will continue to do so when applied in this case.

BACKGROUND

In October 2005, APS filed an application for a rate increase, which was given Docket No. E-01345A-05-0816. APS filed a revised application in January 2006. The revised application, based on a test year ending September 30, 2005, requested a rate increase of approximately $450 million, or 21.34%. The Residential Utility Consumer Office ("RUCO") and other parties filed direct testimony in August 2006. RUCO proposed that APS's rates be increased by $232 million. Parties' positions were further revised as the proceeding progressed.

APS' existing base rates have been in place since April 2005. APS had filed a rate application (based on a test year ending December 31, 2002) in 2003. In 2004, APS and 22 parties filed a Settlement Agreement to resolve the outstanding rate application. The Commission approved the Settlement Agreement with modifications in Decision No. 67744 (April 7, 2005). Among other things, the Decision established a power supply adjustor ("PSA") that could adjust rates to allow recovery of APS' fuel and purchased power costs.

In July 2005, APS filed an application for approval of a PSA surcharge. The Commission declined to implement the requested surcharge, but did move up the annual PSA adjustment by two months.[2]

[2] Decision No. 68437.

In January 2006, APS filed an application for an emergency rate increase of $299 million. After an eight-day hearing, the Commission authorized APS to implement an interim PSA adjustor effective May 1, 2006 to recovery approximately $138 million over the remainder of 2006.[3]

CRITERIA FOR SETTING RATES

In its direct case, APS characterized its need for rate relief as being driven by increased fuel and purchase power costs, which represented approximately 70 percent of its total revenue increase request.[4] As the case progressed, however, APS changed its tune, and began to characterize its need for rate relief as being grounded in satisfying credit rating agencies that additional rates would allow APS' future financial results to satisfy certain benchmarks.[5] The Commission should not be fooled into setting rates based on APS' proposed "financial results" criteria. Instead, it should maintain its settled and historic practice of setting rates based on results achieved in a recent and representative test year.

Free market forces would not adequately constrain prices charged by a monopoly utility. Therefore, the Commission is charged with regulating utility prices to ensure that rates are just and reasonable.[6] To accomplish that task, the Commission's practice, based on constitutional requirements and well-developed rate making principles, has been to establish rates based on an analysis of a utility's investment, revenues and expenses during a recent "test year." Regulation is not meant to provide a guarantee that a utility will recover its authorized return.

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[3] Decision No. 68685.
[4] Exh. APS-1 at 4, 10 (Wheeler direct).
[5] Exh. APS-2 at 2 (Wheeler rebuttal).
[6] A.R.S. Constitution, Art. XV, § 3

The Commission's rate case filing requirements call for an applicant for new rates to submit extensive information in support of its request. Among the requirements, a utility must submit schedules which demonstrate its projected financial results under its current and proposed rates.[7] APS claims that, because the Commission's rules require this information to be provided, the Commission must rely on projections of financial results in setting rates. Further, APS criticizes RUCO and the Commission's own Utilities Division ("Staff") for not testing their revenue requirement recommendations by projecting the financial impact of those rates.[8] However, APS readily admits that the Commission does not use the projected data supplied with a rate application in its determination of a utility's revenue requirement.[9]

APS cites Decision No. 53537 as the basis for its statement that the purpose of rate setting is to set prospective prices.[10] However, Decision No. 53537 includes no discussion of projections of the financial impacts of the rates the Commission adopted therein.[11] Instead, the Commission based its decision on the traditional analysis of test year results with certain adjustments. Thus, Decision No. 53537 provides no support for APS' claim that the Commission should base rates on projections of financial results they may allow a utility to achieve.

Projected financial results are a poor basis on which to set rates, because financial forecasts can be easily biased based on the assumptions on which they are established.[12] Future customer levels, consumption levels, conservation, weather, plant operation efficiency, generation resource mixes, fuel and purchased power prices, management decisions,

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7 A.A.C. R14-2-103, Schedule F-1.
8 Exh. APS-2 at 10 (Wheeler rebuttal)
9 Tr. at 2312-13 (Froggatt).
10 Exh. APS-2 at 10 (Wheeler rebuttal).
11 Decision No. 53537 was admitted at the hearing as Exh. RUCO-1.
12 Exh. RUCO-26 at 4 (Diaz Cortez surrebuttal).

employee productivity, and costs of debt financing are just some of the assumptions which must be made to project a utility's financial results.[13] It would be irresponsible for the Commission to reject its proven and traditional rate making principles in favor of speculating on a host of inputs as its rate setting methodology.

The Company's calculations of projected rating agency metrics are based on the same types of projections discussed above. They are fraught with the same problems as financial forecasts and are only as reliable as the myriad of assumptions and guesswork on which they are built.[14] A projection is no more appropriate as a basis for setting rates merely because it may be relied on by debt rating agencies.

The Commission has long relied on an evaluation of results achieved in a recent past "test year" as the basis for establishing rates.[15] Both the Commission and the Arizona courts have found that approach to be reasonable and to satisfy constitutional standards. The Commission should not discard its tried-and-true method of setting rates in favor of an approach that is based on a shaky foundation of assumptions and projections of unknown, and unknowable, future conditions.

CONTESTED RATE BASE ISSUES

APS has agreed with two rate base adjustments presented in RUCO's direct testimony, relating to the retirement of the Palo Verde Unit 1 steam generator,[16] and the inclusion of a

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13 Exh. RUCO-26 at 4 (Diaz Cortez surrebuttal); Tr. at 169-170 (Wheeler); Tr. at 457-59 (Brandt).
14 Exh. RUCO-26 at 5 (Diaz Cortez surrebuttal).
15 A.A.C. R14-2-103 (A)(3)(p).
16 Exh. APS-57 at 11 (Rockenberger rebuttal).

deferred credit related to payments to employees on long-term disability.[17] RUCO and APS have outstanding disagreements on the following rate base items.

Bark Beetle Regulatory Asset

In adopting the Settlement Agreement in Decision No. 67744, the Commission authorized APS to defer for later recovery the reasonable and prudent direct costs of bark beetle remediation that exceeded the 2002 test year levels of tree and brush control. In its application in this proceeding, APS seeks to begin recovery of the deferred costs of bark beetle remediation. The test year-end deferral balance was $4,469,059. APS has proposed an adjustment of $6,115,000, which represents its estimate of additional deferrals through January 2007.

RUCO opposes the adjustment to the test year balance of deferrals. APS' adjustment was only an estimate of what amount the regulatory asset would be at some future point in time, thus it is not a known and measurable adjustment to the test year deferral balance.[18] Further, the adjustment violates the matching principle, in that it reflects a balance of costs that were deferred after the test year, and thus is not properly matched in time with other elements of rate base, revenues and expenses.

APS' bark beetle regulatory asset should be treated the same as customer deposits that are included in rate base. APS proposes that its unadjusted end-of-test- year customer deposit balance be used to calculate both rate base and interest on customer deposits expenses.[19] Similarly, the actual amount of deferred costs associated with the Company's

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17 Exh. APS-49 at 4 (Frogatt rebuttal).
18 Exh. RUCO-22 at 9-10 (Rigsby direct).
19 Schedule B-1 at 1; Exhibit RUCO-23 at 4-5 (Rigsby surrebuttal).

bark beetle regulatory asset at test year-end should be utilized, and APS should not be permitted to earn a return on the costs it has deferred subsequent to the end of the test year.

RUCO's objection to APS' adjustment will not result in permanent disallowance of the costs incurred between the end of the test year and January 2007. Instead, the Company would be permitted to continue deferring those costs, and any costs incurred subsequent to January 2007, for recovery in its next rate case. [20] Thus, RUCO merely recommends that the Commission continue its standard practice of permitting the Company to earn a return on its rate base measured at the end of the test year, and continue to defer for another day recovery of and return on additions to rate base that took place after the conclusion of the test year.[21]

Supplemental Executive Retirement Program

APS offers a Supplemental Executive Retirement Plan ("SERP") to a select group of its highest-ranking executives.[22] These executives receive this benefit in addition to the regular retirement plan available to all APS employees.[23] 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. The individuals who receive the SERP benefits are already generously compensated for their work, and provided with a wide array of benefits including a medical plan, a dental plan, life insurance, long term disability, paid absence time and a retirement plan.[24]

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[20] Tr. at 3340, 3348 (Rigsby).
[21] RUCO's rate base adjustment relates to earning a return on the deferred bark beetle costs. RUCO's corresponding adjustment to operating expenses relates to APS' recovery of the bark beetle costs.
[22] Exh. RUCO-24 at 8 (Diaz Cortez direct).
[23] Exh. RUCO-24 at 9 (Diaz Cortez direct).
[24] Exh. RUCO-24 at 9 (Diaz Cortez direct).

APS argues that the SERP is necessary to provide highly paid employees with equivalent retirement benefits to lower paid employees.[25] However, in response to similar arguments from a large gas utility, the Commission recently agreed that SERP costs should not be borne by ratepayers. Like Southwest Gas' SERP, APS' SERP is designed to supplement the basic retirement plan's benefit, which is capped due to Internal Revenue Service regulations.[26] With respect to Southwest Gas Company, the Commission concluded that the cost of the SERP

> 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 SERP, the Company's officers still enjoy the same retirement benefits available to any other Southwest Gas 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.[27]

RUCO therefore proposes removing from rate base a $50 million deferred credit and $19 million in accumulated deferred income taxes related to SERP. RUCO also proposes removing $4.7 million in test year SERP costs from operating expenses.

