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EXHIBITS
FOR
E-01345A-03-0437

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ACPA

DIRECT TESTIMONY OF JOSEPH P. KALT

On Behalf of Arizona Competitive Power Alliance

Docket No. E-01345A-03- ____

February 3, 2004

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I. QUALIFICATIONS

Q: **WHAT IS YOUR NAME AND BY WHOM ARE YOU EMPLOYED?**

A: My name is Joseph P. Kalt. I am the Ford Foundation Professor of International Political Economy at the John F. Kennedy School of Government, Harvard University, Cambridge, MA 02138. The Kennedy School of Government is Harvard's graduate school for public policy and administration. I also work as a senior economist with Lexecon, an FTI Company. Lexecon is an economics consulting firm with offices in Cambridge, Massachusetts, and Chicago, Illinois. My *curriculum vitae* is attached hereto (Exhibit JPK-1) and lists my prior testimony as an expert and my publications.

Q: **PLEASE SUMMARIZE YOUR PROFESSIONAL AND EDUCATIONAL BACKGROUND.**

A: I hold B.A., M.A., and Ph.D. degrees in economics and I am a specialist in the economics of competition, antitrust, and regulation, with particular emphasis on the energy and natural resource sectors. Throughout my professional career, I have conducted research, published, taught, and testified extensively on the economics of market structure, contracting, regulation, pricing, valuation, and strategic performance, with particular emphasis on the energy industries. At Harvard, I served as an Instructor, Assistant Professor, and Associate Professor in the Department of Economics from 1978 to 1986, prior to joining the faculty of the Kennedy School of Government as a professor with tenure in 1986. At the Kennedy School, I have also served as Chair of the Economics and Quantitative Methods Cluster, Faculty Chair and Academic Dean for Research, Chair of Teaching Programs, and Chair of Ph.D. Programs. In the Department of Economics, I had primary responsibility for teaching the graduate and undergraduate courses in the economics of regulation and antitrust. At the Kennedy School, my teaching responsibilities have included the economics of regulation and antitrust; the economics of public policy, natural resource and environmental policy; and economic development on American Indian reservations.

My work as a professor in a graduate school for public policy and public administration entails consideration of the criteria of sound public policy, particularly as applied to questions of the regulation of economic affairs. Working with Lexecon (and its predecessors), I provide expert economic analysis and advice, particularly in regulated industries and to public policymakers concerned with such industries. My work in this matter has been supported by Lexecon and its professional staff. The views expressed are my own.

Q: **PLEASE DESCRIBE YOUR BACKGROUND AS IT RELATES TO THIS PROCEEDING.**

A: In the course of my academic and consulting experience, I have studied extensively the economics of the electric power, oil, natural gas, and coal industries, and the impacts on these industries of changing regulatory and competitive environments. I have provided expert testimony on these issues in various state and federal courts, as well as the United States Congress. Over my career, I have testified numerous times before the Federal Energy Regulatory Commission ("FERC") on matters ranging from electric power merger and transmission policy to natural gas pipeline and marketing policy. I have recently studied and testified at length as an expert on behalf of El Paso Merchant Energy, L.P. in the FERC's Nevada Power Company/Sierra Pacific Power Company, Public Utilities Commission of the State of California/California Electricity Oversight Board and PacifiCorp proceedings regarding the role of forward contracts in the electricity industry and the extent to which dysfunctional spot markets in California may have impacted forward electricity markets.

II. PURPOSE OF TESTIMONY AND SUMMARY OF FINDINGS

Q: **ON WHOSE BEHALF IS YOUR TESTIMONY SUBMITTED?**

A: My testimony is submitted on behalf of the Arizona Competitive Power Alliance ("Alliance").

Q: **WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

A: Along with my Lexecon colleague, Mr. Jeffrey Tranen, I have been asked by the Alliance to analyze the request of Arizona Public Service Company ("APS" or "Company") for authorization from the Arizona Corporation Commission ("Commission") to transfer into APS's rate base at 2004 depreciated original cost approximately 1,700 MW of electricity generation capacity[1] built by its unregulated affiliate, Pinnacle West Energy Company ("PWEC"). As a part of this proposal, APS also seeks to abrogate contracts it recently executed with PWEC to provide summer

[1] The plants are Red Hawk Units 1 & 2 with a capacity of 495 MW each; West Phoenix 4 at 120 MW; West Phoenix 5 at 525 MW; and, Saguaro SC 3 at 80 MW, which totals a little more than 1,700 MW of capacity.

capacity and energy through 2006 ("Track B Contracts").[2] I have been asked to investigate APS's assertions that it is in the public interest for APS to acquire and ratebase PWEC's generation assets ("PWEC assets"), and abrogate the Track B Contracts.

Q: **TO WHICH ASPECTS OF APS'S DIRECT CASE DO THE ALLIANCE'S WITNESSES RESPOND?**

A: Mr. Tranen and I respond to the testimony on the proposed PWEC asset transfer sponsored by Messrs. Wheeler, Robinson, Gordon, Landon, Hieronymus and Bhatti.

Q: **ARE YOU FAMILIAR WITH COMMISSIONER GLEASON'S LETTER TO THE PARTIES IN THIS DOCKET REGARDING ISSUES TO BE ADDRESSED IN TESTIMONY?**

A: Yes. The first two questions ask how the market value of a generation plant should be calculated or otherwise determined. In my testimony and in Mr. Tranen's, we discuss the failure of APS to provide any market valuation of these generation plants or any comparison of such a valuation to the book value price it proposes to use. Effectively, our response to these questions is that the market value of the PWEC assets is critical evidence for the Commission that APS should have provided in the first instance in support of its ratebasing proposal. Moreover, to establish the market value would require a fair and transparent request for a proposal process in which

[2] As I use the term in my testimony, Track B Contracts means APS's purchase contracts with PWEC that resulted from the initial Track B solicitation that took place over the past year. Although, I recognize that there are other smaller contracts that APS entered into as a result of the Track B solicitation, they are not covered by this reference.

PWEC competed directly with other market participants for the opportunity to supply APS.

Commissioner Gleason's third question asks about the merchant generation available to serve APS's customers. Mr. Tranen's testimony addresses the competitive market options available to APS instead of ratebasing the PWEC assets; I address this issue more generally by examining the reasonableness of continued reliance on the market for a portion of APS's supply.

Commissioner Gleason's fourth question asks for citation of relevant precedent from other jurisdictions. My testimony addresses the general concerns of regulators here and elsewhere about transactions between a utility and its affiliate. Because this is primarily a legal issue, however, I understand that the answer to this question will be contained in the Alliance's pre-hearing brief in this case.

Commissioner Gleason's final question regarding the impact of APS's proposal on competitive solicitations and the competitive market is addressed in both my testimony and Mr. Tranen's.

Q: **WHAT JUSTIFICATION HAS APS OFFERED IN SUPPORT OF ITS REQUEST TO ACQUIRE AND RATEBASE THE PWEC ASSETS?**

A: APS's filing relies primarily on its assertion that the PWEC assets were developed and have been managed using an "APS centric" planning framework.[3] In other words, APS apparently wants the Commission to believe that in building these large electricity generation plants using its sole shareholder Pinnacle West Capital Corp.'s ("PWCC") money, PWEC has always intended to provide APS's ratepayers a first call on the generation capability of these plants even at lower than market prices. APS further contends that PWEC has not acted as a profit maximizing firm, but instead has sacrificed significant financial gains when it purportedly chose to not market generation from these power plants at times of elevated market prices as it was holding the assets back for APS consumers.[4] APS's filing goes on to argue that although there are costs associated with ratebasing these power plants, there are likely future benefits that outweigh these costs to APS's ratepayers.[5]

A second theme in APS's filing is that APS should not rely on the competitive wholesale electricity market as it will likely be unable to provide reliable supplies sometime after 2006. Even if sufficient supplies are available in the market, APS contends that these supplies would be more expensive to ratepayers than the PWEC assets.

Finally, APS presents a theoretical discussion focused on purported benefits of additional vertical integration achieved by acquiring these assets. APS does not, however, offer evidence to substantiate this argument.

Q: **PLEASE SUMMARIZE YOUR TESTIMONY.**

A: In my testimony, I consider APS's request from the perspective of Arizona customers and ask if it is in the public interest for APS to acquire and ratebase the PWEC assets at book value. Within this framework, I focus in particular on the implications for customer prices, competition, and regulation. As I describe in my testimony, each of these factors is at play in APS's request. As Mr. Tranen shows, APS seeks to

[3] Direct Testimony of Hieronymous, Page 6:15-23.

[4] Id. at 26:11-13, 37:19-21, 38:19-21; Bhatti Direct Testimony at Page 18:16-21.

substantially increase its rates to cover the revenue requirement associated with these new assets. These expenses are much greater than what the market indicates APS must bear to reliably serve its customers.

Further, a central impact of APS's request will be to favor one competitive supplier—PWEC—over other competitive suppliers, including those in the Alliance who have no such ratebasing option available for their newly built generation capacity. APS's request amounts to the exercise of market power by APS, with attendant untoward effects on rates. That is, APS's request asks the Commission to allow APS to exercise market power over its customers by locking in prices that are higher than would otherwise prevail in the competitive market. If this were not true, PWCC, the sole shareholder of both APS and PWEC, would see more value in keeping the PWEC assets unregulated.

Q: **PLEASE OUTLINE THE FRAMEWORK OF YOUR ANALYSIS.**

A. In my analysis, I consider the public policy implications of the Commission's review of APS's requested treatment of the PWEC assets. Because most of APS's ratepayers lack direct access to competitive suppliers of power, APS's ratepayers rely on the Commission to protect them from poor management decisions and exercises of market power by APS, particularly when the risk of self-dealing with an affiliate is present. On these traditional issues of prudence and fairness, APS's filing is wholly inadequate.

APS's filing is targeted largely at evaluating whether PWCC's investment in the PWEC assets (made in anticipation of selling their output at "market" prices) was

[5] Hieronymus Direct Testimony at Page 9:9-10:4 and Bhatti Direct Testimony at Page 5:15-17.

prudent, an issue that is fundamentally irrelevant to this proceeding. In characterizing the investments as "APS-centric," APS simply waves away the fact that PWEC and APS have always been separate companies required by the Commission's rules to operate at arm's length. Even accepting the implicit assertion that altruistic PWCC has thus far eschewed rational profit maximization with its unregulated PWEC assets (contrary to management's fiduciary responsibility to shareholders), the matter at issue is not the prudence of PWCC's investment decisions in PWEC. The transaction before the Commission in this proceeding is APS's request that it be allowed to purchase and ratebase these assets *today* in order to recover their costs and returns from present and future ratepayers.

Q: **IN SUMMARY FORM, WHAT ARE YOUR FINDINGS?**

A: I find that approval of APS's request regarding the PWEC assets would be contrary to the public interest for two main reasons. First, APS's request is not consistent with the interests of APS's customers. The ratebasing of PWEC's assets would substantially increase APS's revenue requirement and thus raise rates to customers, without showing commensurate benefits. Second, the proposed transaction would unduly favor APS's affiliate, PWEC, by allowing the transfer of these assets in a manner that amounts to an exercise of market power. The transaction would force APS customers to bear risks that PWEC is now apparently unwilling to bear, the magnitude of which are uncertain because APS has failed to objectively evaluate the suitability of the PWEC assets for APS's future needs.

Q: **PLEASE EXPLAIN YOUR FINDINGS.**

A: I find that APS's request is economically equivalent to a bail out of PWEC and PWCC at the expense of the electricity customers of APS. It is clear that at least near-term prices paid by customers will be higher with the ratebasing of PWEC's assets than with acquisition of any net power needs on the open market. APS argues that the future portends higher prices on the open market than ratebasing PWEC's assets will yield. Presented as a virtual certainty, this assertion is speculation and contradicted by APS's very request in this proceeding – i.e., if future higher prices on the open market dominate lower prices over the nearer term, PWCC's financial interests would lie in leaving PWEC unregulated, not in transferring the plants to APS.

What APS's proposal here amounts to is a request that the Commission compel customers to pay a very high insurance payment (in the form of elevated prices paid to APS to cover the return on and of PWEC's capital) year-on-year for some twenty years. This insurance policy makes no sense for customers. PWCC's conduct in making the current proposal indicates that the economics it foresees do not support such an insurance policy, and consumers have better alternatives (including forward purchasing of power by APS).

Ownership of the PWEC assets will result in APS having considerably more capability to generate energy than it requires for its system operations for many years into the future. As a consequence, APS's proposal to ratebase the PWEC assets amounts to asking APS's customers to go into the business of selling power on the open wholesale power market – a business that PWCC is now apparently unwilling to continue with PWEC's assets.

It is also clear that granting APS's request would harm the competitive wholesale market and thus substantially undermine the extent to which competitors will be able to discipline APS in the future. Granting APS's request will send a clear and chilling signal to all existing and potential competitors in the Arizona power market that the playing field is not level, but is instead tilted substantially in favor of APS, PWEC and PWCC. Approval of the transaction would allow the Company to circumvent the competitive process that has been Commission policy since at least 1999.[6]

APS's witnesses take pains to argue, albeit only generically, that vertical integration of a regulated utility can be efficient and need not be inconsistent with the existence of competitive wholesale power markets. The data reviewed below, however, indicate that APS is asking the Commission to allow it to become one of the most vertically integrated investor-owned utilities in the Western U.S., and to simultaneously allow it to exercise market power by permitting its affiliate PWEC to obtain prices for its power that that are far higher than extant forward market prices which APS has already locked in as part of the recent Track B procurements. APS makes this request without providing any evidentiary assurance that it is in the interest of its Arizona customers, offering instead only unsubstantiated speculation that there will be future savings.

Q: **HOW IS YOUR TESTIMONY STRUCTURED?**

A: In Section III, I first review the public policy issues raised by APS's request and the importance of the Commission's role in reviewing this affiliate transaction. Thereafter, I discuss the economics of the transaction with a focus on how it will impact APS's Arizona customers. In particular, I examine evidence surrounding the development of the PWEC assets as merchant electricity generation facilities. Finally, in Section IV, I discuss the merits of APS's claim that its proposal for greater vertical integration results in a guarantee of more reliable service in the future without creating future regulatory challenges for the Commission.

III. PUBLIC POLICY IMPLICATIONS OF APS'S PROPOSED PURCHASE OF THE PWEC ASSETS

III.A The Commission's Role in the Review of APS's Request to Ratebase the PWEC Assets and Abrogate the Track B Contracts.

Q: **FROM A PUBLIC POLICY PERSPECTIVE, WHAT IS THE ROLE OF THE COMMISSION IN EVALUATING APS'S PROPOSED RATEBASING OF THE PWEC ASSETS?**

A: The Commission's role is to ensure that APS's proposal is in the public interest, taking into account all relevant facts and circumstances. Because most APS ratepayers lack effective direct access to competitive power suppliers,[7] they rely on the Commission to protect them from bad business decisions and exercises of market power by their power supplier, APS. When a monopoly utility acquires assets on behalf of its captive ratepayers and seeks to place those assets into its ratebase, the

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6 See, e.g., Decision Number 65154, September 10, 2002 at page 23.

7 This does not appear to be in dispute. See, e.g., Direct Testimony of Gordon at Page 9, esp. fn 6.

Commission properly investigates whether the acquisition was a good business decision at the time it was made. Evaluating such acquisitions normally involves investigating whether the assets are needed to provide reliable service to ratepayers, whether the utility's needs could be met more cost-effectively, and whether the utility is paying a fair, competitive price for the assets.

Q: **DO SPECIAL PROBLEMS ARISE WHEN A MONOPOLY UTILITY COMPANY SUCH AS APS ACQUIRES ASSETS FROM AN AFFILIATE?**

A: Yes. In the case where a regulated monopoly utility such as APS is acquiring assets from an affiliated company such as PWEC, the Commission must also guard against the possibility that the transaction represents an exercise of market power by the utility. When a utility purchases goods or services from an affiliated company, the utility has an incentive to pay its affiliate more than the prevailing market price if it believes it has a reasonable prospect of managing the ratemaking process so as to pass the higher costs on to ratepayers. Regulators have long recognized this incentive; and policies to guard against such "vertical market power" include proscriptions on affiliate transactions (e.g., forced divestiture of generation assets), as well as codes of conduct specifying rules for affiliate transactions. These typically require that utilities pay no more than the competitive market price when they purchase goods and services from their affiliates. In this case, APS is attempting to recover the (depreciated) cost of the PWEC assets with no demonstration of their market value.

Q: **DOES THE COMMISSION REGULATE TRANSACTIONS BETWEEN UTILITIES AND THEIR AFFILIATES?**

A: Yes. I understand the Commission has rules governing affiliate interest issues (incl. A.A.C. R14-2-401, *et seq.*). These were designed to "ensure that ratepayers do not pay rates for utility service that include costs associated with holding company structure, financially beleaguered affiliates, or sweetheart deals with affiliates intended to extract capital from the utility to subsidize non-utility operations."[8] As a part of its industry restructuring efforts, the Commission has required utilities to issue and follow Codes of Conduct, which among other things, prevent preferential treatment of affiliated companies. The Commission's Orders in various restructuring dockets have also reiterated the Commission's concerns about and intolerance for preferential treatment or sweetheart deals between a utility and its affiliates.[9]

Q: **HAS THE FERC PROMULGATED ADDITIONAL REGULATIONS ON THESE ISSUES?**

A: Yes. With respect to an intra-corporate transfer of an asset between a utility and its affiliate, for example, to satisfy the public interest standard under Section 203 of the

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8 Commission's Concise Explanatory Statement, In the Matter of the Notice of Proposed Adoption of Rules for Regulation of Public Utility Companies with Unregulated Affiliates, Decision 56844, Attachment B at 2 (1990).

9 See, e.g., Decision 61973 at 10 (1999) ("We share the concerns that the non-competitive portion of APS not subsidize the spun-off competitive assets through unfair financial arrangement."); Decisions 62416 and 62767 (2000) (adopting APS and TEP Codes of Conduct); Decision 65154 at 29-30 (2002) (requiring additional provisions in Codes of Conduct to cover utilities and affiliates in energy-related fields); Decision 65743 at 76, 78-79 (2003) ("We want to make clear that any preferential or discriminatory activity by APS, its parent or affiliates that interferes with a fair, unbiased solicitation process, whether specifically delineated or not in the standards of conduct, the Codes of Conduct, or this Decision, will not be tolerated, and that we will closely scrutinize the solicitation process for signs of any such abuse."; directing additional Staff reports be filed on utility Codes of Conduct); Decision 65796 at 39,40 (2003) (As a condition to approving APS's financing application re: the PWEC assets, requiring APS and PWEC to comply with all Affiliated Interest Rules and directing a preliminary inquiry into APS's compliance with its Code of Conduct).

Federal Power Act, FERC has required parties to demonstrate that the purchase and sale is on terms similar to any other available competitive alternatives.[10]

Q: **HAVE YOU CONSIDERED THESE FACTORS IN YOUR ANALYSIS?**

A: Yes. My analysis of APS's ratebasing proposal looks at the economics of the proposal and the extent to which the proposal is congruent with the stated regulatory objectives of the Commission. As I have indicated, with respect to economic impacts, I in part rely on the Testimony of Mr. Tranen, which offers a dissection of various costs associated with the acquisition of the PWEC assets. I also translate these impacts into a framework that makes clear what these impacts mean for consumers. Additionally, I analyze how the proposal stands to benefit APS's shareholder PWCC at the expense of APS's ratepayers.

III.B APS's Ratebasing Proposal Fails the Public Interest Standard from an Economic Standpoint.

Q: **PLEASE DESCRIBE APS'S PROPOSED TREATMENT OF THE PWEC ASSETS.**

A: APS proposes to purchase the PWEC assets at their current book value and to place them into APS's rate base. APS requests that the costs associated with the PWEC assets, including return of and on capital, operations and maintenance expenses, property taxes, and other items be included in APS's test year revenue requirement. As Mr. Tranen reports, APS's proposal would increase APS's test year revenue

[10] See, e.g., Ameren Energy Co, 103 FERC ¶61, 128 (2003); Boston Edison Company Re: Edgar Electric Energy Co., 55 FERC ¶61,382 (1991). APS and PWEC have not sought FERC approval for the proposed transfer of the PWEC assets. As proposed and supported in this filing, the transaction would not appear to meet a standard of competitive comparability, at least from the perspective of sound economic analysis.

requirement by almost $115 million or 65% of APS's total proposed revenue requirement increase.[11]

Q: **DOES APS ASSERT THAT BUYING THE PWEC ASSETS AND COMMITTING CUSTOMERS TO PAY FOR THEM IS IN THE PUBLIC INTEREST?**

A: Yes. APS's witnesses present a number of arguments to support its claim that the transaction is in the public interest. The general theme of these arguments is that the transaction will make ratepayers better off because it will protect them from future shortages and volatility in the competitive power market. APS claims that ratepayers will benefit because ratebasing the plants will lead to greater off-system sales margins. Further, according to Dr. Hieronymus, unless the Commission allows APS to buy the plants from PWEC, nothing will prevent PWEC from selling the assets' output at market prices to other buyers once the Track B contracts expire and the market is once again purportedly in a state of shortage. For example, Dr. Hieronymus states:

> "PWEC would face the same opportunities in export markets as would other generators and power marketers. A profit maximizing PWEC would not sell to APS for less than it could receive elsewhere, particularly having twice offered its capacity to APS's customers at cost-of-service prices and been turned down."[12]

In a nutshell, APS is telling the Commission that PWEC is offering to sell the assets at a cost-of-service price now, because they have an "APS centric" frame of mind; but if the Commission does not capitalize on this last chance, APS customers

[11] Mr. Wheeler testifies that APS is seeking higher annual revenues of approximately $175 million, of which $115 million is 65%. Wheeler Direct Testimony at Page 3: 4-6.

will surely be disappointed when the wholesale market turns against them in the future. In that purported future of shortages and price spikes, Dr. Hieronymus seems to be averring, PWEC will no longer be "APS centric". Indeed, elsewhere, Dr. Hieronymus indicates that PWEC can be expected to go so far as to exercise market power against APS and its customers if and when tight market conditions return.[13]

Q: **WHAT EVIDENCE DOES APS PRESENT THAT SUCH FUTURE TIGHT CONDITIONS AND PRICE SPIKES WILL IN FACT OCCUR?**

A: None. APS's assertion that the market will not provide adequate resources in the long term is based wholly on conjecture. For example, Dr. Hieronymus offers testimony regarding his predictions of conditions in the wholesale market after 2006, when the Track B Contracts end. According to Dr. Hieronymus:

> "Western power markets will cease to be in surplus, most likely between 2005 and 2008. My best estimate is for 2007."[14]
>
> "My expectation [is] of a near-shortage and price spike in the latter half of the decade . . . essentially at the same time that the Track B contracts will expire...."[15]
>
> It would be "folly" to "requir[e] that APS commit to replace the contracts and buy needed new supply to meet load growth from the market when its current Track B contracts expires at the end of 2006."[16]

According to Dr. Hieronymus, it is because of this "likely tightening" of Western power markets that it would be "quite risky in terms of reliability, prices, and price volatility" for APS to rely on the market for the capacity that rate-basing these

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12 Hieronymus Direct Testimony at Page 64:15-18.
13 Hieronymus Direct Testimony at Page 64:19-21.
14 Id. at Page 9:11-14.
15 Id. at Page 9: 20-22.

[PWEC assets] would cover."[17] In other words, based on this speculative "analysis" of power markets after 2006, Dr. Hieronymus concludes that ratebasing the PWEC assets "is likely to be cost-effective, relative to purchasing from the competitive wholesale market, for APS."[18]

Q: **HAVE YOU ANALYZED APS'S CLAIM THAT THE PROPOSED PURCHASE PRICE IS A GOOD DEAL FOR RATEPAYERS?**

A: Yes. The Commission, as well as the customers who pay APS's regulated rates, would be justified in expressing skepticism at the Company's characterization of its proposal as charitable or magnanimous. As Dr. Hieronymus says: "A profit maximizing PWEC would not sell to APS for less than it could receive elsewhere."[19] Notwithstanding Dr. Hieronymus' assertions to the contrary, sound regulatory policy appropriately views PWEC as a profit maximizing company. Presumably, PWEC is no less "profit maximizing" today than it will be in 2007. This is reasonable and appropriate, since PWEC used shareholder money from PWCC to build the assets and has a fiduciary responsibility to PWCC and its shareholders.

Dr. Hieronymus' testimony is contradicted by PWEC's apparent willingness to sell the PWEC assets to APS at book value. PWEC would presumably violate its fiduciary responsibilities to its shareholder PWCC if it sold the PWEC assets or their output to APS (or to any other entity) at less than market price, regardless of whether the transaction takes place today or in 2007. If PWEC believes that power prices will

16 Id. at Page 50: 16-18.

17 Id. at Page 65: 8-10.

18 Id. at Page 10:3-4.

19 Id. at Page 64: 16-17.

spike beginning around 2007, that the PWEC assets will then be able to make large profits, and that the present value of those future higher price conditions outweighs present value of lower prices in the nearer term, then PWEC would reasonably expect these future profits to be reflected in the current value of the assets. It would be harming its shareholder PWCC if it sold them for anything less than that. On the other hand, APS's shareholder (also PWCC) will benefit if APS pays more than market price for the assets and then is able to recover the ratebased costs by raising the rates it charges its customers. It is reasonable to conclude selling the PWEC assets to APS and ratebasing them is a good deal for its shareholder PWCC, meaning that the proposed sales price is unlikely to be *less* than PWEC's view of the assets' market value.

APS offers no evidence to reassure the Commission and customers that the price is not *above* market value. Indeed, in a response to a data request, APS's policy witness Mr. Wheeler asserts that ratebasing the PWEC assets at book value should occur even if there are lower-cost alternatives available from credit-worthy third parties.[20]

Dr. Hieronymous can assert to have seen the future, but PWCC's conduct is inconsistent with Dr. Hieronymous' prediction. Ratebasing PWEC's assets is consistent with PWCC's shareholders' interests when the impact on the present value of revenues of expected future prices (appropriately adjusted for the probability that those prices will or will not turn out to be higher by various amounts) is such that the assets are worth *less* if they remain *out of* APS's rate base. This occurs when the effect of higher prices that can be secured by ratebasing the assets outweigh (in present value) the effect of purportedly foregoing higher market prices at some point(s) in the future. But this means, concomitantly, that the negative effect on customers (in present value) of having to commit to paying for the ratebased assets of PWEC and paying higher prices in the nearer term outweighs the effect of the possible impact of prices that are higher by some amounts in the future. In short, PWEC's conduct in seeking ratebasing of its assets is a bad deal for APS's consumers.

Q: **WHAT ABOUT APS'S ARGUMENT THAT IT IS BUYING THE PWEC ASSETS IN ORDER TO PROTECT CONSUMERS AGAINST FUTURE POWER MARKET SHORTAGES?**

A: In economic terms, APS argues that ownership of the PWEC assets would provide APS's customers with a form of insurance against future power market shortages. Ratebasing the PWEC assets purportedly would protect APS's customers from such shortages because, in exchange for committing to make large annual payments to APS, they would buy power from the PWEC assets at cost-of-service instead of market prices.

