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October 5, 2006

Docket Control
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

RE: WITNESS SUMMARIES OF DIRECT, REBUTTAL AND REJOINDER TESTIMONY UNDER DOCKET NO.'S E-01345A-05-0816, E-01345A-05-0826 AND E-01345A-05-0827.

Dear Sir or Madam:

Pursuant to the procedural order dated April 5, 2006, in the above referenced Docket, Arizona Public Service Company ("APS") is hereby filing written summary for Steven M. Wheeler, Donald E. Brandt, Peter M. Ewen, Donald G. Robinson, Steven M. Fetter, Laura L. Rockenberger, Chris N. Froggatt, Ronald E. White, Fred Balluff, Patrick Dinkel, Stephen J. Bishoff, Mark K. Gordon, John R. Denman, Edward Z. Fox and David J. Rumolo.

If you or your staff have any questions, please feel free to call me.

Sincerely,

Brian Brumfield
Supervisor
Regulatory Affairs

BB/bec

Arizona Corporation Commission
DOCKETED

OCT 0 5 2006

DOCKETED BY

SUMMARY OF TESTIMONY GIVEN BY STEVEN M. WHEELER

I. DIRECT. (As Amended by January 31, 2006 Filing)

After more than a decade of rate reductions totaling some \$1.74 billion, APS received a 4.21% general rate increase (approximately \$75.5 million) effective April 1, 2005. *See* Decision No. 67744 (April 7, 2005). The Company had requested a 9.8% increase (approximately \$175 million) effective July 1, 2004. Of the \$75.5 million granted by Decision No. 67744, some \$8 million represented a temporary surcharge to recover the prior costs of implementing retail electric competition in Arizona. Another \$9 million represented base rate funding for a portion of the additional Demand Side Management ("DSM") spending mandated by Decision No. 67744. Neither of the latter two amounts provided any additional earnings to the Company. At the Special Open Meeting to consider the 2004 Settlement, which served as the basis for Decision No. 67744, APS stated that because of escalating fuel costs, the Company would have to seek additional rate relief in the near future.

The increased cost of fuel and purchased power is the most significant reason why the Company has filed this request for rate relief. In this proceeding, APS is requesting a 21.34% base rate increase, or approximately \$450 million. Of this amount, approximately \$299 million (which is approximately 70% of the total requested relief), is attributable to higher fuel and purchased power costs. Due to the normalization of power plant performance, as described in Mr. Ewen's testimony, none of the proposed increase is related to the increase in unplanned Palo Verde outages during 2005. This request also is approximately \$169 million or approximately eight percentage points (based on November 30, 2005 market prices) <u>less</u> than it otherwise would have been had the Company not mitigated its fuel costs through its hedging program.

The requested increase is necessary if APS is to continue as the type of viable utility that can ensure APS customers continued reliable service, on demand, and at reasonable prices into the future. Furthermore, I must emphasize that it is crucial that the Company maintain an investment grade credit rating so that it can attract the necessary capital to provide such service. Finally, as discussed in Mr. Robinson's testimony, the Company is also seeking certain modifications of the Power Supply Adjustment ("PSA") mechanism.

APS has serious concerns about its ability to continue to obtain capital at reasonable rates. On December 21, 2005, Standard and Poors downgraded the Company to a BBB- credit rating, which is one level above non-investment grade. The investment community has indicated that further down-grading may be forthcoming if there are delays in resolving outstanding issues related to the cost recovery of fuel expenses. For these reasons, on January 6, 2006, the Company filed for emergency interim rate relief and requested that emergency rates be effective by April 1, 2006, subject to refund. To the extent that such emergency relief is granted, the Company's request for permanent rate relief would be incrementally reduced.

APS has based its revenue requirement on an adjusted historical test period, specifically the twelve months ended September 30, 2005 ("Test Year"), and a cost of common equity of 11.50%. The use of such a non-calendar test year was required by Commission Staff. The cost of equity ("COE") is the midpoint of the range found reasonable by Dr. Avera, the Company's return on equity expert. For APS to recover its cost-of-capital, it must receive a fair rate of return of 6.37% on a fair value rate base of $6,120,755,000.

APS has made various adjustments, both up and down, to the Test Year. Theses adjustments will make the historical test period both more representative of a "typical" year and of the period (2007) in which the new rates authorized by the Commission will likely be in full effect. In large part, the pro forma adjustments to the Test Year represent the implementation of the Commission's decision in the Company's last rate case (Decision No. 67744).

Perhaps the most significant of the Company's pro forma adjustments is the reflection of the very substantial increases APS has experienced in the cost of fuel, especially natural gas, and purchased power from other utilities and unregulated merchant power entities. These two categories of cost have been increasing at an annual rate of 23% since 2003, which was the basis for the fuel and purchased power portion of the 2004 Settlement and Decision No. 67744. Even though the costs reflected in the 2004 Settlement were partially updated to reflect some 2003 prices, it is estimated that overall per kWh fuel and purchase power costs will have increased by at least 54% by the end o f 2006, which is when the rates requested in this proceeding are proposed to take effect.

These increases are offset, at least partially, by the Company's successful gas and power hedging program. In this Application, APS is proposing a program whereby APS shareholders would shoulder another 10% of the risk from hedging activities and, correspondingly, realize another 10% of any realized gain from hedging. The other 90% of either gains or losses from hedging would be reflected in the PSA calculations (and thus subject to the current 90/10 sharing mechanism), as is presently the case.

Another issue presented in this proceeding is the Company's request to include the Sundance generating assets into the APS rate base at cost-or-service, although this inclusion accounts for less than 2% of the proposed increase in base rates. The Sundance assets were prudently acquired through an open and fair competitive bidding process to serve APS customers, and these assets have been and will continue to be "used and useful" in providing service to the Company's customers in the future. Thus, they are entitled to cost-of-service rate treatment under traditional criteria previously established by this Commission.

Environmental compliance costs are another area in which APS faces increasing challenges in the future. In an attempt to get ahead of the curve, APS is asking to implement an Environmental Improvement Charge ("EIC") that will allow recovery of the revenue requirement associated with Commission-approved environmental improvement programs on an annual basis. The EIC would add an additional $4.3 million to the Company's request, or 0.20%. *See* SFR Schedule A-1. In addition, APS is proposing to support the development and utilization of renewable resources by implementing Green Power tariffs, which would allow, but not require, customers to subscribe to specific levels of energy from a variety of renewable sources.

II. REBUTTAL.

Each of the parties making a recommendation to this Commission on APS revenue requirements has acknowledged the need for an increase in base rates. There is, however, significant disagreement over how large that increase should be. APS has reviewed the proposals of Commission Staff and RUCO, and independent of the merit for some of the specific adjustments proposed by those two parties, their final recommendations simply do not produce a reasonable result even as measured by their own criteria. As is shown in APS witness Brandt's Rebuttal Testimony, APS will not earn a return on equity equal to even the lowest recommended cost of equity under either recommendation. Its key financial metrics will be in the junk category by the first year that rates based on these recommendations will have been in effect, and will drop further in 2008. We therefore ask the Commission to reject the major Staff and RUCO adjustments that lead to these dire circumstances.

In addition, APS has proposed, but not included in its test period revenue requirements, several potential adjustments to test year revenue requirements that are in response to and are necessary to compensate for the clearly inadequate revenue requirements recommendations of Staff and RUCO. One adjustment consists of the incremental revenue deficiency on a portion of the additional distribution, generation and general plant to be added through December 31, 2006. A second is an attrition adjustment to the cost of equity to recognize the fact that in the absence of such an adjustment, APS will have NO opportunity to earn its cost of capital, irrespective of what the Commission finds that cost of capital to be.

Yet another is based on our Constitution's "fair value" requirement. Similarly, APS witness Don Brandt discusses additional ratemaking techniques that can be used to preserve and improve the Company's financial condition. These are in response to a letter from Chairman Hatch-Miller. One of these, the inclusion of construction work in progress ("CWIP") in rate base is discussed in my Rebuttal Testimony while the other, accelerated capital recovery, is not. Taken together, there is the potential for adding up to 10.8% in additional revenue requirements to the Staff and RUCO recommendations. See Attachment SMW-2RB.

While these results realized under the Staff and RUCO revenue requirement recommendations are clearly disturbing and would represent a step backward from the level of regulatory support heretofore provided by this Commission, it was equally disturbing that neither Staff nor RUCO made any analysis themselves of the likely consequences of their overall revenue requirement recommendation. In its regulations, the Commission requires that APS provide information on the financial results produced by its rate proposals in the immediate future should they be adopted by the Commission. I have to presume that the purpose for this requirement is to determine the actual financial impact of the Company's proposals and that this information is an important factor in determining whether those proposals are "just and reasonable," as required by our state constitution. The lack of any similar analysis by Staff and RUCO is a significant shortcoming that clouds their overall recommendations in this proceeding.