Working Capital

The Commission traditionally includes in a utility's rate base an allowance for the working capital the company has invested. Working capital represents the amount of cash, materials and supplies, fuel inventories, and prepayments needed to meet current expenses and contingencies that might ordinarily develop.[28] The cash working capital component

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[25] Exh. APS-5 at 64 (Brandt rebuttal).
[26] Exh. APS-5 at 63-64 (Brandt rebuttal); Decision No. 68487 at 11 (excerpts in record as Exh. RUCO-4).
[27] Decision No. 68487 at 19.
[28] Exh. APS-56 at 27 (Rockenberger direct).

represents funds the utility must have on hand to cover expenses that must be paid before revenues are available (received) to make those expense payments.[29] APS relied on a lead/lag study that measures the difference between the time service is rendered and the cash for services are collected in rates (the revenue lag) and compared it to the time that operating costs are incurred and the time they are paid (the expense lag).[30] Contrary to the Commission's historical practice, APS has included depreciation expense in its cash working capital calculation.[31] Further, APS failed to reflect the expense lags associated with its long-term debt in its cash working capital calculation.[32] Together, APS' two errors would result in a working capital requirement that is approximately $75 million higher than it would otherwise be.[33]

Depreciation

APS offers two reasons in support of its request to include depreciation in the cash working capital calculation. First, APS contends that the "fundamental regulatory concept" on which the Commission should focus is that current period depreciation expense has the effect of reducing rate base before cash is collected from customers.[34] Second, APS maintains that depreciation should be included in the cash working capital calculation because there is a lag between the time when the Company records its depreciation expense and when it is recovered from ratepayers.[35] APS' arguments lack merit, as they both are based on the erroneous assumption that a lead lag study and the resulting cash working capital requirement

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[29] Exh. RUCO-24 at 11 (Diaz Cortez direct).
[30] Exh. APS-65 at 5 (Balluff direct).
[31] Exh. RUCO-24 at 11 (Diaz Cortez direct).
[32] Exh. RUCO-24 at 12 (Diaz Cortez direct).
[33] Exh. RUCO-26 at 11 (Diaz Cortez surrebuttal).
[34] Exh. APS-57 at 10 (Rockenberger rebuttal).
[35] Exh. APS-66 at 2 (Balluff rebuttal).

is intended to measure <u>regulatory</u> lag. 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.[36]

APS claims that depreciation should be included in cash working capital because "rate base is reduced during the benefit period when the expense is incurred," but depreciation is recorded some 37 days before APS recovers the revenues related to depreciation.[37] However, the premise on which APS' argument is based is flawed. Rate base is <u>not</u> reduced each month when depreciation is booked. Rather, rate base is a purely regulatory concept,[38] and is recomputed only at the time of a rate case. Thus, when APS books depreciation expense in October 2006, it does not result in an immediate decrease to rate base and does not result in a lower revenue requirement in November 2006. Instead, the revenue APS collected in December 2006 was based on the undepreciated plant levels as of December 2002, the end of the test year in APS' last rate case.

The Commission has long recognized that depreciation is not an appropriate element to include in a cash working capital calculation. Staff witness Dittmer excerpted a host of Commission decisions dating back over 20 years concluding that non-cash items such as depreciation expense should be excluded from the calculation.[39]

<u>Interest Expense</u>

APS omitted interest expense in its working capital calculation, based on a perception that it is unfair to include the interest expense in working capital when interest expense is also

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[36] Exh. RUCO-26 at 9 (Diaz Cortez surrebuttal)
[37] Exh. APS-65 at 9-10 (Balluff direct).
[38] Tr. at 2613 (Rockenberger).
[39] Exh. Staff-34 at Attachment JRD-B (Dittmer direct).

recovered through the weighted cost of capital that is applied to rate base.[40] However, fairness requires that the lead lag study recognize that APS has use of these funds for the extended period of time between their collection from ratepayers and the payout of interest to debt holders.[41] Because interest on long term debt is generally payable semi-annually or annually,[42] omission of it from the working capital calculation has a significant impact on the computation of a company's working capital needs. The Commission has routinely required that interest expense be included in the calculation of working capital[43] and should do so here.

CONTESTED OPERATING INCOME ISSUES

RUCO raised a number of issues regarding APS' operating revenues and expenses that have subsequently been resolved. The following items are no longer at issue between RUCO and the Company: out-of-period PWEC administrative and general expenses,[44] interest on customer deposits,[45] tax consulting fees,[46] depreciation expense,[47] removing unregulated operations expenses,[48] advertising,[49] and nuclear decommissioning.[50] The operating income issues that RUCO raised that remain in dispute are discussed below.

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40 Exh. APS-66 at 11 (Balluff rebuttal).
41 Exh. Staff-34 at 43 (Dittmer direct).
42 Tr. at 3459 (Diaz Cortez).
43 Exh. Staff-34 at Attachment JRD-B (Dittmer direct).
44 Exh. APS-57 at 25-26 (Rockenberger rebuttal).
45 Exh. RUCO-23 at 6 (Rigsby surrebuttal) and Exh. APS-49 at 5 (Froggatt rebuttal).
46 Exh. RUCO-26 at 13 (Diaz Cortez surrebuttal) and Exh. APS-49 at 8 (Froggatt rebuttal).
47 Exh. RUCO-23 at 7 (Rigsby surrebuttal).
48 Exh. APS-49 at 3-4 (Froggatt rebuttal).
49 Exh. APS-57 at 23-24 (Rockenberger rebuttal).
50 Tr. at 3437.

Estimated Net Lost Revenues from Demand Side Management

In the Settlement Agreement approved in 2005, APS committed to spend an average of $16 million per year for three years on demand side management ("DSM") programs to reduce load growth.[51] APS received approval for its consumer products DSM program in August 2005, and received approval of its non-residential programs in February 2006.[52] Its remaining residential programs were approved in April 2006.[53] APS recovers $10 million per year of DSM funding through its base rates, and has the opportunity to recover its remaining DSM expenditures through a DSM adjustor mechanism.[54]

APS has proposed an adjustment to decrease test-year revenues by $4.9 million to reflect its estimate of future revenues that will be lost as a result of APS' implementation of its DSM programs.[55] APS based its calculation of lost revenues on an estimate of average lost sales of 94,201 MWh per year from the DSM programs it submitted for approval in July 2005.[56]

APS' adjustment is inappropriate for three reasons. First, the adjustment seeks to recover estimated lost revenues and expenses that have not yet actually been realized. For this reason the proposed adjustment violates the rate making principle that adjustments must be known and measurable.[57] Even the earliest of the DSM programs has been in place less than one year at the time of the hearing, and the others less than that.[58] APS cannot yet know with certainty the amount of lost sales that will result, and thus has estimated the annual

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51 Decision No. 67744 at Attachment A, ¶ 40; Tr. at 3415 (Diaz Cortez).
52 Tr. at 1402 (Orlick).
53 Tr. at 1402 (Orlick).
54 Decision No. 67744 at Attachment A, ¶¶ 40, 44.
55 Exh. RUCO-24 at 14 (Diaz Cortez direct).
56 Exh. RUCO-24 at 14 (Diaz Cortez direct).
57 Exh. RUCO-24 at 15 (Diaz Cortez direct).
58 Tr. at 1402-03 (Orlick).

savings. Staff agrees that the estimated revenue losses are not known and measurable, and should be denied.[59]

A net lost revenue adjustment is also inappropriate because it results in an improper mismatch of the time period over which revenues are measured. The adjustment seeks to recover post-test year losses of revenue due to DSM programs, but fails to recognize post-test year gains in revenue from customer growth.[60] The DSM requirements of the Settlement Agreement were not designed to reduce APS' load below what existed at the time,[61] thus it is not surprising that its load continues to grow. If changes to all aspects of revenues the Company expects to earn in a future period were properly matched, one would see that the concept of "net lost revenues" is illogical in the context of a growing load. Though load may be smaller than it otherwise would be without the DSM programs, there is still an overall increase in load, and therefore an increase in revenues. It would be unfair to permit APS to recoup additional revenues due to load "lost" as a result of DSM programs, but not credit customers with the additional revenues APS earns as a result of the additional kWh's sold above test year levels.

The third reason recognition of APS' adjustment is improper is that 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.[62] The test year used in APS' application does not reflect the lost sales volumes that it seeks to recover; that is why APS proposed to accomplish recovery by way of a pro-forma adjustment to the actual test

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59 Exh. S-17 at 4 (Anderson surrebuttal).
60 Exh. RUCO-24 at 15 (Diaz Cortez direct).
61 Tr. at 3415 (Diaz Cortez).
62 Decision No. 67744 at paragraph 46 to Settlement Agreement (excerpted as Exh. RUCO-5).

year revenues.[63] The parameters of a request for recovery of net lost revenues is directly addressed by the Settlement Agreement, which provides that APS shall not recover for net lost revenues "except to the extent reflected in a test year...in future rate proceedings", and "[i]n no event will APS recover...net lost revenues incurred in periods prior to such a test year..."[64] The test year in these proceedings ended on September 30, 2005. All of the net lost revenues APS seeks to recover arose from programs implemented after the conclusion of the test year. Thus, APS is prohibited from recovering such net lost revenues in this proceeding.