It is particularly important to understand what APS is arguing here. As noted, APS repeatedly asserts that, thus far, PWEC has eschewed rational profit-maximizing strategies and forgone opportunities to capture market price spikes (e.g., during 2000-01).[21] This, it asserts, reflects its "APS centric" focus and willingness to sacrifice its

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[20] See Exhibit JPK-2, Wheeler Discovery Response AzCPA 1-107.

[21] See note 4 above.

shareholder PWCC's interests in "the bottom line."[22] Yet now, APS is effectively threatening that the next time market prices spike, PWEC will not be so nice. Rather, it will ride the market and visit the full force of the price spikes it purportedly foresees on APS's customers.[23]

Q: **WHETHER THIS THREAT IS EMPTY OR NOT, DO YOU BELIEVE THAT IT IS IN APS'S CUSTOMERS' INTERESTS TO "BUY" THE INSURANCE THAT RATEBASING IMPLIES?**

A: No. Insurance inherently involves committing to payments certain to be incurred in order to avoid the impact of otherwise uncertain payments. Notwithstanding risks that may otherwise be borne in an uncertain world, it is not always in a consumer's interests to buy insurance, especially when the price of insurance is high relative to the risks. In this regard, it is folly to treat speculation (e.g., by Dr. Hieronymus) of a price spike in 2007 as a certainty and to argue, therefore, that customers would be better off committing to ratebase treatment of power purchased from PWEC. In fact, as I have discussed, APS's conduct in seeking to get PWEC's assets into ratebase and away from the risks of relying on the marketplace suggests that the "insurance" that APS is offering is a good deal for the sole shareholder of APS and PWEC, PWCC, and therefore likely a bad deal for customers.

Q: **HAVE YOU ANALYZED THE TRANSACTION USING THE "INSURANCE" FRAMEWORK YOU JUST DISCUSSED?**

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22 Direct Testimony of Hieronymus at Page 26:11-13.

23 See, e.g., Direct Testimony of Hieronymus at Page 50:21-23.

A: Yes. Using this framework, I have prepared Exhibit JPK-3. This Exhibit illustrates the nature of the long-term commitment to paying APS that is implied by ratebasing of PWEC's assets. In the Exhibit, the insurance payment reflected is the annual commitment by customers (attendant to ratebasing) associated with covering both return of and on capital for the PWEC assets. As shown in Exhibit JPK-3, this payment ranges from approximately $160 million to approximately $40 million per year in nominal terms over the next twenty years, or slightly more than $1 billion in present value terms.[24] In the near years — 2004-2006 – this payment commitment makes APS's proposed rates much higher than they would be if the Company instead relied on the Track B Contracts.

This cost disparity should alarm customers, especially since APS's filing provides no quantitative support to show that this insurance policy is cost-effective for APS's customers. As I have discussed above, serving PWCC's shareholders' interests by ratebasing PWEC's assets indicates that the insurance policy PWCC is offering is *not* cost-effective on a net present value basis for consumers. Not only does the Company's conduct indicate that customers do not need this insurance; even if the insurance were needed, it has not been demonstrated that other forms of insurance are available more cheaply from other providers (such as various options that APS has previously purchased through the Track B process). The alternative to this insurance policy, particularly using the forward market as a means of satisfying

[24] Exhibit JPK-3 presents annual costs including only depreciation and return on undepreciated ratebase grossed up to account for income taxes. For purposes of taking this present value, I have employed a 10% discount rate. This rate is conservative relative to other rates that the ACC applies to various consumers' funds when it requires utilities to pay customers interest on their deposits. These interest

expected future demand, is already providing benefits through the Track B Contracts. To ask APS customers to pay for after-the-fact insurance, and throw out reliance on forward purchase contracts, is nonsensical. As I have found in my recent studies,[25] and Mr. Tranen discusses in his testimony, there is no reason to doubt that the forward market can provide adequate supplies. Moreover, APS's January 27, 2004 Summary of Responses Received to its Power Supply Resource Request for Proposals Dated December 3, 2003 indicates that nine entities submitted a total of thirteen bids in response to APS's request for future power supplies.

III.C APS's Proposal Would Put Its Customers in the Merchant Power Business.

Q: **PLEASE EXPLAIN HOW APS'S CUSTOMERS WILL INCUR MORE RISK IF APS BUYS THE PWEC ASSETS AND PLACES THEM IN ITS RATE BASE.**

A: Placing the PWEC assets in APS's rate base will shift the market risk associated with the PWEC assets from PWEC's shareholder PWCC to APS's customers. Having decided it no longer desires to bear this merchant risk itself, PWEC is attempting to off-load the risk onto APS's customers.

As Mr. Tranen's Exhibit JDT-7 shows, in acquiring the assets APS would enormously increase the amount of power it has available for off-system sales during

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rates range from 0.77% to 10%. See tariffs of APS, Tucson Electric Power, Ajo Gas Service, Duncan Rural Services Corp., and Southwest Gas Corp.

[25] See, for example, Prepared Direct Testimony of Joseph P. Kalt, Ph.D., October 17, 2002, Federal Energy Regulatory Commission Docket Nos. EL02-60-003 and EL02-62-003, and Prepared Direct Testimony of Joseph P. Kalt, Ph.D., October 8, 2002, Federal Energy Regulatory Commission Docket Nos. EL02-80-003, *et al*, Direct Testimony, June 28, 2002, and Prepared Answering Testimony,

those months when it is already at or above its capacity requirements. Similarly, Exhibit JPK-4 shows that the PWEC assets would make APS annually, on net, a large net *seller* of capacity and energy in the wholesale market. Mr. Wheeler testifies that the benefits of these off-system sales will flow through to ratepayers through lower rates. However, the magnitude of these future benefits is small in the test year and highly speculative in future years. Conversely, the increased cost to APS's ratepayers resulting from ratebasing the PWEC assets is immediate, substantial and ongoing for years. In fact, the Company's filing only offers a limited test-year quantitative analysis of these off-system sales benefits (which Mr. Tranen shows are quite small relative to the insurance payment customers would have to commit to under ratebasing (see Exhibit JDT-2)) and does not make the case that these benefits would off-set the year-on-year commitment to increased costs that ratepayers would incur as a result of rate-basing the PWEC assets. Mr. Wheeler also neglects to point out the downside — that if off-system sales do not materialize, the losses associated with the unused excess capacity would also flow through to APS ratepayers.

Q: **ARE YOU SAYING THAT THE RISKS ASSOCIATED WITH THESE SPECULATIVE BENEFITS ARE MORE APPROPRIATELY BORNE BY PWEC'S SHAREHOLDER, PWCC?**

A: Yes. From a public policy perspective, PWCC should bear this risk because it chose to make the investment in the PWEC assets and stood to gain if it had turned out to be profitable. My analysis of documents relevant to this proceeding leads me to

August 27, 2002, of Joseph P. Kalt, PhD., in Federal Energy Regulatory Commission Docket No. EL02-26-000, *et al.*

conclude that PWCC built the PWEC assets as merchant investments with the expectation that their output could be sold profitably at market prices. While, as noted above, APS takes pains to now assert that PWEC's *intention* has been to eschew the bottom line and serve APS's customers' interests at PWCC's (and PWCC's shareholders') expense, this proposition lacks credibility because it is inconsistent with the public policy expectation that unregulated firms will be profit maximizing.

I find no evidence that PWEC expected or desired to sell the plants' output to APS at anything other than market prices or to place them in rate base prior to the market turning so soft after 2000. Further, the terms of the 1999 Settlement stipulated that PWEC would sell to APS at market prices.[26] Mr. Wheeler indicates that, during the Track B proceeding, APS fully expected PWEC to offer power service to APS at nothing less than the wholesale market price.[27]

APS is petitioning the Commission for preferential treatment that amounts to a "heads I win, tails you lose" bargain. Consider the arguments PWCC and PWEC would make if the Commission attempted to force PWEC to sell the plants or their output to APS at cost-of-service prices if the present value of PWEC's assets implied by those cost-of-service prices were *lower* than the market value of the assets under continued market pricing. PWCC and PWEC (or, at least, PWCC's shareholders if they were properly informed) would rightly be expected to argue that such an action by the Commission would be tantamount to an illegal taking of shareholder property.

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[26] APS Settlement Agreement, May 14, 1999 at page 7.

[27] See Exhibit JPK-2, Wheeler Discovery Response AzCPA 1-110 and AzCPA 1-112.

Q: **IS THERE EVIDENCE THAT APS IS AWARE THAT THE TRANSACTION WOULD TRANSFER MARKET RISK FROM PWEC TO APS'S CUSTOMERS?**

A: Yes. For example, PWEC planning documents from June 2001 include an analysis of four scenarios for sales from the PWEC assets. One of the dimensions analyzed was the amount of market risk PWEC would face under each scenario. In the scenario where PWEC sells its output at market prices, the company's market risk is "high." In the scenario where the assets are covered under full cost of service ratemaking, PWEC's market risk is "nil." See Exhibit JPK-5.

Q: **IN ADDITION TO THIS RISK TRANSFER, ARE THERE OTHER BENEFITS PWCC AND PWEC WOULD GAIN FROM THE TRANSFER?**

A: Yes. PWCC and PWEC would be able to exit investments that they no longer expect to be profitable. At the time PWCC built the PWEC assets, it believed the plants would be able to make high profits by selling into California. See Exhibit JPK-6. PWCC explained its investment decisions as being based on policy changes in the western markets. To capture these profits, PWCC sited the PWEC assets on key transmission lines. See Exhibit JPK-6.

Q: **WHAT CHANGED?**

A: The enormous increase in merchant power investment in Arizona and the west generally has led to a glut in capacity and thereby made the PWEC assets much less valuable. As Exhibit JPK-7 shows, during the planning stages, PWEC expected these assets to run at very high levels of output. When its analyses showed high plant values, PWEC apparently did not consider either a cost-of-service contract or ratebase treatment for the assets. To the contrary, PWEC explicitly counted on being able to make sales at competitive wholesale prices.[28] See Exhibit JPK-6. Today, as Exhibit JPK-7 shows, PWEC's planning documents show expectations that the plants will run only at a fraction of what was originally expected. It is as if a company built a factory expecting it to operate at 70-80% of its capacity utilization and now finds it operating at much lower level of capacity utilization, which severely impacts its expected future operating margins.

Q: **HAVE YOU FOUND EVIDENCE THAT PWEC HAS CONSIDERED THIS SITUATION?**

A: Yes. Exhibit JPK-8 is an excerpt of an analysis carried out in mid-2001 which shows that PWEC realized that, following price declines in the wholesale market, (see Exhibit JPK-9), a better approach for it to ensure stable earnings from the PWEC assets was to move them into the APS rate base, a scenario it referred to as "re-regulation."

Q: **FROM A PUBLIC POLICY PERSPECTIVE, IS IT SOUND ECONOMICALLY FOR THE COMMISSION TO APPROVE TRANSFERRING THESE MERCHANT GENERATION RISKS FROM PWEC SHAREHOLDERS TO APS'S CONSUMERS?**

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[28] The actual arrangements for selling output for the PWEC assets varied over time given various changes PWCC made to its corporate structure. Initially PWCC set-up a marketing and trading business unit which was responsible for disposing of the PWEC assets' capacity (PWEC is primarily responsible for insuring the plants operate reliably). Eventually PWCC placed responsibility for the marketing and trading of the PWEC assets' output into a different unregulated APS affiliate called APS Marketing and Trading. See Exhibit JPK-2, Discovery Responses LCA 4-97 and 4-98.

A: No. APS is requesting that the Commission sanction a significant transfer of risk from PWEC's shareholder PWCC to APS customers. As I discuss below, this, in effect, constitutes a request to exercise market power. PWCC made a clearly documented business decision to enter the merchant energy sector through the creation of PWEC and the construction and acquisition of various power assets. PWCC is now attempting to significantly reduce its exposure to the merchant sector by selling some of its assets to APS. APS's filing does not address this transfer of risk to customers and does not in any way demonstrate that this transfer is in the customers' interest.

III.D The PWEC Assets Are Merchant Plants.

Q: **APS SUPPORTS ITS PROPOSAL BY CLAIMING THAT THE PWEC ASSETS WERE BUILT TO SERVE APS'S RATEPAYERS. DOES THIS CONTENTION HAVE ANY BEARING ON THIS APPLICATION?**

A: No. This argument is a red herring. Documents produced in discovery and presented in Exhibit JPK-6 show that the PWEC assets were planned and constructed based on wholesale market expectations, not expectations of being part of the APS rate base. And, as noted, the terms of the 1999 Settlement stipulated that PWEC would sell to APS at market prices.

Q: **APS ASSERTS THAT RATEBASING IS APPROPRIATE BECAUSE THE PWEC ASSETS WERE BUILT EXPRESSLY TO SERVE APS'S NATIVE LOAD AND WITH THE EXPECTATION THAT THEY WOULD BE**

COMBINED WITH EXISTING APS GENERATION RESOURCES. DO YOU AGREE?

A: No. APS's argument appears to be that raising consumer prices by ratebasing the assets is fair, because PWEC built the assets with the subjective *intention* of serving APS's consumers. However, APS does not claim that the PWEC assets were built with the intent of serving APS's customers on a cost-of-service basis, or placing the assets in rate base. Furthermore, although Mr. Wheeler argues that the PWEC assets were built with the expectation that they would be combined with APS generation to create a highly competitive asset portfolio, Mr. Bhatti's testimony demonstrates that PWEC expected that the new generation, on a stand alone basis, would yield very high returns from sales at expected market prices. It was apparently not until the middle of 2001 that PWEC began to consider the extent to which a softening wholesale market may be rendering its initial profitability estimates for these assets inaccurate.[29] As shown in Exhibit JPK-9, PWEC's desire to reduce its exposure to the wholesale market came only after wholesale prices had collapsed.

Q: **IS THERE OTHER EVIDENCE THAT SUPPORTS THE PROPOSITION THAT THE PWEC ASSETS WERE BUILT AS MERCHANT PLANTS?**

A: Yes. The huge energy surplus that would result from including the PWEC assets in the APS rate base suggests that had the investment decisions really been made on an "APS centric" basis, PWEC would have invested in lower-cost simple-cycle combustion turbines that would have been sufficient to meet the APS's capacity requirements while avoiding the need to rely upon market energy sales to justify the higher capital costs of combined-cycle units.

Based on these observations and my analysis of discovery documents in this case, I conclude that the PWEC assets were intended to serve the western wholesale market. As the western market comprises Arizona, then APS's ratepayers are included in this market. The car dealer sometimes says that: "This car was built for you." Economically, what this means is: "I ordered this car because I knew you (or people like you) would be likely to buy it from me at a price that would be profitable." In summary, it is irrelevant whether PWEC's decision to build plants was based in part on expected load growth in Arizona or on the hope that the PWEC assets would be combined in a generation portfolio with deregulated APS generation. PWEC understood that the plants' output was to be sold at market prices rather than through cost of service rates and analyzed the decision to build these plants on a stand-alone basis.

IV. REGULATORY IMPACT OF APS'S PROPOSAL ON CURRENT COMMISSION OBJECTIVES

IV.A APS is Already Vertically Integrated and Making It More So by Ratebasing the PWEC Assets Is Inconsistent with Competitive Market Development.

Q: **PLEASE ADDRESS APS'S EXPRESSED INTENT TO INCREASE ITS "VERTICAL INTEGRATION" BY ACQUIRING THE PWEC ASSETS.**

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[29] I also note that Exhibit JDT-9 shows the extent to which PWEC underestimated the amount of new capacity that would be built in the Western U.S. Given this now-observed change in supplies, the capacity utilization levels shown in Exhibit JPK-7 are hardly surprising.

A: APS's witnesses claim that increasing APS's vertical integration through acquisition of the PWEC assets is beneficial to customers.[30] Acquisition of the PWEC assets would unquestionably make APS much more vertically integrated, and thereby decrease its reliance on the competitive market for future resource procurement. In fact, if APS buys the PWEC assets it will be one of the two most vertically integrated utilities in the WECC. Further, APS is already "vertically integrated" at an above-average level when compared with other electric utilities in the WECC. See Exhibit JPK-10. Given these facts, APS's generic assertions that some vertical integration can be efficient do not establish that the increased vertical integration associated with ratebasing the PWEC assets is in the best interest of customers, especially given the negative impacts it will have on the development of competitive wholesale markets.

IV.B APS's Proposal Is an Attempt to Exercise Market Power.

Q: **PLEASE EXPLAIN THE RISK OF VERTICAL MARKET POWER.**

A: Regulators and economists have long recognized that a regulated utility with market power in one sector of the energy industry (e.g., distribution) would have both the incentive and possibly the opportunity (through manipulation of the rate-making process) to use that monopoly to extract rents from competitive sectors (e.g., generation). For example, as APS's expert, Dr. Gordon, and a co-author have written:

> "Vertical market power, a leading concern in the regulation of utilities and their affiliates, refers to the possibility that a firm can exercise its horizontal market power at one stage of the production process (such as transmission or distribution) to influence price and output at another

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[30] See, e.g., Wheeler Direct Testimony, Page 12: 22:25.

> stage, such as generation and retail sales, or in new markets... the principal vertical market power concern in the industry has been that integrated transmission and distribution owners would use their control of bottleneck facilities to favor sales of their own generation over sales of their competitors."[31]

Q: **HAVE UTILITY REGULATORS EXPRESSED CONCERN ABOUT VERTICAL MARKET POWER?**

A: Yes. Concerns about vertical market power have been central to most of the efforts to promote competition in power and gas markets. For example, the FERC has recently issued new rules on codes of conduct for gas and electricity transmission providers specifically intended to prevent the exercise of vertical market power by transmission providers.

> "9. The Commission is concerned that a Transmission Provider's market power could be transferred to its affiliated businesses because the existing rules do not cover all affiliate relationships. For example, an integrated entity could exercise market power in delivered natural gas service to raise costs of rival generators or inhibit entry of new generators into wholesale power markets."[32]

In addition, in calling for renewed attention to both affiliate and non-affiliate transactions, the Chairman of the FERC has recently voiced particular concern about "the acquisition of temporarily distressed generation assets by the local utilities that would otherwise be buying under long-term contract."[33]

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31 Kenneth Gordon and Charles Augustine, "Fostering Efficient Competition in the Retail Electric Industry: How Can Regulators Help Solve Vertical Market Power Concerns? First, Do No Harm." Prepared for the Edison Electric Institute, August 1998.

32 Standards of Conduct for Docket No. RM01-10-000 Transmission Providers ORDER NO. 2004 FINAL RULE (Issued November 25, 2003), slip. op., at 6.

33 See Exhibit JPK-2, attached as Comments of FERC Chairman Pat Wood during Merrill Lynch Conference Call, January 26, 2004 at page 13.

Q: **PLEASE EXPLAIN WHY APS'S PROPOSAL CONSTITUTES AN ATTEMPTED EXERCISE OF MARKET POWER.**

A: It is a textbook case. Economically, APS's proposal is a proposal to pay higher-than-market prices to PWEC over at least the near term and raise rates in present value terms to get its customers to pay the costs and assume the risks of PWEC's merchant power business. Competition is defined as price-taking – the competitive firm takes market prices as given and supplies accordingly; it lacks the power to unilaterally control the price and push higher prices onto consumers. Thus, as a matter of straightforward economics, PWEC's ability to realize higher-than-market prices at any time going forward by putting the PWEC assets in APS's rate base arises because doing so enables PWEC to utilize APS's regulated status to allow it to exercise market power. If it was not exercising market power, PWEC would not be able to realize above-market prices. This ability arises from PWEC's vertical relationship under ratebasing, coupled with APS's status as a local regulated utility whose rates are not being set by competition. That is, APS's ability to pass higher-than-market wholesale prices emanating from the ratebasing of PWEC's assets reflects the fact that APS is not a price taking, competitive seller at the retail level. The ability to make, rather than take, retail prices is not surprising. As APS acknowledges:

> "[APS's r]etail customers can, in principle, choose to take service from a competitive provider, although few (if any) competitors are offering retail service in Arizona at the present time."[34]

If its retail prices were being set by the discipline of competition, APS would not be able to pass higher-than-competitive-market wholesale prices from PWEC onto the APS retail customers. And if APS thereby were unable to pass what are effectively higher-than-competitive-market PWEC prices at wholesale onto retail consumers, PWCC would not benefit from ratebasing the PWEC assets.

Q: **HOW DO YOU RESPOND TO DR. HIERONYMUS' TESTIMONY THAT THE COST-EFFECTIVENESS OF APS'S ACQUISITION OF THE PWEC ASSETS, RELATIVE TO THE WHOLESALE MARKET, IS IRRELEVANT TO THE COMMISSION'S RULING ON APS'S REQUEST?**[35]

A: I strongly disagree. The Commission has stated that it expects APS to apply least cost planning principles in acquiring new generation.[36] These principles require a comparison of APS's proposal to market-based alternatives. It is clear that APS has failed to adequately assess and analyze the cost-effectiveness of its proposal as compared to market alternatives, notwithstanding the fact that the Commission requires this analysis.

Q: **WHY IS THIS ANALYSIS SO CRITICAL TO THE COMMISSION'S REVIEW OF APS'S PROPOSAL?**

A: Overseeing a regulated utility's acquisition of resources on behalf of its customers, with the intent of recovering the cost of those assets from its customers, is a fundamental role of the Commission. Recognizing that inter-affiliate transactions could be a source of ratepayer harm, regulators (including the Commission) and

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[34] Direct Testimony of Gordon at Page 9, fn. 10.

[35] Direct Testimony of Hieronymus at Page 51: 16-20.

[36] Decision 65743 at 75 (2003).

economists have found that careful analysis of such transactions is critical for ensuring ratepayers are protected.

The current proceeding is an opportunity for the Commission to prevent such an abuse. If the Commission approves APS's request to shift cost and risk from shareholders to ratepayers, and ratepayers actually enjoy economic benefits (which, as I have shown, is inconsistent with the evidence of APS's conduct), the Commission should not be surprised to find APS before it at a later date with a new proposal that would attempt to transfer the merchant cost and risk back to shareholders to recapture these benefits.

IV.C APS's Proposal Would Harm the Competitive Market.

Q: **IS THE IMPACT OF APS'S RATEBASING PROPOSAL ON THE COMPETITIVE WHOLESALE MARKET RELEVANT TO THE COMMISSION'S DECISION-MAKING?**

A: Yes. APS's ratepayers stand to benefit substantially from an efficient and well-functioning wholesale market in Arizona and the west generally. These benefits are provided in a number of ways. First, availability of wholesale providers gives APS important options for procuring resources to meet its growing load. Absent the wholesale market, APS would have no choice but to own sufficient generation capacity to meet its entire load. Further, the presence of competitive providers acts as a discipline on the costs and the behavior of a regulated company such as APS. This is true even if APS retains its effective monopoly in serving retail customers in its service territory.

Q: **DO YOU AGREE WITH APS'S WITNESSES' TESTIMONY TO THE EFFECT THAT APS'S PROPOSAL IS CONSISTENT WITH THE COMMISSION'S STATED POLICY OF SUPPORTING COMPETITIVE WHOLESALE POWER MARKETS?**[37]

A: No. The Commission should take no comfort from these assurances. To the contrary, it must be recognized that the Commission's action in this matter is likely to have a material effect on the future development of wholesale competition in Arizona. Approving APS's request would send a clear signal to potential investors in future projects that Arizona is not a level playing field.

Q: **PLEASE EXPLAIN HOW APPROVAL OF APS'S PROPOSED TREATMENT OF THE PWEC ASSETS WOULD HAVE A "CHILLING EFFECT" ON WHOLESALE POWER MARKETS.**

A: As described above, at the time the PWEC assets were built, PWEC expected, and the regulatory framework was designed, to sell those assets' output at competitive wholesale market prices. In this regard, the PWEC assets are no different from other merchant power plant investments that have been made in the west and throughout the country. Now, PWEC is attempting to transfer the risks and costs of these assets to ratepayers—an option that doesn't exist for other merchant investors in Arizona. If the rate basing request is approved, other market participants will have been denied a fair opportunity to compete with PWEC. Such preferential treatment will signal the market that the playing field is not level. Going forward, this will adversely impact current and future investors' expectations and willingness to participate in the

[37] See, e.g., Gordon Direct Testimony, Page 20:3:7

wholesale marketplace. As the Chairman of the FERC recently pointed out, conduct of the form that APS requests here "take[s] players out of the competitive market and the wholesale market, and they make that market thereby thinner and weaker as a consequence."[38]

V. CONCLUSION

Q: **PLEASE SUMMARIZE YOUR CONCLUSIONS.**

A: I find that APS is asking the Commission to sanction an enormous transfer of risk and costs from PWEC's shareholder PWCC to APS's ratepayers. APS attempts to characterize this transfer as a high-minded action by PWCC to give up the opportunity to make high profits from the PWEC assets so that customers can be protected from future power market shortages and provided with bountiful supplies of excess power to sell at high prices. The Commission should reject APS's proposal. Allowing APS to buy the PWEC assets would harm customers by forcing them to accept the costs and risks of merchant investments that, had they been profitable, would have benefited PWCC, not customers. In its economic essentials and impacts, this is a case of a regulated utility attempting to game the regulatory process in a manner that harms customers and enriches shareholders.

Q: **DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY IN THIS CASE?**

A: Yes.

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[38] See Exhibit JPK-2, attached as Comments of FERC Chairman Pat Wood during Merrill Lynch Conference Call, January 26, 2004 at page 29.

Exhibit JPK-1

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Faculty Chair, Interfaculty Initiative, Harvard University Native American Program, 2000 - present
Co-Director, The Harvard Project on American Indian Economic Development, 1987 - present
Chair, Economics and Quantitative Methods Cluster, 1995 - 2000
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Chairman of Degree Programs, 1990 - 1992
Chairman of Ph.D. Programs, 1989 - 1990
Assistant Director for Natural Resources, Energy and Environmental Policy Center, 1985 - 1990
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Ph.D. in Economics, 1980
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What Can Tribes Do: Strategies and Institutions in American Indian Economic Development, Vol. II, ed. (with Amy L. Besaw and Stephen Cornell) and co-author of one chapter, UCLA American Indian Studies Program, University of California Press, forthcoming 2004.

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"One Works, the Other Doesn't: Two Approaches to Economic Development on American Indian Reservations" (with Stephen Cornell), working paper, Harvard Project on American Indian Economic Development, November 2002.

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"Means-Testing Indian Governments: Taxing What Works" (with Jonathan Taylor), in Richard C. Monk, ed., *Taking Sides: Race and Ethnicity*, McGraw-Hill/Dushkin, 2001.

"Where's the Glue? Institutional and Cultural Foundations of American Indian Economic Development" (with Stephen Cornell), *The Journal of Socio-Economics*, vol. 29, 2000.