Regulatory lag and the related problem of attrition are as old as regulation itself. However, given the Company's exploding growth and associated capital requirements, and especially combined with the protracted regulatory process in Arizona, they are problems that can no longer be ignored. Regulatory bodies throughout the country have used a variety of means to both address the issues of regulatory lag and attrition and mitigate their impacts. These include including CWIP in the utility's rate base, forward-looking test years, explicit adjustments to either test year plant or to the cost of equity, interim rates, and prompter rate proceedings. Another technique is based on the use of "fair value" rate base to produce rates that are, in practice, "just and reasonable." One of these, interim rates, has already been authorized by the Commission in the form of the interim PSA adjustor. Continuation of this interim rate past its present expiration date would be one easily accomplished means of both dealing with regulatory lag and avoiding a "yo-yo" effect on customer rates.

Regulatory lag and attrition are not just "utility" issues. The deterioration of the Company's financial condition will have direct and adverse impacts on APS customers in both the quality and the cost of their service. And as is discussed in Mr. Brandt's Rebuttal Testimony, these ratemaking techniques can and have been used for years by municipal utilities to smooth the impact of higher costs by getting out in front of them and adjusting rates more often and in smaller increments than has historically been possible for investor-owned utilities such as APS.

APS witness Robinson and APS witness Ewen present Rebuttal Testimony outlining the serious consequences (in terms of escalating fuel cost deferrals) of Staff consultant Aronuk's proposal to set the base fuel rate below the level of what Staff itself believes to reasonably reflect anticipated fuel costs when the new base fuel rate would become effective, i.e., in 2007. This deficiency also partially explains the poor cash financial metrics discussed by Mr. Brandt under one of two possible sets of assumptions concerning Staff's proposals to modify the Power Supply Adjustor ("PSA").

Although, as discussed by Mr. Brandt, Mr. Robinson and Mr. Ewen, concurrent implementation of a prospective annual PSA adjustor could resolve much of the Company's concern relative to 2007 PSA deferrals, we still believe getting the base fuel rate right to begin with is important for several reasons. Setting the base fuel rate too low in the Company's last rate case led to spiraling fuel cost deferrals that eventually necessitated a series of PSA surcharge requests and an emergency rate application. I am sure the Commission has no desire to repeat this pattern in the present base rate proceeding and note that no other party has taken exception to the Company's calculation of base fuel costs, although AECC witness Kevin Higgins did modify that calculation for one and only one impact – the decline in fuel prices since November 30, 2005. Second, until we have some clarification from Staff concerning its specific PSA proposal, there remains the possibility that APS would have to absorb 10% of the difference between the Staff and APS base fuel cost numbers. Because 2007 fuel costs are essentially already fixed, this would be nothing less than an automatic disallowance of otherwise prudent fuel costs.

The Company's revised additional revenue requirement is $451.3 million per year. Thus, APS is reducing its overall base rate increase request by roughly $7 million, although as discussed in the Rebuttal Testimony of APS witnesses Fox and DeLizio, the requested Environmental Improvement Charge ("EIC") has been increased by a little over $200,000. APS has also accepted Staff's proposal to institute an Environmental Portfolio Standard surcharge of $4.25 million. The net impact is to reduce the overall asking from 21.3% to 21.2%. The percentage of the overall request related solely to higher fuel costs has risen from 14% in our original filing to 15.6% in Attachment SMW-1RB.

In arriving at its revised annual revenue requirement, APS has accepted, in whole or in part, a number of Staff's and RUCO's proposed adjustments to the Test Period. In addition, APS has corrected or, in the case of fuel and purchased power expense, updated its previous pro forma adjustments to be more representative of the period new rates will become effective, which now appears to be sometime in the first quarter of 2007. The Company's revised revenue requirement is summarized on Attachment SMW-1RB to my Rebuttal Testimony.

Staff consultant Jacobs has suggested an operating performance plan covering Palo Verde. Other expert APS witnesses discuss this issue in more detail. I would only state that Dr. Jacobs' proposal does not address all the important and relevant issues in sufficient detail to support adoption of such a performance plan. Moreover, any consideration of a generating unit performance plan, at a minimum, should: (1) heed the NRC's warning not to create perverse incentives that could compromise safety; (2) be symmetrical in that it provides the opportunity for both penalties and reward; (3) be comprehensive in that it would cover all base load generation; (4) allow for a range of reasonable operating performance that provides neither rewards or penalties; (5) recognize extraordinary events and the unique characteristics of APS generation; and (6) cap both penalties and rewards at a reasonable amount.

APS has an employee incentive program that grants both cash and stock incentives as part of overall employee compensation. And as is indicated in the testimony of Mark Gordon, APS incentive compensation is in line with that of other electric utilities and is an important tool in retaining and motivating employees. RUCO's proposal to eliminate 20% of that compensation is arbitrary and based on no analysis of either the program itself or overall APS employee compensation levels, including stock and cash incentives. Staff consultant Dittmer, on the other hand, concluded that the cash incentive payments were reasonable but disallowed all stock incentives on the faulty premise that the goal of improving the Company's financial performance was somehow contrary to the interests of customers or at least did not benefit customers. Like RUCO, Mr. Dittmer did not find that overall APS employee compensation or even the compensation of employees receiving stock incentives was unreasonable. I must again note that in an effort to reduce the potential issues in this proceeding, APS had already eliminated ALL officer incentive payments from its test period cost of service.

APS also has departments that represent the interests of the Company and its customers at both the state and federal level both with legislative bodies and administrative agencies. Often APS representatives appear at the request of these governmental bodies to provide expert testimony and other information on pending matters. The cost to run these departments is allocated by APS between "below-the-line" activities that do not directly benefit APS' regulated utility operations and "above-the-line" activities that are intended to and do benefit APS customers. The resulting cost savings and other benefits are and should be reflected in rates, but then so should be the cost of activities that help to produce these very savings. Staff consultant Dittmer's blanket dismissal of these costs as somehow per se unreasonable fails to acknowledge the contribution of these two departments to reducing costs to our customers.

In response to testimony from Staff and certain intervenors, as well as various Commissioner letters in this Docket, APS has also submitted: (1) revisions to its "Green Pricing" proposal; (2) a new optional "Total Solar" rate schedule; (3) new and revised partial requirements rates; and (3) discussions of topics ranging from the EPS to hook-up fees. Although some of these issues are specifically discussed in my own Rebuttal Testimony, as the lead Company witness in this proceeding, I believed it appropriate to mention these important aspects of our overall case before the Commission.

III. REJOINDER.

Staff and RUCO have failed to demonstrate the reasonableness of their overall revenue requirement recommendations during the period the rates established in this case will be effective. Neither have they presented their own studies to challenge the Company's financial analysis showing that the Staff and RUCO recommendations will plunge the Company into the "junk" credit category. Mr. Dittmer's explanation for this failure does nothing to change the evidence in this case or improve the Company's obviously deteriorating financial condition.

In addition, I believe the Commission should reject Mr. Dittmer's criticism of the Company's proposed revenue requirement adjustments. Mr. Dittmer concedes they will improve the Company's earnings and cash flow performance, but nevertheless rejects them for reasons far less compelling than the Company's clear need for adequate rate relief.

RUCO witness Diaz Cortez attempts to demonstrate that RUCO's recommendation will produce the return its witness has proposed. Her analysis is essentially a tautology. If APS expenses were what RUCO suggests they were during the 2004-2005 test period, and if APS received the revenues also suggested by RUCO, APS would have earned its return for the historical test period. Aside from the faulty premises to this thesis, it is simply irrelevant whether or not APS would have earned a specified return in the past. Rates are set for the future, and it is that theme that permeated my Rebuttal Testimony.

RUCO witness Rigsby continues to support an across-the-board 20% cut in incentive pay. He does not present any analysis of the reasonableness of APS employee compensation nor provide any new justification for this arbitrary adjustment.

SUMMARY OF TESTIMONY GIVEN BY
DONALD E. BRANDT

I. DIRECT. (As Amended by January 31, 2006 Filing)

Since the late 1990s, we have been in the midst of one of the most turbulent business cycles in utility and energy industry history. The financial markets have reacted by becoming increasingly cautious and demanding in their evaluation of the financial condition of utilities. In reaction to the piecemeal re-imposition of regulation across the country, the financial community has demonstrated heightened sensitivity to the financial stability of electric utilities and the impact of regulatory decisions on them.

APS' has requested a rate increase in order to maintain financial ratios consistent with an investment grade credit rating needed to fund at a reasonable cost the significant infrastructure required to meet the needs of its rapidly growing customer base. This request will not allow the Company to improve its credit ratings to the more desirable "A" level, but, if timely implemented, it should prevent further deterioration of APS' credit ratings.

In addition to the requested rate increase, the credit rating agencies seriously weigh APS' regulatory environment in their assignment of ratings. Positive regulatory consideration of the rate case, including the manner of treatment and timing of the PSA adjustor and surcharges, will provide the rating agencies an indication of the level of regulatory support for APS' credit ratings. When they assess the level of regulatory support as low, the rating agencies characterize the overall business risk of that company as being higher. S&P's recent negative revision of APS' business profile from '5' to '6' means we must now meet more stringent financial metrics to maintain "BBB" credit rating. As a result of this revision, APS' projected financial metrics rank below those needed for a typical "BBB" rating. This negative revision of APS' business profile and the consequent downgrade of its credit ratings to "BBB-" have already increased the Company's borrowing costs by approximately $1 million per year.