Pension Expense

APS is requesting to recover $44 million annually for five years to "pre-fund" its pension. APS claims that its pension is underfunded, and that the portion of the underfunding attributable to APS ratepayers is $218 million.[65] APS's unique proposal is to collect an additional $44 million each year for five years, and to create a regulatory liability that will be amortized over the following 10 years, effectively returning the funds to customers.[66] RUCO, Arizonans for Electric Choice and Competition ("AECC") and Staff all oppose this adjustment.

The fact that APS has an underfunded pension liability does not mean that its retirees are in danger of losing their pension benefits.[67] In fact, the underfunded situation could change without the Commission authorizing APS' novel "pre-funding" solution. The entire calculation of the level of funding and the projected benefit obligation is based on a myriad of assumptions, including interest rates, mortality rates, retirement ages and discount rates.[68]

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63 Tr. at 1094-95 (Ewen); at 3639-40 (Anderson).
64 Decision No. 67744 at paragraph 46 to Settlement Agreement (excerpted as Exh. RUCO-5).
65 Exh. APS-56 at 25 (Rockenberger direct).
66 Exh. APS-56 at 24-25 (Rockenberger direct) and Tr. at 546-47 (Brandt).
67 Exh. RUCO-24 at 18 (Diaz Cortez).
68 Exh. RUCO-24 at 18 (Diaz Cortez).

Interest rates hit an all-time low during the period that APS' pension became underfunded, but the recent increase in interest rates will have a mitigating effect on the underfunding.[69]

Because APS employees' pensions are not at risk, there is no real need to further burden ratepayers by pre-funding pension costs over the next five years. In addition to being unnecessary, the proposal would result in intergenerational inequities since ratepayers who pre-fund the pension over the next five years may not be the same ratepayers who receive reimbursement over the subsequent ten years.[70]

SERP Expense

See discussion in the rate base section above.

Bark Beetle Amortization Expense

RUCO and APS agree that whatever bark beetle regulatory asset the Commission authorizes for recovery at this time should be amortized over three years. APS' and RUCO's difference related to the amount of expense arises from the disagreement over the amount of regulatory asset that should be recovered at this time, as discussed previously in the rate base section.

PWEC and Sundance Plant O&M Expense

APS has proposed a pro forma adjustment to the operating and maintenance ("O&M") expense of the PWEC generation units. There are several flaws in APS' calculations, which

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69 Exh. RUCO-24 at 18 (Diaz Cortez).
70 Exh. RUCO-24 at 19 (Diaz Cortez); .

require a downward adjustment of $5.7 million. APS' errors are as follows.

First, APS began with what are designated as the actual PWEC O&M expenditures for the calendar year 2004, rather than for the test year of October 2004 through September 2005.[71] Second, APS based its adjustment on its forecasts made in 2005.[72] Instead, the adjustment should be based on the most recent forecasts, performed in 2006.[73] Third, APS based its adjustment on the average generation projection for each PWEC Unit for the years 2006-2011.[74] Pro forma adjustments from test year plant performance should be based on very specific known and measurable information. Speculative forecasts of generating unit performance five or six years into the future should not form the basis for such adjustments in this case.[75] Instead, a more near-term generation forecast should be used. However, the Company's most recent forecast projects that the PWEC units' 2007 and 2008 generation levels will differ from their 2006 generation levels significantly enough that 2006 is not a representative year on which to base an adjustment.[76] Therefore, RUCO recommends O&M expense based on projected PWEC generating performance, forecasted in 2006, for the years 2006-2008. The dollar value of this adjustment is approximately $5.7 million.[77]

APS also proposed a pro forma adjustment for variable maintenance costs of its relatively recently-acquired Sundance generating facility. APS' $2.75 million adjustment was based on a projection (performed in 2005) that Sundance will generate an average of 630,000

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[71] Exh. RUCO-29 at 4 (Schlissel).

[72] Exh. RUCO-29 at 4 (Schlissel).

[73] APS maintains that both the magnitude of the difference between the 2005 and 2006 Long Range Forecasts, and the direction of that difference, are confidential. See Tr. at 3714, 3822. Both the direction and the magnitude of the differences are discussed in the confidential portions of Exh. RUCO-30 at 4, 7-8 (Schlissel direct).

[74] Exh. RUCO-29 at 6-7 (Schlissel direct).

[75] Exh. RUCO-29 at 7 (Schlissel direct).

[76] Exh. RUCO-29 at 7 (Schlissel direct).

[77] Exh. RUCO-29 at 9 (Schlissel direct).

MWH per year.[78] However, APS' more recent 2006 forecasts indicate that the average MWHs that Sundance will generate over the 2006-2008 period will be lower than the 630,000 MWHs APS used in its adjustment. RUCO recommends that the Commission utilize the 2006-2008 average generation, which results in a decrease of just over $1.1 million in O&M expense.[79]

APS' only response to these two O&M adjustments was to claim that they were inconsistent with the testimony of Commission Staff's consultants, which found that APS' O&M expenditure patterns were consistent with operational requirements, and that Staff made no similar adjustments.[80] However, Staff's consultants reviewed only APS' <u>historic</u> O&M expenditure levels (and only for the PWEC Units, not the Sundance Units), and therefore Staff's consultants' conclusion does not conflict with RUCO's adjustments to forecasts of <u>future</u> variable O&M expenses.[81] In fact, Staff witness Dittmer proposed his own adjustment to the projections of Sundance O&M expense, and he testified that his adjustment is not mutually exclusive with RUCO's adjustment.[82] Further, Mr. Dittmer testified that, though he did not make an adjustment of his own to the PWEC O&M, he was "somewhat uncomfortable" with the high level of recovery APS was proposing, and it would not be unreasonable for the Commission to make a downward adjustment to it.[83] The Commission therefore should adopt both RUCO's adjustment to PWEC O&M, and its adjustment to Sundance O&M.

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78 Exh. RUCO-29 at 9 (Schlissel direct).

79 Exh. RUCO-30 at 9 (Schlissel direct). APS waived the confidentiality of the dollar figures at page 10 of Exh. RUCO-30. See Tr. at 3714, 3822.

80 Exh. APS-17 at 13 (Ewen rebuttal); Tr. at 1093 (Ewen).

81 Exh. RUCO-31 at 1-2 (Schlissel surrebuttal), citing the consultants' report that was admitted as Exh. S-33, at 92.

82 Exh. S-34 at 95 (Dittmer direct); Tr. at 4184-85 (Dittmer).

83 Exh. S-37 at 50-51 (Dittmer surrebuttal) and Tr. at 4186 (Dittmer).

Miscellaneous Expenses

RUCO made several adjustments to APS' miscellaneous expenses, and APS has agreed to all but one. The remaining dispute involves $400,000 expended on lunches for employees required to work through their lunch hour.[84] This discretionary expenditure should not be recovered from ratepayers, especially when ratepayers are shouldering considerable rate increases over a relatively short period of time.

Lobbying Expense

APS incurs lobbying expenses through its Federal Affairs and Public Affairs departments, and has recorded some of those expenses "above the line" and some "below the line."[85] Of the amounts APS seeks to recover from customers, the $137,686 the Federal Affairs department paid for outside lobbyist should be disallowed entirely. Additionally, the remaining expenses of the Federal Affairs department ($696,629) should be split between ratepayers and shareholders. According to the employees' job descriptions, the Federal Affairs department's employees represent the Company to the federal government on proposed legislation of concern to the Company and its customers, and maintain relationships with legislators and agency staff to affect policy decisions favorable to Pinnacle West, the Company's parent.[86] Because the work of the Federal Affairs department benefits both APS's customers and its shareholders, the expenses of the department should be shared evenly between them. Similarly, the Public Affairs department's function is to influence public policy decisions favorable to APS.[87] Therefore, fifty percent of the payroll expense of the Public

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[84] Exh. RUCO-26 at 14 (Diaz Cortez surrebuttal).
[85] Exh. RUCO-24 at 24-25 (Diaz Cortez direct).
[86] Exh. RUCO-24 at 26 (Diaz Cortez direct).
[87] Exh. RUCO-24 at 26-27 (Diaz Cortez direct).

Affairs department ($599,309) should also be disallowed. APS already recorded the lobbying expenses of the Public Affairs department below the line. RUCO's total adjustment for lobbying expenses is $785,654.

Amortization Expense

In an attempt to match the level of amortization expense to the end-of-test-year balances of the amortizable plant and intangible accounts, APS proposed an adjustment of more than $10 million to the actual test year amortization expense.[88] The Company is not requesting any change to its existing amortization rates, but it is proposing new amortization rates for leased vehicles that the Company subsequently purchases.[89] Thus the entire expense increase would be attributable to changes in the balances of the amortizable accounts over the course of the test year. The balances in those underlying accounts increased only 5.5% during the test year.[90] However, APS is requesting a 35% increase in annual amortization expense for these accounts.[91] Once RUCO has provided evidence that an expense level is inappropriate, the burden of proving the reasonableness of the entire expense level rests with the utility.[92] APS has not disputed the computation of this disparity between the change in account balances and the change in requested expense.[93] Nor has APS demonstrated that the proportion of plant balances amortized at the various rates has changed.[94] Thus, APS has not adequately justified the disproportionate 35% increase in

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[88] Exh. RUCO-24 at 27 (Diaz Cortez direct); Tr. at 3422 (Diaz Cortez).
[89] Exh. APS-56 at 22 (Rockenberger direct).
[90] Exh. RUCO-24 at 28 (Diaz Cortez direct); Tr. at 3424 (Diaz Cortez).
[91] Exh. RUCO-24 at 28 (Diaz Cortez direct).
[92] *See* Decision No. 68487 at 21.
[93] Tr. at 2605 (Rockenberger).
[94] Tr. at 2606-07 (Rockenberger).

amortization expense when there has only been a 5.5% increase in the underlying account balances.