"Open Access for Railroads? Implications for a Non-Hub, Congestible Network Industry"(with Amy B. Candell), Advanced Workshop in Regulation and Competition, Center for Research in Regulated Industries, May 2000 (unpublished working paper).

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"Sovereignty and Nation-Building: The Development Challenge in Indian Country Today" (with Stephen Cornell), *The American Indian Culture and Research Journal*, vol. 22, no. 3, February 1999.

"Making Research Count in Indian Country: The Harvard Project on American Indian Economic Development" (with Manley A. Begay, Jr., and Stephen Cornell), *Journal of Public Service and Outreach*, vol. 3, no. 1, Spring 1998.

"Successful Economic Development and Heterogeneity of Governmental Form on American Indian Reservations" (with Stephen Cornell), in Merilee S. Grindle, ed., *Getting Good Government: Capacity Building in the Public Sector of Developing Countries*, Harvard University Press, 1997.

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"Introduction: The New World of Gas Regulation" (with Jerry Ellig), J. Ellig and J. P. Kalt, eds., *New Directions in Natural Gas Deregulation*, Greenwood Press, 1995.

"Incentive Regulation for Natural Gas Pipelines" (with Adam B. Jaffe), in J. Ellig and J. P. Kalt, eds., *New Directions in Natural Gas Deregulation*, Greenwood Press, 1995.

"Where Does Economic Development Really Come From? Constitutional Rule Among the Modern Sioux and Apache" (with Stephen Cornell), *Economic Inquiry*, Western Economic Association International, Vol. XXXIII, July 1995, pp. 402-426.

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"Re-Establishing the Regulatory Bargain in the Electric Utility Industry," *Discussion Paper Series*, Energy and Environmental Policy Center, Kennedy School of Government, March 1987, published as Appendix V in *Final Report of the Boston Edison Review Panel*, W. Hogan, B. Cherry and D. Foy, March 1987.

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OTHER PUBLICATIONS AND LEGISLATIVE TESTIMONY

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"Redistribution of Wealth in Federal Oil Policy," *San Diego Business Journal*, August 18, 1980, pp. 22-3.

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"Windfall Profits Tax Will Reap Bonanza—But For Whom?" (with Peter Navarro), *The Miami Herald*, December 23, 1979, editorial page.

SELECTED PRESENTATIONS

"The State of U.S. Railroads and the Challenges Ahead," briefing of Capitol Hill staff, Association of American Railroads, April 17, 2003.

"The State of the Railroad Industry and the Challenges Ahead," briefing of Roger Nober, Chairman, US Surface Transportation Board, Association of American Railroads, January 28, 2003.

"The Wealth of American Indian Nations: Culture and Institutions," Federal Reserve Bank of Boston, December 11, 2002.

"The Roots of California's Energy Crisis: Law, Policy, Politics, and Economics," Regulation Seminar, Center for Business and Government, Kennedy School, Harvard University, November 7, 2002.

"Public Policy Foundations of Nation Building in Indian Country," National Symposium on Legal Foundations of American Indian Self-Governance," Mashantucket Pequot Nation, February 9, 2001.

"Twenty-Five Years of Self-Determination: Lessons from the Harvard Project on American Indian Economic Development," Udall Center for Studies in Public Policy, University of Arizona, November 13-14, 1999.

Proceedings of the Fourth Annual DOE-NARUC Natural Gas Conference, Orlando, FL, February 1995.

Keynote Address, "Sovereignty and American Indian Economic Development," Arizona Town Hall, Grand Canyon, AZ, October 1994.

"Is the Movement Toward a Less-Regulated, More Competitive LDC Sector Inexorable?, (Re)Inventing State/Federal Partnerships: Policies for Optimal Gas Use," U.S. Department of Energy and The National Association of Regulatory Utility Commissioners Annual Conference, Nashville, TN, February 1994.

"Cultural Evolution and Constitutional Public Choice: Institutional Diversity and Economic Performance on American Indian Reservations," Festschrift in Honor of Armen A. Alchian, Western Economic Association, Vancouver, BC, July 1994.

"Precedent and Legal Argument in U.S. Trade Policy: Do they Matter to the Political Economy of the Lumber Dispute?" National Bureau of Economic Research, Conference on Political Economy of Trade Protection, February, September 1994.

"The Redesign of Rate Structures and Capacity Auctioning in the Natural Gas Pipeline Industry," Natural Gas Supply Association, Houston, TX, March 1988.

"Property Rights and American Indian Economic Development," Pacific Research Institute Conference, Alexandria, VA, May 1987.

"The Development of Private Property Markets in Wilderness Recreation: An Assessment of the Policy of Self-Determination by American Indians," Political Economy Research Center Conference, Big Sky, MT, December 4-7, 1985.

"Lessons from the U.S. Experience with Energy Price Regulation," International Association of Energy Economists Delegation to the People's Republic of China, Beijing and Shanghai, PRC, June 1985.

"The Impact of Domestic Regulation on the International Competitiveness of American Industry," Harvard/NEC Conference on International Competition, Ft. Lauderdale, FL, March 7-9, 1985.

"The Welfare and Competitive Effects of Natural Gas Pricing," American Economic Association Annual Meetings, December 1984.

"The Ideological Behavior of Legislators," Stanford University Conference on the Political Economy of Public Policy, March 1984.

"Principal-Agent Slack in the Theory of Bureaucratic Behavior," Columbia University Center for Law and Economic Studies, 1984.

"The Political Power of the Underground Coal Industry," FTC Conference on the Strategic Use of Regulation, March 1984.

"Decontrolling Natural Gas Prices: The Intertemporal Implications of Theory," International Association of Energy Economists Annual Meetings, Houston, TX, November 1981.

"The Role of Government and the Marketplace in the Production and Distribution of Energy," Brown University Symposium on Energy and Economics, March 1981.

"A Political Pressure Theory of Oil Pricing," Conference on New Strategies for Managing U.S. Oil Shortages, Yale University, November 1980.

"The Politics of Energy," Eastern Economic Association Annual Meetings, 1977.

WORKSHOPS PRESENTED

Federal Reserve Bank of Boston; University of Indiana; University of Montana; Oglala Lakota College; University of New Mexico; Columbia University Law School; Department of Economics and John F. Kennedy School of Government, Harvard University; MIT; University of Chicago; Duke University; University of Rochester; Yale University; Virginia Polytechnic Institute; U.S. Federal Trade Commission; University of Texas; University of Arizona; Federal Reserve Bank of Dallas; U.S. Department of Justice; Rice University; Washington University; University of Michigan; University of Saskatchewan; Montana State University; UCLA; University of Maryland; National Bureau of Economic Research; University of Southern California.

OTHER PROFESSIONAL ACTIVITIES

Board of Trustees, The Communications Institute, 2003-present

Board of Trustees, Fort Apache Heritage Foundation, 2000-present

Mediator (with Keith G. Allred), Nez Perce Tribe and the North Central Idaho Jurisdictional Alliance, MOU signed December 2002

Mediator, *In the Matter of the White Mountain Apache Tribe v. United States Fish and Wildlife Service*, re: endangered species management authority, May-December, 1994

Steering Committee, National Park Service, 75th Anniversary Symposium, 1991-93

Board of Trustees, Foundation for American Communications, 1989-2003

Editorial Board, *Economic Inquiry*, 1988-2002

Advisory Committee, Oak Ridge National Laboratory, Energy Division, 1987-1989

Commissioner, President's Aviation Safety Commission, 1987-88

Principal Lecturer in the Program of Economics for Journalists, Foundation for American Communications, teaching economic principles to working journalists in the broadcast and print media, 1979-present

Lecturer in the Economics Institute for Federal Administrative Law Judges, University of Miami School of Law, 1983-1991

Research Fellow, Energy and Environmental Policy Center, John F. Kennedy School of Government, Harvard University, 1981-1987

Editorial Board, MIT Press Series on *Regulation of Economic Activity*, 1984-1992

Research Advisory Committee, American Enterprise Institute, 1979-1985

Editor, *Quarterly Journal of Economics*, 1979-1984

Referee for *American Economic Review, Bell Journal of Economics, Economic Inquiry, Journal of Political Economy, Review of Economics and Statistics, Science Magazine, Journal of Policy Analysis and Management, Social Choice and Welfare, Quarterly Journal of Economics*, MIT Press, North-Holland Press, Harvard University Press, *American Indian Culture and Research Journal*

TEACHING EXPERIENCE

Native Americans in the 21st Century: Nation Building I & II (University-wide, graduate and undergraduate); Introduction to Environment and Natural Resource Policy (Graduate, Kennedy School of Government); Seminar in Positive Political Economy (Graduate, Kennedy School of Government); Intermediate Microeconomics for Public Policy (Graduate, Kennedy School of Government); Natural Resources and Public Lands Policy (Graduate, Kennedy School of Government); Economics of Regulation and Antitrust (Graduate); Economics of Regulation (Undergraduate); Introduction to Energy and Environmental Policy (Graduate, Kennedy School of Government); Graduate Seminar in Industrial Organization and Regulation; Intermediate Microeconomics (Undergraduate); Principles of Economics (Undergraduate); Seminar in Energy and Environmental Policy (Graduate, Kennedy School of Government)

HONORS AND AWARDS

Allyn Young Prize for Excellence in the Teaching of the Principles of Economics, Harvard University, 1978-79 and 1979-80

Chancellor's Intern Fellowship in Economics, 9/73 to 7/78, one of two awarded in 1973, University of California, Los Angeles

Smith-Richardson Dissertation Fellowship in Political Economy, Foundation for Research in Economics and Education, 6/77 to 9/77, UCLA

Summer Research Fellowship, UCLA Foundation, 6/76 to 9/76

Dissertation Fellowship, Hoover Institution, Stanford University, 9/77 to 6/78

Four years of undergraduate academic scholarships, 1969-1973; graduated with University Distinction and Departmental Honors, Stanford University

Research funding sources have included: The National Science Foundation; USAID (IRIS Foundation); Pew Charitable Trust; Christian A. Johnson Family Endeavor Foundation; The Ford Foundation; The Kellogg Foundation; Harvard Program on the Environment; The Northwest Area Foundation; the U.S. Department of Energy; the Research Center for Managerial Economics and Public Policy, UCLA Graduate School of Management; the MIT Energy Laboratory; Harvard's Energy and Environmental Policy Center; the Political Economy Research Center; the Center for Economic Policy Research, Stanford University; the Federal Trade Commission; and Resources for the Future; The Rockefeller Foundation.

Exhibit JPK-2
APS WITNESS WORKPAPERS, DISCOVERY RESPONSES, AND OTHER RELEVANT DOCUMENTS CITED IN KALT TESTIMONY

ARIZONA COMPETITIVE POWER ALLIANCE FIRST SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND FOR APPORVAL OF PURCHASED POWER CONTRACT E-01345A-03-0437

AzCPA 1-107. Do you believe that APS should acquire the PWEC generation assets even if it could be demonstrated that power could be procured on a long-term basis from a credit-worthy third party at a lower cost following the expiration of the PWEC Track B contracts? Please explain your response in detail, including supporting workpapers for any calculations performed.

RESPONSE:

Yes. While APS believes that future energy needs should be met through a mix of generation assets owned and operated by APS and purchases from the wholesale generation market, the purpose for and benefits of acquiring and rate basing the PWC assets as part of this plan are provided in Mr. Wheeler's testimony at page 13, line 1, through page 18, line 25. In addition, APS recently announced that it soon will be soliciting competitive bids for long-term power in order to further this objective.

Witness: Steve Wheeler

**ARIZONA COMPETITIVE POWER ALLIANCE FIRST SET OF DATA REQUESTS
TO ARIZONA PUBLIC SERVICE COMPANY
IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND FOR APPORVAL OF PURCHASED POWER CONTRACT
E-01345A-03-0437**

AzCPA 1-110. Regarding the direct testimony commencing at page 15, line 4, had the Electric Competition Rules and the 1999 Settlement been fully implemented, would PWEC have been legally obligated to enter into contracts to sell power to APS at below prevailing market prices? If your answer is in the affirmative, please provide a detailed explanation for your conclusion.

RESPONSE:

APS assumed that PWEC sales would be at the market prices prevailing in an efficiently-functioning competitive market. It is not aware of any legal obligation of PWEC to sell power to APS or any other entity for less than this fully-competitive market price.

Witness: Steve Wheeler

ARIZONA COMPETITIVE POWER ALLIANCE FIRST SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND FOR APPORVAL OF PURCHASED POWER CONTRACT E-01345A-03-0437

AzCPA 1-112. Did PWEC intentionally propose what it believed to be below-market prices in response to the Track B solicitation? If your response is in the affirmative, please describe in detail why PWEC proposed such prices.

RESPONSE:

PWEC did an independent Track B bid. APS has no reason to believe PWEC bid less that its (PWEC's) evaluation of then current prices.

Witness: Steve Wheeler

**LA CAPRA'S FOURTH SET OF DATA REQUESTS
TO ARIZONA PUBLIC SERVICE COMPANY
IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND FOR APPORVAL OF PURCHASED POWER CONTRACT
E-01345A-03-0437**

LCA 4-97 (a) Please identify all APS departments, groups, committees, etc. that have had past involvement in generation planning, generation development, power procurement, power trading, or making decisions regarding the foregoing at APS (if different from those in the preceding data request). (b) Please specify the specific responsibilities of each such entity, and (c) please identify the persons involved by name and position for each entity.

RESPONSE:

Generation planning is and was performed by the Resource Planning department. The responsibilities of the APS Resource Planning Department were already provided in response to LCA 3-71. Ajit Bhatti, currently the Vice President, Resource Planning, heads the Resource Planning department.

New generation development was performed by the GBU, which originally encompassed only APS generation Planning and Development, but with the creation of PWEC in late 1999, covered both APS and PWEC. See Response to LCA 4-96.

David Hansen, currently the Vice President, Marketing & Trading headed the Marketing & Trading department first at PWCC and now at APS. This department has responsibility for power procurement and power trading.

Witness- Ajit Bhatti

**LA CAPRA'S FOURTH SET OF DATA REQUESTS
TO ARIZONA PUBLIC SERVICE COMPANY
IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND FOR APPORVAL OF PURCHASED POWER CONTRACT
E-01345A-03-0437**

LCA 4-98 Please identify the entity that is responsible for executing sales transactions for PWEC supplies (i.e., who sells PWEC power):
(a) in real-time markets;
(b) in day-ahead markets;
(c) involving transactions of less than three months; and
(d) involving transactions of more than three months.

RESPONSE:

(a), (b), (c) All sales of PWEC output acquired under Track B for APS customers is controlled by APS Marketing and Trading (Regulated). All sales of PWEC output outside of Track B are controlled by APS Marketing and Trading (Unregulated).

(d) Only PWEC personnel were involved with respect to the sale from PWEC to APS as part of Track B; APS Marketing and Trading (Unregulated) in conjunction with PWEC, is responsible for all other transactions.

Witness-Steve Wheeler/Donald Robinson

MERRILL LYNCH

January 26, 2004
10:00 a.m. ET

Coordinator Good day, ladies and gentlemen, and welcome to your FERC conference call. At this time, all lines are in a listen only mode. After our presentation, we'll open the call to questions. I'd like to advise you this conference is being recorded for replay purposes. Now I'd like to turn the call over to your host, Mr. Steve Fleischman. Sir, please proceed.

S. Fleischman Thank you. Good morning. I'm sure a lot of you had trouble getting into your offices today, but thanks of taking the time. I'm very happy to have Pat Wood, who is the Chairman of FERC, speak with us today. One of our focuses this year is to highlight a number of the key regulatory developments and regulatory movers and shakers, so to speak, as we think, in general, the sector has somewhat calmed down from its crisis mode over the last few years and that, in many cases, regulatory developments will be key issues from a value perspective, and who better to kick that off

Atlantic, but also to talk about the issue more broadly. It's coming up in MISO. It's coming up in California. It's coming up in New England and New York. It's everywhere, but how to deal with just these little local market power issues. When you might have a competitive market working pretty much across a large region, you don't necessarily need to get in there with real heavy-handed approaches everywhere. We just need to be more surgical about how we look at market power and not try to use, I think as we have in the past, including even in the recent past, a real broad brush to deal with that.

Not you asked kind of a parenthetical question about a pending case. As the Commission always has, we will look at any acquisitions, mergers or sales that impact the competitive power market. We look at those for their effect on the marketplace, their effect on rates, their effect on customers. As the wholesale regulator, I will admit some concern about the acquisition of temporarily distressed generation assets by the local utilities that would otherwise be buying under a long-term contract.

I think we're, to cut to the chase, concerned about not only deals with the affiliates, but just deals that make the power markets more concentrated as opposed to more disaggregated. That means less competition, and it

P. Wood — I think we're concerned about both, for slightly different reasons. I think the Ameren case probably was that. We had a Cinergy case that we basically let get through, but announced the reasons why we care about those things, but those are the same reasons why we care about all the …. They take players out of the competitive market and the wholesale market, and make that market thereby thinner and weaker as a consequence.

We're concerned on a number of levels, but that's one, with both the affiliated acquisitions and the non-affiliated acquisitions. The OGE would probably be a good example of the second category that you mentioned.

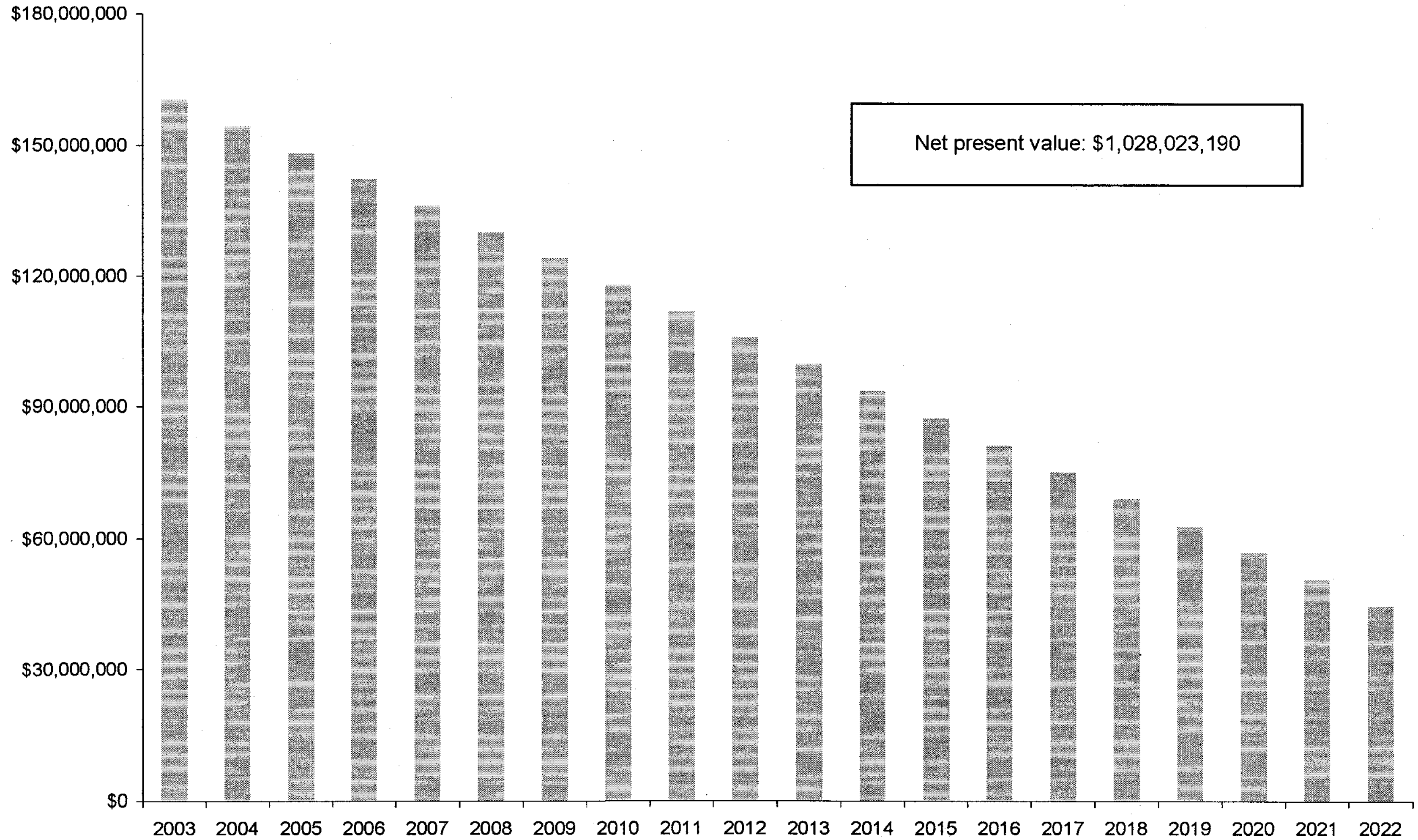
J. Green — Is it fair to say, from what I heard you mention, that you would rather see an arrangement of the long-term PBA or something like that as opposed to outright ownership?

P. Wood — Correct.

J. Green — Thank you very much.

Coordinator — You have a question from Jessica Rutledge of Lazard Asset Management.

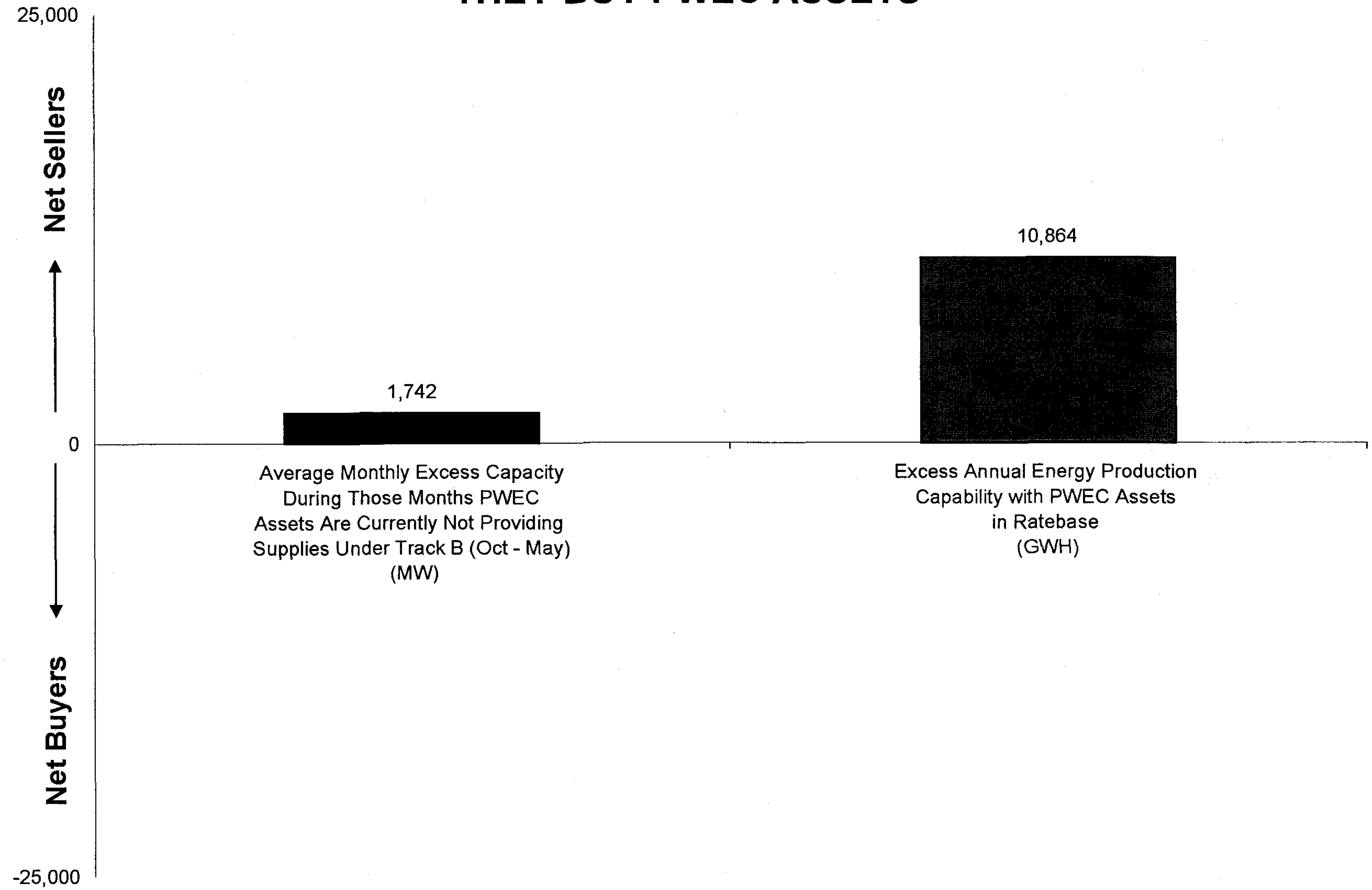
Exhibit JPK-3
"INSURANCE" PURCHASED BY CONSUMERS IF PWEC ASSETS ARE RATEBASED



Annual amount is calculated as depreciation plus the annual return on undepreciated ratebase (at 8.31%), grossed up to account for taxes (using the Company's "gross up factor" of 1.6529). A twenty-year depreciable life is assumed. Present value is calculated using a discount rate of 10%.

Sources: Schedule B-2 (revised); Direct Testimony of Chris N. Froggatt; Direct Testimony of Donald G. Robinson; Ajo Gas Service Tariff.

Exhibit JPK-4
APS RATEPAYERS WILL BE NET SELLERS OF POWER IF THEY BUY PWEC ASSETS



Sources: APB_WP9, DR001654, 12/03 AZ RFP, RC001035, APS Response to MR 1.4. See also Exhibits JDT-4 through JDT-7.