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. (The ranges of additional interest expense reflect estimated financing costs calculated using the upper and lower limits of the difference between historical interest rates for "BBB" rated and non-investment grade utility debt financings.)

Wall Street supplies the capital that will allow APS to grow to meet the energy needs of its customers. Non-investment grade credit ratings and a poor view of APS by Wall Street would eliminate the Company's ability to attract capital at a reasonable cost.

The Company also proposes to adjust its capital structure, as shown on Attachment DEB-3, to 46% debt/54% equity to buttress its financial metrics and prevent further degradation of its current credit ratings. Although APS' balance sheet would reflect this nominally stronger structure, the rating agencies routinely include items such as off-balance sheet financings, operating leases and debt imputed for purchased power agreements ("PPAs") in their analysis. Using these more rigorous criteria, our capital structure becomes more leveraged and hence more risky 50% debt/50% equity.

II. REBUTTAL.

Should the Commission accept either Staff's or RUCO's recommendations, I believe the Company's credit ratings will be downgraded to non-investment grade "junk" levels. Over the next ten years, APS will require access to the capital markets to issue several billion dollars of debt to fund its massive infrastructure additions and improvements. A downgrade of APS' credit ratings to "junk" status will severely limit this crucial access to the capital markets and will add over $1 billion of additional interest expense - a cost increase that customers would eventually shoulder.

In Section II of my Rebuttal testimony, I prepared a chart entitled "Arizona Public Service Company Risk of Credit Rating Downgrade to Junk" that illustrated my expert assessment of the various recommendations currently before the Commission and their probable effect on APS' credit ratings. This chart was prepared utilizing my experience as a financial expert, as an executive with more than 22-years experience in the utility industry, as a chief financial officer of several major utilities over a period of more than 18-years, and as a senior financial executive who has dealt continuously with the major credit rating agencies since 1983. The Commission should take several measures to help APS improve its credit quality, which I provide in response to the recent request by Chairman Hatch-Miller. Because we have responsibility for providing high quality electric service to one of the country's fastest growing economies, we regard the timely recovery of costs and the challenge of regulatory lag as being of the utmost importance. Moreover, APS must have the ability to earn an adequate ROE to meet the significant financial tasks we will confront. I have offered several innovative ideas that the Commission should consider at this time. Given the enormous infrastructure financing needs that lie ahead, APS must have ready access, on reasonable terms, to both the debt and equity capital markets. The Commission should establish an appropriate capital structure and ROE for APS that helps to attract and retain fixed income and equity investors. Unfortunately, the ROE proposals of both Staff and RUCO witnesses fail these critical requirements as does the capital structure suggested by RUCO. These recommendations would further exacerbate APS' already strained financial condition. I describe the recent significant underperformance of Pinnacle West's common stock that has resulted in enormous costs to shareholders and a resultant impact on APS customers. Staff witness Antonuk and RUCO witness Hornby have provided testimony on the APS hedging program. In general, I concur with most of the observations made by Mr. Antonuk about APS' conservative hedging program, but I disagree with many of the characterizations and conclusions reached by Mr. Hornby. The Staff, RUCO and AECC have all recommended the denial of the Company's request to accelerate the recovery of its underfunded pension liability. APS firmly believes this issue, which currently confronts companies nationally, warrants resolution at this time rather than postponing the day of financial reckoning. I also disagree with RUCO witness Diaz-Cortez's pro forma adjustment to remove all SERP costs from the test period. SERP forms an integral part of the total compensation package to enable management employees to receive equitable pension benefits.

III. REJOINDER.

As a broadly experienced financial expert, with in excess of 20-years of specific expertise in the area of corporate credit ratings, I continue to believe that the major credit rating agencies will downgrade the Company's debt ratings to non-investment grade "junk" levels should the Commission accept either Staff's or RUCO's recommendations. Staff and RUCO have failed to demonstrate that their recommendations will provide APS any opportunity whatsoever to earn its allowed ROE or maintain investment grade credit metrics during the effective period of the rates established in this case.

In the face of the serious challenges confronting the Company, I continue to support my proposals regarding CWIP in rate base, accelerated depreciation, and an attrition adjustment. Each of these would improve APS' creditworthiness and the attrition adjustment would provide the Company a reasonable opportunity to earn its allowed ROE. Staff and RUCO have offered neither constructive criticism of these proposals nor suitable counterproposals. Rather, they have cavalierly rejected the notion that a problem might even exist.

RUCO witness Hill ignores the clear implications of his proposed 50/50 capital structure and 9.25% ROE recommendation: the rating agencies will downgrade the Company to a non-investment grade level. No amount of wishful thinking will alter the hard reality of financial analysis that yields numbers and percentages falling into the non-investment grade ranges.

RUCO witness Diaz Cortez has failed to provide any evidence whatsoever to support her pro forma adjustment to remove all SERP costs from the test period. She bases her entire argument on inaccurate descriptions and mischaracterizations of SERP costs. An integral component of APS' total compensation package for senior managers, the SERP constitutes a necessary, prudent business expenditure. As such, we strongly recommend its continued allowance in cost of service.
Staff witness Dittmer offers a combination of speculation and several incorrect and baseless arguments to deny the Company's request to accelerate the recovery of its underfunded pension liability. APS firmly believes that addressing the issue at this time serves the best interests of our customers, our employees, and our Company.

A recurring theme repeats throughout the surrebuttal testimony of Staff and RUCO. For example, Staff witness Dittmer cites his concerns about "intergenerational inequity" (p. 33) with respect to APS' proposed pension funding proposal. RUCO witness Diaz Cortez (1) expresses her concern about "biased rates" (pp. 30 and 32) resulting from APS' proposed adjustments for post-test year plant in service and attrition, (2) decries that "there is no symmetry" in the APS proposal to accelerate depreciation expense, and (3) states "Utility regulation has routinely excluded CWIP from rate base" (p. 33, emphasis added) in response to APS' proposal to include CWIP in rate base. RUCO witness Hill states, "...that is precisely why utilities have the right to seek re-balancing of those relationships in future rate cases and, over time, an appropriate balance can be restored" (p. 5) in response to APS testimony that demonstrates under RUCO's proposal APS has virtually no opportunity to earn even RUCO's proposed 9.25% ROE.

This testimony by Staff and RUCO witnesses ignores the fact that, as I explained, I structured my testimony in large part to respond appropriately and constructively to Chairman Hatch-Miller's July 21, 2006 letter (Attachment DEB-11RB). In that letter, the Chairman specifically referred to APS' enormous capital expenditure budget and the related financing costs that will ultimately be borne by APS' customers, and requested that APS provide testimony on measures the Commission could adopt to improve APS creditworthiness so as to lessen cost to customers.

Several potential avenues for improving APS' financial situation became readily apparent. In particular, I suggested proposals to include CWIP in rate base and to adopt accelerated depreciation. Additionally, APS' witnesses Avera, Wheeler and I proposed an attrition adjustment that would provide APS a reasonable opportunity to earn its allowed ROE, and thus to make progress toward the goal of preserving access to the equity capital markets and to maintain an investment grade credit rating.

On the other hand, in spite of the Chairman's call for forward thinking and innovative solutions to cure the structural impediments APS faces as it wrestles with providing high quality service to the second fastest growing service territory in the US and providing a reasonable return to its shareholders, Staff and RUCO witnesses have not responded on the merits to these proposed solutions, but rather have suggested that "if one ignores the problem long enough, it just might go away". APS does not believe that this collective refusal to assess fairly our wide array of potential solutions responds appropriately to the Chairman's request.

I believe both the Commission and APS understand that our current economic and demographic environment does not call for "business as usual". As previously discussed at length, we have a rapidly growing service population and a dynamic and productive economy, both of which have large energy requirements. As a consequence, APS faces a massive, multi-billion dollar capital expenditure program to serve these needs stretching for more than a decade into the future. Effectively addressing the difficult tasks at hand will require creative thinking and innovative regulatory policies.

Chairman Hatch-Miller, I believe, called for just such innovative and collaborative thinking to solve economically and efficiently the enormous challenges facing APS and our State in the coming years. Unfortunately, I believe, Staff and RUCO witnesses appear to have reflexively rejected any such forward-looking and constructive solutions to a problem that portends adverse financial consequences for the Company, its customers, and the State of Arizona generally, if we continue to practice regulation as usual.

Summary of Testimony Given By

Peter Ewen

I. Direct Testimony

My testimony sets forth the Company's requested base rate level of fuel and purchased power expenses of 3.1904 ¢/kWh, which reflects conditions expected to exist at, or prior to, the time the requested rates are likely to be in effect. The Company's current base rates include a base fuel rate of 2.0743 ¢/kWh. I discussed the reasons for this increase, in particular the increases in wholesale market prices and price volatility for natural gas and power, and described the impact of the Company's hedging program on the Company's fuel expenses, which is a net benefit to customers of $169 million. Absent that benefit, the requested rate level would be 8 percentage points higher (approximately 29%). The discussion on price volatility provides support for APS witness Mr. Donald Robinson's testimony demonstrating the necessity of retaining the power supply adjustment ("PSA") mechanism authorized in Decision No. 67744.