RUCO's adjustment to amortization expense does not completely disallow an increase to match the expense with the end-of-test-year account balances. Instead, RUCO multiplied the $29 million increase in intangible and general plant balances by the composite amortization rate of 10.38%, resulting in a more justifiable increase in amortization expense of $3.1 million.[95] APS criticized RUCO's adjustment as being an imprecise measure of amortization expense.[96] However, RUCO's analysis was the only analysis possible to determine a more appropriate level of amortization expense, given the data provided.[97] Therefore, RUCO's downward adjustment of $6.991 million is appropriate.

Incentive Pay

RUCO proposed an adjustment reducing APS' incentive program expenses by approximately 20 percent, or $4,563,000.[98] RUCO's adjustment is not tied to a formal analysis of the compensation levels of APS employees. Instead, it is based on a policy view that, in light of the increased electric rates APS customers have been required to pay as a result of recent increases[99] and will likely be paying as a result of this proceeding, customers should not be required to fund the entire incentive program that allows APS employees to earn more than

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95 Exh. RUCO-24 at 28 (Diaz Cortez direct).

96 Exh. APS-57 at 18 (Rockenberger rebuttal).

97 Exh. RUCO-26 at 16 (Diaz Cortez surrebuttal).

98 Exh. RUCO-22 at 13 (Rigsby direct).

99 Increases in APS' power supply adjustor rates have been recently approved in Decision No. 68437 (February 2, 2006) and Decision No. 68685 (May 5, 2006).

what is included in their regular wages and salaries.[100] Many APS customers will not have the opportunity to earn more money to make up for what they will lose as a result of higher electric bills.[101] APS already removed the cash incentive compensation of its officers from its application.[102]

The Commission has previously expressed its dissatisfaction with bonuses for certain APS employees during a time of compounding rate increases. In its May 2006 order approving an interim power supply adjustor for APS to collect additional 2006 fuel costs, the Commission stated that it

> believes that at a time when APS is asking for multiple rate increases, funds that might be used for such bonuses could be better directed toward mitigating the impact of rate increases on the Company's customers. We believe that APS in 2007 should continue to disallow bonuses for its executive managers ("officers"), as well as the Company's 50 senior managers.[103]

Adopting RUCO's adjustment to disallow 20 percent of the incentive pay of all employees would continue to send a strong message to investors, rating agencies, Wall Street analysts and customers that the Commission is serious about keeping rates as low as possible in the face of rising fuel costs.[104]

Further, the Company's entire cash-based incentive plan is primarily driven by APS' parent corporation's attainment of minimum earnings levels.[105] Until the parent's earnings

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[100] Exh. RUCO-22 at 13 *et seq.* (Rigsby direct); Exh. RUCO-23 at 9 (Rigsby surrebuttal).
[101] Exh. RUCO-22 at 11 (Rigsby direct).
[102] Exh. APS-2 at 21 (Wheeler rebuttal); Exh. RUCO-23 at 10 (Rigsby surrebuttal).
[103] Decision No. 68685 at 37.
[104] See Exh. RUCO-23 at 11 (Rigsby surrebuttal).
[105] Exh. S-34 at 110 (Dittmer direct).

reach $250 million, the plan is not even funded.[106] After the threshold parent earnings levels are achieved, individual business units must achieve certain performance levels that are tied to benefits to APS customers.[107] Thus, the cash-based incentive plan payouts are based on goals that benefit both shareholders and customers. In Southwest Gas' recent rate case, the Commission required a 50-50 sharing of an incentive plan for management that was based on performance goals that benefited both customers and shareholders.[108] RUCO's proposed disallowance of 20 percent of APS' incentive pay program costs is very modest by comparison.

Property Tax expense

In its direct testimony, RUCO proposed an adjustment to recognize a post-test year reduction in the tax rate by which APS' property taxes are computed.[109] In 2006, the Arizona Legislature suspended the county education tax, effective with the tax bills issued in September 2006.[110] RUCO's adjustment would reduce property tax expense approximately $6 million.

APS opposed RUCO's adjustment, claiming that it failed to consider other post-test year changes that would impact property tax expense, including the recently-approved value on which APS' 2007 property taxes would be assessed.[111] If the impacts of the 2007 assessed value were considered, APS asserted that the adjustment would fall to $2.4 million.[112]

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106 Exh. S-34 at 109 (Dittmer direct).
107 Exh. S-34 at 110 (Dittmer direct).
108 Decision No. 68487 at 18 (February 23, 2006).
109 Exh. RUCO-22 at 17 (Rigsby direct).
110 Exh. RUCO-22 at 17 (Rigsby direct).
111 Exh. APS-57 at 20-21 (Rockenberger rebuttal).
112 Exh. APS-57 at 21 (Rockenberger rebuttal). APS claimed that the $2.4 million included the impact of a Staff adjustment to property tax, to which the Company had agreed.

APS' objection to RUCO's adjustment is ill-founded. RUCO's adjustment recognizes a known and measurable change to the rate at which property taxes will be calculated. It does not create any degree of mismatch between rate making elements, because property taxes would still be recovered based on the tax basis used during the test year. The additional post-test year changes that RUCO has not recognized are inappropriate for recognition. The 2007 assessed value includes property that was not in rate base at the conclusion of the test year.[113] Thus, it would create a mismatch between the time periods used to calculate rate base and property tax expense.[114] While Staff did not propose the same adjustment to property based on the suspension of the county education tax, Staff witness Dittmer indicated that he supported it, and would have made the same adjustment had he been aware of the tax rate change.[115]

Income Tax expense/Synchronized interest

RUCO and APS agree on the formula to be used to calculate income taxes.[116] Their only disagreement relates to their differing views on rate base and the weighted cost of debt.[117] These issues are discussed elsewhere in this brief.

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113 Tr. at 2625 (Rockenberger).
114 Tr. at 4188-89 (Dittmer).
115 Tr. at 4192 (Dittmer).
116 Exh. APS-49 at 7 (Froggatt rebuttal).
117 Exh. RUCO-23 at 17 (Rigsby surrebuttal).

COST OF CAPITAL ISSUES

Capital Structure

APS proposes a capital structure comprised of 45.5 percent long-term debt, and 54.5 percent common equity.[118] This is a much more expensive capital structure than APS has utilized historically.[119] The Company has maintained a capital structure of 55% long-term debt and 45% common equity while maintaining investment-grade bond ratings.[120] However, just prior to filing its application in this proceeding, APS' parent company, Pinnacle West, Inc. ("Pinnacle West"), infused equity into APS bringing APS' equity ratio up to approximately 54% of total capital.[121] The increase in the percentage of APS' equity from 45% to 54%, if adopted for rate making purposes, would cost Arizona's ratepayers an additional approximately $58 million annually.[122]

Pinnacle West's capital structure over the most recent five-quarter time period consisted of 50.20% common equity, 49.06% long-term debt and 0.74% short-term debt.[123] On a consolidated basis, Pinnacle West has higher operating risk than APS.[124] A business with higher operating risk should have less debt and more equity since its income stream is more risky and less debt is appropriate to avoid default.[125] However, APS requests that its rate base set with a 54% equity ratio, while its riskier parent is capitalized with 50% common equity. For rate making purposes, it is **not** appropriate for APS to have a capital structure with less debt and more equity than its higher-risk parent.

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118 Exh. RUCO-11 at 23 (Hill direct).
119 Exh. RUCO-11 at 24 (Hill direct).
120 Exh. RUCO-11 at 24 (Hill direct).
121 Exh. RUCO-11 at 24-25 (Hill direct).
122 Exh. RUCO-11 at 24-25 (Hill direct).
123 Exh. RUCO-11 at 26 (Hill direct).
124 Exh. RUCO-11 at 26 (Hill direct).
125 Exh. RUCO-11 at 27 (Hill direct).

APS' requested capital structure should also be rejected because it is likely to result in financial cross-subsidization of Pinnacle West by APS' ratepayers. Financial cross-subsidization is likely to occur in situations where the parent company has a more leveraged capital structure (more debt, less equity), and the regulated subsidiary faces lower business risk than the parent.[126] The utility provides financial strength to its holding company which in turn capitalizes its consolidated operations with more debt and less equity than the holding company would otherwise be able to maintain.[127] In turn, ratepayers assume the risk of the unregulated affiliates by allowing the holding company to be capitalized in a manner different than it would be in a stand-alone situation.[128]

The Commission should reject the Company's recommended capital structure. Instead, it should adopt a capital structure of 50 percent debt and 50 percent equity. This capital structure has a common equity ratio that is similar to that of APS' parent, and therefore will be sound for the lower-risk utility.[129] It also has more common equity than APS has utilized in the past, which will provide additional financial safety for the Company during its construction period. At the same time, RUCO's recommended 50/50 capital structure will provide a better balance of the interests of ratepayers and stockholders, because it is a more economically efficient (less costly) capitalization than that requested by the Company.[130]

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126 Exh. RUCO-11 at 27 (Hill direct).
127 Exh. RUCO-11 at 30 (Hill direct).
128 Exh. RUCO-11 at 30 (Hill direct).
129 Exh. RUCO-11 at 32 (Hill direct).
130 Exh. RUCO-11 at 32 (Hill direct).