Exhibit JPK-5

Planning Scenarios- Attributes

	Scenario 1 Return to Regulation	Scenario 2 Return to Part Regulation	Scenario 3 Current Path - Dereguation	Scenario 4 Bilateral Ten Year Agreement
Business Transaction	APS/PWEC Full Reqmts Contract	Existing Units Contract	Full Market	APS/PWEC Full Reqmts Contract
Off System Purchases	PWEC buys emergency purchases	Delivery Buys @ Mkt	Delivery Buys @ Mkt	PWEC Manages
APS DELIVERY:				
PCorp & SRP Purchases	Stays with Delivery	Stays with Delivery	Stays with Delivery	Stays with Delivery
Delivery Energy Price	PWEC Units @ 11.25% plus emergency purchase	Existing Gen @ 11.25% + Purchases @ Mkt	Market Price	Ten Year Bi-lateral contract w/ PWEC
Delivery Customer Prices	To maintain 11.25% ROE before O/S margins	To maintain 11.25% ROE before O/S margins	To maintain 11.25% ROE	Affordable PBR
Delivery Purchase Power Adjustment Clause	YES	YES	YES	NO
PWEC GENERATION:				
Existing Generation Sales	Priority to APS, excess to market	Priority to APS, excess to market	To Market	Priority to APS, excess to market
Existing Generation Price	APS load @ 11.25% + Off-System margin kept	APS Load @ 11.25% + Off-System Margin	Market Price	Affordable delivery price, Allocated
New Generation Sales	Priority to APS, excess to market	To Market	To Market	Priority to APS, excess to market
New Generation Price	APS load @ 11.25% + Off-System margin kept	Market Price	Market Price	Affordable delivery price, Allocated
Exposure to market risk	Nil	Moderate	High	Nil
Capacity - MW's (2006)	754	3779	7705	754
Energy - GWH (2006)	xxx	xxx	xxx	xxx

APB_W830 6/104

Exhibit JPK-6

PWEC PLANTS WERE BUILT TO SELL INTO THE COMPETITIVE WHOLESALE MARKET

Before the Arizona Power Plant and Transmission Line Siting Committee ("Siting Committee"), PWCC clearly stated its intent to develop the Redhawk facility as a merchant plant in the proceedings for its Certificate of Environmental Compliance ("CEC"). In that hearing, the following exchange occurred:

> Q. (Steve Wheeler, counsel for Pinnacle West Energy Corp.) What specific authority is being requested from the Siting Committee in this application?
>
> A. (Ed Fox, PWCC Vice President for Communications, Environment and Safety) We are requesting that the Siting Committee grant a Certificate of Environmental Compatibility for the construction of four 530 MW combined cycle natural gas fired generating units in western Maricopa County.
>
> I want to provide a quick overview of the project. These facilities will be merchant plants. They truly will be in the competitive market. They will sell energy or not depending on their ability to sell at a price that can get into the market, and as such, the risk for the generation in selling that generation will be with Pinnacle West Energy.
>
> It is intended to provide the need of the expanding, not just the Phoenix market, but also the general market in the southwest which continues to grow. And we've heard a lot of testimony on the need for new generation in both Maricopa County in Arizona and the southwest, and this site was selected in part to meet that need.

Likewise, PWCC clearly stated in its intent to develop the West Phoenix facility as a merchant plant in the proceedings for its CEC before the Siting Committee, where the following exchange occurred:

> THE WITNESS: Thank you, Sir.
> Let me start over. Pinnacle West Energy requests that the Commission grant it a Certificate of Environmental Compatibility for the construction of two combined cycle natural gas-fired generating units here in Phoenix, Arizona. Unit 1 that we call unit combined cycle four, CC4, will be 120 megawatts, and CC5, which will be 530 megawatts.

Source: Various trade press.

Exhibit JPK-6

PWEC PLANTS WERE BUILT TO SELL INTO THE COMPETITIVE WHOLESALE MARKET

> Q. (BY MR. WHEELER) Will these be dedicated units? And by that I mean, will the output be sold to one particular customer in the contract?
>
> A. No, they won't. As I explained earlier, as the utility industry moves in the competitive marketplace, part of that competitive marketplace is in the generation of electricity itself. And these facilities will be merchant plants that will be selling into the wholesale market. In this regard, and being part, selling into the wholesale market, the competitive market, being an unregulated subsidiary of Pinnacle West Capital Corporation, the ratepayers will not be at risk for this venture and for this expansion.

Finally, in March 2000, PWCC further clarified that the Redhawk unit was intended as a merchant facility when it announced that it had entered into a joint development agreement with Reliant Energy Power Generation, Inc. under which Reliant and PWCC would share "construction and operation of three merchant power plants in Arizona and Nevada" including the planned Redhawk facility. In describing the Joint Development Agreement, Mr. Post stated that the Nevada projects and the Redhawk facility "will allow us to meet increasing demands for power across the southwest and at the same time promote a competitive market that will ultimately benefit consumers. . . . We intend to create a robust generation business that helps ensure a reliable supply of electricity in the West." The same article quoted Bill Stewart, PWEC's President, as stating:

> We intend to offer competitively priced electricity in growing Southwest markets by producing low-cost energy that is accessible to key transmission hubs. . . . These projects are part of our overall growth strategy that will keep us near the top of western power producers. This partnership is a demonstration of our oft-stated goal of being a broad-based supplier for power markets in the West, where we have extensive business experience and market knowledge.

Likewise, in describing the planned development of the Redhawk facility, a September 29, 1999, article in Business Wire stated that "the plant will compete in deregulated energy markets of Arizona, California and other western states and will be operated by Pinnacle West Energy, the new Pinnacle West generating entity that was formed earlier this week." The article went on to quote PWEC's President Bill Stewart as saying:

Source: Various trade press.

Exhibit JPK-6

PWEC PLANTS WERE BUILT TO SELL INTO THE COMPETITIVE WHOLESALE MARKET

> We intend to be a vigorous player in these competitive generation markets . . . We have a strong record of low-cost, efficient plant operation. We can best serve the public and our shareholders by pursuing these developing markets, particularly in Arizona and the Southwest.

"PWE[C] entered into two agreements with APS on March 15, 2000 for APS to provide firm transmission from both West Phoenix Unit 4 and West Phoenix Unit 5 to the Palo Verde 500 Kv switchyard. For West Phoenix Unit 4, APS is providing 125 MW of reserved capacity beginning August 1, 2001 and ending March 31, 2004. For West Phoenix 5, a reserved capacity of 525 MW will begin June 1, 2003 and end September 30, 2004."
- Workpaper APB_WP28

"Pinnacle West Capital Corporation plans to develop a natural gas-fired electric generating station of up to 2,120 megawatts approximately 50 miles west of Phoenix near the Palo Verde Nuclear Generating Station switchyard, Generation President Bill Stewart announced today.
The plant will compete in deregulated energy markets of Arizona, California and other western states and will be operating by Pinnacle West Energy, the new Pinnacle West generating entity that was formed earlier this week.
'We intend to be a vigorous player in these competitive generation markets,' Stewart said.
(...)
The plant's location was selected because the Palo Verde switchyard is a major transmission hub and provides access to energy markets in Arizona, California and across the Southwest, a region that has seen significant growth. Since 1994, electricity usage in Arizona has increased more than 4.5 percent a year. "

- Pinnacle West press release, "Pinnacle West to Build Large Power Plant Project in Western Maricopa County", September 19, 1999

"Pinnacle West Energy, the generation subsidiary of Pinnacle West Capital Corporation (NYSE: PNW), today announced the beginning of construction of the Redhawk Power Plant, the largest of the projects among the company's current generation expansion activities. The Dec. 19 groundbreaking marks just one of three important milestones for the company's expansion program.
The 2,120-megawatt Redhawk Power Plant, located near the Palo Verde Nuclear Generating Station 55 miles west of Phoenix, will be the first project to actually break ground in the Palo Verde area.
"This is a major accomplishment for us, as well as for customers throughout Arizona and the West," said Bill Stewart, President of Pinnacle West Energy. "This project, along with others we have announced, will allow us to help meet increasing demands for power in Arizona and markets across the Southwest

Source: Various trade press.

Exhibit JPK-6

PWEC PLANTS WERE BUILT TO SELL INTO THE COMPETITIVE WHOLESALE MARKET

and at the same time promote a competitive market that will ultimately benefit customers. We intend to offer competitively priced electricity in these markets by producing reliable, low-cost power that is accessible to key transmission hubs.'"

- Pinnacle West press release, " A Pinnacle West Energy Announces Generation Expansion Milestones", December 4, 2000

"Redhawk is a larger merchant plant..."

- Generation Business Plan 2000, Pinnacle West Energy Redhawk Project (Exhibit P-12)

"PWE is evaluating potential partnerships with other generating companies. We plan to use our ownership of the West Phoenix and Redhawk projects as leverage to obtain interests in generating plants outside Arizona under favorable conditions.

Potential partners find the growth in our service area and the Redhawk location at Palo Verde power trading "hub" to be to be attractive business opportunities. We in turn will look for turbine availability, diversification outside Arizona, immediate entry into competitive western markets, operating plants with cash flow and earnings and strategic locations in high-growth areas and/or on the "right" side of transmission constraints."

- Generation Business Plan 2000, Pinnacle West Energy Negotiate Partnerships (Exhibit P-12)

" Pinnacle West Energy has signed a joint development agreement with Reliant Energy Power Generation, Inc. (Reliant) covering construction and operation of three new merchant plants. Pinnacle West Energy plans to contribute the first two units (1,060 MW) of the Redhawk project to the joint agreement. Construction is expected to start in the third quarter of 2000, with commercial operation scheduled in the summer of 2002. Reliant plans to contribute two new natural gas-fired projects (1,500 MW) in Nevada to the venture."

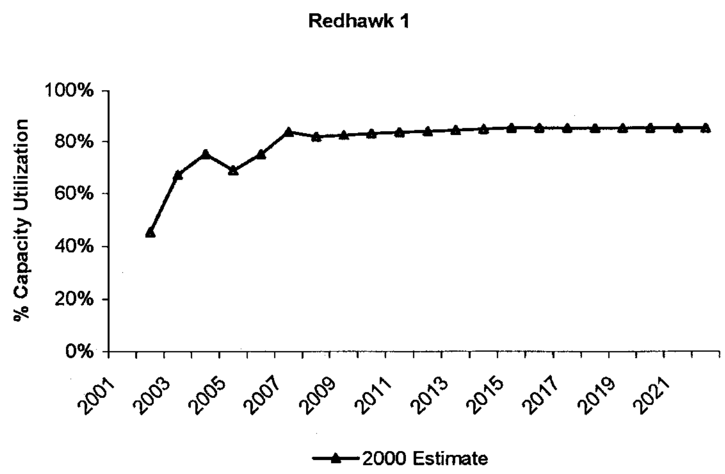
- Pinnacle West Capital Corporation, 1999 Form 10-K at 52, filed March 30, 2000.

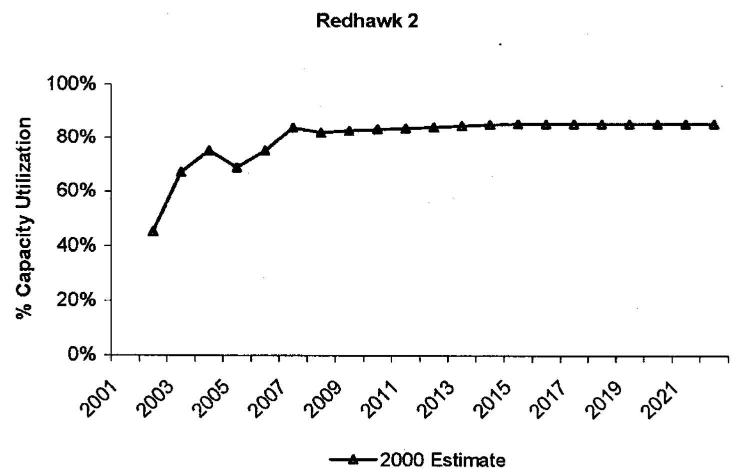
"The new generating facilities will be used to sell capacity and energy to the wholesale market and the delivery amounts will vary depending on the seasonal prices at the specified delivery points."

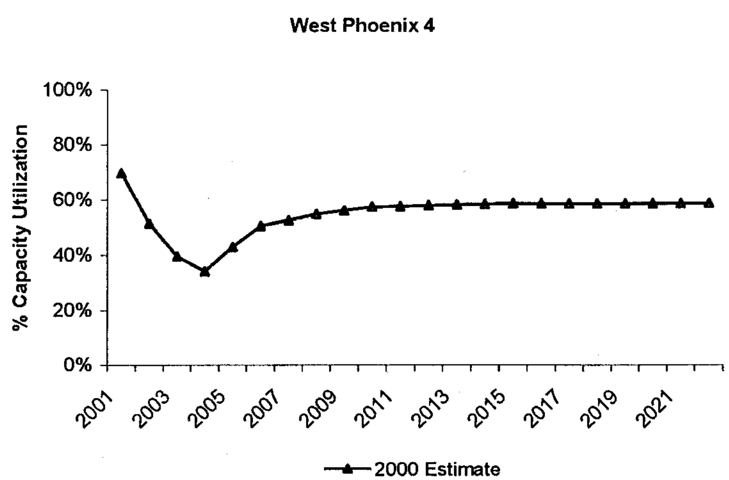
- Description of the supply characteristics of the capacity and energy to be delivered by W. Phoenix Power Plant, AZPS Firm Point to Point Transmission Service Application, November 1, 1999.

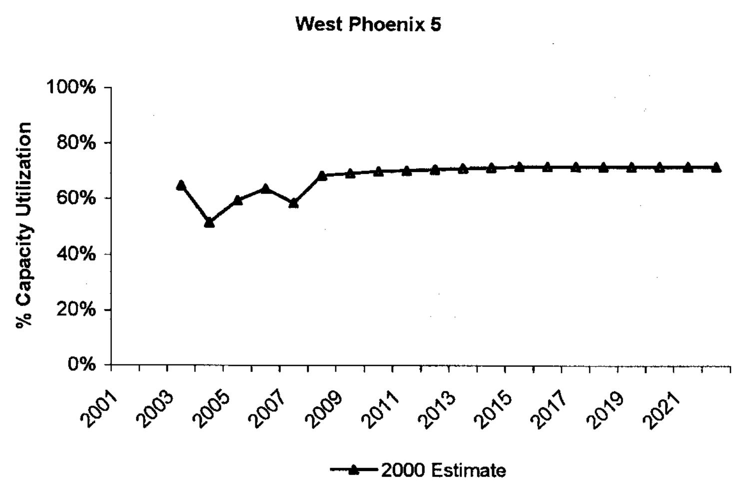
Source: Various trade press.

Exhibit JPK-7a
PWEC'S ORIGINAL FORECASTS OF CAPACITY UTILIZATION FOR ITS NEW ASSETS



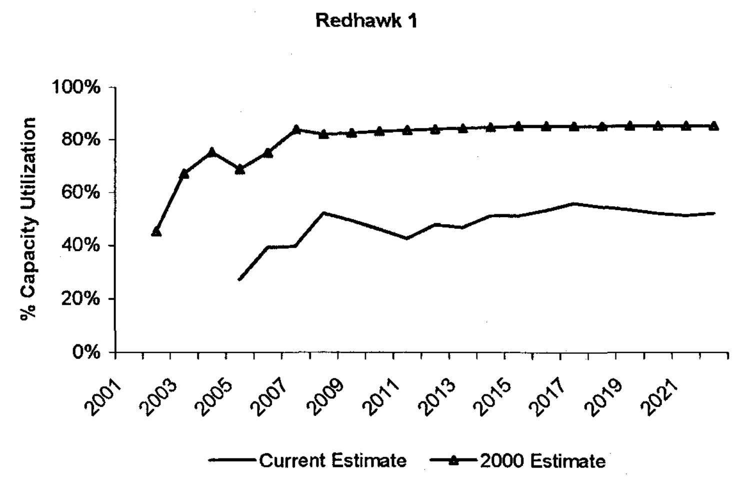


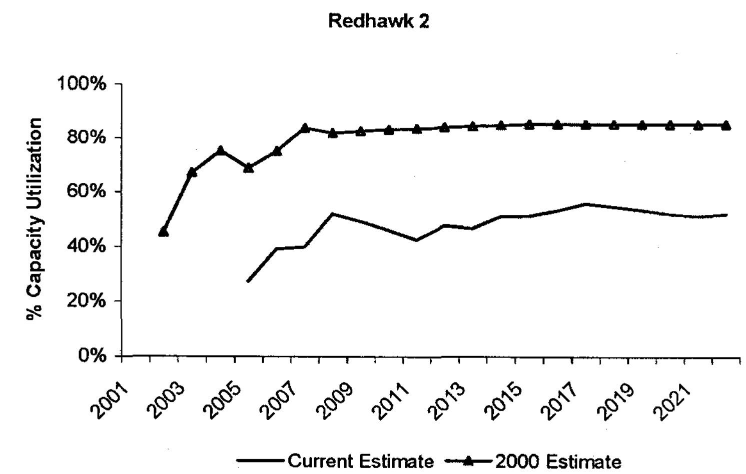


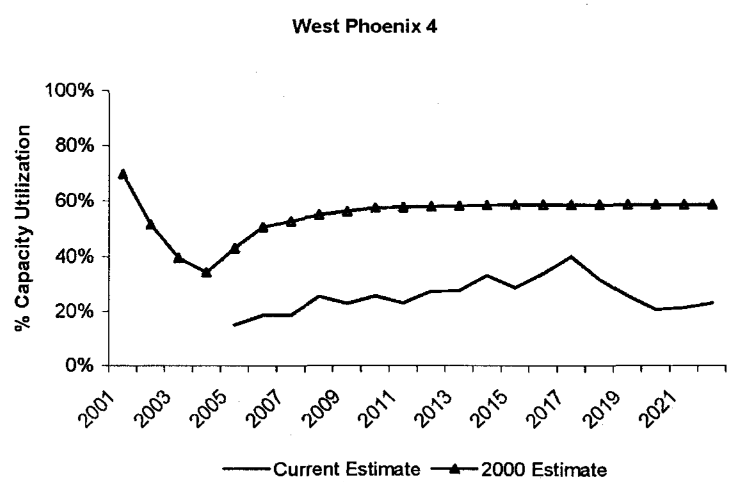


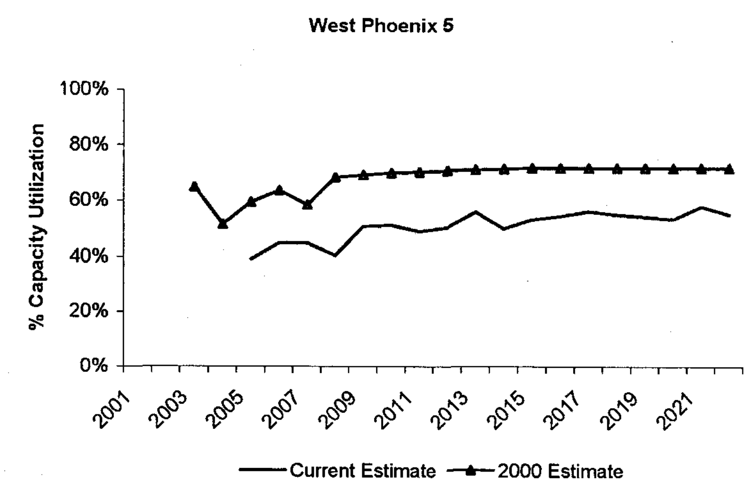
Source: APS' 2nd Informal Response to AZCPA's Data Request (Back up analyses for Direct Testimony of Ajit Bhatti, Attachment AB-5).

Exhibit JPK-7b
PWEC'S ORIGINAL v. CURRENT FORECASTS OF CAPACITY UTILIZATION FOR ITS NEW ASSETS







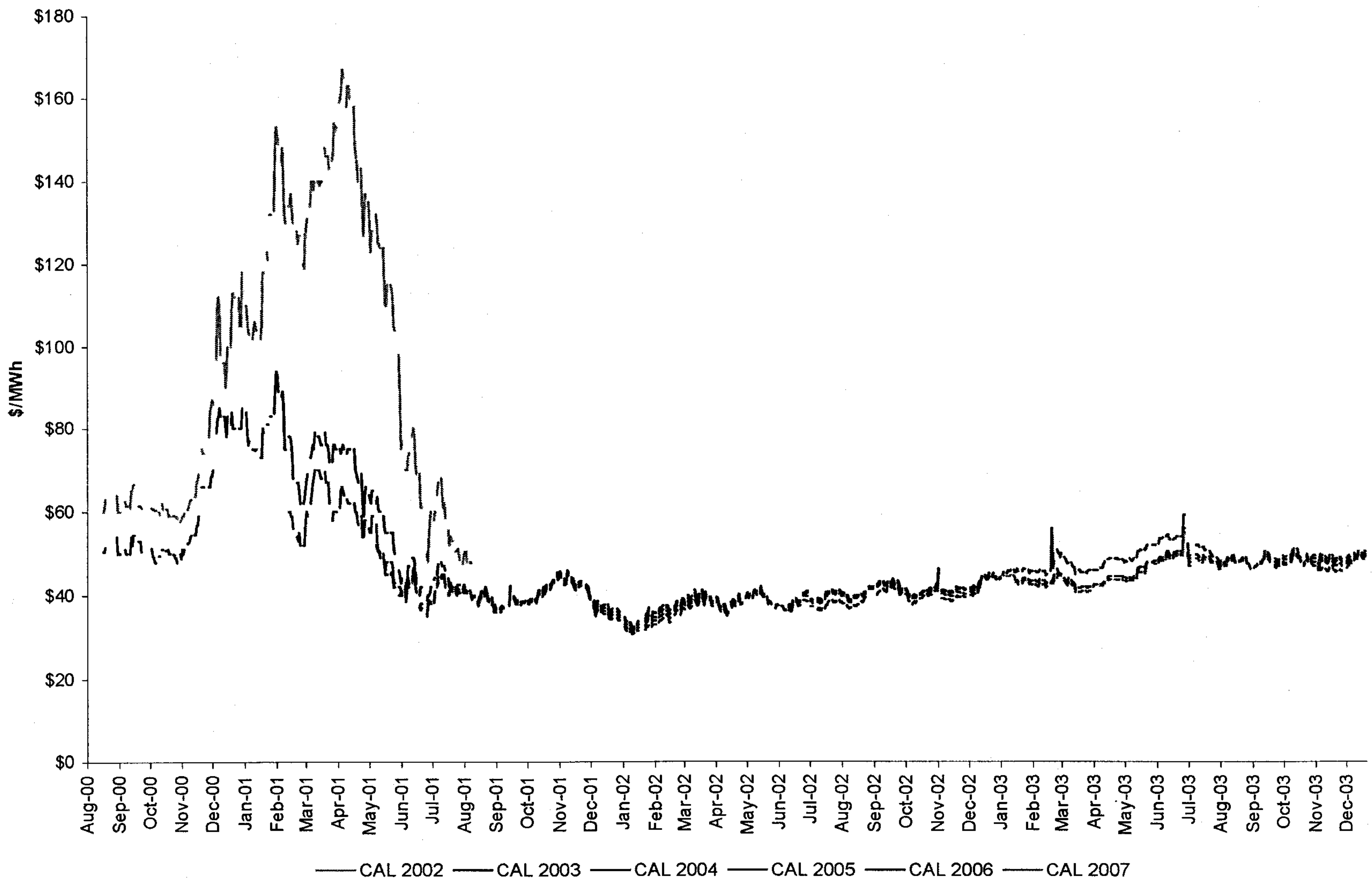


Sources: RC01243, RC01244; APS' 2nd Informal Response to AZCPA's Data Request (Back up analyses for Direct Testimony of Ajit Bhatti, Attachment AB-5).

Significant Results - Continued

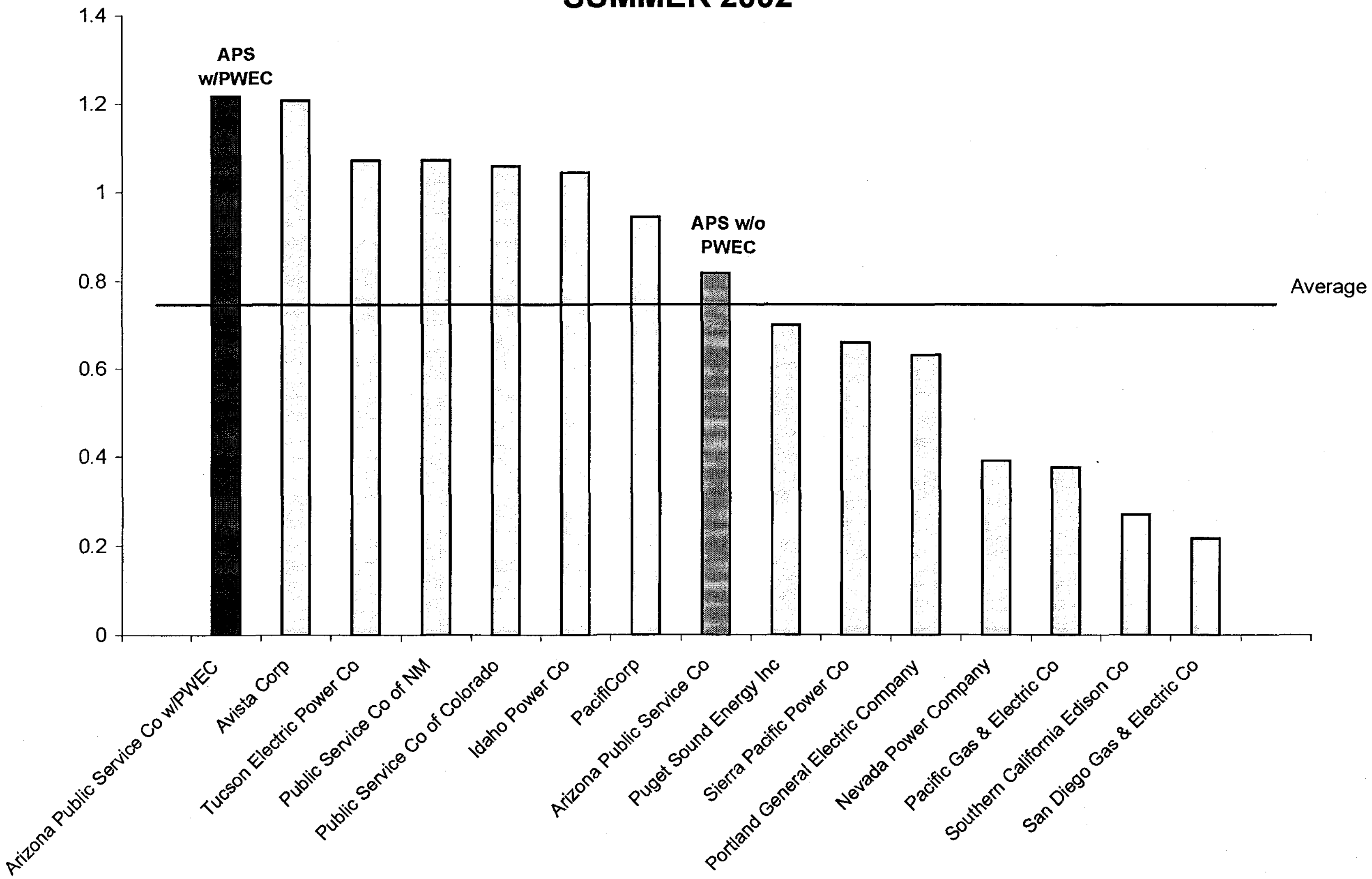
- Earnings
  - PWEC earnings steadily increase under re-regulation ($189-$300 Million)
  - PWEC earnings steadily increase under bi-lateral contract ($189-$368 Million)
  - PWEC earnings flat 2004 though 2009 under market scenario ($220-$245 Million)
  - PNW earnings based on Delivery receiving rate increase to retain 11.25% ROE each year

Exhibit JPK-9
PALO VERDE WHOLESALE FORWARD PRICES FELL SIGNIFICANTLY IN SPRING 2001



Source: TFS Energy.