I also discuss the overhaul maintenance and revenue components of the Pinnacle West Energy Corporation ("PWEC") (Redhawk Units CC1 and CC2, West Phoenix Units CC4 and CC5, and Saguaro Unit CT3) and Sundance units operating income pro forma, and the operating revenue portion of the Demand Side Management ("DSM") pro forma.

II. Rebuttal Testimony

In my rebuttal testimony, I address three key issues. Specifically, I:

1. Update the Company's base fuel, purchased power, and off-system sales pro forma to reflect the evolution of time and prices, which results in an additional $32 million that the Company is seeking in this rate application bringing the Company's total fuel-related request to $331 million. I discuss why I do not agree with the base fuel adjustment proposals by Staff and AECC. I show why the Company's updated base fuel rate is a more correct and appropriate level than either of these proposals because it more accurately portrays the on-going level of costs facing the Company.

I also discuss why I do not agree with Staff and RUCO's proposed DSM lost revenue adjustments, as well as their respective treatment of overhaul costs at the Company's Sundance, Redhawk, and West Phoenix power plants.

2. Provide the procedural details and missing elements associated with Staff's proposed changes to the operation of the Power Supply Adjustor ("PSA"), in the event those recommendations are adopted by the Commission. Staff was largely silent on several key aspects of how their proposed PSA would be implemented, so I describe some of the important steps that would have to be in place for such a

proposal to work effectively. In any case, if the Commission were to adopt Staff's approach to the PSA and Staff's proposed base fuel rate, it is imperative that the Commission also establish the 2007 adjustor rate in this proceeding at the level I propose, and implement it concurrently with Staff's proposed base fuel rate.

3. Demonstrate that the financial disallowance recommended by Staff witness Jacobs overstates the actual costs of the PV outages charged to the PSA by $8.6 million, and does not reflect the impact of the superior performance at the Company's other low-cost baseload generating units.

In addition, I address recommendations contained in Staff's Fuel Audit Report, specifically those regarding 1) written PSA policies and procedures, and 2) ways to incorporate 90/10 load forecasts in the future.

III. Rejoinder Testimony

I have recomputed the base fuel expense for 2007 using closing forward prices for natural gas and purchased power from September 29, 2006 for calendar 2007 delivery. Those prices yield a base fuel cost of 3.2491¢/kWh and a revenue requirement over the Company's current rates of $314.4 million. This revenue requirement is lower than the one filed in my Rebuttal Testimony by $16.6 million, but is some $120.8 million greater than the level recommended by Staff witness Antonuk. It is imperative that the Commission set the Company's rates at a level that is sufficient to recover these expenses. In the alternative, if the Commission chooses to adopt both the Staff-recommended base fuel rate and Staff's recommended modifications to the Power Supply Adjustment ("PSA") mechanism, then it is imperative that the prospective adjustor for 2007 be set at 0.4516¢/kWh in order to limit the amount of under-recovery of fuel expenses that may occur in 2007. This under-recovery is likely even if the 3.2491¢/kWh level is adopted by the Commission for the simple reason that new rates are not likely to take effect until several months into the year 2007, and the Company needs the revenue collected in the spring and fall months of each year to even out the shortfall that inevitably occurs in the summer months of each year. Without the chance of starting the year 2007 at the correct level, it is most likely that the recovery of fuel expenses, through either base rates or a combination of base rates and a prospectively-set adjustor, will fall short of the Company's actual 2007 fuel expenses.

In response to Staff witness Anderson's assertions related to DSM-related reduced revenue, I have re-estimated the amount of net lost revenues associated with the Company's DSM program achievements to be $6.9 million. In an attempt to deal with Staff's assertion that revenue reductions attributable to DSM measures are not known and measurable, this revised estimate takes into account only the energy reductions associated with the amounts already spent and planned to be spent in the remainder of this year, as addressed by Ms. Teresa Orlick in her Rejoinder Testimony regarding the DSM spending plan. The Settlement Agreement that led to Decision No. 67744 provides for the recovery of DSM-associated net lost revenues in the Company's rate cases, and the Company is merely seeking to be kept whole for the energy reductions that have already been or are about to be achieved.

Finally, I provide a more quantitative illustration of the problem posed by Staff witness Dittmer's recommendation to disallow the Sundance O&M overhaul expense pro forma adjustment. Mr. Dittmer's recommendation precludes the Company from recovering its full overhaul costs until several years in the future, if at all. Under Staff's approach, customers in the future will be required to pay for overhaul expenses that are being incurred based on the usage of Sundance today.

SUMMARY OF TESTIMONY GIVEN BY DONALD G. ROBINSON

I. DIRECT. (As Amended by January 31, 2006 Filing)

The Company's last rate case request culminated in a settlement agreement ("2004 Settlement") that was adopted with modifications by the Commission in Decision No. 67744. In that Decision, the Commission authorized a PSA mechanism for APS, and established the amount to be recovered through base rates ("Base Fuel Recovery Amount") at $.020743 per kWh, which as based on 2003 costs. The PSA permitted the Company to defer for later recovery or refund, 90% of the fuel and purchased power costs that were in excess of or below the Base Fuel Recovery Amount. The other 10% was to be expensed (and paid for by APS shareholders, despite the fact that they were presumptively prudent costs incurred solely to provide service to APS customers) or retained as Other Income, depending on whether the costs were above or below the Base Fuel Recovery Amount plus the PSA factor.

APS has deferred nearly $170 million in higher fuel and purchased power costs since April 7, 2005 (the effective date of the PSA, pursuant to Decision No. 67744) through December 31, 2005, as well as interest on such under-recoveries. The remaining amounts of these higher costs, approximately $19 million, were expensed against income as a result of the 90/10 sharing, which therefore reduced the Company's earnings.

It was the Company's understanding pursuant to Decision No. 67744, that adjustments to PSA charges were made at least annually. Under that Decision, the annual change to the PSA Factor was to be made on April 1 of each year beginning in 2006, based on filing, which had to be filed by March 1st, but could be filed earlier. (The timing of the PSA Factor was later changed to February 1 of each year, as I discuss later in my testimony.) That filing would compare fuel and purchased power costs per kWh for the preceding calendar year (in this fist instance, April through December 2005), as indicated by the PSA bank balance, after application of the 90/10 sharing provision with the Base Fuel Recovery Amount.

Pursuant to Decision No. 67744, APS was also authorized to request a special PSA surcharge. That Decision required that APS file a report with the Commission to either request a PSA surcharge or to explain why such a surcharge was unnecessary when fuel and purchased power cost deferrals reached $50 million. Decision No. 67744 also required the Company to seek such a surcharge before the bank balance of cost deferrals reached $100 million. Upon the date APS requested the PSA surcharge, the level of deferrals used to determine the timing of any subsequent surcharge application would be reduced by the amount requested.

Pursuant to this provision of Decision No. 67744, the Company requested a PSA surcharge on July 22, 2005 ("July Surcharge Request"). On January 13, 2006, APS also notified the Commission that the PSA bank balance had again reached $50 million (in addition to the $80 million subject to the July Surcharge Request), but the Company did not request an additional PSA surcharge at that time.

The July Surcharge Request came before the Commission at the January 24th/25th, 2006 Open Meeting. During that Open Meeting, the Commission convened an A.R.S. § 40-252 evidentiary hearing to create an adequate record to advance the PSA adjustor date from April 1 to February 1. In Open Meeting on January 25, 2006, the Commission denied the Surcharge Request and modified some of the PSA provisions that were adopted in Decision No. 67744.

Rate adjustment mechanisms for fuel and purchased power costs have been and continue to be a routine regulatory practice in this country. As of the date this testimony was filed, some 40 jurisdictions having regulated electric utilities have adopted some manner of PSA mechanism and others have otherwise addressed the need to provide timely recovery of costs.

By the end of 2005, APS has under-recovered its fuel and purchased power costs by approximately $187 million (before the 90/10 sharing mechanism). The Company's 2005 earned return on equity ("ROE") of 6.8% was already below the 10.25% cost of equity ("COE") established in Decision 67744 (and far below the COE of 11.5% recommended by Dr. William Avera in this filing).

For 2006, the financial implications would be worse absent the PSA. Unrecovered fuel and purchased power costs would accumulate to approximately $460 million. As noted in APS witness Donald Brandt's direct testimony, even with the present PSA, the Company's financial results do not have the strength necessary to address current and future capital needs. This will directly impact both future costs of providing the service and, sooner or later, the adequacy of that service. The delays that have occurred in the recovery of fuel and purchased power costs through the PSA surcharge mechanism have already caused APS to be downgraded by Standard & Poors ("S&P") to BBB- status (which is one grade above "junk" status) in December 2005. S&P indicated at that time that further rating downgrades may result if there is not more prompt recovery of fuel costs. As discussed in Mr. Brandt's testimony, a downgrade to junk status would have significant and severe impacts upon the Company's ability to provide reliable electric service at reasonable rates to its customers.

The PSA does more than protect the Company's financial integrity, although that is certainly an important function that directly impacts both APS and its customers. The PSA also provides customers with relevant pricing information between general rate proceedings that can positively influence energy usage and their willingness to invest in energy efficiency. The PSA charges on a customer's bill appropriately reflect the changes in the market in a more timely manner, so customers can react to changes in the cost of this commodity by modifying their energy usage. Encouraging conservation and energy efficiency by more accurate pricing signals was one of the Commission's primary goals expressed in decision No. 67744.