Return on Equity

RUCO recommends an overall rate of return of 7.33 percent, which is the weighted cost of RUCO's recommended costs of debt and equity capital.[131] RUCO's 9.25 percent recommended return on equity, when applied to RUCO's recommended capital structure of 50% common equity and 50% long-term debt, results in a recommended cost of capital (7.33%) which allows APS the opportunity to achieve pre-tax interest coverage of 3.85 times.[132] That level of interest coverage is well above the pre-tax interest coverage levels APS has achieved over the past three years and, therefore, is sufficient to support and improve the Company's financial position for years to come.[133]

The Company originally recommended a return on equity ("ROE") of 11.50%.[134] During the hearing of this matter the Company changed its recommendation to reflect an upward adjustment for an attrition allowance.[135] With the attrition adjustment, the Company is now recommending a ROE of 13.3%. The Company's ROE analysis differs from the Commission's historical approach. The Company proposes a unique methodology which has the effect of inflating the ROE. Moreover, the Company's proposed ROE is not representative of the proxy of integrated electric utilities the Company uses in its ROE analyses.

The Company calculated its ROE by applying "...alternative quantitative methods to a proxy group of other electric utilities operating in the Western U.S."[136] The Company's analysis, after allowing for flotation costs, resulted in a fair rate of return range for the electric

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131 Exh. RUCO-11 at 4 (Hill direct).
132 Exh. RUCO-11 at 4 (Hill direct).
133 Exh. RUCO-11 at 4 (Hill direct).
134 Exh. APS-41 at 3 (Avera direct).
135 Tr. at 1867 (Avera).
136 Exh. APS-41 at 4 (Avera direct).

utility proxy group of 11.0% to 12.0%.[137] The Company based its original 11.5% ROE recommendation on the midpoint of that range.[138]

The Company relied on the following market-based models in calculating its ROE: the Discounted Cash Flow ("DCF") model, the Risk Premium Method, and Comparable Earnings Model.[139] The Company, however, placed its reliance on the market-based models that yielded the highest costs of equity. The Company's witness, Dr. William Avera, placed little to no reliance on the model which provides the best indication of the cost of equity, the DCF.[140] Yet the Company admits that the Commission has relied historically on the DCF Model when making its ROE Decisions.[141] Moreover, the Company in its most recent rate case argued that the DCF "... is the most reasonable way to go about estimating the cost of common equity..."[142] There is nothing unusual or extraordinary about this case that requires or justifies the Commission adopting the Company's about-face. The Commission should reject the Company's methodology for determining its proposed ROE.

The DCF Model replicates the market valuation process that sets the price investors are willing to pay for a share of the Company's stock.[143] To yield a more accurate determination of ROE, the DCF analysis is applied to a proxy group of similar companies.[144] Dr. Avera's DCF analysis resulted in a ROE of 9.0%,[145] however Dr. Avera ignored this result in making his

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137 Exh. APS-41 at 4 (Avera direct).
138 Exh. APS-41 at 4 (Avera direct).
139 Exh. APS-41 at 3 (Avera direct).
140 Exh. RUCO-11 at 50 (Hill direct).
141 Tr. at 1870 (Avera).
142 Tr. at 1892 (Avera); Exh. RUCO-10 at 12.
143 Exh. APS-41 at 30 (Avera direct).
144 Exh. APS-41 at 35 (Avera direct).
145 At the hearing, Dr. Avera testified that applying the most recent data would result in a ROE recommendation of 10%. Tr. at 1871 (Avera). RUCO believes that using the data provided by Dr. Avera in support of his updated DCF of 10%, the result would be 9.6 or 9.7 percent. Tr. at 2023 (Hill).

ROE recommendation.[146, 147] Dr. Avera's DCF results are 430 basis points lower than his final ROE recommendation. Dr. Avera's failure to consider his DCF results in his final ROE recommendation results in an exaggerated ROE recommendation.

Dr. Avera next considered the Risk Premium Method ("RPM"). The RPM extends the risk-return tradeoff observed with bonds to common stocks.[148] Dr. Avera's RPM analysis resulted in a very wide range of estimates.[149] Precisely, the range went from a 9.8% to 13.3%.[150] In its last rate case, the Company testified "Primarily, because of the difficulty in selecting an appropriate time period to use to estimate the expected risk premium, this approach can produce a wide range of results."[151] It is for that reason, the Company argued in that proceeding that the RPM should be used only as a "check."[152]

However, as with the DCF Model, the Company no longer agrees with its RPM position in its last rate case. The Company now takes the position that the RPM should be used in combination with other methods to reach a reasonable result.[153] In fact, since the Company placed no reliance on its DCF results, the only other method the Company relied on is the Comparable Earnings Model ("CEM").[154] The CEM model references the rates of returns available from alternative investments of comparable risk to assess the return necessary to assure confidence in the financial integrity of a firm and its ability to attract capital.[155]

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146 RUCO's DCF analysis resulted in a ROE of 9.44% which is within RUCO's range of equity costs for electric utilities used in RUCO's proxy group. Exh. RUCO-11 at 3, 41 (Hill direct).
147 Exh. APS-41 at 42 (Avera direct).
148 Exh. APS-41 at 43 (Avera direct).
149 Exh. APS-41 at 53 (Avera direct).
150 Dr. Avera testified the updated high end of the RPM approach is 13.3%. Tr. at 1890 (Avera).
151 Tr. at 1894 (Avera).
152 Tr. at 1894 (Avera).
153 Tr. at 1894–95 (Avera).
154 Exh. APS-41 at 53 (Avera direct).
155 Exh. APS-41 at 53 (Avera direct).

Dr. Avera's analysis of the CEM relied on Value Line's safety rank and beta to estimate ROE.[156] Using Value Line's projections, in his Direct Testimony, Dr. Avera determined that a fair ROE, based on his CEM analysis, would be in the range of 11% to 12%.[157] Dr. Avera's original 11.5% ROE recommendation is the mid-point of his CEM estimates.

Dr. Avera's updated CEM analysis highlights the inherent flaws in the CEM. Dr. Avera's updated CEM considered 182 different companies.[158] Among them is American Standard with a ROE of 60.3%, Black and Decker (35.7% ROE), and Conoco Phillips (20.3% ROE). These companies, like all of the 182 companies in the Company's CEM analysis, are unregulated and have substantially different risk than APS.[159] They are not monopolies; they do not operate in a franchise service territory and have much different market positions than APS.[160] Moreover, there is no way of knowing if the returns of the companies used in the study are equal to the cost of capital, unless a market-based analysis like the DCF is performed. That is why the DCF replaced comparable earnings when it came into existence in the 1960s. With the advent of the DCF, regulators had direct evidence of what the cost of equity capital was and they essentially abandoned CEM as a means to set ROE. The Commission should give little weight to the results of the Company's inflated CEM recommendation.

Staff recommends a rate of return of 8.05% and a ROE of 10.25%.[161] Staff's witness, David C. Parcell, used the DCF model, Capital Asset Pricing Model and CEM to determine his recommended ROE.[162] Mr. Parcell's ROE recommendation, however, is based on the upper

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156 Exh. APS-41 at 55 (Avera direct).
157 Exh. APS-41 at 55 (Avera direct).
158 Exh. APS-44 (Avera workpapers).
159 Tr. at 2024 (Hill).
160 Tr. at 2025 (Hill).
161 Exh. S-8 at 4 (Parcell direct).
162 Exh. S-8 at 4 (Parcell direct).

ends of the respective model ranges.[163] Mr. Parcell provides no explanation for his reliance on figures in the upper range.[164] Mr. Parcell's reliance on the upper range figures is misplaced, since the capital structure that Mr. Parcell is recommending in this case contains substantially more common equity than the other companies Mr. Parcell reviewed in his analysis. Mr. Parcell's common equity ratio recommendation indicates that APS has substantially less financial risk than the other companies in Mr. Parcell's sample group, which would indicate that a move to the upper end of the range is a move in the wrong direction. If an adjustment were to be made to Staff's ROE range, it should be downward due to APS' lower financial risk. The Commission should also reject Staff's inflated cost of capital recommendation.

The 9.25 percent cost of common equity estimated by RUCO witness Stephen Hill is reasonable when the Company's capital structure is compared with the capital structures of other integrated electric utility companies.[165] RUCO's 9.25 ROE is appropriately set at the lower end of a reasonable range of equity costs for integrated electric utilities due to APS' lower financial risk.[166]

In arriving at RUCO's final 9.25 percent ROE estimate, Mr. Hill took into account not only the financial risks that the Company faces, but also the current economic environment. Mr. Hill's final recommendation takes into consideration anticipated interest rate increases by the Federal Reserve Bank and the impact that these increases could have on

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163 Exh. RUCO-13 at 29 (Hill surrebuttal).
164 Exh. RUCO-13 at 29 (Hill surrebuttal).
165 Exh. RUCO-11 at 3 (Hill direct).
166 Exh. RUCO-11 at 3 (Hill direct).

utility stocks.[167] RUCO's ROE estimate is fair to both the Company and the Company's ratepayers. The Commission should adopt RUCO's 7.33 percent rate of return.