Exhibit JPK-10
RATIO OF REPORTED CAPACITY TO PEAK LOAD FOR SEVERAL WESTERN U.S. INVESTOR-OWNED UTILITIES
SUMMER 2002



Sources: WECC Summary of Estimated Loads and Resources, EIA 860 Data, EIA 861 Data.

EXHIBIT
tabbies
ACPA-2
admitted

DIRECT TESTIMONY OF JEFFREY D. TRANEN

On Behalf of Arizona Competitive Power Alliance

Docket No. E-01345A-03- ___

FEBRUARY 3, 2004

Table of Contents

I QUALIFICATIONS AND INTRODUCTION

Q: **PLEASE STATE YOUR NAME, ADDRESS AND OCCUPATION.**

A: My name is Jeffrey Tranen. My business address is 145 East 76th Street, New York, NY. I am a Senior Vice President of Lexecon Inc., an FTI Company. Lexecon is a large consulting firm specializing in economics, energy, and finance. Lexecon professionals provide economic analysis and strategic advice to large industrial clients such as utilities, regulatory agencies, and other private and public sector entities.

Q: **PLEASE STATE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.**

A: I am an electrical engineer by training. I attended the Massachusetts Institute of Technology, where I received a B.S. and M.S. in electrical engineering, and subsequently an Electrical Engineer Degree (meaning I completed the course work, but not the dissertation, for a PhD). From 1970 to 1997, I held a variety of positions at New England Electric Systems ("NEES"), an electric utility holding company in New England. From 1993 to 1997, I was President of a NEES subsidiary, New England Power Company, which operated the wholesale generation and marketing business for NEES. From 1978 to 1997, I held various positions at NEES with responsibility for operating the transmission system as part of the New England Power Pool ("NEPOOL"). During my time at NEES, I served on numerous NEPOOL and North American Electric Reliability Council ("NERC") Committees. In addition, from 1995 to 1997, I served as Chairman of the NEPOOL Management Committee.

From September 1997 until March 1999, I was the CEO of the California Independent System Operator Corporation. My tenure there covered the startup and first year of commercial operation of the ISO (from April 1998 through March 1999). From March 1999 to February 2000, I was President of Sithe Northeast, a holding company that owned and operated generation in the ISO-run markets in place in New England, New York and PJM. Since Spring 2000, I have been employed by Lexecon working on a variety of federal and state regulatory matters related to the electricity industry. I have testified several times before state and federal regulatory commissions. Details regarding my educational background and experience can be found in Exhibit JDT-1.

Q: **ON WHOSE BEHALF IS YOUR TESTIMONY SUBMITTED?**

A: My testimony is submitted on behalf of the Arizona Competitive Power Alliance ("Alliance").

Q: **WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

A: I have been asked by the Alliance to review the request made by the Arizona Public Service Company ("APS" or the "Company") on June 27, 2003 for authorization from the Arizona Corporation Commission ("Commission") to transfer into APS's rate base at 2004 depreciated original cost approximately 1,700 MW of electricity generation capacity[1] built by its unregulated affiliate, Pinnacle West Energy Company ("PWEC") and to abrogate contracts APS recently executed with PWEC for summer capacity and energy through

---

[1] The plants are Red Hawk Units 1 & 2 with a capacity of 495 MW each; West Phoenix 4 at 120 MW; West Phoenix 5 at 525 MW; and, Saguaro SC 3 at 80 MW, which totals a little more than 1,700 MW of capacity.

2006 ("Track B Contracts").[2] My testimony analyzes and responds to APS's arguments in support of its request to rate base its affiliate's generation ("PWEC assets") and abrogate the Track B Contracts.

Q: **PLEASE PROVIDE AN OVERVIEW OF YOUR TESTIMONY.**

A: My testimony focuses on the following specific observations I make as a result of my analysis of the APS request:

- Over the near term (2004 through 2006), the cost to APS ratepayers of APS's proposal to rate base the PWEC assets and abrogate the Track B contracts is almost \$115 million per year. At the same time, the addition of the PWEC assets to the rate base provides no material short-term reliability benefits over those already realized under the Track B Contracts.
- Over the longer term (post 2006), APS has not demonstrated that its ratebasing proposal is either necessary for reliability or provides economic benefits for APS ratepayers.
- Contrary to APS's assertions, there is considerable evidence that the competitive wholesale market will respond to a competitive solicitation by APS at the expiration of the Track B contracts in lieu of the proposed ratebasing, as long as this solicitation is fair and transparent.

---

[2] In my testimony, I refer to the APS purchase contracts with PWEC that resulted from the initial Track B solicitation that took place over the past year as the "Track B Contracts." Although I characterize the contracts as only being between APS and PWEC, I recognize in my analysis that APS has also entered into smaller supply contracts with other market participants as a result of the Track B process. When I refer to the revenue requirement excluding Track B Contracts in my testimony I am only eliminating the contracts

- The Commission's policy of encouraging a robust wholesale electricity market remains an important goal for Arizona retail customers. Rolling these plants into rate base, as opposed to requiring APS to continue to rely on the market for capacity requirements, runs counter to this goal and is not in the long term interest of APS customers.

II APS'S RATE BASING PROPOSAL RAISES NEAR-TERM RATES WITHOUT PROVIDING NEAR-TERM RELIABILITY BENEFITS OR CLEAR LONG-TERM BENEFITS.

II.A The Short-Term Impacts of APS's Proposal (through 2006).

Q: **HAVE YOU ANALYZED THE IMPACT OF APS'S RATEBASING PROPOSAL ON ITS RATES?**

A: Yes. In Exhibit JDT-2, I show that APS's proposal increases its revenue requirement by almost $115 million when compared to a test year that includes various medium-term market purchases (Track B Contracts and other anticipated medium-term and economy purchases). This represents approximately 65 percent of APS's proposed rate increase in this proceeding.[3] By requesting that PWEC assets be rolled into its rate base, APS is locking in unnecessarily higher rates for at least the years 2004-2006, and quite possibly longer, given the fact that APS already has available through contracts the quantity of

---

between APS and PWEC, not any other supply contract obligations that APS has with other market participants.

supply it would obtain through ownership of the PWEC assets during the peak summer months when needed to serve its load.

Q: **PLEASE DESCRIBE HOW YOU DEVELOPED YOUR ANALYSIS.**

A: To calculate the test year revenue requirement impact of APS's proposed treatment of the PWEC assets, I relied on cost data in the Company's rate case filing. Schedules B and C of the Company's filing show adjusted test year Rate Base and Income Statement results, as well as the cost impacts of ratebasing the PWEC assets. APS witness Donald G. Robinson discusses the rate base and income statement cost effects of the PWEC assets. Because Schedules B and C of APS's filing include both the adjusted test year results and the cost impacts of the PWEC assets, I was able to compare the Company's test year revenue requirement with and without PWEC assets in the rate base.

Q: **WOULD YOU EXPLAIN THE MECHANICS OF YOUR ANALYSIS?**

A: Yes. First, ratebasing the PWEC assets increases APS's test year revenue requirement by the amount required to provide a return on the capital associated with the assets. Placing the PWEC assets in APS's rate base increases the adjusted test year rate base by $890 million, an increase of more than 25%.[4] To calculate the revenue requirement associated with this increased capital investment, I applied the weighted average cost of capital reported in Mr. Robinson's testimony (8.67%).[5] I then used the "gross up" factor provided

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[3] Mr. Wheeler testifies that APS is seeking higher annual revenues of approximately $175 million of which $115 is 65%. (Wheeler Direct Testimony at Page 3: 4–6)

[4] Schedule B-2 (Revised), 1:6, attached as Exhibit JDT-3.

[5] Direct Testimony of Robinson at Page 29: 20.

in Mr. Froggatt's testimony[6] and found a revenue requirement impact of $127 million. Mr. Robinson testifies that the transaction would lower APS's weighted average cost of capital to 8.31% by increasing the debt in APS's capital structure.[7] When this change in capital cost is applied to APS's entire rate base, and the lower income taxes associated with increased debt are considered, I find a revenue requirement reduction of $40 million. APS's test year revenue requirement is also affected by changes in several income statement items, reported in Schedule C-2 of the Company's filing. These items include fuel and purchased power costs to meet APS's own load, depreciation and amortization, operations and maintenance, and property taxes. Finally, Mr. Robinson testifies that APS's gross margin from off-system sales will be $32 million higher as a result of ratebasing the PWEC assets, thus reducing the revenue that APS says will be required from ratepayers based on the adjusted test year analysis. I then compiled these numerical values (Exhibit JDT-2) for the case where PWEC assets are in the rate base and for the case where PWEC assets are not in the rate base and calculated the difference. I then summed the differences to find that inclusion of the PWEC assets in rate base increases the Company's test year revenue requirements by almost $115 million per year.

Q: **CAN YOU EXPLAIN WHY APS'S RATE BASING PROPOSAL IS SO COSTLY AS DEMONSTRATED BY YOUR ANALYSIS?**

A: Yes. The market value of the energy and capacity provided by the PWEC assets, at least in the near-term, cannot support the carrying costs of the PWEC assets. This is not surprising

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[6] Direct Testimony of Froggatt at Page 7: 6.
[7] Direct Testimony of Robinson at Page 29:19-22.

given the large increase in supply in the region in the past few years. This is clear by looking at the cost of energy under the Track B Contracts versus the carrying costs of the PWEC assets. As shown in Exhibit JDT-2, the reduction in fuel and purchased power by APS's abrogation of the Track B Contracts roughly equals the increased operations and maintenance costs associated with APS owning the PWEC assets. This leaves very little if any money to cover the roughly $180 million of return of and on capital associated with these assets, including taxes. APS claims they will have roughly $40 million savings associated with restructuring of their overall cost of capital and an additional roughly $30 million associated with margins from off-system sales from the PWEC assets. This leaves the roughly $115 million shortfall shown in Exhibit JDT-2. The off-system sales are derived primarily from sales during the eight months that these units are not needed to supply APS load. APS's own forecasts show that these units are projected to run at reduced capacity factors when compared to their original projections demonstrating that they are also not significantly needed off-system.[8] Thus the off-system sales cannot overcome the lack of need on the APS system and the high carrying costs associated with this excess capacity.

Q: **IS RATE BASING THE PWEC ASSETS REQUIRED FOR APS TO RELIABLY SERVE ITS PROJECTED DEMAND IN THE NEAR-TERM?**

A: No. APS has been making market purchases—including in particular the Track B Contracts—to ensure it has resources on hand to meet the majority of its summer peak

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[8] See Exhibit JPK-7.

forecast in the near-term future. For example, Exhibits JDT-4, 5 and 6 present comparisons of APS monthly peak loads and its resource base for 2004 as of mid-2003. Exhibit JDT-4 shows that month-by-month APS has available surplus capacity to meet its projected monthly peak demand.[9] Moreover, Exhibits JDT-5 and 6 compare APS's resource base with and without the PWEC assets in the rate base against projected monthly loads. The Exhibits clearly show that APS's recent Track B purchases, combined with its own resources, very closely match near-term coverage of monthly demand. Additionally, Exhibit JDT-6 shows the extent to which the roll in would cause APS to have significant excess capacity in those months other than June-September when the Track B Contracts provide capacity resources to APS. Thus there is no material improvement in reliability in the near-term to justify the significantly higher costs proposed by rate basing the PWEC assets.

Q: **IS THE RATE BASING REQUIRED FOR APS TO RELIABLY SERVE ITS PROJECTED ENERGY REQUIREMENTS?**

A: No. Exhibit JDT-7 shows a comparison of projected 2004 APS customer monthly energy requirements compared to the amount of energy production APS has available to it both

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[9] APS has revised its supply/demand projections as part of its Request for Proposal issued December 3, 2003. These revised projections indicate that APS may require additional purchases of energy and/or capacity during the 2004-2006 time period. The projections do not demonstrate, however, that the offsetting actions of rate basing the PWEC assets and abrogating the Track B Contracts could materially assist APS in serving these increased loads. Although APS may contend that these projected revisions are sufficient evidence that its current resource base is inadequate, as I discuss in Section III of my testimony, it is quite common for a utility to rely on the market for a portion of its supplies—especially when the need for the supplies is uncertain.

with and without the PWEC assets in the rate base.[10] The Exhibit clearly depicts the fact that the addition of the PWEC assets to the rate base results in considerable excess production capability for all those months other than June-September. Without the PWEC assets, APS's portfolio of supply much more closely matches the energy requirements of its customers. Thus, adding PWEC assets to rate base shifts the burdens and risks of marketing and selling large quantities of the energy available from the PWEC assets from PWEC to APS, and subsequently to APS's retail customers.

Q: **WHY WOULD THE RATE BASING OF THE PWEC ASSETS CREATE SO MUCH EXCESS ENERGY PRODUCTION CAPABILITY FOR APS?**

A: APS's load requirements for its customers are sharply higher in the summer months. In recent years, the annual load factor for the APS load is 52 -55%, which means that, on average, APS only needs one half of the energy that it needs in the peak demand hour of the year.[11] APS already has in its supply portfolio a significant amount of capacity that is capable of economically operating throughout the year toward satisfaction of its load requirements.

Mr. Bhatti's workpapers APB_WP9 reveal that APS expects to obtain more than 21,500 GWh or greater than 80% of its forecasted Standard Offer load of 26,494 GWh from its base load, low-cost power plants Palo Verde, Four Corners, Cholla and Navajo.[12] Mr.

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10 When developing this Exhibit, I excluded combustion turbines and hydroelectric facilities; these plants contribute only small amounts of energy to APS's overall energy supply.

11 Workpaper APB_WP12, attached as Exhibit JDT-3.

12 Workpaper APB_WP 9 and WP11, attached as Exhibit JDT-3.

Bhatti's analyses show that APS expects to enjoy access to this low cost power regardless of whether PWEC assets are in the rate base.

Q: **PLEASE SUMMARIZE YOUR CONCLUSIONS REGARDING THE NEAR-TERM IMPACT OF APS'S PROPOSAL TO RATE BASE THE PWEC ASSETS AND ABROGATE THE TRACK B CONTRACTS.**

A: I conclude that APS ratepayers will enjoy lower power supply costs without the PWEC assets in APS's rate base and that APS system reliability will be virtually unchanged. As I explain above, APS is asking the Commission to allow it to recover the considerable fixed costs of the PWEC assets that APS can avoid if it instead relies on the current Track B Contracts. APS has not shown that relying on Track B Contracts in the near term will result in any reduction in system reliability. On these facts alone, I believe that the Commission should reject APS's proposal.

II.B The Longer Term Impacts of APS's Proposal (Post 2006).

Q: **HAS APS SHOWN THAT OWNERSHIP OF THE PWEC ASSETS IS NECESSARY FOR IT TO RELIABLY SERVE ITS CONSUMERS POST 2006?**

A: No. APS witness Bhatti asserts in his testimony that the PWEC assets were built to serve APS and thus they are uniquely suited to the needs of APS.[13] However, Mr. Bhatti's contention that the assets must be owned in order for APS to operate its system reliably is limited to his identified Valley must-run requirements for PWEC Units West Phoenix 4 and

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[13] Bhatti Direct Testimony at Pages 8-24.

5.[14] Dr. Hieronymus and Mr. Wheeler similarly assert that Valley unit must-run generation provided by West Phoenix 4 and 5 leads to greater system reliability.[15] Aside from the specific characterization of these resources as necessary for providing must-run generation in the Phoenix Valley load pocket at certain very limited times of the year, APS has not explained how ownership of the PWEC assets is required for system reliability.

Q: **WHAT ABOUT APS'S CLAIMS THAT IT SHOULD RATEBASE THE PWEC ASSETS BECAUSE THESE PLANTS PROVIDE APS'S VALLEY LOAD POCKET MUST-RUN RELIABILITY SERVICES?**

A: I have reviewed a recent reliability must-run analysis performed by APS and I agree that its analyses show that there are some 500-600 hours per year when generation in the Valley must be run in order to assure system reliability.[16] I also agree that APS could show that PWEC units West Phoenix Units 4 and 5 can fulfill this need from time-to-time. I do not agree that putting these plants into rate base is the only means of obtaining the indicated must-run services on a reliable basis or that it is the most economical means of assuring Valley reliability. In APS's January 31, 2003 Reliability Must-Run Analysis, the Company concluded that its system could be operated reliably as presently configured. The report indicates that although West Phoenix Units 4 and 5 can provide must-run services, there are other options available as well.[17] For example, the report examines the trade-off between improving transmission import capability into the region with using local generation

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14 Bhatti Direct Testimony at Page 5:12-14.
15 Hieronymus Direct Testimony at Page 5:12 and Wheeler Direct Testimony at Page 13: 8-9.
16 Discovery Response LCA 3-90, RC00820 at page 6, attached as Exhibit JDT-3.
17 Id. at pages 9-10, attached as Exhibit JDT-3.

resources. APS notes that it will require from 365 MW in 2003 to 554 MW in 2005 of non-APS resources within the Phoenix area to serve APS's Phoenix-area load. APS estimates that it could relieve 452 MW of the Phoenix area's transmission constraint through the addition of a 600 MVAR static var compensator at an annualized cost associated with this investment of about $2.4 million.[18] Thus there are various low cost approaches for APS to assure Valley reliability upon expiration of the Track B Contracts. APS has not demonstrated that a reliability problem will exist in the Valley without certain of the PWEC assets in rate base.

Q: **IS THERE OTHER EVIDENCE THAT UNDERMINES THE PROPOSITION THAT APS'S OWNERSHIP OF WEST PHOENIX UNITS 4 AND 5 IS CRITICAL TO APS'S SYSTEM RELIABILITY?**

A: Yes, although it is clear that the Valley load pocket is subject to occasional periods where must-run operation of certain facilities is required, PWEC never assumed that the West Phoenix plants would be built to exclusively provide reliability must-run services. Actually, evidence indicates that PWEC fully expected to export power from these facilities for sale at Palo Verde. For example, a PWEC S&W Consultants' report[19] from February 12, 2001 indicates:

> "PWE[C] entered into two agreements with APS on March 15, 2000 for APS to provide firm transmission from both West Phoenix Unit 4 and West Phoenix Unit 5 to the Palo Verde 500 Kv switchyard. For West Phoenix Unit 4, APS is providing 125 MW of reserved capacity beginning August 1, 2001 and ending March 31, 2004. For West Phoenix 5, a reserved capacity of 525 MW will begin June 1, 2003 and end September 30, 2004."

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[18] Id. at pages10 and 44, attached as Exhibit JDT-3.
[19] Workpaper APB_WP28 at page 12, attached as Exhibit JDT-3.

Moreover, in the 2003 Reliability Must Run Report, APS noted that because the actual number of out-of-merit dispatch hours is low in the Valley, generation reliance was the cheap, and preferred alternative, when compared to transmission upgrades.[20] The evidence indicates that these units were built with an intention to be able to provide energy at various points in the transmission system, not to just meet APS's occasional must-run requirements.

Q: **HAVE YOU CONSIDERED APS'S CONTENTION THAT ITS TRACK B SOLICITATION SHOWS THAT IT CANNOT OBTAIN NEW GENERATION RESOURCES IN THE VALLEY TO MEET ITS NEED FOR MUST-RUN SERVICES?**

A: Yes. I believe that APS's contention that it is unable to secure incremental megawatts in the Valley area is not based upon actual efforts to obtain these services.[21] For example, APS has not issued a Valley specific RFP. Nor have they taken into account low cost transmission solutions. The low number of must-run hours for the Valley is well-suited for economic supply by peaking units instead of the combined cycle PWEC assets that are more typically used to meet base load requirements. An RFP for Valley must-run services would allow the market to provide this service with peaking units that could be constructed prior to the end of the Track B Contracts.

Q: **WHAT ABOUT APS'S CLAIMS THAT THE PWEC ASSETS COULD PROVIDE OPERATIONAL FLEXIBILITY THAT CANNOT BE PROVIDED BY OTHER GENERATION FACILITIES?**

A: I do not disagree with APS's claims that it would dispatch and operate its system differently if it completely controlled the generation facilities that were built by PWEC, but I find that APS has not demonstrated that these operational benefits translate into secure, long-term savings for ratepayers.[22]

First, if the benefits of ownership and subsequent joint dispatch of these facilities with APS's existing generation facilities were significant in the near-term, APS would not need to ask for a rate increase to accommodate the addition of these plants to its fleet. As I have demonstrated above (and as Professor Kalt discusses in his testimony), the PWEC assets will be a financial drag on APS in the near years, and there is no guarantee that out year performance will produce significant benefits. APS is asking the Commission to conclude that APS's customers will benefit from rate basing the PWEC assets on the bet that speculative, long-term revenues associated with the PWEC assets will be able to significantly offset certain near year losses. The Commission should reject this attempt to shift the merchant generation risk that PWEC assumed when it built the PWEC assets to APS's customers.

Q: **HOW DO YOU RESPOND TO APS'S CLAIM THAT RATE BASING THE PWEC ASSETS OFFERS ECONOMIC ADVANTAGES TO ITS CUSTOMERS THAT**

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[20] Discovery Response LCA 3-90, RC00820 at pages 9-10 attached as Exhibit JDT-3.

[21] Bhatti Direct Testimony at Pages 14-15 and Wheeler Direct Testimony at Pages14: 3-20.

[22] Mr. Wheeler testifies that because Track B provides operational control of PWEC assets only during the months of June-September 2004-2006, that additional operational benefits would accrue if there were an unexpected outage of an APS generation facility. (Wheeler Direct Testimony at Page 16:13-21.) Presumably, APS targeted only the summer months for its procurement process because it recognized that there are ample resources available from its current generation resources and the wholesale market to cover its load during the fall/winter/spring months, including reserves to cover a plant outage.

WOULD OTHERWISE BE UNAVAILABLE FROM THE WHOLESALE MARKET?

A: I find APS's contention purely speculative. Because APS has not provided any evidence of the value of the PWEC assets in the market, APS cannot credibly claim that its proposal to rate base the PWEC assets at current book value offers APS's customers long-term benefits over the status quo. A market appraisal is a fundamental part of any generation purchase and sale, and presumably APS (and PWEC) have conducted market analyses of the value of the PWEC Assets. Indeed, the failure of APS to include a market appraisal of the PWEC assets in its direct case suggests either that it is acting imprudently with respect to this proposed transaction or that the results of such a market appraisal would not support APS's proposal to purchase the PWEC assets at book value. Instead of relying on a market valuation, APS points to savings based upon depreciation that has somewhat reduced the PWEC assets' original book value. But book value, whether original or current, has no direct relationship to market value, which is the only value by which the actual savings or costs of APS's rate basing proposal can appropriately be measured. Savings off the original book value of the PWEC assets are irrelevant to the relative economic benefits or disbenefits of APS's rate basing proposal.

Q: **HOW DOES APS SUPPORT ITS CLAIM THAT RATEBASING THE PWEC ASSETS PROVIDES ECONOMIC BENEFITS TO CUSTOMERS?**

A: APS witness Wheeler offers an analysis that claims that putting the PWEC assets into the rate base at 2004 book value of $896.1 million or $533/Kw produces almost $500 million of savings to ratepayers.[23] Mr. Wheeler first compares the $533/Kw value to various observed costs to construct other similar facilities, then finds that those realized costs on average are higher than $533/Kw and ultimately concludes that the difference between the book value and recently observed costs to construct facilities should be considered indicative of savings available to APS customers.

Q: **DO YOU FIND MR. WHEELER'S ANALYSIS PERSUASIVE?**

A: A: No. Mr. Wheeler's reliance on recently observed construction costs for combined cycle power plants cannot be considered suitable evidence to support his claims. His entire analysis assumes that it is appropriate for APS to add base-load combined cycle plants only, which are considerably more expensive to build than peaking plants, without any analysis to support a conclusion that the higher capital costs of PWEC's combined cycle plants are justified based on lower energy costs versus a peaking unit.

Moreover, there are a significant number of existing underutilized plants and partially completed plants in the Southwest whose output may be available for well less than the cost of new generation. Figure 3 of page 21 of Mr. Bhatti's testimony shows that the demand requirement in Arizona does not substantially exceed the current supply until 2009. In fact, in conjunction with its new RFP, Mr. Wheeler recently indicated to the Arizona Republic that APS is hoping to take advantage of a buyer's market for Arizona power plants.[24]

Q: **HAVE YOU REVIEWED APS'S SUMMARY RESPONSE TO ITS NEW RFP?**

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[23] See Workpaper SMW_WP17, attached as Exhibit JDT-3. Note that the PWEC asset's book value shown in the workpaper is slightly higher than the amount ($889 million) shown in Schedule B-2 of the rate case filing.

[24] Arizona Republic Article, November 26, 2003, attached as Exhibit JDT-3.

A: Yes. The results clearly indicate that there are power plant owners in Arizona ready and able to offer long-term power supplies to APS. APS reports that 9 companies submitted 13 proposals offering approximately 6,800 MW.[25] These results call into question APS's claims that the wholesale market cannot be expected to meet its requirements (see Section III) and indicate that as opposed to ratebasing PWEC assets at book value, PWEC should be competing along with other suppliers in the market for the opportunity to enjoy the benefits of a long-term contract with APS.

Q: **WILL APS'S RECENT RFP FOR LONG TERM CAPACITY SERVE AS A REASONABLE BENCHMARK FOR RATEBASING THE PWEC ASSETS?**

A: No. Given the terms under which the December 3, 2003 RFP is being conducted, the results will not provide a reasonable benchmark. For example, the RFP includes a Draft Asset Purchase Agreement with a "Regulatory Out Clause" that shifts significant risk from APS's shareholders to all potential sellers.[26] APS has not imposed a similar condition on PWEC in the proposed rate-basing of PWEC assets. From my experience, this type of provision may either eliminate some potential bids or materially add to the price bid for the sale of the asset.[27] Indeed, as I discuss further below, the Independent Monitor in the Track B process concluded that APS's Regulatory Out provision for long term bids likely had a chilling effect on the receipt of such bids.

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25 APS' Summary of Responses Received to its Power Supply Request for Proposals Dated December 3, 2003, January 27, 2004.

26 APS December 3, 2003 RFP, (Section 8.7, page 31), attached as Exhibit JDT-3.

27 APS's summary of its RFP responses submitted on January 27, 2004 included an indication that no party who submitted a bid objected to this clause. However, this does not reveal whether parties failed to submit bids because of this provision or whether this provision affected the prices of the bids received.

Q: PLEASE SUMMARIZE YOUR CONCLUSIONS REGARDING APS'S CLAIMS THAT PUTTING THE PWEC ASSETS INTO RATE BASE PROVIDES LONG TERM BENEFITS.

A: I conclude that APS's claimed benefits are largely speculative and anecdotal. APS has not shown that it needs the PWEC assets to operate its system reliably and it has not offered any credible evidence that a transfer at book value provides reasonable value to its customers.

III APS SHOULD RELY ON THE WHOLESALE MARKET TO SUPPLY A PORTION OF ITS CUSTOMERS' NEEDS.

Q: HAVE YOU EXAMINED APS'S CONTENTION THAT OVER THE LONGER TERM, THE COMPETITIVE MARKET CANNOT BE RELIED UPON TO ECONOMICALLY MEET APS'S NEEDS?