The PSA has other significant restrictions and limitations that were neither part of the comprehensive 2004 Settlement that was reached by APS with Staff and the twenty-three other parties in August 2004, nor are they components of adjustment mechanisms for other Arizona utilities. These include:

1. A cap on total annual fuel and purchased power costs includable in PSA calculations of $776.2 million ("Total Fuel Cost Cap");
2. A limit on the annual PSA Factor adjustment to a maximum of $.004 per kWh over the duration of the PSA mechanism; and
3. A requirement that APS file a PSA surcharge request before the deferred costs reach $100 million.

These restrictions and limitations were added to the 2004 Settlement in the Administrative Law Judge's ("ALJ") Recommended Order or during the Commission's Open Meeting deliberations that resulted in Decision No. 67744. All have the practical effect of requiring APS to file this rate case and perhaps future rate cases sooner and more often than might otherwise be the case.

Total Fuel Costs Cap is especially troublesome because APS projects it will reach the $776.2 million Total Fuel Cost Cap during the fourth quarter of 2006. In its January 25 Open Meeting Decision, the Commission addressed the issue of the Total Fuel Cost Cap and stated that APS was permitted to continue to defer fuel and purchased power costs that were above the $776.2 million cap adopted in Decision No. 67744, and that it was never the Commission's intent that this "cap" create automatic disallowances of costs. If the Commission had not clarified that these costs could be deferred, APS would have been faced with significant potential disallowances of legitimate fuel and purchased power costs. However, it is still unclear how costs above the "cap" will be recovered, unless the "cap" is permanently removed.

In the last APS rate case, the Total Fuel Cost Cap was at least partially premised on the theory that the additional recovery of fixed costs through sales growth would offset the known under-recovery of variable fuel and purchased power costs. This hypothesis was unproven by its proponents during the last rate proceeding and in fact was refuted by the only evidence of record in that proceeding. Again in this rate filing, APS has shown that this "growth pays for itself" theory is erroneous. This is demonstrated by Mr. Brandt's analyses of the 2005-2006 financial results, which included the PSA, and indicated the Company is experiencing a significant and rising level of under-earning. It is for these reasons that APS urges the Commission to permanently eliminate the Total Fuel Cost Cap. In the alternative, the Commission should increase the Total Fuel Cost Cap to at least $1.5 billion. This level should provide enough headroom for fuel and purchased power costs into the next decade, or roughly five years after the rates in this case have taken effect.

Second, the four mill cumulative cap on the PSA Factor should be made an annual cap, as was intended in the 2004 Settlement. With the volatility in the fuel and purchased power markets and with the January 25 Open Meeting Decision, which determined that a surcharge would only be implemented using the balance remaining after the annual PSA Factor adjustment was determined, the four mill cumulative cap is far too restrictive and does nothing but necessitate repeated PSA surcharge applications that otherwise might be addressed over time by additional PSA Factor adjustments.

A third reform to the PSA would be the elimination of the $100 million deferral "trigger" for mandatory PSA surcharge applications, because with the determination in the January 25 Open Meeting Decision that the surcharge can only be calculated once a year, the $100 million "limit" has been effectively mooted and should be eliminated.

APS also is requesting to modify the 90/10 cost sharing mechanism in the present PSA in the following respects. Renewable resources that are purchased and not covered by the Commission's Environmental Portfolio Standard ("EPS") surcharge are included in the PSA's calculation of fuel and purchased power costs. Because acquiring additional renewable resources is both required by Decision No. 67744 and is consistent with Commission policy, APS should not have to suffer an automatic 10% disallowance of such costs, as would happen under the current 90/10 cost sharing mechanism. Similarly, APS is proposing to exclude the demand costs of purchased power agreements ("PPAs") acquired through competitive processes from this cost sharing. Because the demand costs are fixed and market-based, APS has no ability to further reduce or avoid them, and thus the 90/100 "sharing" becomes simply an arbitrary disallowance of reasonable and prudent costs. The energy portion of the PPAs, i.e., the per MWH charge, would continue to be subject to the 90/10 cost sharing.

Finally, APS proposes to exclude 10% of the realized gains or losses from hedging from the calculation of both base fuel costs and the PSA. The remainder (90%) of gains and losses would continue to be included in such calculations and would be subject to the 90/10 cost sharing mechanism.

II. REBUTTAL.

There is universal agreement among the parties that a PSA should be retained. There is likewise unanimity that the current PSA structure should be modified to make it more flexible and do a better job of timely recovering prudent fuel costs incurred to serve our customers. The extent of the needed modifications to the PSA is really the question that must be resolved by the Commission in this proceeding and is at the heart of the remaining disagreement among the parties relative to the PSA.

As we understand it, Staff would establish a base fuel cost based on "as-incurred" 2006 costs with normalizations for weather and power plant maintenance, but with no annualization adjustments for certain of the known and measurable changes occurring in 2006, let alone any in 2007. By Staff's own admission, this would set the base fuel rate well below the level of costs anticipated during the period the new base fuel rate would become effective. The resulting deferrals would be in the area of $150 million. To mitigate some of this tremendous run-up in 2007 PSA cost deferrals that would otherwise result from this conscious understatement of base fuel costs, a 2007 "prospective" PSA adjustor would be established (concurrently with the new base fuel rate or shortly thereafter) based on forecasted 2007 fuel costs. It is assumed by APS that the as-of-yet unrecovered amount of 2006 fuel costs would flow into the existing Annual PSA Adjustor effective February 1, 2007, which would now become a "retrospective" PSA adjustor to collect the difference between the forecasted fuel costs used to set the prospective PSA adjustor and actual fuel costs for the projected year – in this instance 2008. The following year, the 2008 prospective PSA adjustor would be established in some sort of proceeding in late 2007. The present "90/10" sharing mechanism, the four mill "cap" on what is now the Annual PSA Adjustor (both annual and cumulative), and what is described in my Direct Testimony as the Total Fuel Cost Cap would all seem to be replaced by what Staff's consultant believes to be a more comprehensive regime of regulatory oversight of fuel costs.

The Staff proposal is a dramatic change to both the determination of base fuel costs and the current form of Annual PSA Adjustor. However, if implemented as a package and early in 2007, and with the application of any continued 90/10 sharing as described in my Rebuttal Testimony, the Staff proposal could be effective in reflecting changes in fuel costs on a more-timely basis than is presently the case. Nevertheless, APS still favors its original recommendations, and most specifically a properly updated and adjusted base fuel cost, in this case to the levels testified to in APS witness Ewen's Rebuttal Testimony.

APS believes its original proposals, with the exception of a change to the sharing of hedging gains and losses – a suggested change the Company is withdrawing, appear to have support, albeit to varying degrees, from all the parties filing testimony on the PSA and thus could be more easily implemented without significant changes to the already-approved PSA Plan of Administration. Moreover, if not implemented in a timely and comprehensive fashion, the Staff's proposal would result in a significant increase in PSA cost deferrals similar to what occurred after Decision No. 67744 was implemented (and for the same reason – an inadequate allowance for fuel costs in the base fuel rate) and the near automatic disallowance of prudently-incurred fuel costs during 2007. David Rumolo has attached a modified PSA Plan of Administration to his Rebuttal Testimony that would implement the Company's proposed changes to the PSA as discussed above with the exception of our originally suggested change in the allocation of hedging gains and losses.

Nevertheless, in the event the Commission accepts the Staff PSA proposal, APS has also submitted a Plan of Administration with the Rebuttal Testimony of David Rumolo that we believe would implement the Staff's recommendation. APS made, necessarily, a number of assumptions as to the details attendant to the Staff PSA proposal, which admittedly was more of a concept in Mr. Antonuk's testimony than a specific point by point proposal for modifying the present PSA structure. APS witness Ewen provides the calculation of the new Base Fuel Rate and the 2007 PSA Adjustor using our understanding of Staff's proposal with certain adjustments described in Mr. Ewen's Rebuttal Testimony.

III. REJOINDER.

My rejoinder testimony makes clear that the Company's PSA proposal, as modified in my Rebuttal Testimony, should be adopted and is supported in several of its key provisions by the parties filing testimony on the PSA. I also discuss certain structures that must be present if the Commission decides to adopt the Staff proposal. Finally, I re-emphasize the need to set the base fuel rate at a level that will allow the Company to recover its 2007 fuel and purchased power costs on a timely basis.

SUMMARY OF TESTIMONY GIVEN BY STEVEN M. FETTER

I. DIRECT. (As Amended by January 31, 2006 Filing)

I offer my opinion as to what comprises fair and economically prudent regulation within today's electric utility industry. Additionally, I provide a brief discussion of the mechanics of the utility rate-setting process, which includes the steps necessary to ensure a regulated utility's financial viability and ability to provide service on a going-forward basis. I further note my belief that the recent instability in the financial markets has created challenges to an extent that has never existed in the past. As a result, I believe that utilities operating within today's more stressful environment, and their 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. Of course, a utility's ability to maintain its financial strength also helps customers, by allowing the company's cost of capital to remain at reasonable levels. In that vein, I highlight recent statements from S&P as to what its analysts look for to conclude that a constructive regulatory environment exists within a particular jurisdiction: "...consistency and predictability, as well as efficiency and timeliness," and limits on "uncertainty in the recovery of a utility's investment [and] rate-case lag that may prove detrimental if a utility needs rate relief."