RESULTING REVENUE REQUIREMENT

RUCO recommends a $212 million overall base rate increase, which includes a $280 million increase related to fuel and approximately a $68 million decrease related to all non-fuel items.[168]

RATE DESIGN/RATE SPREAD BETWEEN CUSTOMER CLASSES

APS' current rate design is the product of the Settlement Agreement in APS' 2003 rate case. That Settlement Agreement was agreed to by 22 parties.[169] Given the diverse perspectives of the parties in that proceeding, rate design was one of the more contentious issues.[170] In that proceeding, residential customers received somewhat higher rate increases than other customer classes in an effort to move rates more toward costs.[171] However, the rate design arrived at was fair, and therefore RUCO is recommending very little change to it.

Because the need for a rate increase in this proceeding is driven by increases in purchased power and fuel costs,[172] it is appropriate to recover the increased costs through commodity charges. That way, customers bear the increased costs in proportion to their

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167 Exh. RUCO-11 at 15-19 (Hill direct).
168 Tr. at 3405 (Diaz Cortez).
169 Decision No. 67744 at 6.
170 Exh. RUCO-25 at 2 (Diaz Cortez rate design direct).
171 Decision No. 67744 at 31.
172 Staff and RUCO are both proposing overall increases that are completely attributable to increases in fuel and purchase power costs. Tr. at 4179 (Dittmer); Tr. at 3405 (Diaz Cortez). Even at APS' requested revenue increase, APS concedes that 16% of its 21% rebuttal case increase is attributable to fuel. Exh. APS-2 at 6 (Wheeler rebuttal).

individual consumption of the commodity.[173] Allocating the rate increase primarily to the commodity charge also allows customers to mitigate the cost of the increase through conservation.[174] Designing rates to reward customers for conservation efforts is consistent with the Commission's DSM and demand response goals.

RUCO also proposes that the rate increase be spread evenly across all rates schedules, at least as far as possible. Pursuant to the requirements of Decision No. 67744, a number of rate schedules were frozen in anticipation of elimination in this proceeding. Customers on those rate schedules will default to particular active rate schedules if they do not affirmatively select another schedule. Therefore, because the rates must now be designed to reflect the elimination of those frozen rates, the eliminated schedules will reflect rate increases attributable to both the rate increase approved in this proceeding, and to the fact that customers are being migrated off of them and onto other rate schedules.[175] Other than these unequal impacts, RUCO's rate design spreads the rate increase evenly.

DEMAND SIDE MANAGEMENT

In the Settlement Agreement, APS committed to spend a total of $48 million on DSM programs over the period 2005-2007. Base rates included $10 million per year of funding, and expenditures above that would be deferred and collected in the following year through a DSM adjustor mechanism.[176] Because of concerns about the pace at which APS would be able to

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[173] Exh. RUCO-25 at 3 (Diaz Cortez rate design direct).
[174] Exh. RUCO-25 at 3 (Diaz Cortez rate design direct).
[175] Exh. RUCO-25 at 3 (Diaz Cortez rate design direct).
[176] Decision No. 67744, Attachment A, ¶¶ 40, 44.

"ramp up" new DSM programs, APS's spending obligation was stated as a total over three years amount, rather than particular amounts for specific years.[177]

Interest on DSM adjustor

In its application in this case, APS made several requests related to DSM recovery. First, APS requested that it be permitted to accrue interest on the unrecovered DSM adjustor balance.[178] APS conceded that the Settlement Agreement does not provide for interest on the DSM adjustor balance.[179] However, APS' witness claimed that he believed the omission of a provision for interest on the DSM adjustor was merely a "drafting oversight."[180] Curiously, APS' witness, Mr. Rumolo, never explicitly stated that APS' intention at the time of the negotiation was that interest would accrue on any balance. Rather, he merely states that interest would be "appropriate."[181]

Staff did not oppose APS' request, but Staff's only witness on the issue was not even employed by Staff at the time of the negotiation of the Settlement Agreement, and was therefore unable to testify what any party's statements or intentions were at the time of the negotiation.[182] Staff's lack of opposition, therefore, was based not on agreement with APS' claim of a drafting error, but because it would be normal for a utility to accrue interest on a cost deferred for future recovery.[183]

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177 Exh. RUCO-24 at 40 (Diaz Cortez direct); Decision No. 67744, Attachment A, ¶¶ 40, 44
178 Exh. APS-69 at 15 (Rumolo direct).
179 Exh. APS-70 at 5 (Rumolo rebuttal).
180 Exh. APS-70 at 5 (Rumolo rebuttal).
181 Exh. APS-69 at 15 (Rumolo direct).
182 Tr. at 3629-31 (Anderson).
183 Tr. at 3630 (Anderson).

RUCO opposes APS' attempt to insert this new provision into the Settlement Agreement that did not provide for interest. APS' contention that the omission of an interest component was merely a drafting error is belied by the attention to detail the settling parties paid in drafting the Settlement Agreement. The Settlement Agreement is 26 pages of single-spaced text, not including signature pages and attachments.[184] Of those pages, five pages, or nearly 20 percent of the document, is dedicated to provisions related to DSM.[185] The Commission should have difficulty believing that the parties would have paid such attention to setting forth the details of the DSM requirements, but failed to include a provision that all parties had intended to include. Further, no party presented any evidence that any party actually <u>intended</u> for the DSM adjustor to accrue interest. In fact, APS' witness Rumolo, who was a participant in the negotiation of the Settlement Agreement, testified that he could not recall any specific discussion about the topic of interest on the DSM adjustor balance at the time the Settlement was negotiated, and that he had no knowledge of what any other party's intention had been regarding the issue at the time of the negotiations.[186] Additionally, not all parties to the Settlement Agreement are even parties to this proceeding,[187] so there is no way of knowing whether the missing parties in fact intended for the DSM adjustor to <u>not</u> accrue interest. Finally, due to the ramping up of programs over the three year term of the DSM program, it was always expected that in the initial months APS would collect more DSM funds through

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[184] Decision No. 67744, Attachment A.
[185] *Id.*
[186] Tr. at 2918-19 (Rumolo).
[187] For example, the Arizona Community Action Association was a signatory to the Settlement Agreement, but is not a party to this proceeding. The Commission has not provided notice to the parties to the Settlement Agreement that it might be considering amending its prior decision adopting the Settlement Agreement.

base rates than it spends on DSM, but that it would self-correct in later periods when APS would spend more than it collects. Thus, it was no surprise that as of the hearing, APS' total post-Settlement Agreement DSM collections have exceeded its total DSM expenditures.[188] While this temporary pre-paying of DSM costs was built into the Settlement Agreement provisions, 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.

Post-2008 Demand Side Management Obligation

The Settlement Agreement required that APS spend $48 million on DSM during the three years of 2005, 2006 and 2007 (an average of $16 million each year). While the DSM adjustor would be operating in 2008 to collect amounts APS spent previously, the Settlement Agreement did not explicitly require APS to spend any amounts on DSM after 2007. Therefore, RUCO proposes that the Commission make its intentions about future years' DSM spending clear.[189] RUCO further proposes that the Commission expand APS' DSM spending requirement beginning in 2008, by requiring total annual spending of at least $20 million ($10 million to be recovered through base rates, and at least $10 million through the DSM adjustor mechanism).[190]

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188 Tr. at 1401-02.
189 Exh. RUCO-24 at 39 (Diaz Cortez direct).
190 Exh. RUCO-24 at 40 (Diaz Cortez direct).

Staff and APS both testified that they expected APS to continue funding DSM at the Settlement-approved level, even after 2007, absent Commission action requiring something different.[191] APS further indicated the RUCO's proposal to require $20 million of annual DSM funding is not needed, because the existing framework of recovery from both base rates and an adjustor provides enough flexibility for APS to spend more than $16 million in a year.[192]

It is important for the Commission to affirmatively state that it expects APS to continue investing in DSM after 2007 to insure continuity of the DSM programs. Further, by 2008, APS will have had several years to implement its DSM program. The Commission should require APS to increase its DSM commitment. At the time of the Settlement Agreement, there was never any question about the desirability of an aggressive DSM program.[193] At that time, there were concerns about the time it might take to ramp up spending and implement new programs.[194] However, APS' learning curve is no longer an issue, as they now have programs up and running. An additional minimum of $4 million of required DSM investment will encourage more new programs and more savings to customers. As the cost of energy increases, the value of DSM as a resource grows. The Commission should increase APS' reliance on DSM to meet its growing load.