A: Yes. APS witnesses state at several points throughout their testimony that the Western U.S. wholesale electricity market may be incapable of providing APS with reliable electricity supplies beyond 2006. To support its concerns about reliance on the wholesale market for longer term supply, APS relies chiefly upon the dearth of long term bids it received in its Track B solicitation. Mr. Wheeler, for example, states as follows:

> "[T]he results of the Commission's Track B solicitation . . . demonstrated that the competitive market is as of yet too immature . . . and cannot be

> relied upon to reasonably meet APS customers' needs at all times and under all market conditions."[28]

> "Offers of power for delivery after 2005 [in the Track B solicitation] were virtually non-existent [and] . . . underscore[s] the essential difference between a vertically-integrated utility's obligation and ability to plan for and provide for the resources needed to assure reliability and the market's concern for profit maximization."[29]

APS fails to note, however, that the Track B solicitation was expressly designed to cover APS supply needs through 2006, not beyond, and that APS proposed the inclusion of a "Regulatory Out" provision in all contract deliveries after 2005. The Independent Monitor specifically identified this as one reason why some bidders chose not to provide bids for power to be supplied after 2005.[30] Indeed, I believe that APS's inclusion of an onerous "Regulatory Out" clause was much more likely the limiting factor on long term bids into the Track B process than the reason suggested by Mr. Wheeler and Dr. Hieronymus, i.e., the expectation of high prices after 2005.[31] In that regard, my view is consistent with APS's stated explanation for the urgency in issuing its latest RFP – that there are several

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[28] Direct Testimony of Wheeler at Page 5: 14-18. APS witness Hieronymus makes similar statements in his testimony regarding the capability of the competitive wholesale generation market to meet the needs of APS's customers. According to Dr. Hieronymus:

> "Even in the Track B solicitation, long after the electricity crisis had waned, only quite modest and insufficient amounts of generation owned by others was made available for contracts to meet APS's load." Direct Testimony of Hieronymus at Page 8: 1-4.

[29] Direct Testimony of Wheeler at Page 14: 3-10.

[30] Independent Monitor's Final Report on Track B Solicitation, Accion Group, May 27, 2003 at pages 45-46, attached as Exhibit JDT-3.

[31] Direct Testimony of Hieronymus at page 50: 9-11 where he states: "The absence of long-term offers [in the Track B solicitation] suggests that potential sellers view the post-2005 market with greater optimism than is reflected in current forward markets."

merchant plant owners that may be interested in selling Arizona power plants or in entering long term power sales agreements.[32] As I describe below, based upon my examination of various aspects of the competitive wholesale western U.S. electricity markets, I conclude that it is reasonable for APS to rely on the competitive market for a portion of its longer term needs.

Q: **HAVE YOU RESEARCHED THE RESULTS OF RECENT REQUEST FOR PROPOSAL SOLICITATIONS FOR ELECTRICITY SUPPLIES IN THE WESTERN U.S.?**

A: Yes. Exhibit JDT-8 shows a listing of several RFPs that have been conducted in the Western U.S. over the past couple years. As the Exhibit shows, there have been numerous RFPs issued recently in the West (especially following the shortage experienced by California in 2000-01). These solicitations have requested a variety of short-term and long-term energy and capacity products. Although the outcomes of these RFPs vary considerably, there is no evidence that the market has been unresponsive. This includes the Track B solicitation. Although APS now claims that this solicitation was poorly subscribed, the Independent Monitor's report concluded otherwise:

> "Successful outcome. APS received more than 175 bids from 10 bidders and TEP evaluated 26 bids from 5 bidders. Based upon the number of bids received, we believe that the process produced competitive prices for the products purchased."[33]

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[32] Response of APS in Opposition to Motion of Arizona Competitive Power Alliance, p. 5, lines 6–8. APS also recognized in its internal report on Market Structure Scenarios that there is inadequate transmission to California for all of this Arizona merchant generation to seek markets outside of Arizona. See Bhatti Workpaper 30, Pages 11 and 17, attached as Exhibit JDT-3.

[33] Independent Monitor's Final Report on Track B Solicitation, Accion Group, May 27, 2003 at page 4, attached as Exhibit JDT-3.

This successful outcome was achieved despite the existence of the "Regulatory Out" clause and other provisions that the Independent Monitor concluded may have reduced the number of the bids and the time period covered by the bids.[34]

Q: **HAS THE WESTERN WHOLESALE ELECTRICITY MARKET BROUGHT FORTH NEW CAPACITY ADDITIONS IN RECENT YEARS?**

A: Yes. Exhibit JDT-9 shows that the market has placed in service approximately 32,000 MW of new capacity in recent years, and this level is expected to increase to a total of nearly 37,000 MW by the end of 2005. In particular, some 10,000 MW of new capacity will have been added in Arizona alone. This represents 15 plants of which more than 9,000 MW are already in service.[35] These new facilities represent a significant amount of new capacity in the region competing to sell electricity for delivery now and in the future.

Q: **WHAT ARE YOUR CONCLUSIONS REGARDING APS'S CONTENTION THAT THE COMPETITIVE WHOLESALE ELECTRICITY MARKET WILL BE INCAPABLE OF SUPPLYING APS POWER POST 2006?**

A: I find that APS has not offered any evidence that the wholesale market will be incapable of meeting APS's future needs. Although it is quite likely that the PWEC assets will play a role in providing APS capacity and energy post 2006, there is no reason to believe that other generating units will not also be available to meet APS demand. Just because APS

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[34] Id. at pages 45-47, attached as Exhibit JDT-3.

[35] Those plants already in-service are: Arlington Valley I, 570 MW; Desert Basin Generating, 500 MW; Gila River I-IV, 2,080 MW; Griffith Energy, 600; Harquahala Generating Station, 1,092 MW; Kyrene, 250 MW; Mesquite Power 1-2, 1000 MW; Red Hawk 1-2, 1,060 MW; Saguaro, 80 MW; South Point, 550 MW; Sundance Energy Project 1, 450 MW; West Phoenix 4-5, 650 MW; and, Tucson CTs, 96 MW.

may not be able to point to a particular asset at this juncture to meet its forecasted needs does not mean that the market is not working. As I described above, APS is largely assuming that as a result of the specific results of the 2004-2006 Track B RFP, the market cannot fulfill its future needs. Prior to seeking to ratebase the PWEC assets, however, APS had not gone to the market and requested longer-term resources. The inclusion of an onerous "Regulatory Out" clause in APS's recent RFP calls into question whether this will be a reasonable test of the market or is simply window-dressing for APS's ratebasing strategy. Evidence from western markets seriously undermines APS's suggestion that the Commission should change its current power procurement policies. Finally, APS's approach has attributes of a self-fulfilling prophecy. To the extent that APS fails to seriously consider third-party purchases and unreasonably favors its affiliate, a competitive market will be less likely to develop.

Q: **DO YOU CONCLUDE THAT THE COMMISSION POLICY OF HAVING APS RELY IN PART ON THE WHOLESALE MARKET IS STILL GOOD POLICY AND DICTATES REJECTION OF APS'S RATE BASING PROPOSAL?**

A: Yes. The Commission's policy of encouraging a robust wholesale electricity market remains an important goal for Arizona retail customers. Abrogating the Track B Contracts and rate basing the PWEC assets rather than APS relying on the market to supply this load runs counter to the Commission's policy objectives and is not in the long-term interest of APS customers. I believe the Commission's policy of requiring generation portfolio diversity through some continuing reliance on the competitive markets is measured and sensible—indeed the policy is so difficult to assail that APS itself appears to support it in the policy testimony of Mr. Wheeler:

> "APS understands that the wholesale market is not just some place where utilities dump their unneeded energy or take advantage of each other's relative economies of generation. It is a viable and necessary resource that can and should be incorporated into a broad-based portfolio of resources used to serve customer needs. This is why APS supports a vibrant and robust wholesale market and why it has taken significant steps to encourage that market."[36]

The best way for APS to support a vibrant and robust wholesale market is to honor rather than abrogate the Track B Contracts and meet its post 2006 resource needs through fair and transparent competitive solicitations, rather than by rate basing the PWEC assets. To the extent that APS has concerns about the credit capacity of potential sellers under contracts, market contract purchases can be used for the short term and medium term portions of a diverse portfolio. The inconsistency between APS's rate basing proposal and the development of a vibrant and robust wholesale market is stark. The continued support of the latter goal requires rejection of APS's rate basing proposal.

Q: **DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?**

A: Yes.

[36] Wheeler Direct Testimony at Page 32: 13-19.

Exhibit JDT-1
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PROFESSIONAL EXPERIENCE

Lexecon Inc., New York, NY
Senior Vice President, 2000 - present

Leads Lexecon's business strategy consulting for the electricity industry with a focus on the significant challenges associated with industry restructuring. Provided testimony in a number of proceedings related to potential refunds from the California electricity markets. Developed and successfully implemented a strategy for an electric utility in PJM to mitigate its risks associated with wholesale power procurement for its default service customers. Played a leadership role in the development of the filing for an RTO in New England, including the negotiations between the transmission owners, ISO New England, and other stakeholders. Provided strategic advice to an electricity marketer in New England on the evolution of market rules in that region.

Sithe Energies, Inc., New York, NY
President and Chief Operating Officer, Sithe Northeast, 1999 - 2000

Led the effort to close on the acquisition of generating assets to more than double the size of Sithe Northeast to 8,000 megawatts. Initiated and led the transformation of the Sithe generating assets and organization in the Northeast into an integrated competitive generation and trading company. Created the management team and put the information system infrastructure in place. Established Sithe Northeast's market structure strategy to work with the Independent System Operators to promote rapid evolution of the Northeast markets to greater efficiency.

California Independent System Operator, Folsom, CA
President and Chief Executive Officer, 1997 - 1999

Led the effort to successfully start up the California Independent System Operator to provide reliable, efficient transmission and market operation and enable retail choice throughout eighty percent of California. Guided the evolution of the markets during the first year of operation. Identified market design flaws, built consensus for solutions among highly diverse constituencies, gained regulatory approvals, and implemented the new design.

New England Electric System, Westborough, MA
1970 - 1997

New England Electric System
Senior Vice President, 1996 - 1997

As Chairman of the NEPOOL Management Committee, led the most significant reform in the structure of the New England Power Pool, preparing it for deregulation and retail competition. Key member of senior management team that developed the strategy and negotiated agreements that are shaping deregulation in the Northeast and resolved $4.5 billion in potentially strandable investments.

New England Power Company
President, 1993 - 1997

Led a wholesale generation and transmission company with gross revenue of approximately $1.5 billion and an all-requirements load of over 4,000 megawatts. Achieved a Return on Equity consistently in the 16-17% range through aggressive cost control and effective regulatory activities. Completed 500 megawatts repowering project ahead of schedule and over $150 million under budget.

New England Electric System
Vice President, 1991 - 1996
New England Electric Transmission Company, New England Hydro Transmission Corporation, New England Hydro Electric Transmission Company, Inc., New England Hydro Finance Company, Inc.
President and Director, 1991 - 1996

Led the development of NEESPlan4, NEES's corporate resource plan that fully integrated environmental, economic, and reliability objectives. Played a major role in restructuring the New England Electric System into business units. Chosen to lead Wholesale Business Unit when created in 1993. Led the effort to restructure the entire information system at NEES. Developed contracts with all system users to justify the expenditures based on projected benefits.

New England Electric Transmission Company, New England Hydro Transmission Corporation, New England Hydro Electric Transmission Company, Inc., New England Hydro Finance Company, Inc.
Vice President, 1987 - 1991

Led the licensing and construction of the $500 million Hydro-Quebec/New England HVDC Transmission Interconnection Project as managing agent for a consortium of New England utilities. The project was completed $80 million under budget.

New England Power Company
Vice President, 1984 - 1991
Yankee Atomic Electric Company, Connecticut Yankee Atomic Electric Company, Maine Yankee Atomic Electric Company, Vermont Yankee Atomic Electric Company
Director, 1984 - 1991

Chaired audit and compensation committees on the four nuclear Boards of Directors. Led New England Electric's efforts as a partner in Ocean State Power, the first major gas fired independent power project in New England. Led the negotiations for purchases of power from independent power projects.

Various Engineering and Management Positions, 1970 - 1984

Led major components of a recovery team to restore New England Power Company's largest, most efficient generator to service after a catastrophic turbine failure.

Managed New England Electric's relationship with the New England Power Pool and served on the NEPOOL Operating Committee.

Managed distribution line crews, customer service, metering, and field engineering functions.

Acted as a liaison with all functions reporting to Senior Vice President, including generation operations, fuel, engineering, and environmental.

Played a major role in designing and implementing a new automated billing and settlement system for NEPOOL and restructuring the controls at NEES to ensure accurate billings among the NEPOOL participants.

Performed numerous studies recommending transmission additions and modifications to the New England transmission grid. Served on NEPOOL transmission task force.

Performed increasingly responsible studies to select and set protective relay equipment on the transmission system and for major new generation plants.

EDUCATION

Massachusetts Institute of Technology, Cambridge, MA
S.B., Electrical Engineering, 1968
S.M., Electrical Engineering, 1969
Electrical Engineer, 1970

Harvard Business School, Cambridge, MA
Advanced Management Program, 1990

TESTIMONY AND REPORTS

Idaho Power Company

Lexecon Audit of Idaho Power Company Compliance with its Standard of Conduct, December 8, 2003.

Coral Power, LLC

United States of America, Before the Federal Energy Regulatory Commission, Coral Power, LLC. Written testimony in response to order to show cause, November 3, 2003; affidavit in support of settlement, November 14, 2003; declaration, December 15, 2003.

Dynegy Inc.; Duke Energy Services LLC; Mirant Americas, Inc.; Williams Energy Marketing and Trading Co.

United States of America, Before the Federal Energy Regulatory Commission, San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services into Markets Operated by the California Independent System Operator and the California Power Exchange; Investigation of Practices of the California Independent System Operator and the California Power Exchange. Affidavit (with P. Wang), May 12, 2003.

Reliant Energy

United States of America, Before the Federal Energy Regulatory Commission, Fact-Finding Investigation into Possible Manipulation of Electric and Natural Gas Prices. Affidavit attached to Reliant response, April 11, 2003.

Duke Energy Trading and Marketing LLC

United States of America, Before the Federal Energy Regulatory Commission, San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services into Markets Operated by the California Independent System Operator and the California Power Exchange; Investigation of Practices of the California Independent System Operator and the California Power Exchange. Prepared direct and rebuttal testimony, March 20, 2003.

Dynegy Inc.; Duke Energy Services LLC; Mirant Americas, Inc.; Reliant Energy; Williams Energy Marketing and Trading Co.

United States of America, Before the Federal Energy Regulatory Commission, San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services into Markets Operated by the California Independent System Operator and the California Power Exchange; Investigation of Practices of the California Independent System Operator and the California Power Exchange. Prepared direct and answering testimony for five California generators in a suit claiming refunds from them for sale of energy into California markets; Issue 1 direct and answering testimony, November 6, 2001; Issue 1 deposition, December 3, 2001; Issue 1 supplemental direct and answering testimony, January 31, 2002; Issue 1 rebuttal testimony, February 25, 2002; Issue 1 oral testimony, March 14-15, 2002; Issue 1 affidavit, June 14, 2002; Issues 2/3 direct and answering testimony, July 3, 2002; Issues 2/3 supplemental testimony, July 26, 2002; Issues 2/3 rebuttal testimony, July 26, 2002; Issues 2/3 surrebuttal testimony, August 9, 2002; Issues 2/3 deposition, August 16, 2002; Issues 2/3 oral testimony, August 23, 2002.

TransCanada Power Marketing Ltd.

In the Matter of the Arbitration Between Transcanada Power Marketing, Ltd. and ISO-New England, Inc., Case #71 198 000 4101 of the American Arbitration Association. Expert report in arbitration between TransCanada Power Marketing Ltd. and ISO-NE regarding implementation of the ISO-NE tariff, September 19, 2001.

ARTICLES AND PUBLICATIONS

"Shining Light on the Blackout" (with Janet Gail Besser), *The Energy Daily*, September 24, 2003.

OTHER PROFESSIONAL ACTIVITIES

Member, Oglethorpe Power Corporation Board of Directors, 2000 - present

Member, Doble Engineering Company Board of Directors, 1998 - present

Member, Harvard Electricity Policy Group, 1990 - present

Member, EarthFirst Technologies, Inc., Board of Directors, 2001-2002

PAST AFFILIATIONS

Chairman, NEPOOL Management Committee

Member, Executive Committee, Northeast Power Coordinating Council

Member, Research Advisory Council, Electric Power Research Institute

Member, State of Massachusetts Board of Environmental Management

Member, Corporate Support Committee, Joslin Diabetic Center

Member, Board of Overseers, Boston Museum of Science

Exhibit JDT-2
FINANCIAL IMPACT OF RATEBASING PWEC ASSETS ON APS'S ADJUSTED TEST YEAR REVENUE REQUIREMENT

Categories of Revenue Requirement Costs	Revenue Requirement w/o PWEC	Sources	Revenue Requirement w/ PWEC	Sources	Revenue Requirement Impact of PWEC Assets	Sources
Return on Rate Base	$ 475,524,985	(Calculated)	$ 602,958,365	(Calculated: 8.67% x $4,207,475,999 x 1.6529; sources: Sch. A-1, lines 5 & 7; Sch. B-2, p. 1, line 6)	$ 127,433,380	(Calculated: 8.67% x $889,237,000 x 1.6529; sources: Sch. A-1, lines 5 & 7; Sch. B-2, p. 1, line 6)
Revenue Requirement Reduction from Change in Capital Structure (Includes Reduced Cost of Capital and Lower Income Taxes)	-	-	-	-	$ (40,315,333)	(Calculated: $4,207,475,999 x (8.67% - 8.31%) x 1.6529 + 15,279,000; sources: Sch. C-2, p. 3, line 15; Direct Testimony of Donald G. Robinson at 29, line 20)
Fuel and Purchased Power for Own Load	$ 594,849,000	(Calculated)	$ 559,879,000	(Sch. C-1, p. 2, line 2)	$ (34,970,000)	(Sch. C-2, p 3, line 2)
Depreciation and Amortization	$ 288,514,000	(Calculated)	$ 329,983,000	(Sch. C-1, p. 2, line 6)	$ 41,469,000	(Sch. C-2, p. 3, line 7)
Operations & Maintenance (Including A&G)	$ 548,815,000	(Calculated)	$ 590,073,000	(Sch. C-1, p. 2, line 5)	$ 41,258,000	(Sch. C-2, page 3, line 4, 5, 9)
Other Taxes	$ 99,013,000	(Calculated)	$ 110,197,000	(Sch. C-1, p. 2, line 8)	$ 11,184,000	(Sch. C-2, p. 3, line 10)
Off-System Sales Margin	$ (14,749,000)	(DGR-WP13 p.3)	$ (46,411,000)	(DGR-WP14 p. 7)	$ (31,662,000)	(Calculated)
Test Year Revenue Requirement Impact from PWEC Roll-In					$ 114,397,046	

Note: Pages 2-10 of this Exhibit contain various source documents referenced above.

ARIZONA PUBLIC SERVICE COMPANY
Computation of Increase in Gross Revenue Requirements
ACC Jurisdictional
Adjusted Test Year Ended 12/31/2002
(Dollars in Thousands)

Line No.	Description	Electric: Original Cost	Electric: RCND	Electric: Fair Value	Line No.
1.	Adjusted Rate Base	$ 4,207,476 (a)	$ 6,727,455 (a)	5,467,466	1.
2.	Adjusted Operating Income	263,870 (b)	263,870 (b)	263,870	2.
3.	Current Rate of Return	6.27%	3.92%	4.83%	3.
4.	Required Operating Income	364,788	364,788	364,788	4.
5.	Required Rate of Return	8.67%	5.42%	6.67%	5.
6.	Operating Income Deficiency	100,918	100,918	100,918	6.
7.	Gross Revenue Conversion Factor	1.6529 (c)	1.6529 (c)	1.6529 (c)	7.
8.	Increase in Base Revenue Requirements	$ 166,807	$ 166,807	$ 166,807	8.
9.	CRCC Surcharge (d)	8,283	8,283	8,283	9.
10.	Total Increase in Revenue Requirements	$ 175,090	$ 175,090	$ 175,090	10.

Line No.	Customer Classification	Projected Revenue Increase Due to Rates	% Increase	Line No.
11.	Residential	86,586	9.73%	11.
12.	General Service	86,758	9.82%	12.
13.	Irrigation	207	9.86%	13.
14.	Outdoor Lighting	1,041	9.64%	14.
15.	Dusk-to-Dawn	498	9.58%	15.
16.	Total	$ 175,090	9.77%	16.
17.	Total Sales to Ultimate Retail Customers	$ 1,791,584 (d)		17.

Supporting Schedules
(a) B-1 (c) C-3
(b) C-1, page 2 (d) H-1

ARIZONA PUBLIC SERVICE COMPANY
Original Cost Rate Base
Pro Forma Adjustments
(Dollars in Thousands)

		(1)		(2)		(3)	
		Actual at End of Test Year 12/31/2002 (a)		PWEC Units		Remove Regulatory Assets Amortized under Prior Settlement	
Line No.	Description	Total Co. (A)	ACC (B)	Total Co. (C)	ACC (D)	Total Co. (E)	ACC (F)
1.	Gross Utility Plant in Service	$ 8,486,874	$ 8,203,305	$ 1,021,886	$ 1,015,393	$ -	$ -
2.	Less: Accumulated Depreciation & Amort.	3,542,547	3,405,509	73,395	73,045	-	-
3.	Net Utility Plant in Service	4,944,327	4,797,796	948,491	942,348	-	-
4.	Less: Total Deductions (Deferred Taxes)	1,614,838	1,589,887	53,382	53,111	(41,080)	(41,080)
5.	Total Additions (Regulatory Assets)	563,800	556,554	-	-	(104,000)	(104,000)
6.	Total Rate Base	$ 3,893,289	$ 3,764,463	$ 895,109	$ 889,237	$ (62,920)	$ (62,920)

(2) Adjustment to Test Year rate base to include the Pinnacle West Energy Units including West Phoenix Combined Cycle Unit No. 4, West Phoenix Combined Cycle No. 5, Redhawk Combined Cycle No. 1, Redhawk Combined Cycle No. 2 and Saguaro Combustion Turbine No. 3.

(3) Adjustment to Test Year rate base to exclude certain net regulatory assets which, pursuant to the terms of the 1999 Settlement Agreement, will be fully amortized by June 30, 2004.

Supporting Schedules:
(a) E-1

ARIZONA PUBLIC SERVICE COMPANY
Original Cost Rate Base
Pro Forma Adjustments
(Dollars in Thousands)

		(7)		(8)		
		Total Original Cost Rate Base Pro Forma Adjustments (b)		Adjusted at End of Test Year 12/31/2002 (b)		
Line No.	Description	Total Co. (M)	ACC (N)	Total Co. (O)	ACC (P)	Line No.
1.	Gross Utility Plant in Service	$ (242,704)	$ 13,895	$ 8,244,170	$ 8,217,200	1.
2.	Less: Accumulated Depreciation & Amort.	(426,560)	(307,558)	3,115,987	3,097,951	2.
3.	Net Utility Plant in Service	183,856	321,453	5,128,183	5,119,249	3.
4.	Less: Total Deductions (Deferred Taxes)	(9,553)	12,698	1,605,285	1,602,585	4.
5.	Total Additions (Regulatory Assets)	134,321	134,258	698,121	690,812	5.
6.	Total Rate Base	$ 327,730	$ 443,013	$ 4,221,019	$ 4,207,476	6.

Recap Schedules:
(b) B-1

ARIZONA PUBLIC SERVICE COMPANY
ACC Jurisdiction
Adjusted Test Year Statement of Income
Test Year 12 Months Ended 12/31/02

Schedule C-1
Page 2 of 2

(Dollars in Thousands)

Line No.	Description	ACC Jurisdiction Actual For The Test Year Ended 12/31/02	*Proforma* Adjustments (a)	Test Year Results After *Proforma* Adjustments (b)	Line No.
1.	Electric Operating Revenues	$ 2,051,730	$ (111,584)	$ 1,940,146	1.
2.	Purchased power and fuel costs	616,873	(56,994)	559,879	2.
3.	Operating revenues less purchased power and fuel cost	1,434,857	(54,590)	1,380,267	3.
4.	Other Operating Expenses:				4.
5.	Operations and maintenance	489,041	101,032	590,073	5.
6.	Depreciation and amortization	393,035	(63,052)	329,983	6.
7.	Income taxes	129,307	(43,163)	86,144	7.
8.	Other taxes	104,205	5,992	110,197	8.
9.	Total	1,115,588	809	1,116,397	9.
10.	Operating Income	$ 319,269	$ (55,399)	$ 263,870	10.

Supporting Schedules:
(a) C-2

Recap Schedules:
(b) A-1

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Twelve Months Ended 12/31/2002
(Thousands of Dollars)

Line No.	Description	(7) Base Fuel and Purchased Power Total Co. (M)	(7) ACC (N)	(8) Normalize Off-System Sales Total Co. (O)	(8) ACC (P)	(9) PWEC Units Total Co. (Q)	(9) ACC (R)
1.	Electric Operating Revenues	$ -	$ -	$ (128,200)	$ (126,332)	$ 56,779	$ 56,237
2.	Purchased Power and Fuel Costs	120,584	120,584	(151,868)	(149,655)	(34,970)	(34,970)
3.	Oper Rev Less Purch Pwr & Fuel Costs	(120,584)	(120,584)	23,668	23,323	91,749	91,207
	Other Operating Expenses:						
4.	Operations Excluding Fuel Expense	-	-	-	-	14,110	14,086
5.	Maintenance	-	-	-	-	18,549	18,390
6.	Subtotal	-	-	-	-	32,659	32,476
7.	Depreciation and Amortization	-	-	-	-	41,541	41,469
8.	Amortization of Gain	-	-	-	-	-	-
9.	Administrative and General	-	-	-	-	8,797	8,782
10.	Other Taxes	-	-	-	-	11,256	11,184
11.	Total	-	-	-	-	94,253	93,911
12.	Operating Income Before Income Tax	(120,584)	(120,584)	23,668	23,323	(2,504)	(2,704)
13.	Interest Expense	-	-	-	-	36,179	35,977
14.	Taxable Income	(120,584)	(120,584)	23,668	23,323	(38,683)	(38,681)
15.	Current Income Tax Rate - 39.5%	(47,631)	(47,631)	9,349	9,213	(15,280)	(15,279)
16.	Operating Income (line 12 - line 15)	$ (72,953)	$ (72,953)	$ 14,319	$ 14,110	$ 12,776	$ 12,575

(7) Adjustment to Test Year operations to include 2003 base fuel and purchased power cents/kWh costs at adjusted 2002 consumption.

(8) Adjustment to Test Year operations to include off-system revenues consistent with the Base Fuel and Purchased Power pro forma adjustment.