For a utility like APS, whose customer growth means that it has to rely upon a substantial amount of purchased power and Company-owned natural gas generation, a power supply adjustor ("PSA") to reflect actual costs is a key factor in the eyes of the financial community. While Wall Street viewed the introduction of a PSA for APS last year as a positive event, the way in which the PSA has operated has not been consistent with the theoretical underpinning of other PSA-like mechanisms that are being utilized across the U.S. nor, for that matter, as the PSA in Arizona was intended to operate when it was negotiated by the parties to APS' last rate case. On this point, I discuss the workings of the existing PSA that has resulted in large unrecovered power supply cost balances for APS, and how delays in dealing with these deferred amounts and uncertainty with regard to ultimate recovery has led S&P to downgrade APS' corporate credit rating to the lowest investment-grade level. In response to these circumstances, prompt, supportive regulatory action that encourages fair cost recovery will help to ensure the financial integrity of utilities, will benefit customers, and will help to attract new business.

II. REBUTTAL.

In my Rebuttal Testimony, I conclude that, if the Arizona Corporation Commission ("Commission") were to accept the positions put forward by either Commission Staff or the Residential Utility Consumer Office in this proceeding, the financial condition of APS would suffer significant deterioration, leading in all likelihood to a credit rating downgrade to below investment-grade level. Such negative rating actions would have a deleterious effect on APS customers, as access to capital would become more expensive. In addition, I discuss the concept of regulatory lag, which undercuts the ability of a regulatory body to be timely in its decision-making. I explain how such delay in implementation of regulatory policy determinations can have a negative impact on both regulated utility companies as well as their customers.

SUMMARY OF TESTIMONY GIVEN BY
LAURA ROCKENBERGER

I. DIRECT. (As Amended by January 31, 2006 Filing)

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

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

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

II. REBUTTAL.

Most importantly, my Rebuttal Testimony addresses the critical need of the Company to maintain an appropriate level of cash working capital and refutes both the Staff and Residential Consumer Utility Office ("RUCO") recommended reductions in cash working capital that will further handicap the Company's ability to have cash available to operate and maintain its electric system on a daily basis. The Company opposes Staff recommendations that cash working capital be reduced by $59,600,000 by removing "non-cash items" and including interest expense in the Cash Working Capital calculation. RUCO also recommends that depreciation expense, as a "non-cash item," be excluded from and interest expense be included in the cash working capital calculation. Certain income statement expenses have been casually referred to as "non-cash" items; but, the stark reality is that these items provide cash resources that the Company desperately needs to maintain operations while funding expansive growth in its service territory. The fundamental regulatory concept that we must remain focused on is that the current period depreciation expense, and other non-cash expenses, reduce rate base before the cash is collected from the customers. Because there is a gap in time from the rate base reduction (when the Company stops earning a return on the assets which are "consumed" in operations and allocated to expense) and the cash collection from the customers, it makes sense to bridge that "gap" in time by including those expenses in the cash working capital calculation. APS witness Balluff will provide further elaboration on the technical merits of including these non-cash items and excluding interest expense in the cash working capital calculation. Finally, the Company does not oppose $5,019,000 in cash working capital reductions recommended by Staff which are based on adjustments to the cash working capital calculation.

My Rebuttal Testimony also discusses the rate base and operating income adjustments advocated by Staff, RUCO and Arizonans for Electric Choice and Competition ("AECC"). These adjustments fall into these categories: recommendations we do not oppose; those we can support in part; and, those we completely oppose. These adjustments are summarized below. All the rate case and operating income adjustments summarized are stated as total company numbers. The jurisdictional portion of the adjustments are summarized in Attachments LLR-3-1RB through LLR-3-3RB.

Adjustments to Both Rate Base and Operating Income

A. Palo Verde Unit 1 Steam Generators

The Company does not oppose RUCO's recommendation to record the \$36,684,000 retirement of the old steam generators and low pressure turbines which has no impact on rate base. Accordingly, the Company does not oppose the related \$262,000 adjustment to reduce operating income for depreciation expense related to a portion of the old low pressure turbine equipment retired, but does oppose the recommended \$404,000 adjustment for depreciation on the old steam generators which was included in the Company's calculation.

B. Bark Beetle Remediation

The Company has deferred bark beetle remediation costs in compliance with Decision No. 67744, and opposes both (1) Staff recommendations to remove 2005 expenses from January 1, 2005 through March 31, 2005, and (2) RUCO's recommendation to remove projected costs from the end of the Test Year through December 31, 2006. These recommendations would decrease the allowable deferred bark beetle remediation costs and related annual amortization expense. The Company is not opposed to certain adjustments to include the impacts of deferred income taxes in rate base and correct the original pro forma for the actual costs at September 30, 2005. The Company is also proposing to update the projected costs through December 31, 2006. This will increase the total deferred bark beetle remediation costs by \$333,000 to \$11,622,000. The net pro forma adjustment will reduce rate base by \$1,755,000 and increase amortization expense by \$110,000.

Additional Pro Forma Adjustments to Operating Income

A. PWEC Units and Sundance Units

Mr. Ewen discusses the PWEC Units' and Sundance Units O&M in his Rebuttal Testimony.

The Company is opposed to Mr. Higgins' recommended adjustment to reduce the PWEC Units' A&G by \$11,618,000 based on the concept that A&G recovery should be limited to historical levels. It should be noted, however, that the Company is not opposed to \$5,098,000 in out-of-period adjustments related to PWEC A&G which I address in "J. Other Administrative and General Adjustments".

B. Decommissioning

The Company is opposed to RUCO's recommended $765,000 reduction in operating expenses related to decommissioning. RUCO included the decommissioning costs, but did not take into consideration that funding into the decommissioning trusts also provides for post-shutdown spent nuclear fuel storage costs which was properly recorded as $765,000 in fuel expense and funded into the decommissioning trusts.

C. Spent Nuclear Fuel Storage

The Company is not opposed to Staff's recommendation to reduce operating income by $264,000 for ongoing spent nuclear fuel storage expenses.

D. Depreciation and Amortization

The Company is opposed to RUCO's recommended $6,991,000 reduction in amortization expense, as RUCO provided an historical average rate which understates normalized amortization expense in a period of time when assets balances are increasing significantly and, thus, amortization expense is increasing.

E. Property Taxes

The Company is not opposed to Staff's recommended $1,708,000 reduction in property taxes related to the 2007 phase-in of new generation plant costs. Accordingly, the Company is opposed to RUCO's adjustment to reduce the property taxes by $5,977,000 based on the temporary suspension of the County Education Tax Rate, because RUCO did not take into consideration all known and measurable factors impacting the assessed value which would impact the pro forma adjustment.

F. Payroll

The Company is opposed to both Staff and RUCO recommendations to disallow stock-based incentive compensation and to have an overall 20% reduction in incentive compensation. Mr. Wheeler discusses this further in his Rebuttal Testimony. The Company is also opposed to RUCO's recommendation that Supplemental Excess Benefit Retirement Plan ("SEBRP") expense be disallowed. Mr. Brandt discusses this further in his Rebuttal Testimony.

Staff has proposed an $8,155,000 increase in pension costs and a $2,038,000 increase in post retirement medical costs based on estimated 2006 expenses. The Company agrees that the Test Year expenses should be based on 2006 cost levels and has now received final 2006 actuarial calculations, which increase Test Year pension expense by $2,249,000 and decrease post retirement medical costs by $3,191,000. The Company is proposing adjustments based on these final 2006 actuarial calculations.

G. Underfunded Pension Liability

The Company opposes Staff, RUCO and AECC recommendation to deny the Company's request to accelerate the recovery of its underfunded pension liability over a five-year period beginning in 2007. Mr. Brandt discusses the necessity for the Company to accelerate this funding in his Rebuttal Testimony.

H. Advertising

The Company is not opposed to the $437,000 reduction in advertising costs recommended by Staff, $66,000 of the $566,000 reduction recommended by RUCO, and the $4,625.00 reduction recommended by Mr. Rigsby. The Company is opposed to RUCO's recommendation to remove $400,000 of meals expense from operating expenses as these costs are incurred to provide company lunches for employees that are working during their personal lunch time. The Company is proposing a pro forma adjustment to reduce operating expenses by $508,000.

I. Lobbying

The Company is opposed to adjustments to remove lobbying costs from the Test Year, as Mr. Wheeler discusses in his Rebuttal Testimony.

J. Other Administrative and General Adjustments

The Company is not opposed to Staff and RUCO recommended adjustments to reduce A&G by $8,520,000 for out-of-period costs and legal fees. This amount includes $5,098,000 in PWEC Units out-of-period adjustments.