POWER SUPPLY ADJUSTOR/BASE COST OF FUEL AND PURCHASED POWER

APS has proposed a number of modifications to the design of its power supply adjustor ("PSA") in an attempt to allow collections to more closely match expenditures. RUCO supports the changes to the PSA that APS is proposing. RUCO and APS propose different, but very

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[191] Exh. APS-32 at 3 (Orlick rebuttal); Exh. S-16 at 6 (Anderson).
[192] Exh. APS-32 at 9 (Orlick rebuttal).
[193] Exh. RUCO-24 at 40 (Diaz Cortez direct).
[194] *Id.*

close, base costs of fuel and purchased power ("base cost of fuel"). Both the existing PSA and that proposed by APS are retrospective mechanisms that collect the difference between the fixed base cost of fuel and actual costs on a retrospective basis. Staff has proposed a radically different PSA mechanism, one that would effectively change the base cost of fuel each year. RUCO opposes the monumental shift in approaches that the Staff proposal represents.

APS originally proposed four modifications to its PSA mechanism: 1) elimination of the $776.2 million cap on total fuel and purchase power costs; 2) changing the current 4 mil lifetime cap on the PSA adjustor to an annual cap; 3) excluding from the 90%/10% sharing mechanism the costs of renewable resources and the fixed costs of purchased power agreements acquired through the competitive bidding process; and 4) excluding 10 percent of the gains and losses realized on hedging from both the base fuel amount and in subsequent PSA operations.[195] In its rebuttal testimony, APS withdrew the fourth proposed modification due to opposition from other parties.[196] RUCO supports the remaining three modifications that APS has proposed.[197] A strong and stable PSA mechanism is a better way to address the financial difficulties that APS has recently experienced than is adoption of the novel approaches to rate making that APS proposes in this proceeding.[198]

In its original application, APS proposed a base cost of fuel of 3.1904 ¢/kWh, based on its proposed adjustments to test year conditions.[199] APS revised its proposed base cost of fuel

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195 Exh. APS-7 at 22 (Robinson direct).
196 Exh. APS-8 at 3 (Robinson rebuttal).
197 Exh. RUCO-24 at 30 (Diaz Cortez direct).
198 Tr. at 3394 (Diaz Cortez).
199 Exh. RUCO-21 at 1 (Hornby surrebuttal); Exh. APS-16 at 3 (Ewen direct).

in its rebuttal testimony, and in its rejoinder testimony APS again modified its proposal, to 3.2491 ¢/kWh. This most recent figure was based upon a new set of proposed adjustments as well as the Company's withdrawal of its hedging gains/losses proposal.[200] RUCO proposes that the Commission adopt a base cost of fuel of 3.1202 ¢/kWh, which is the amount of APS' original base cost of fuel proposal, adjusted for the withdrawal of the proposed sharing of hedging gains and losses.[201] APS's original proposal was based on conditions the Company expected to experience during 2006.[202] APS's rejoinder proposal is based on estimates of 2007 prices and 2007 loads.[203] The estimate of 2007 conditions includes adjustment to reflect conditions APS expects for 2007 that differed from the conditions that APS expected for 2006, including different planned maintenance schedules and resource mixes.[204] Finally, one of the components of the various base cost of fuel proposals is the margin credit for off-system sales. In APS' original proposal, APS included a margin credit of approximately 0.09, but its rejoinder proposal includes a credit of only 0.02.[205] The parties had substantial time to analyze APS' original base fuel cost proposal, but there was not adequate time to undertake discovery and fully analyze APS' rejoinder proposal.[206] Therefore, RUCO recommends that the Commission adopt the Company's original base cost of fuel estimate, adjusted for its withdrawal of the proposal to share hedging gains and losses, which computes to 3.1202 ¢/kWh.

Staff has proposed a radically different form of a PSA than either the existing PSA or the PSA with APS' proposed modifications. Staff's proposal begins with a much lower base

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[200] Exh. RUCO-21 at 1 (Hornby surrebuttal); Exh. APS-18 at 4 (Ewen rejoinder).
[201] Exh. RUCO-21 at 1 (Hornby surrebuttal).
[202] Exh. APS-16 at 3 (Ewen direct).
[203] Tr. at 1051-1053 (Ewen).
[204] Tr. at 1052, 1055, 1099-1102 (Ewen).
[205] Tr. at 3101-02 (Hornby).
[206] Tr. at 3105 (Hornby); *see also* Exh. RUCO-21 at 6 (Hornby surrebuttal).

cost of fuel than either APS or RUCO. Staff's proposed PSA uses that base cost of fuel, but also includes a "Forward Component" so that in each year APS will collect that year's forecasted fuel costs.[207] At the end of each year, the sum of the base cost of fuel and the Forward Component are then compared to the actual fuel and purchased power costs, and this difference is collected in the following year as the "Historical Component."[208] By comparison, the existing PSA and the PSA APS proposes recover only the base cost, with a true-up to actual costs in the following year.

After the current PSA was adopted in 2005, the Commission went to great lengths in the Plan of Administration proceeding (resulting in Decision No. 68437) to clarify the details of the PSA as the Commission desired them. It would be premature to discard those efforts and adopt a PSA that is based on completely different philosophical underpinnings than the current PSA. It is more appropriate to tweak the existing PSA to better address fuel cost recovery than to throw out the existing PSA and start again.

The Commission should also reject the Staff-proposed PSA because it omits one of the important characteristics of the current PSA—the mechanism providing that the variation between actual fuel costs and the base cost is shared 90/10 by the customers and the Company. The purpose of the 90/10 sharing is to provide APS an incentive to minimize total fuel and purchase power costs, including maximizing the margin from off-system sales.[209] A mechanism to create such an incentive is critical to a PSA, because if customers are responsible to pay for all fuel costs, the utility would not otherwise have any incentive to minimize those costs. APS has not proposed elimination of the 90/10 sharing mechanism.

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207 Staff's PSA Plan of Administration at 1,7 (included as an attachment to Exh. S-30 (Antonuk supplemental) ("Staff's Plan of Administration"); and Tr. at 3873 and 4001 (Antonuk).

208 Staff's Plan of Administration at 2, 7.

209 Decision No. 67744 at 13.

Staff witness Antonuk criticizes the 90/10 sharing mechanism as a "blunt instrument" for creating such an incentive, but concedes that it does create a strong incentive.[210] Staff indicated that it would prefer to see sharper instruments to incent APS to efficient performance.[211] But Staff's witness agrees that the time is not yet right to develop such finely-tuned instruments, and suggests that they may be more appropriate after APS has gone through a few years of the administration of a PSA.[212] Curiously, Staff's recommendation is to implement PSA mechanism that has no incentive to minimize total costs rather than retain the "blunt instrument" of cost sharing in the existing PSA.[213, 214]

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. Staff's PSA proposal is out of touch with recent Commission actions balancing these interests. First, Staff believes that its proposed PSA represents an improvement over the existing PSA because it will engage the Commission and interested parties in more frequent examinations of APS' growth and fuel usage when its resets the Forward Component each year.[215] However, Staff's witness is careful to point out that such examinations should not become long, drawn-out proceedings.[216] If the Commission cannot insure that the annual proceeding to reset the Forward Component will remain an abbreviated process, Staff would not recommend adoption of its PSA approach.[217] But

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210 Tr. at 3896 (Antonuk).
211 Tr. at 3897 (Antonuk).
212 Tr. at 3896-98 (Antonuk).
213 Tr. at 3922 (Antonuk).
214 In Decision No. 68685 (May 2006), the Commission addressed what it characterized as "APS' disappointing off-system sales revenues." If the Commission is concerned that APS is not maximizing the use of off-system sales for retail customers' benefit, it should not adopt a PSA that provides APS no incentive to make cost-effective off-system sales.
215 Tr. at 3886 (Antonuk).
216 Tr. at 3932-33 (Antonuk); Exh. S-30 at 7-8 (Antonuk supplemental).
217 Tr. at 3936 (Antonuk); Exh. S-30 at 8 (Antonuk supplemental).

proceedings with prospective adjustors become more complicated than proceedings involving only retrospective adjustors.[218] The Commission had recently given great attention to the proper collection of fuel costs through the PSA, including holding an eight day hearing in March 2006 and a three day hearing in October 2005. The Commission should not now change course and adopt a PSA mechanism that is based on the premise that the Commission will not invest whatever time is necessary to ensure proper fuel cost recovery.

Second, Staff's witness John Antonuk's views on the balance between timely recovery and volatility in customers' rates are inconsistent with a number of recent Commission actions that go to great lengths to properly balance elements of adjustor mechanisms. Staff's witness was not aware of the Commission's ruling from February 2006 that APS can request a surcharge only after the annual adjustor reset in February.[219] He likewise indicated that he was not familiar with the Commission's thinking expressed in its May 2006 decision adopting APS' interim surcharge.[220] It was in this action that the Commission expressed that it believed the 90/10 sharing mechanism was an "important benefit for customers."[221] Mr. Antonuk's lack of knowledge of the Commission's view on this lead him to propose a PSA that eliminates this "important benefit." Further, Staff's witness never contemplated that the Commission might not be prepared to act to adopt a new Forward Component a mere 30 days after APS files it final proposal.[222]

Finally, Staff witness Antonuk is deeply out of touch with the Commission's views when he indicates that tempering volatility of customer rates is **not** a desirable feature of a PSA.[223]

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[218] Tr. at 3124 (Hornby).
[219] Tr. at 3935 (Antonuk).
[220] Tr. at 3921 (Antonuk).
[221] Decision No. 68685 at 25.
[222] Tr. at 3938-39 (Antonuk).
[223] Tr. at 3943 (Antonuk).