(9) Adjustment to Test Year operations to include the Pinnacle West Energy Units including West Phoenix Combined Cycle No. 4, West Phoenix Combined Cycle No. 5, Redhawk Combined Cycle No. 1, Redhawk Combined Cycle No. 2 and Saguaro Combustion Turbine No. 3.

DIRECT TESTIMONY OF DONALD G. ROBINSON

On Behalf of Arizona Public Service Company

Docket No. E-01345A-

June 27, 2003

Component six, administrative and general expenses ("A&G"), includes 2003 budgeted A&G expenses at each of the PWEC Units. Included in many of the components discussed are allocated costs from the APS and Pinnacle West shared services organizations.

Component seven, property taxes for the PWEC Units, were forecasted for 2005 based on anticipated December 31, 2003 plant in service balances and the current valuation factor, assessment rate and property tax rates.

Q. HAVE YOU INCLUDED IN THE PRO FORMA ADJUSTMENT THE BENEFIT TO CUSTOMERS OF A REDUCED WEIGHTED COST OF DEBT AND A CHANGE IN THE COMPANY'S CAPITAL STRUCTURE?

A. Yes. I have included in the Electric Operating Revenue line the benefit to customers of including the PWEC Units related debt as part of the Company's permanent capital structure. As part of APS' acquisition of the PWEC Units, the debt owed by PWEC to APS will be cancelled and the loans obtained by APS in May 2003 will be treated as utility debt for ratemaking purposes. The impact of including this $500 million debt lowers the Company's overall long-term weighted cost of debt from 5.8% to 5.7% and changes the percentage of debt in the capital structure from approximately 50% to 55%. This lowers the overall cost of capital from 8.67% to 8.31%. The change in the rate of return has been applied to the Test Year and pro forma adjustment rate base amounts with the resulting savings included in the PWEC Units pro forma adjustments.

The general income tax benefit associated with the additional tax deductions for interest associated with the $500 million debt issuance in our capital structure also has been reflected in the pro forma. The final component, the income tax calculation, includes this benefit and also includes a specific additional

APS FUEL AND PURC' ED POWER PROFORMA
BASED ON 4/24/03 MARKET AN ACCEPTED TRACK B CONTRACTS
PWE UNITS NOT RATE BASED
2003 RATE CASE FILING
Gas Price Reduced 10%

	FOR THE YEAR 2003												
REVENUE ($000)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
OFF SYSTEM SALES													
APS Gen Off System Rev	2,391	1,395	835	170	1,444	2,757	745	774	641	959	2,969	2,251	17,332
APS T&C	416	456	1,316	31	1,936	3,884	3,323	3,115	2,010	1,305	1,341	788	19,921
APS Hedge Liquidation	2,081	1,292	1,519	510	1,839	955	492	459	581	1,820	2,108	1,953	15,609
PWE Gen	-	-	-	-	-	4,989	1,983	1,118	2,127	-	-	-	10,217
Sundance	-	-	-	-	-	-	-	1	-	-	-	-	1
Off System Additional Revenue Target	-	-	-	-	-	-	-	-	-	-	-	-	-
PWE Purchase	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTAL	4,888	3,144	3,670	712	5,220	12,585	6,544	5,467	5,358	4,083	6,417	4,991	$\boxed{63,079}$
OFF SYSTEM MARGIN ($000)	493	416	514	(79)	1,337	3,968	2,314	1,651	1,203	684	1,672	575	14,749
Pacificorp Supplemental Revenue ($000)	2,567	2,138	2,107	2,125	1,495	1,855	843	856	1,518	1,115	1,758	1,942	20,319

DGR - WP13 3/4

APS FUEL AND PURCH.) POWER PROFORMA
BASEL 4/24/03
MARKET AND ACCEPTED TRACK B CONTRACTS
W/ PWE UNITS RATE BASED
2003 RATE CASE FILING
Gas Price Reduced 10%

FOR THE YEAR 2003

REVENUE ($000)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
OFF SYSTEM SALES													
APS Gen Off System Rev	2,740	2,095	2,033	337	2,485	2,961	1,128	1,084	656	1,699	3,550	3,504	24,272
APS T&C	1,123	1,022	1,491	1,609	2,670	3,990	3,472	3,068	1,911	2,163	1,614	1,748	26,082
APS Hedge Liquidation	5,019	4,213	4,489	3,486	5,708	1,070	569	567	530	8,634	4,166	5,397	43,848
PWE Gen	10,407	8,503	5,307	1,467	2,340	3,584	2,124	952	2,237	7,723	12,206	13,405	70,256
Sundance	-	-	-	-	-	-	0	2	2	-	-	-	5
Off System Additional Revenue Target	-	-	-	-	-	-	-	-	-	-	-	-	-
PWE Purchase	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTAL	19,289	15,833	13,319	7,099	13,202	11,605	7,295	5,674	5,336	20,219	21,537	24,054	164,463
OFF SYSTEM MARGIN [$000]	4,989	4,392	3,342	711	3,734	3,308	2,655	1,777	1,291	5,475	7,406	7,331	46,411
Pacificorp Supplemental Revenue ($000)	2,567	2,138	2,107	2,125	1,495	1,855	843	856	1,518	1,115	1,758	1,942	20,319

1.B.1

DGR - WP14 7/21

Exhibit JDT-3
APS WITNESS WORKPAPERS, DISCOVERY RESPONSES, AND OTHER RELEVANT DOCUMENTS CITED IN TRANEN TESTIMONY

ARIZONA PUBLIC SERVICE COMPANY
Original Cost Rate Base
Pro Forma Adjustments
(Dollars in Thousands)

		(1)		(2)		(3)	
		Actual at End of Test Year 12/31/2002 (a)		PWEC Units		Remove Regulatory Assets Amortized under Prior Settlement	
Line No.	Description	Total Co. (A)	ACC (B)	Total Co. (C)	ACC (D)	Total Co. (E)	ACC (F)
1.	Gross Utility Plant in Service	$ 8,486,874	$ 8,203,305	$ 1,021,886	$ 1,015,393	$ -	$ -
2.	Less: Accumulated Depreciation & Amort.	3,542,547	3,405,509	73,395	73,045	-	-
3.	Net Utility Plant in Service	4,944,327	4,797,796	948,491	942,348	-	-
4.	Less: Total Deductions (Deferred Taxes)	1,614,838	1,589,887	53,382	53,111	(41,080)	(41,080)
5.	Total Additions (Regulatory Assets)	563,800	556,554	-	-	(104,000)	(104,000)
6.	Total Rate Base	$ 3,893,289	$ 3,764,463	$ 895,109	$ 889,237	$ (62,920)	$ (62,920)

(2) Adjustment to Test Year rate base to include the Pinnacle West Energy Units including West Phoenix Combined Cycle Unit No. 4, West Phoenix Combined Cycle No. 5, Redhawk Combined Cycle No. 1, Redhawk Combined Cycle No. 2 and Saguaro Combustion Turbine No. 3.

(3) Adjustment to Test Year rate base to exclude certain net regulatory assets which, pursuant to the terms of the 1999 Settlement Agreement, will be fully amortized by June 30, 2004.

Supporting Schedules:
(a) E-1

ARIZONA PUBLIC SERVICE COMPANY
Original Cost Rate Base
Pro Forma Adjustments
(Dollars in Thousands)

Line No.	Description	(4) Independent Spent Fuel Storage Installation ("ISFSI") Total Co. (G)	ACC (H)	(5) Reversal of Settlement Write-Off Total Co. (I)	ACC (J)	(6) Transmission Assets Total Co. (K)	ACC (L)
1.	Gross Utility Plant in Service	$ -	$ -	$ -	$ -	$ (1,264,590)	$ (1,001,498)
2.	Less: Accumulated Depreciation & Amort.	-	-	-	-	(499,955)	(380,603)
3.	Net Utility Plant in Service	-	-	-	-	(764,635)	(620,895)
4.	Less: Total Deductions (Deferred Taxes)	1,707	1,682	92,430	92,430	(115,992)	(93,445)
5.	Total Additions (Regulatory Assets)	4,321	4,258	234,000	234,000	-	-
6.	Total Rate Base	$ 2,614	$ 2,576	$ 141,570	$ 141,570	$ (648,643)	$ (527,450)

(4) Adjustment to Test Year rate base to include the amount of System Benefits related ISFSI costs anticipated to be accrued between the end of the Test Year and June 30, 2004.

(5) Adjustment to Test Year rate base to restore the pre-tax $234 million deduction taken by the Company in consideration of benefits previously agreed to under the 1999 Settlement.

(6) Adjustment to Test Year rate base to remove transmission assets and generation plant functionalized to ancillary services consistent with FERC rules requiring APS to take transmission service and related ancillary services for the APS Standard Offer customers under the APS OATT.

ARIZONA PUBLIC SERVICE COMPANY
Original Cost Rate Base
Pro Forma Adjustments
(Dollars in Thousands)

		(7)		(8)		
		Total Original Cost Rate Base Pro Forma Adjustments (b)		Adjusted at End of Test Year 12/31/2002 (b)		
Line No.	Description	Total Co. (M)	ACC (N)	Total Co. (O)	ACC (P)	Line No.
1.	Gross Utility Plant in Service	$ (242,704)	$ 13,895	$ 8,244,170	$ 8,217,200	1.
2.	Less: Accumulated Depreciation & Amort.	(426,560)	(307,558)	3,115,987	3,097,951	2.
3.	Net Utility Plant in Service	183,856	321,453	5,128,183	5,119,249	3.
4.	Less: Total Deductions (Deferred Taxes)	(9,553)	12,698	1,605,285	1,602,585	4.
5.	Total Additions (Regulatory Assets)	134,321	134,258	698,121	690,812	5.
6.	Total Rate Base	$ 327,730	$ 443,013	$ 4,221,019	$ 4,207,476	6.

Recap Schedules:
(b) B-1

ARIZONA PUBLIC SERVICE COMPANY

HISTORIC PEAK LOAD, SYSTEM ENERGY and LOAD FACTOR

YEAR		PEAK LOAD		SYSTEM ENERGY		LF	Residential Customer Use	
		(Mw)	Growth %	(Gwh)	Growth %	Percent	KWH/ Cust	Growth %
1949	E	152	8.4%	766	8.4%	57.7	1,746	
1950	E	168	10.8%	849	10.8%	57.7	1,887	8.1%
1951	E	199	18.6%	1,008	18.6%	57.7	2,049	8.6%
1952	E	238	19.4%	1,203	19.4%	57.7	2,262	10.4%
1953	E	271	13.9%	1,371	13.9%	57.7	2,370	4.8%
1954	E	291	7.3%	1,471	7.3%	57.7	2,570	8.4%
1955	E	319	9.6%	1,613	9.6%	57.7	2,682	4.4%
1956	E	395	23.9%	1,998	23.9%	57.7	2,962	10.4%
1957	E	446	13.0%	2,257	13.0%	57.7	3,173	7.1%
1958	E	523	17.3%	2,650	17.4%	57.8	3,562	12.3%
1959	E	575	9.9%	2,786	5.1%	55.3	3,664	2.9%
Compound Growth			6.4%		5.8%			7.7%
1960	A	651	13.3%	3,290	18.1%	57.5	3,958	8.0%
1961	A	681	4.6%	3,407	3.5%	57.1	4,004	1.2%
1962	A	728	6.9%	3,654	7.3%	57.3	4,228	5.6%
1963	A	777	6.7%	3,859	5.6%	56.7	4,536	7.3%
1964	A	815	4.9%	4,191	8.6%	58.7	4,817	6.2%
1965	A	817	0.2%	4,215	0.6%	58.9	4,867	1.0%
1966	A	888	8.7%	4,574	8.5%	58.8	5,508	13.2%
1967	A	900	1.4%	4,675	2.2%	59.3	5,613	1.9%
1968	A	983	9.2%	4,934	5.5%	57.3	5,896	5.0%
1969	A	1,143	16.3%	5,487	11.2%	54.8	6,853	16.2%
Compound Growth			7.1%		7.0%			6.5%
1970	A	1,273	11.4%	5,921	7.9%	53.1	7,266	6.0%
1971	A	1,407	10.5%	6,806	14.9%	55.2	7,738	6.5%
1972	A	1,659	17.9%	7,975	17.2%	54.9	8,617	11.4%
1973	A	1,811	9.2%	8,925	11.9%	56.3	9,209	6.9%
1974	A	2,032	12.2%	9,672	8.4%	54.3	9,412	2.2%
1975	A	2,068	1.8%	9,865	2.0%	54.5	9,274	-1.5%
1976	A	2,191	5.9%	10,605	7.5%	55.3	9,268	-0.1%
1977	A	2,373	8.3%	11,536	8.8%	55.5	9,570	3.3%
1978	A	2,549	7.4%	12,150	5.3%	54.4	9,918	3.6%
1979	A	2,579	1.2%	12,765	5.1%	56.5	10,209	2.9%
Compound Growth			8.5%		8.8%			4.1%
1980	A	2,773	7.5%	13,143	3.0%	54.1	9,995	-2.1%
1981	A	3,019	8.9%	14,660	11.5%	55.4	10,247	2.5%
1982	A	2,899	-4.0%	14,121	-3.7%	55.6	9,840	-4.0%
1983	A	2,899	0.0%	14,008	-0.8%	55.2	10,357	5.3%
1984	A	2,971	2.5%	14,339	2.4%	55.1	10,355	0.0%
1985	A	3,198	7.6%	15,229	6.2%	54.4	10,499	1.4%
1986	A	3,195	-0.1%	14,887	-2.2%	53.2	10,176	-3.1%
1987	A	3,159	-1.1%	15,902	6.8%	57.5	10,684	5.0%
1988	A	3,372	6.7%	16,638	4.6%	56.3	10,945	2.4%
1989	A	3,646	8.1%	17,777	6.8%	55.7	11,077	1.2%
Compound Growth			3.5%		3.4%			0.8%
1990	A	3,680	0.9%	18,151	2.1%	56.3	11,033	-0.4%
1991	A	3,532	-4.0%	18,213	0.3%	58.9	10,941	-0.8%
1992	A	3,796	7.5%	18,989	4.3%	57.1	11,035	0.9%
1993	A	3,802	0.2%	19,084	0.5%	57.3	11,041	0.1%
1994	A	4,214	10.8%	19,923	4.4%	54.0	11,712	6.1%
1995	A	4,420	4.9%	20,350	2.1%	52.6	11,218	-4.2%
1996	A	4,575	3.5%	21,801	7.1%	54.4	11,853	5.7%
1997	A	4,609	0.7%	22,794	4.6%	56.5	12,013	1.3%
1998	A	5,072	10.0%	23,368	2.5%	52.6	12,047	0.3%
1999	A	4,935	-2.7%	23,749	1.6%	54.9	12,191	1.2%
Compound Growth			3.1%		2.9%			1.0%
2000	A	5,479	11.0%	25,186	6.1%	52.5	13,053	7.1%
2001	A	5,687	3.8%	26,538	5.4%	53.3	13,312	2.0%
2002	A	5,803	2.0%	26,681	0.5%	52.5	13,025	-2.2%

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2004 APS/PWEC GENERATION ENERGY MIX

APS

	GWH	%
PALO VERDE	8,901	37.7%
COAL		
FOUR CORNERS 1-2-3	3,995	
FOUR CORNERS 4-5	1,554	
CHOLLA 1-2-3	4,867	
NAVAJO 1-2-3	2,482	
SUB-TOTAL	12,898	54.7%
GAS/OIL		
WEST PHOENIX CC 1-2-3	982	
WEST PHOENIX CT 1-2	24	
OCOTILLO STM 1-2	379	
OCOTILLO CT 1-2	37	
SAGUARO STM 1-2	161	
SAGUARO CT 1-2	61	
YUCCA CT 1-4	67	
DOUGLAS	0	
SUB-TOTAL	1,711	7.3%
OTHER		
CHILDS & IRVING	0	
ENVIRONMENTAL PORTFOLIO	79	
SUB-TOTAL	79	0.3%
TOTAL	23,589	

APS/PWEC

	GWH	%
PALO VERDE	8,901	30.9%
COAL		
FOUR CORNERS 1-2-3	3,936	
FOUR CORNERS 4-5	1,542	
CHOLLA 1-2-3	4,818	
NAVAJO 1-2-3	2,480	
SUB-TOTAL	12,776	44.3%
GAS/OIL		
WEST PHOENIX CC 1-2-3	380	
WEST PHOENIX CT 1-2	8	
OCOTILLO STM 1-2	141	
OCOTILLO CT 1-2	13	
SAGUARO STM 1-2	67	
SAGUARO CT 1-2	26	
YUCCA CT 1-4	30	
DOUGLAS	0	
W. PHOENIX CC 4	250	
W. PHOENIX CC 5	1,432	
REDHAWK CC 1&2	4,679	
SAGUARO SC 3	60	
SUB-TOTAL	7,086	24.6%
OTHER		
CHILDS & IRVING	0	
ENVIRONMENTAL PORTFOLIO	79	
SUB-TOTAL	79	0.3%
TOTAL	28,842	

APB_WP9 2/2

2003 Long Range Forecast
APS Annual Energy Forecast

Energy (GWHs)

Year	2003 LRF
2003	26,494
2004	27,841
2005	28,999
2006	30,178
2007	31,388
2008	32,670
2009	33,983
2010	35,305
2011	36,425
2012	37,531
2003 - 2008	4.3%

Reliability Must-Run Analysis

2003–2005

January 31, 2003
APS Transmission Planning
APS Resource Planning

RC00820

Additionally, transmission alternatives were studied to compare the costs of mitigating the annual RMR conditions with the potential benefits of such mitigation.

The Phoenix area is a tight network of APS and Salt River Project (SRP) load, resources, and transmission facilities. Because the Phoenix system is highly integrated, the import limits must be determined for the combined area. This analysis was coordinated with SRP personnel, who had significant involvement in the study and were helpful in the overall analysis. The Western Area Power Administration (WAPA) participated in the study because their transmission facilities interface with the Phoenix network and also provided helpful comments.

After the combined import limit (SIL) for the Phoenix area was determined, RMR conditions were evaluated for APS based on APS' share of the combined import limits, APS' Phoenix-area load, and Phoenix area local generation, which includes generation owned by APS, SRP and Pinnacle West Energy Corporation (PWEC).

The Yuma area, which has a summer peak demand of approximately 300 MW, is served by an internal APS 69-kV sub-transmission network containing all of the load in the import-limited area. There are external ties to WAPA and the Imperial Irrigation District (IID), as well as a bulk power interface with the Palo Verde-to-North Gila transmission system. This analysis was coordinated with the WAPA Phoenix office to ensure accurate modeling.

B. Summary of Results

Results of the analysis for the three years of the study, which are summarized in the following tables, assume that present plans for system improvements are completed on schedule.

The following table summarizes the estimated RMR effects and costs for APS load in the Phoenix area.

Table ES1
Phoenix-Area RMR Effects and Costs for APS Load

Year	SIL[1] (MW)	Peak Demand (MW)	Max RMR[2] (MW)	RMR[3] Hours	RMR Energy[4] (GWH)	RMR Energy (% of total)	RMR Cost[5] ($M)
2003	3621	4456	835	518	170	0.9	0.03
2004	3658	4614	956	590	211	1.0	0.4
2005	3709	4733	1024	656	243	1.1	0.7

Table ES5
APS Phoenix-Area RMR Outside Economic Dispatch

Year	Hours outside economic dispatch	Energy outside economic dispatch (GWH)	RMR Cost ($M)
2003	32	7	0.03
2004	146	43	0.4
2005	174	44	0.7

The following table summarizes the estimated total number of hours that APS local Yuma generation must run out of economic dispatch, the amount of energy that is produced out of economic loading and the associated cost.

Table ES6
APS Yuma Area RMR Outside Economic Dispatch

Year	Hours outside economic dispatch	Energy outside economic dispatch (GWH)	RMR Cost ($M)
2003	1066	54	1.5
2004	974	49	1.3
2005	1196	56	1.5

C. Report Conclusions

Phoenix-Area Conclusions

1. During the summer, APS Phoenix-area load is expected to exceed the available transmission import capability for approximately 500 hours in 2003 and 650 hours in 2005. However, these hours represent only one percent of the annual energy requirements for APS' Phoenix area.

2. From a total Phoenix load, transmission, and resources viewpoint (APS, SRP, and PWEC), import limits are expected to cause APS local generation to be dispatched out of economic dispatch order for 32 hours in 2003, 146 hours in 2004, and 174 hours in 2005.

3. The estimated annual economic cost of Phoenix-area generation required to run out of economic dispatch order is estimated to be $720,000 in 2005, compared to a cost of approximately $16 million to relieve 452 MW of the Phoenix area's transmission constraint. Thus, the transmission alternative currently is not cost justified.

4. All Phoenix-area transmission and local generation are necessary to reliably serve all Phoenix-area peak load.

5. In capacity terms, APS will require from 365 MW in 2003 to 554 MW in 2005 of non-APS resources within the Phoenix area to serve the APS Phoenix-area load. These resources could be supplied from non-APS local generation (including PWEC West Phoenix Units 4 and 5, SRP Phoenix-area generation, or newly constructed local generation) or from remote generation delivered to APS using SRP Phoenix-area import capability.

6. Non-APS generation outside of the Phoenix load area (or inside the Phoenix load area when serving load outside) has the following impact on Phoenix-area import capability, measured as a percent of additional MW of import capability to MW of output:

   West Phoenix Units 4 and 5........................134%

   Sundance... 35%

   Desert Basin.. 24%

   Hassayampa Area.................................... 0%

   Panda Gila River.................................... 0%

7. Removing the transmission constraint would reduce total Phoenix-area air emissions by the following average annual amounts over the 2003-2005 period.

Table ES7
Phoenix-Area Air Emissions Reduction

Pollutant	Avg. Reduction (tons/year)	Reduction of Phoenix Area Emissions (% of total emissions from all sources)
VOC	1.0	0.001
NO_x	29.5	0.049
CO	5.5	0.002
PM_{10}	1.8	0.002

8. Removing the import restriction into the Phoenix area reduces the APS local generation capacity factor from 1.4% to 0.9%.

VII. Transmission Alternatives to Mitigate RMR

A. Phoenix Area

Two transmission alternatives were evaluated as potential mitigation of RMR conditions for the Phoenix area. For comparison purposes, a cost-benefit analysis was performed on the 2005 case with no Phoenix area generation operating.

The first alternative is the addition of 600 Mvar of shunt compensation (e.g. a static var compensator-SVC) at Kyrene with associated remedial action scheme logic and switching equipment to automatically insert the capacitor portion of the SVC at a very high speed upon detection of a loss of the Jojoba-Kyrene 500kV line. This alternative mitigates the voltage instability limitation by adding a strong reactive source of 600 Mvars of shunt compensation into the Phoenix area at the location that has lost the voltage support from the Palo Verde/Hassayampa area. This alternative would increase import capacity by 452 MW for a generation cost savings of $720,000 in 2005. However, the SVC alternative would cost $16 million. The annualized cost associated with this investment is estimated to be $2.4 million.

The second alternative considered was to modify the existing transmission system by looping the Jojoba-Kyrene 500kV line into the Rudd 500kV substation. This alternative is limited by the Rudd 500/230 kV transformers reaching thermal overload for a Rudd-Kyrene 500 kV line outage. This alternative provides no increase in SIL and, in fact, lowers the SIL due to increased loading on Rudd 500/230 kV transformers.

Neither of these alternatives is cost justified for the period covered by this study.

B. Yuma Area

For the 2005 timeframe, a second 500/69 kV 240 MVA transformer was added along with a 69 kV bus section breaker to the North Gila substation to evaluate the resultant increase in the SIL and MLSC for the Yuma area, and the resulting mitigation of RMR conditions. The cost of this project is estimated to be $3.5 million. With no local generation, completion of this project will increase the SIL by approximately 110 MW. Figure 11 shows the effect on the load serving capability (at or below the load forecast) of the Yuma area from adding the transformer.

This sensitivity case contains the same planned additions as in the 2005 base case (see Table 4) plus the addition of the re-conductoring of the 32nd Street-Ivalon 69 kV line and the Foothills-Foothills tap 69 kV line. These two additional projects are presently planned for 2006 and 2007, respectively, however both were advanced to maximize the effect of adding the second transformer.

If the evaporator vessel, compressor, recirculation pump, or heat exchanger are delivered to the site on December 3, 2000 or earlier, PWE will pay RCC a bonus of $1,000 per day for each equipment item delivered early. The bonus period will not exceed seven days. The total liquidated damages payable by RCC will not exceed 10% of the contract price. S&W Consultants believes, based on its review, that the liquidated damages provisions are sufficient to motivate RCC to meet their contractual obligations.

Firm Point-To-Point Transmission Service Agreements

PWE entered into two agreements with APS on March 15, 2000 for APS to provide firm transmission from both West Phoenix Unit 4 and West Phoenix Unit 5 to the Palo Verde 500 kV switchyard. For West Phoenix Unit 4, APS is providing 125 MW of reserved capacity beginning August 1, 2001 and ending March 31, 2004. For West Phoenix Unit 5, a reserved capacity of 525 MW will begin June 1, 2003 and end September 30, 2004. PWE will pay APS $1.43/kW of reserved capacity per month. There is no escalation or price adjustment clause in the agreement. PWE has requested that APS Transmission Services construct the interconnection facilities and will pay the total cost of the construction.

Guarantee Agreement

The Transmission Service Agreements described above are backed by a parent guarantee whereby PWC irrevocably and unconditionally guarantees the timely payment of PWE's obligations to APS.

Memorandum of Understanding Concerning Interconnection Construction

The Memorandum of Understanding ("MOU") between PWE and APS Transmission Services is dated June 20, 2000 and provides for APS Transmission Services to design, engineer, and construct the transmission interconnections necessary to connect the West Phoenix Unit 4 to the APS switchyard at West Phoenix. The MOU effective date was June 8, 2000 and remains in effect until the project is complete, currently estimated to be March 1, 2001. This provides a schedule margin of five months before West Phoenix Unit 4 is expected to go on-line. There are no penalties for schedule delays caused by APS Transmission Services.

Contract for Services – Special Service Request – West Phoenix Unit 4

This contract between PWE and APS Transmission Construction, dated July 25, 2000, provides for APS Transmission Construction to relocate an existing West Phoenix CC 3 transformer to its new West Phoenix Unit 4 position, install a new West Phoenix CC 3 transformer, perform all testing required by the Interconnection Agreement to allow West Phoenix Unit 4 to connect to the APS transmission system, and provide technical support for power system stabilizer, digital fault recorder, and generator, exciter, and governor model verification. This contract became effective July 25, 2000 and will remain in effect until the project is complete. The completion date for the transformer portion of the contract is expected to be April 1, 2001, which provides a four-month schedule margin. The other services being provided under this contract are expected to be complete by August 1, 2001. There are no penalties for schedule delays caused by APS Transmission Construction.