Liberty Consulting Group Fuel Audit

My Rebuttal Testimony also responds to one recommendation which was addressed by Staff's consultant, Liberty Consulting Group, in its *Final Audit Report: APS Fuel and Purchased Power Procurement and Costs* ("Fuel Audit Report"), which was issued August 31, 2006. This recommendation addresses an accounting practice for allocating refunds on fuel transportation costs to fuel expense and inventory. The Fuel Audit Report noted that the recommended accounting adjustment is only a short-term timing issue regarding the flow of fuel expense through the Power Supply Adjustor ("PSA").

Finally, my Rebuttal Testimony includes the calculation of estimated Plant-in-Service at December 31, 2006, as discussed in Mr. Wheeler's Rebuttal Testimony. The estimated Plant-in-Service is $11,369,665,000. The increase in Plant-in-Service from the Test Year to December 31, 2006 is estimated to be $572,058,000, which has a related revenue requirement of $13,480,000.

III. REJOINDER

My rejoinder focuses specifically on RUCO proposals on decommissioning costs, amortization, and property taxes, and provides support for the Company's position on these costs.

SUMMARY OF TESTIMONY GIVEN BY CHRIS FROGGATT

I. DIRECT. (As Amended by January 31, 2006 Filing)

As the Controller of APS, I am responsible for the accounting and financial reporting by the Company, and my direct testimony presents historical accounting data and pro forma adjustments to support the Company's rate case filing. I sponsor the historical and test year information contained in Standard Filing Requirement Schedules A-2, A-3, C-1, a portion of C-2, C-3, D-1, D-2, D-3, E-1, E-2, E-3, E-4, E-7, E-8, E-9, F-1 and F-2. Specifically, I discuss and sponsor several pro forma adjustments included in Schedule C-2, and present the Company's Total Company Adjusted Test Year Operating Income in Schedule C-1. I also present the Company's consolidated income tax rate in Schedule C-3.

In addition, I discuss and present the actual cost of capital for the test year in Schedule D-1 and D-2, and discuss the Company's outstanding log-term debt that is used in the calculation of the cost of capital.

II. REBUTTAL.

In my rebuttal testimony, I respond to several of the Staff and intervenor proposed adjustments to the test year. In some cases, proposals are for reasonable revisions due to legislative changes, updated information that was not available at the time the Company filed its original request, or corrections for errors identified during the discovery process. Other adjustments that have been proposed are clearly inappropriate or inaccurate, and I discuss why these adjustments should either be revised or not accepted at all.

III. REJOINDER

My rejoinder focuses specifically on an investment tax credit proposal Staff made in surrebuttal testimony. The Company does not agree with Staff's proposed treatment.

TESTIMONY SUMMARY OF
DR. RONALD E. WHITE

Foster Associates was engaged by APS to conduct technical updates of depreciation rates for 2005 for APS and for certain Pinnacle West Energy Corporation generating units (PWEC Units) acquired by APS. Current depreciation rates used by APS and for the PWEC Units were approved by the Commission pursuant to a settlement agreement in Decision No. 67744. A technical update is intended to align depreciation rates with the accounting year the rates will become effective.

In a full depreciation study projection curves, projection lives and future net salvage rates are estimated from a statistical analysis of recorded retirements and net salvage realized in the past. A technical update generally retains the parameters currently used or proposed by the utility and adjusts depreciation rates for known and measurable changes in the age distributions of surviving plant, depreciation reserves, and average net salvage rates due to the passage of time.

Adjustments developed in the technical update for APS produce a composite depreciation rate of 2.95 percent. Depreciation expense is presently accrued at 2.89 percent. The proposed change in the composite depreciation rate represents an increase of 0.06 percentage points.

Annual depreciation expense at the current approved rates would be $221,616,212 compared with an annual expense of $226,858,380 using the rates developed in the update. The proposed expense increase of $5,222,168 is largely attributable to: a) a change in the mix of plant investments among primary accounts; b) changes in the age distributions of surviving plan; and c) plant additions to Four Corners generating station.

The technical update for the PWEC Units produces a composite depreciation rate of 2.67 percent. Depreciation expense is presently accrued at an equivalent rate of 2.87 percent. The proposed change in the composite depreciation rate represents a reduction of 0.20 percentage points.

A continued application of rates currently approved for the PWEC Units would provide annual depreciation expense of $28,789,932 compared with an annual expense of $26,809,242 using the rates developed in the update. The proposed expense decrease of $1,980,690 is largely attributable to: a) a change in the mix of plant investments among primary accounts; b) changes in the age distributions of surviving plant; and c) the estimation of parameters for West Phoenix Unit 5.

Summary of Testimony Given By
Fred H. Balluff

I. Direct. (As Amended by January 31, 2006 Filing)

My testimony presents the lead/lag approach used by APS to determine the cash working capital to be included in rate base. Based on the lead/lag study, APS has a negative cash working capital requirement which reduced the APS test year rate base. Cash working capital is a part of the investment made to provide utility service to customers and thus is a component of rate base. A lead/lag study measures the difference between when services are rendered until cash for services are collected in rates (the revenue lag) and compares it to when operating services are incurred until they are paid (the expense lag).

The objective of the cash working capital study is to determine the amount that is necessary to include in rate base so that investors are adequately compensated for the funds needed to maintain cash operating requirements and to reflect certain offsets to rate base for items that have not actually been recovered by investors at any single point of time due to the lag in receiving the associated revenues.

II. Rebuttal

When depreciation expense and deferred income tax charges are recorded, accumulated depreciation and deferred income tax credits are recorded. These items are reductions from rate base. Yet, the expenses have not been recovered from customers because of the revenue lag. Unless the revenue lag is included with a zero expense lag in the calculation of cash working capital, APS will not earn a return on a significant portion of its unrecovered invested capital.

By including interest expense in Mr. Dittmer's calculation of cash working capital, he has treated it as an operating expense without any justification. If it is appropriate to include the interest component of the return on rate base in the calculation, it would be necessary to include the entire return in the calculation.

III. Rejoinder

Mr. Dittmer believes that depreciation expense should not be included in a lead lag study in part because some expenditures related to recently completed construction projects have not been paid at the end of the test year. This is not relevant to our argument that the revenue lag applicable to depreciation expense should be included in the calculation of CWC.

SUMMARY OF TESTIMONY GIVEN BY STEPHEN J. BISCHOFF

I. DIRECT. (As Amended by January 31, 2006 Filing)

In my direct testimony, I explain how APS has implemented an extensive program to address the threat posed to its transmission and distribution system by the bark beetle infestation. In Decision No. 67744 (April 7, 2005), the Arizona Corporation Commission ("Commission") authorized APS to defer the reasonable and prudent costs of those efforts incurred beginning in 2005, which have exceeded 2002 test year levels. APS seeks to recover such costs as authorized by Decision No. 67744, including the appropriate allocation between distribution and transmission costs.

Although APS has performed an extensive amount of remediation efforts relating to bark beetle infestation, there is still much to do. APS must continue to patrol approximately 2100 miles of distribution and transmission lines that cross the impacted forest area, removing trees that pose a danger to APS' system. Currently, APS estimates that it will spend in excess of $11 million during the two (2) year period from 2005 through 2006 clearing distribution lines, and approximately $1.7 million doing the same for transmission lines. It is important to recognize that APS' plans in 2006 and beyond are subject to modification, based on weather conditions and the beetle infestation rate. APS will continue to monitor these conditions and adjust its plans accordingly. APS witness Laura Rockenberger is sponsoring the pro forma adjustment to the test year for the amortization of this increased cost for 2005-2006.

II. REBUTTAL.

My rebuttal testimony modifies the level of reasonable and prudent bark beetle remediation costs discussed in my Direct Testimony. The adjustment reflects the way such costs are recorded in the General Ledger by FERC account, as well as correcting for costs and credits that were inadvertently excluded in the original submission. These modifications increase the previous level of deferred costs by less than three percent.

I also address concerns raised by Staff regarding reliability issues and APS' corresponding reliability projects.

My rebuttal testimony also describes APS' participation in the ongoing distributive generation workshops, setting forth the position that the workshops are the proper forum for the Commission to address concerns raised by Solar Advocates and DEAA regarding distributed generation interconnection requirements.

SUMMARY OF TESTIMONY GIVEN BY PATRICK DINKEL

I. DIRECT. (As Amended by January 31, 2006 Filing)

APS' long range forecasts in 2002 and 2003 showed that APS would need a significant amount of additional generation resources to meet its continued load growth. The Company's ultimate decision to purchase the Sundance Assets was based on a fair and appropriate Request for Proposal ("RFP") process. The acquisition of the Sundance Assets was analyzed with sound economic principles and determined to be a cost effective means of acquiring critical long-term peaking capacity for our customers. We also analyzed the performance of the units and found that they were well suited for our customers' needs. APS had a clearly defined need for the peaking plant based upon its previous resource plans and in fact is already using the Sundance Assets to meet the reliability and energy needs of its customers.

II. REBUTTAL.

My testimony will address the use of renewables as a hedge. APS agrees that renewable energy should be a bigger percentage of APS' generation portfolio and that renewable energy will offset the need for generation from conventional resources. However, to date, APS is paying a premium for renewable energy. Project specific analysis is required to adequately measure the economic value of each renewable project. While renewable energy will offset some of the need for generation from natural gas, this displacement comes at a higher cost than natural gas, based on current prices. In general, there is a cost premium for any "hedge", and careful consideration of the cost is required. So, while renewable generation may be "effective" as a hedge due to its displacement of future gas needs, the critical questions are whether they are a *cost effective* hedge and whether the added costs are acceptable from the perspective of APS customers.