Instead, Staff's witness believes that entire burden of volatility of the fuel markets should fall on customers.[224] On numerous occasions recently Commission has acted to restrain extreme volatility in an adjustor mechanism. In 2005 the Commission, out of its concern that customers would be faced with too much volatility risk, modified the PSA mechanism of APS' Settlement Agreement by making the 4 mil cap on the adjustor a lifetime cap rather than an annual cap.[225] In February 2006, the Commission limited the volatility customers could otherwise experience when it ruled that APS could not implement a surcharge prior to the annual PSA adjustment.[226] In May 2006, the Commission approved an interim adjustor for APS, but only in an amount that would leave approximately $110 million in the 2006 Tracking Account, such that the February 2006 adjustor would remain at or close to its current 4 mils.[227] The Commission's recent actions limiting volatility in adjustor mechanisms goes beyond APS. In February 2006, the Commission rejected Southwest Gas Company's proposal to widen the bandwidth within which gas costs can move over a year from 10¢/therm to 20¢/therm, and instead modified the bandwidth to 13¢/therm.[228] The Commission has repeatedly given careful attention to moderating the volatility of customer bills when it strikes the balance in establishing a fuel adjustor.

Staff's witness believes that there should be no tempering of the costs that flow through to customers—no 90/10 sharing, no cap on the annual reset of the Forward Component, and no cap on the retroactive true-up. No one would deny that there have been difficulties due to

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224 Tr. at 3944 (Antonuk).
225 Decision No. 6774 at 16-17.
226 Decision No. 68437.
227 Decision No. 68685.
228 Decision No. 68487 at 55.

the constraints on the current PSA. But Staff's solution swings too far the other direction by rejecting all restraints on the price variations customers can experience. The Commission should not overcompensate for problems with the current PSA by rejecting it altogether. Instead the Commission should make only minor adjustments to the terms of the current PSA, and reset the base cost of fuel and purchased power to a more realistic level given current conditions.

ENVIRONMENTAL IMPROVEMENT CHARGE

APS requests that the Commission authorize an Environmental Improvement Charge ("EIC"), which would allow it to estimate at the beginning of each year its annual costs associated with environmental improvements and implement a surcharge to begin recovering those costs. Eligible costs would include estimated plant investment in environmental improvements, as well as the estimated costs of maintaining those improvements.[229] The proposed mechanism would be trued-up to actual costs in the following year.[230] APS believes that the EIC is justified because it will foster environmental improvements, and because the environmental improvements are not revenue-producing and may be difficult to fund.[231]

RUCO opposes approval of the EIC. The proposal is completely contrary to the normal rate making process for plant additions and improvements. Normally plant must be actually built (known and measurable) and in service (used and useful) prior to being given rate making consideration in the context of a rate case.[232] Ratepayers are required to reimburse utilities for

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229 Exh. APS-37 at 4 (DeLizio direct).
230 Exh. APS-37 at 5 (DeLizio direct).
231 Exh. APS-34 at 7, 9 (Fox direct).
232 Exh. RUCO-24 at 35 (Diaz Cortez direct).

their prudent and reasonable operating expenses and a fair return on the utilities' investment. In the name of "fostering" environmental improvement, APS would have the Commission authorize increased rates so that ratepayers could pre-pay for plant.[233] This would cast ratepayers in the role of investors, albeit without any return on their investment. Further, the Commission does not need to "foster" environmental improvements. There are a number of laws and regulations that have recently been enacted that require the Company to make environmental improvements.[234] These include revisions to the New Resource rule under the Clean Air Act, a new EPA Clean Air Mercury rule, a Clean Air Visibility rule, as well as the pending Clear Skies Act.[235] The Company has all the incentive it needs to make these improvements—because they are mandated. Thus, there is no need for the Commission to turn traditional rate making on its head by approving the EIC.

MISCELLANEOUS ISSUES

APS' hedging program is designed to stabilize prices that it pays for natural gas and purchased power, but APS has no explicit strategy to minimize its overall natural gas and purchased power costs.[236] RUCO recommends that the Commission require APS to develop a strategy to minimize its fuel and purchased power costs, in the context of minimizing its overall costs.[237] The cost minimization strategy would not be a part of the hedging program, but would be a separate program, and should be given as much emphasis as the Company's hedging program.[238]

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233 Exh. RUCO-24 at 36 (Diaz Cortez direct).
234 Exh. RUCO-24 at 37 (Diaz Cortez direct).
235 Exh. RUCO-24 at 37 (Diaz Cortez direct).
236 Exh. RUCO-20 at 2-3, 7 (Hornby direct).
237 Exh. RUCO-20 at 3 (Hornby direct).
238 Tr. at 3131 (Hornby); Exh. RUCO-20 at 3 (Hornby direct); Tr. at 3902 (Antonuk).

EXTRAORDINARY RATE MAKING METHODS

APS' rebuttal testimony identified several new rate making proposals that it claimed would increase its financial strength. Notably, APS does not actually propose that the Commission adopt any of these extraordinary devices if it otherwise approves APS' full rate request. However, APS does suggest that the Commission could implement one or more of the devices to make up the difference between a lower revenue requirement that the Commission might otherwise approve and the revenue increase APS seeks.[239]

One of the Company's proposals to boost earnings is to include all plant additions made through the end of 2006 in rate base for both a return and depreciation expense recovery. While this proposal would surely boost earnings as APS intends, it would create a serious mismatch between the rate making elements used to set rates. Plant-in-service would be measured as of December 31, 2006, but all other rate making elements would be measured as of September 30, 2005, some 15 months earlier. The fact that the Company would be collecting revenues from new customers served by the new plant, and that the new plant could result in operation and maintenance savings, are just some examples of the mismatches inherent in this proposal.[240]

The Company also suggests that the Commission could adopt an attrition adjustment, increasing its authorized return on equity by 1.7%. This proposal is also biased against customers, as it looks only at the aspects of regulatory lag that are disadvantageous to the Company, and ignores other aspects that benefit the Company.[241] Likewise, because the

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239 Exh. APS-2 at 18 (Wheeler rebuttal).
240 *See, e.g.*, Exh. RUCO-26 at 31 (Diaz Cortez surrebuttal).
241 Exh. RUCO-26 at 31-32 (Diaz Cortez surrebuttal).

proposed attrition adjustment is based on estimates of future events, it shares the same inadequacies inherent in financial forecasts discussed previously.

APS' third extraordinary rate making proposal is for an allowance for accelerated depreciation. The proposal is likewise asymmetrical. It would automatically increase rates for depreciation on new assets, but would not decrease rates for asset retirements. It also would not decrease rates for the decline in rate base that would take place after another year of depreciation is recovered. Neither would it look at deferred income tax impacts, changes in debt, or changes in equity costs. The proposal is entirely slanted in favor of APS, at ratepayer cost.[242]

The Company also suggests that the Commission could include its construction work in progress ("CWIP") balance in its rate base, thus creating a larger base on which to calculate a return. Utility regulation has routinely excluded CWIP 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.[243] Utility accounting already allows the accrual of interest, in the form of an allowance for funds used during construction ("AFUDC"), on the CWIP balances. These interest accruals are ultimately recovered over the life of the asset, once it enters service, through depreciation expense.[244] Thus, rate base treatment of CWIP does not change a utility's level of earnings, merely the timing of earnings recovery. Though there are rare occasions when utility regulators have made an exception to the general rule and included CWIP in rate base, they have been only in extraordinary circumstances, such as an extreme drain on cash flow caused by the construction of nuclear

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242 Exh. RUCO-26 at 32-33 (Diaz Cortez surrebuttal).
243 Exh. RUCO-26 at 33 (Diaz Cortez surrebuttal).
244 Exh. RUCO-26 at 33 (Diaz Cortez surrebuttal).

plants.[245] APS is not facing similar conditions today.[246]

CONCLUSION

The Commission's traditional method of setting rates, based on evaluation of financial results in a historic test period with appropriate adjustments, has served the public—both utilities and all classes of consumers—well for nearly a century. The Commission should not abandon that method based on questionable predictions of APS' future financial results.

APS's need for additional rates at this time is exclusively due to increases in fuel and purchased power costs. The existing PSA would eventually allow APS to recover all (except for APS's portion under the 90/10 sharing mechanism) of those costs. APS' proposed modifications to the PSA will allow APS to recover its fuel costs on a more timely basis, but still maintain the important protections that benefit all classes of customers. A better-functioning PSA, together with an increase in the portion of fuel costs collected through base rates, will adequately remedy the impacts of recent fuel cost increases that APS has recently experienced.

Unfortunately, all APS customers will feel the impact of another in a series of recent increases in electricity rates. However, by adopting RUCO's proposed revenue requirement and base cost of fuel, the Commission can take some comfort in the fact that the non-fuel portion of APS' rates has decreased, and the Commission has passed on to consumers only the higher fuel and purchased power costs that APS has incurred on its customers' behalf. Further, the Commission should increase APS' required funding for DSM after 2007 to

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245 Exh. RUCO-26 at 32-34 (Diaz Cortez surrebuttal).
246 *Id.*

minimize the growth in load that would otherwise be met with high-fuel cost resources and to further empower customers to conserve electricity for the good of their pocketbooks and for the good of the public.

RESPECTFULLY SUBMITTED this 22nd day of January 2007.

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