My testimony includes a discussion of APS' pending Wind Integration Cost Study ("Study") and the concerns raised by Interwest Energy Alliance. We believe it is in everyone's best interest that we continue to study the impact of the integration of renewable resources into our portfolio. For this reason, APS is in the final stages of discussion with Northern Arizona University for the coordination of a Study. The Study is being designed to answer the question of what are the system impacts and costs associated with effectively integrating potential wind projects into APS' system. A time frame is currently being evaluated, but APS expects the Study to be complete in approximately 6 to 8 months.

Finally, my testimony addresses the Company's interest in pursuing Demand Response Programs. In short, a thorough assessment is needed to determine which types of Demand Response programs would be likely to produce the most cost effective benefits for the APS system and our customers.

SUMMARY OF TESTIMONY GIVEN BY MARK K. GORDON

I. DIRECT. (As Amended by January 31, 2006 Filing)

None Filed.

II. REBUTTAL.

I focus on the purpose, prevalence, cost, and effectiveness of variable pay incentive programs. I also respond to Arizona Corporation Commission Staff ("Staff") and Intervenor witnesses, who suggest that the Commission should disallow some of these incentive pay programs when calculating APS' recoverable costs. In support of my testimony, I evaluated the nature and effectiveness of APS' incentive compensation program using a variety of objective data. Additionally, I interviewed select APS employees, representing a cross-section of those participating in the incentive program. I discuss the importance of these programs for key constituents (including customers, employees, and shareholders); the programs' ability to encourage employees to achieve key goals; and the need to be market competitive to attract and retain a stable, talented workforce.

I conclude that APS' annual variable incentive plans, long-term incentive plan, and targeted compensation value are either consistent with competitive market practices or below market value. This indicates that APS has conservatively managed cash compensation. The elimination of any of these programs may significantly impair APS' ability to attract and retain employees, leading to higher turnover rates; reductions in productivity; increased recruiting and training costs; damaged morale; and the erosion of the Company's system of high performance, accountability, and performance-based pay. As such, these compensation and benefit programs are a normal and reasonable "cost of doing business," and they should be allowed by the Commission. In addition, the variable incentive plan aligns employees with the Company's business objectives. The design and administration of the variable pay programs, including the goals and objectives, appear to correlate well with performance results that have significantly benefited customers over the past 10 years.

SUMMARY OF TESTIMONY GIVEN BY JOHN R. DENMAN

I. DIRECT. (As Amended by January 31, 2006 Filing)

None Filed.

II. REBUTTAL.

In his testimony, Mr. Antonuk confirms that APS appropriately handles fuel and energy procurement, that the Company effectively operates its fossil generating facilities, and that his recommendations are intended to improve already-appropriate systems and operations. APS considered all of Mr. Antonuk's recommendations and agrees with most of them. In several instances, such as with the process for handling coal weight information for the coal sample analysis, APS either already addressed or was addressing the recommendations at the time of the audit. In other instances, such as the inventory target at the Cholla Power Plant and the coal contract management process, APS agrees with Mr. Antonuk's suggested changes and intends to implement his recommendations. As for his other recommendations, APS believes it already had in place the suggested changes, but perhaps did not adequately explain them during the audit process.

SUMMARY OF TESTIMONY GIVEN BY EDWARD Z. FOX

I. DIRECT. (As Amended by January 31, 2006 Filing)

APS requests that the Commission establish an Environmental Improvement Charge ("EIC"), which would allow the Company to recover Commission-approved costs associated with APS' investment in environmental improvements at its facilities. APS' fossil plants are a vital part of the Company's diverse fuel mix, providing customers with greater price stability and reliability. While these plants meet all current environmental regulations, they still present some unique challenges. APS is mindful of the potential environmental impacts of its fossil operations, and is keenly aware of the need to significantly reduce emissions over the next several years to comply with existing and proposed laws and regulations. In fact, APS estimates that the necessary environmental compliance changes for the Cholla Power Plant alone will cost approximately $135 ($160) million over the next several years. Similar improvements at the Four Corners and Navajo Power Plants are also anticipated. Additionally, APS and the utility industry face significant challenges as a result of climate change and the potential costs associated with addressing this looming problem. The acceleration and scale of environmental compliance costs has reached a point where an adjustment mechanism is necessary to timely recover costs.

Additionally, I present direct testimony regarding Green Power offerings, net metering, and I comment on the Environmental Portfolio Standard ("EPS") rules. The issues related to Green Power have been subsequently adopted by APS witness Barbara Lockwood in her Rebuttal Testimony.

II. REBUTTAL.

In my rebuttal testimony, I respond to Staff and Intervenor assertions that the EIC is unique and violates the traditional ratemaking process. As such, I describe why APS believes that the EIC is appropriate and I describe the benefits for Arizona. To put the benefits in context, I identify the relevant environmental standards that APS will be required to meet and the connection between such standards and the environmental projects proposed. I also discuss why pollution control projects should be pursued sooner rather than later and why traditional ratemaking treatment to recover such expenses is not sufficient. Additionally, I identify the projects currently planned at the Cholla Plant to address conventional pollutants and APS' estimated costs, for which it will seek recovery through the EIC. Finally, I identify the types of costs that should be recoverable through the EIC, including costs associated with addressing greenhouse gas emissions and future improvements at the Four Corners and Navajo Power Plants.

SUMMARY OF TESTIMONY GIVEN BY DAVID J. RUMOLO

I. DIRECT. (As Amended by January 31, 2006 Filing)

First, I discuss the cost-of-service study prepared to functionalize, classify, and allocate test year costs and revenues between wholesale and retail customers, as well as the allocation of costs and revenues between the various classes of retail service. This cost allocation study allows APS to determine the rate of return produced by each class and subclass of customer, along with the unit cost of providing service to each customer grouping. Second, I discuss the rate schedules and rate design changes that will allow APS to recover its cost of service. Finally, I discuss changes to Service Schedule 3 which is the APS line extension policy.

II. REBUTTAL.

In my rebuttal testimony I compare production cost allocation methods proposed by Arizona Corporation Commission Staff ("Staff") and energy allocation methods proposed by Arizonans for Electric Choice and Competition ("AECC") with methods used in the APS rate case filing. Although the alternative methods shift cost responsibility between customer classes, when the alternatives are combined, class revenue responsibilities are not substantially different from those proposed by APS. In fact, the alternative methods can shift cost responsibility within a class. Furthermore, the alternative rate designs proposed by intervenors can result in higher rate increases for lower load factor customers. I also rebut the rate design arguments of Distributed Energy Alliance of Arizona ("DEAA"), noting that DEAA cannot factually support some of its arguments. Additionally, I discuss the concept of hook-up fees, concluding that such fees are an expensive way to finance plant additions. Since this important policy decision should involve other parties who may not be participating in this rate case, but who will be impacted by the policy, I agree with Staff and RUCO that the hook-up fee discussion should occur in the context of generic workshops for all utilities.

III. REJOINDER.

My rejoinder testimony addresses two topics that were discussed in the surrebuttal testimony of Staff Witness Erinn Andreasen. First, Ms. Andreasen notes in her testimony that the winter off-peak charges under Rate Schedule ET-2 are higher than the summer off-peak charges under the APS design proposal. She also comments that generation costs tend to be higher in summer than winter. I agree with her observation to a limited extent. On-peak generation is clearly more expensive for APS in the summer. However, that higher cost has a significant capacity cost element in addition to an energy cost element. In the winter, gas prices tend to be higher than during the summer, and off-peak electricity prices at the Palo Verde hub can be higher in winter than during the summer, due to the gas cost impacts. Therefore, it is appropriate that off-peak prices for winter electricity charged to customers be higher than off-peak summer prices. Next, assuming the Commission approves Schedule 3 as modified, we will include Staff's changes in our tariff compliance filing at the conclusion of the case.

I also discuss the issue of transmission cost allocation that was raised by AECC Witness Kevin Higgins in his surrebuttal testimony. First, the current "across the board" energy-based charge is consistent with the rate designs that were part of the Settlement Agreement that was incorporated in Decision No. 67744. We made no changes to that method in this case, i.e. the transmission element costs were allocated based on energy. Second, transmission costs are incurred by APS for retail sales based on charges found in the Open Access Transmission Tariff ("OATT"). Therefore "allocation" of OATT charges by applying a demand allocator, such as the 4CP allocator, does not reflect an accurate representation of how the costs are incurred to provide transmission service and is therefore inappropriate.

Finally, in his surrebuttal testimony, Staff Witness Jerry Anderson discusses Demand Side Management ("DSM") Performance Incentives and DSM lost revenue adjustments and describes them as duplicative. I disagree with that statement. DSM Performance Incentives are designed to encourage DSM programs. Lost revenue adjustments are designed to recognize that the utility will have fixed costs that must still be recovered over a reduced sales volume. These are very distinct concepts.