Other Contracts for Services

Other Contracts for Services between PWE and APS for West Phoenix include:

- Purchase and install new CEMS
- Retrofit a SCR on West Phoenix CC 3
- Purchase new GSU transformer for West Phoenix CC3, and relocate existing West Phoenix CC3 GSU to West Phoenix Unit 4
- Purchase and install a plantwide DCS
- Purchase DCS for West Phoenix Unit 4 HRSG, brine concentrator, gas heating skid, GE CT hardwired I/O and BOP equipment
- Upgrade the telephone system at West Phoenix

AFB-WP28 12/39

DRAFT DECEMBER 1, 2003

ASSET PURCHASE AGREEMENT

by and among

____
as Seller[1]

and

ARIZONA PUBLIC SERVICE COMPANY,
as Purchaser

dated as of ________, 2003

---

[1] As noted in the Request for Proposals, APS requires a creditworthy party, either as principal or guarantor, to be a party to this Asset Purchase Agreement.

8.2 *Performance.* Seller shall have performed and complied, in all respects, with the agreements, covenants and obligations required by this Agreement to be so performed or complied with by Seller at or before the Closing.

8.3 *Deliveries.* Seller shall have made all deliveries required of it under **Section 3.4** hereof.

8.4 *Orders and Laws.* There shall not be any litigation or proceedings (filed by a Person other than Purchaser or its Affiliates) or Law or order restraining, enjoining or otherwise prohibiting or making illegal or threatening to restrain, enjoin or otherwise prohibit or make illegal the consummation of any of the transactions contemplated by this Agreement.

8.5 *Consents and Approvals.* The consents and approvals listed on Schedule 8.5 shall have been duly obtained, made or given and shall be in full force and effect.

8.6 *Material Adverse Effect.* There shall not have occurred and be continuing a Material Adverse Effect.

8.7 *Approvals of Governmental Authorities.*

(a) All consents and approvals of Governmental Authorities required for the consummation of the transactions contemplated hereby or by the Ancillary Agreements, including, without limitation, the Seller Approvals and the Purchaser Approvals, shall have become Final Orders with such terms and conditions as shall have been imposed by the Governmental Authority issuing such Final Order, and such terms or conditions shall be acceptable in all respects to Purchaser in its sole discretion.

(b) The ACC shall have issued one or more orders, which shall be acceptable in all respects to Purchaser in its sole and absolute discretion and each of which shall have become a Final Order, approving the transactions contemplated hereby and by the Ancillary Documents and the regulatory treatment of the Purchased Assets, including, without limitation, (i) to the extent Purchaser, in its sole discretion, determines such approval is necessary, Purchaser's financing of the Purchase Price, and (ii) the inclusion, on or before June 1, 2007, in Purchaser's rate base of the Purchased Assets at Net Book Value without any direct or indirect disallowance, as well as (A) the timely recovery in Purchaser's retail rates of all reasonable costs of owning and operating the Purchased Assets after the termination or expiration of the term of the Sale Back Agreement, and (B) the deferral and recovery of any adverse earnings impact on Purchaser attributable to the Sale Back Agreement.

8.8 *Transferred Permits.* Purchaser shall be satisfied that all Environmental Permits and Permits will be transferred to Purchaser or obtained by Purchaser on or before the Closing Date.

8.9 *Title Insurance.* Purchaser shall have received unconditional and binding commitments to issue policies of title insurance consistent with **Section 6.11**, dated the Closing Date, in an aggregate amount equal to the amount of the Purchase Price allocated to the Real Property, deleting all requirements listed in ALTA Schedule B-1, amending the effective date to the date and time of recordation of the Deed conveying title to the Real Property to Purchaser

SMW_WP17
1/1

Estimated Saving by Acquiring PWEC Reliability Units vs New Build

	Year	MW	$/Kw	$ Million	30 year (1) Revenue Requirement $ Million
New CC Cost	2003	500	622	311.0	
	2004	500	631	315.7	
	2005	500	641	320.4	
PWEC Assets (rate base)	6/30/2004	1681	533	896.1	2467
PWEC Assets New Build	1/1/2005	1681	641	1077.2	2966
Savings			107.7	181.1	499

Note 1: Revenue requirement to cover capital investment and depreciation only

	Capital Structure	Cost	Weighted Cost	Income Taxes	After Tax
Debt	55	0.057	3.135	1.238	1.897
Equity	45	0.115	5.175	0.000	5.175
Total	100		8.31	1.238	7.072
		Revenue Grossup factor			1.653
		Pre-tax			11.689

Business

APS PREDICTS SHORTFALL, LOOKS TO BUY A PLANT

By Max Jarman, The Arizona Republic
272 words
26 November 2003
The Arizona Republic
Final Chaser
D1
English

Arizona Public Service Co. is predicting a power shortfall by 2007 and is looking to buy an existing power plant to cover the gap.

Consumers could eventually pick up the estimated $200 million to $300 million tab for such a facility through higher rates. The state's largest electric utility also is considering building its own facility or buying a plant in the planning stages.

APS Executive Vice President Steve Wheeler said the company is facing shortfalls during periods of peak electricity demand in 2005 and 2006, but that by 2007 demand will be great enough to warrant buying or building a plant.

The utility hopes to take advantage of a buyer's market for Arizona power plants caused by a spate of new plant construction and the subsequent collapse of wholesale prices.

"We understand several merchant plant owners might be interested in selling, and we want to see what's out there," Wheeler said.

Without the new plant, Wheeler said APS could be forced to rely on the spot market to cover shortfalls. The reliance of spot power buys in California bankrupted one of the state's largest electric utilities and led to huge rate increases for consumers.

Other power companies are also shopping for plants. Earlier this year, Salt River Project paid $289 million for the Desert Basin Power Plant developed by Reliant Energy in Casa Grande. The price was about what Reliant paid to build it.

Billionaires Warren Buffett and Carl Icahn are on the hunt for power plants at near-liquidation prices, too.

Document PHX0000020031127dzbq0003m

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Accion Group

to

Arizona Corporation Commission

INDEPENDENT MONITOR'S FINAL REPORT ON TRACK B SOLICITATION

MAY 27, 2003

Submitted by:
Accion Group, Inc.
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Concord, New Hampshire 03301
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Accion Group

manner consistent with good commercial practices and the bidders concerns, but still comply with the Solicitation's conditions.

- **Inclusive evaluation process**. In an effort to maximize the number of successful bidders, the evaluation process was designed to have only a minimum number of non-negotiable conditions A bid did not advance to full evaluation only if the bid fee was not paid. All bids meeting that condition were evaluated to determine if the bidder was technically capable of providing the service. The remaining evaluation factors were applied on a consistent basis in order to distinguish among bids. All of the evaluation criteria were clearly articulated in the RFP.
- **Successful outcome**. APS received more than 175 bids from 10 bidders and TEP evaluated 26 bids from 5 bidders. Based on the number of bids received, we believe that the process produced competitive prices for the products purchased.

As previously noted, the process resulted in two supply contracts for TEP – the first with PPL Energy Plus, LLC for 37 MW in 2003 and for 75 MW in 2004 through 2006, and the second with Panda Gila River, LC for 50 MW of June through September on peak capacity in 2003 through 2006. APS contracted for 1700 MW of July through September 2003 capacity and for 1700 MW of June through September 2004 through 2006 capacity from Pinnacle West Energy Corp., and for 112 MW of capacity from PPL Energy Plus LLC for July through September of 2003 and for 150 MW of capacity for the periods June through September of 2004 and 2005. Additionally, APS executed a contract with Panda Gila River LC for

1. Bid Fee

Bid fees are frequently used in competitive Solicitations, though not in all Solicitations. Participants to the Track B workshops agreed that any bid fee should be applicable to each bidder, as opposed to each bid, and recognized the Track B Solicitation would require APS and TEP to incur additional costs. Most bidders were willing to pay the $10,000 bid fee, but some did not. Two bidders submitted bids, but failed to provide the requisite bid fee. Both companies were given additional days to submit the bid fee, but chose to be disqualified rather than pay the fee.

From our discussion with bidders, we believe other potential bidders may have elected not to participate because of the bid fee. Some of these bidders either have or had contracts to supply APS or TEP that were arranged bilaterally, without a bid fee. Some may have chosen to wait until the Solicitation was over and to then deal with the utilities bilaterally because the bid fee represented a disproportionately large percentage of their anticipated profit margin.

We believe the bid fee was reasonable as applied, that is, each bidder paid one bid fee. At the same time, APS and TEP may have received more competitive bids if there had been no bid fee. In future solicitations, it may be appropriate to eliminate bid fees for all bids for short-term standard products.

2. Regulatory Out

APS proposed the inclusion of a "Regulatory Out" provision in all contracts with power deliveries after 2005. The provision permits APS or bidders to terminate a Track B power supply contract in the event of certain regulatory actions or inactions. This provision appears to have been acceptable to the marketers that submitted bids.

However, it was identified as one reason some bidders chose not to provide bids for power to be supplied after 2005.

PWEC, one of the few bidders offering supplies beyond 2005, accepted the Regulatory Out provision, but, for purposes of its firm energy bid, it required a risk premium for energy contracted through the year 2006. PWEC offered prices for 2006 power that differed, depending on whether the Regulatory Out clause was included in the contract. By PWEC's calculation, the risk premium associated with the Regulatory Out provision for a firm energy commitment through 2006 was $28 million . PWEC's firm energy bid was not among the bids accepted by APS.

Prior to any future solicitation, the ACC should determine whether it will permit the use of Regulatory Out clauses in mandated solicitations.

3. Bidder Certificate

The ACC Decision required each bidder to certify it would not engage in unlawful market manipulation, and that the ACC may terminate a contract and exclude the bidder from future solicitations if it violates this pledge. Further, the certificate needed to be signed by the bidder's Chief Financial Officer (CFO). This requirement created considerable concern among bidders, due to a misunderstanding of the scope and intent of the requirement. APS required bidders to execute a separate Bidder Certificate (Attachment 23), and TEP included the commitment in the body of the RFP bidders were required to sign.

Most bidders agreed to a verbatim recitation of the Decision requirement, while expressing reservations. One potential bidder expressly declined to bid because of uncertainty of what obligations could flow from agreeing to the Decision requirement, as drafted. At least two bidders submitted bids without the signature of their CFO, while others submitted bids with the understanding that clarification would be available before contracts would be executed. Release of a Federal Energy Regulatory Commission (FERC) Staff Report on market manipulation, after the Decision was issued, added to the confusion. The principal concern of bidders was a desire to avoid creating a dispute between FERC and the ACC concerning jurisdiction to determine market manipulation, and whether the ACC would attempt to rescind a contract retroactively to the date of execution.

With the assistance of the Staff, the Independent Monitor provided clarification of the ACC requirements. The clarification assured bidders that the ACC required FERC's authority to determine market manipulation, and that the ACC would only act after a FERC determination. Also, the Independent Monitor clarified that the ACC would only terminate contracts prospectively from a determination of unlawful market manipulation. Finally, the Independent Monitor confirmed that certification by the most senior officer of a bidder's company was acceptable, and that the absence of an officer holding the title of CFO was not a barrier to executing a contract. Prior to future solicitations, the Commission should clarify the scope and intent of the required Officer's Certification.

4. Procurement Freeze

APS and TEP were required to procure their unmet needs for 2003 through the Track B Solicitation process before contracting for or otherwise hedging their needs through bilateral contracts or open market transactions. When the Track B process became more protracted than expected, the utilities found themselves unable to take advantage of market opportunities even as they foresaw market prices rising.

We have not identified lost opportunities from this approach, and we appreciate the legitimate reasons for requiring the concurrent solicitation of all needs.

Significant Results

■ AZ Merchant Generation

- Over 20,000 MW merchant generation is public in AZ
- Estimated 13,000 is projected to be built by 2010
- Capacity margins will be pushed to near 35%
- Over 5,000 MWs will require home for other markets (on-peak)
- Over 10,000 MWs will require displacement generation in Calf (off-peak)
- Transmission lines to California becomes MUST
- Down stream (other end of PV-Devers line) projects no help
- El Paso's southern line will require expansion (double current capacity)

■ Market Prices

- California (CDWR) contracts - $61- 79 / MWH ($69 / MWH 10 Yrs)
- PV forward market continues to be above $50 / MWH over 10 yrs
- Simulated market ranges $35 - 40 / MWH over 10 yrs

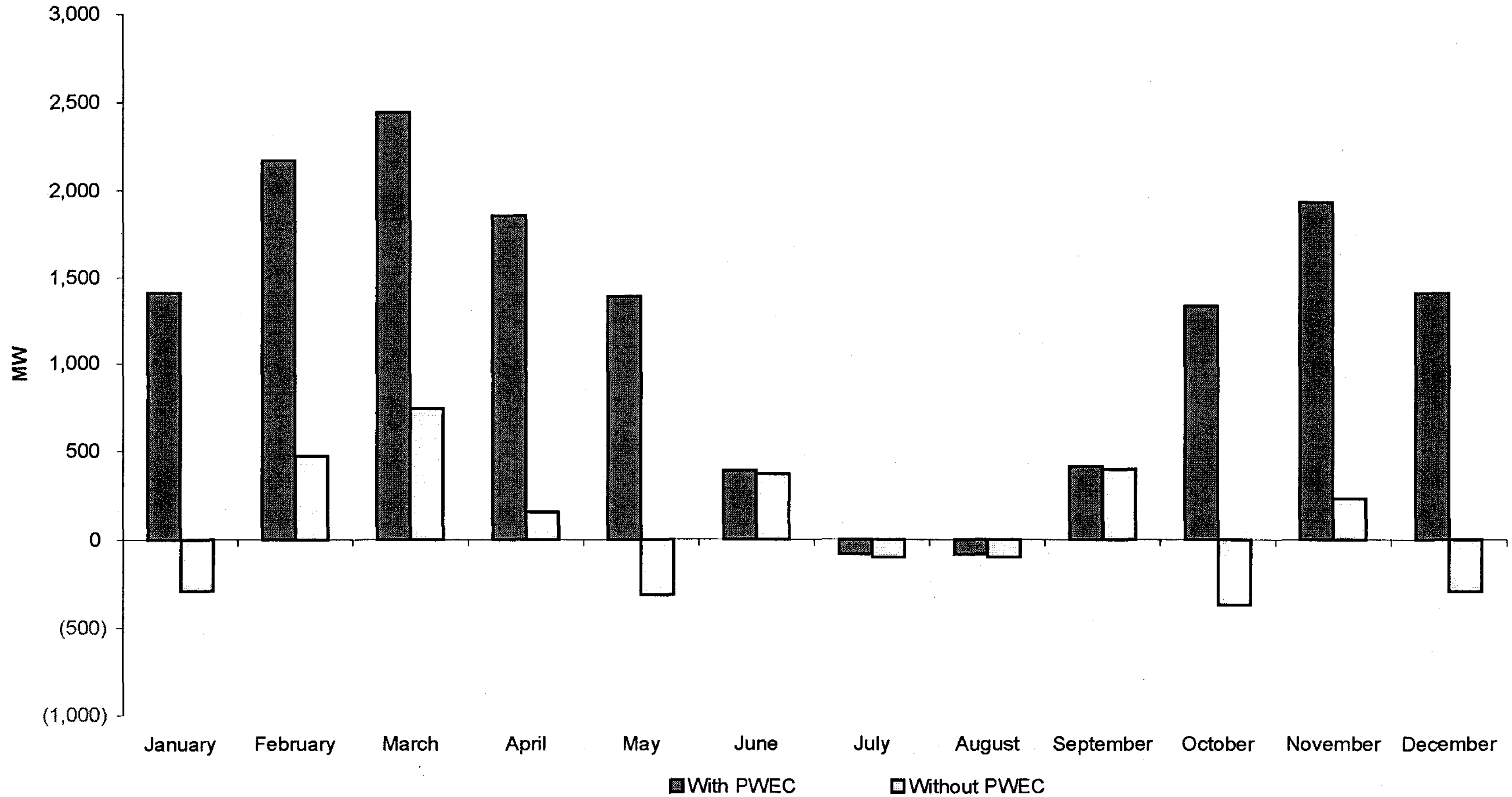
APB_WP30 11/04

Arizona Supply & Demand

- Includes APS, PWEC, SRP, TEP, AEPCO, WAPA, NPC and Merchant Generation
- Over 20,500 MW of new generation proposed in Arizona.
- 12,200 new generation built in Arizona by 2006
- Reference Case
  - Load Growth 2.86% 2001-2010
  - APS Purchases all PWEC output, still needs market purchases. Enterprise is short.
  - Up to 650 MW of new generation trapped inside Arizona in 2006-2009
- Scenario 1
  - APS and SRP purchase 70% of the non-PWEC/non-SRP new merchant generation in Arizona
  - PWEC has up to 3,000 MW of generation to market
- Scenario 2
  - Load Growth 3.82% 2001-2010
  - APS and SRP purchase 70% Arizona Merchant Generation (same as Scenario 1)
  - PWEC has up to 2,600 MW of generation to market
- Scenario 3
  - Low Load Growth 1.78% 2001-2010
  - APS and SRP purchase 70% Arizona Merchant Generation (same as Scenario 1)
  - PWEC has up to 3,300 MW of generation to market
  - Up to 1,925 MW of generation trapped inside Arizona 2005-2010+

APB_wP30 47/104

Exhibit JDT-4
APS MONTHLY SURPLUS GENERATION CAPACITY
2004



Notes:

1) "With PWEC" refers to the generation capacity APS would own if the rate base request were approved. "Without PWEC" refers to the generation capacity currently owned, and available under contract by APS, and therefore includes APS's Track B purchases.

2) Capacities are not adjusted to account for variations that will result due to maintanance and forced outages.

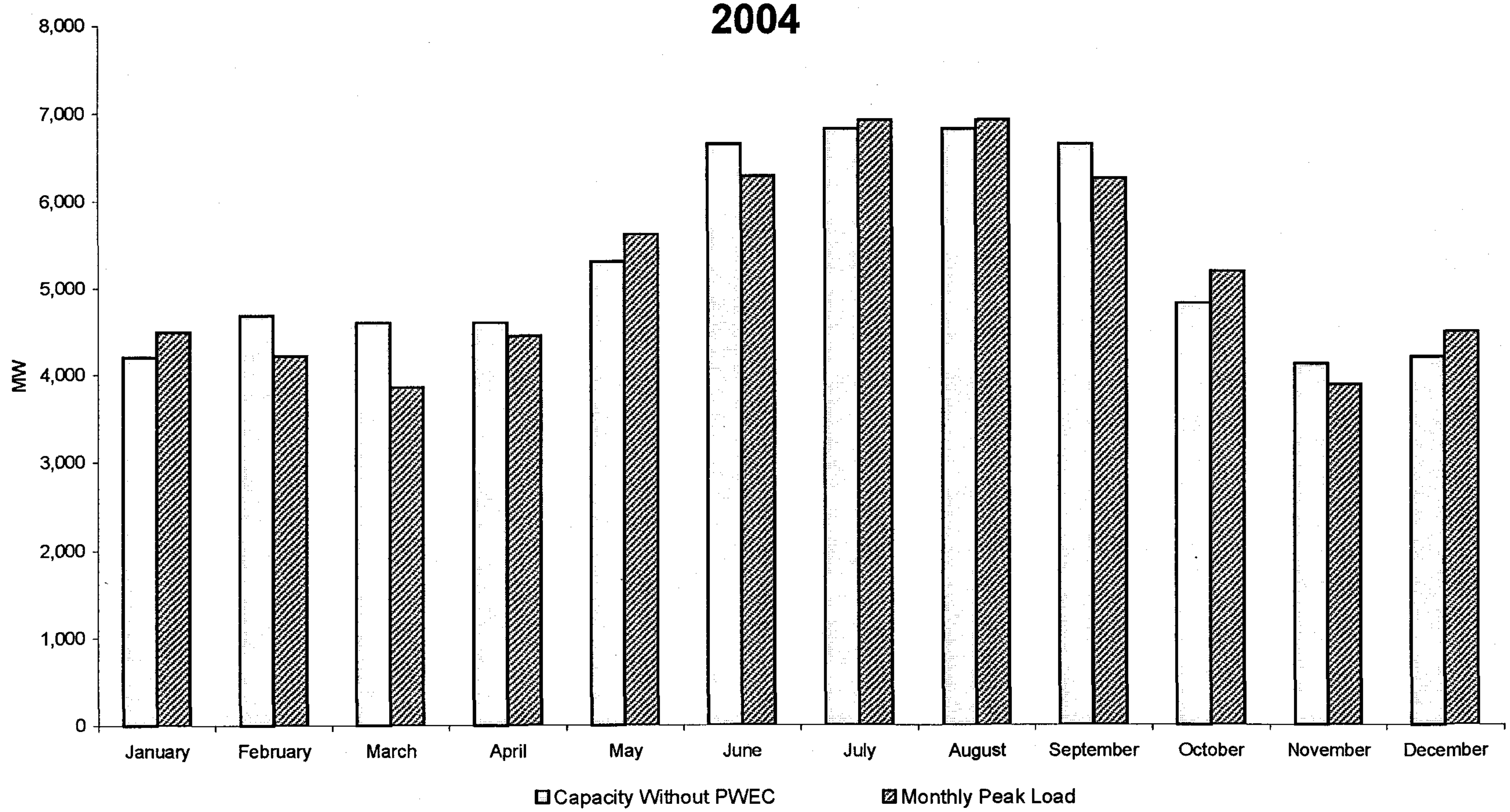
3) Pacificorp exchange allows APS access to capacity from May 15 to September 15 and allows Pacificorp access to APS capacity from October 15 to February 15. It is assumed that APS receives the capacity or retains its own capacity in agreement with its intramonth expected peak demands. (i.e. In the figure, APS receives exchange in May and September, and does not provide exchange in February and October.

4) Monthly demands include 15% reserve margin.

5) Monthly demands have not been updated to reflect any more recent hourly forecasts that APS may have developed.

Sources: APB_WP9, DR001654_0051_TRACKB_APS-EWEN-WORKPAPERS, 12/03 APS RFP (Summer Supply and Demand Balance, 1/9/04); RC00819.

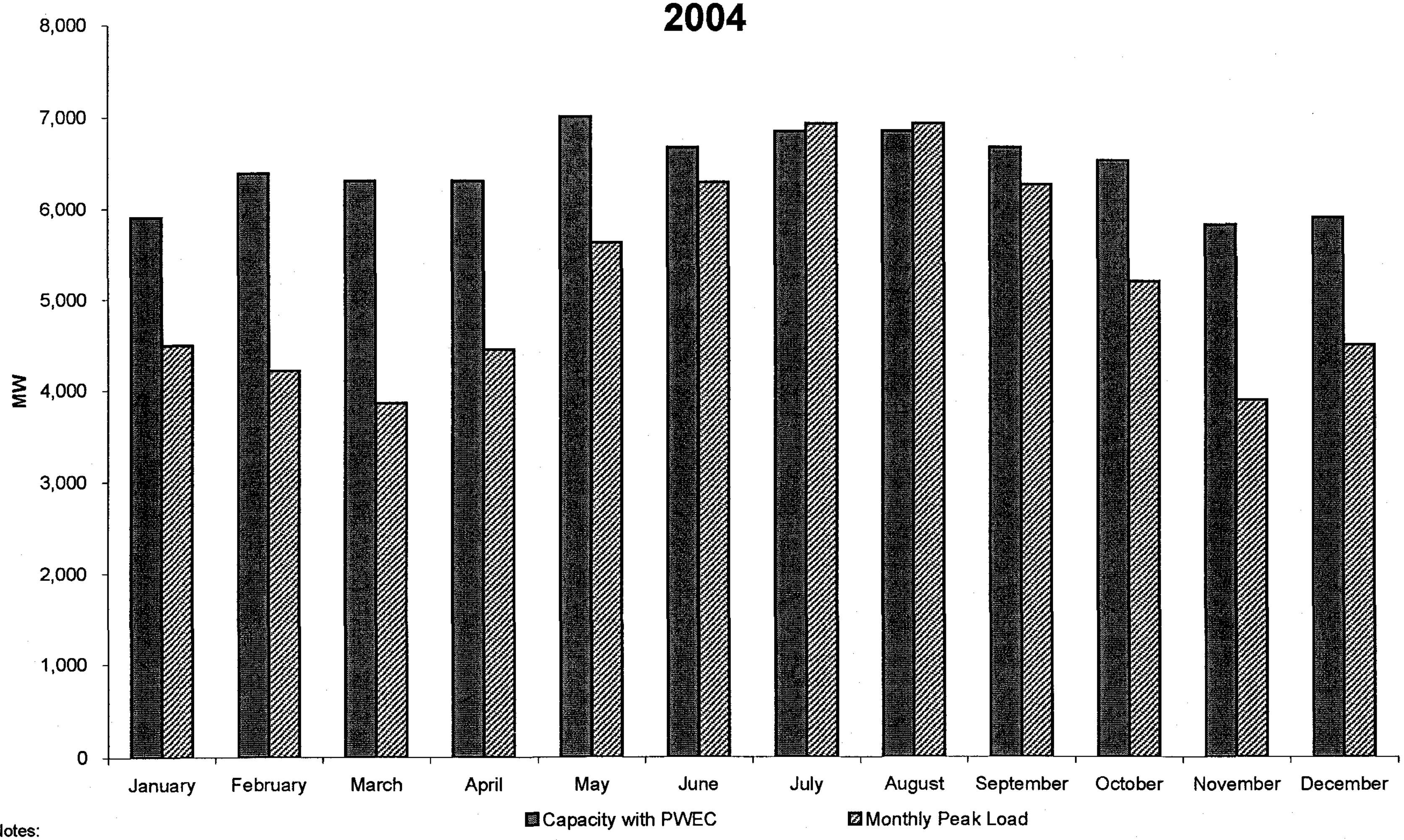
Exhibit JDT-5
APS FORECASTED MONTHLY PEAK LOAD v. GENERATION CAPACITY WITHOUT PWEC ASSETS
2004



Notes:
1) "Without PWEC" refers to the generation capacity currently owned, and available under contract by APS, and therefore includes APS's Track B purchases.
2) Capacities are not adjusted to account for variations that will result due to maintanance and forced outages.
3) Pacificorp exchange allows APS access to capacity from May 15 to September 15 and allows Pacificorp access to APS capacity from October 15 to February 15. It is assumed that APS receives the capacity or retains its own capacity in agreement with its intramonth expected peak demands. (i.e. In the figure, APS receives exchange in May and September, and does not provide exchange in February and October.
4) Monthly demands include 15% reserve margin.
5) Monthly demands have not been updated to reflect any more recent hourly forecasts that APS may have developed.

Sources: APB_WP9, DR001654_0051_TRACKB_APS-EWEN-WORKPAPERS, 12/03 APS RFP

Exhibit JDT-6
APS FORECASTED MONTHLY PEAK LOAD v. GENERATION CAPACITY WITH PWEC ASSETS
2004



Notes:

1) "With PWEC" refers to the generation capacity APS would own if the rate base request were approved.

2) Capacities are not adjusted to account for variations that will result due to maintanance and forced outages.

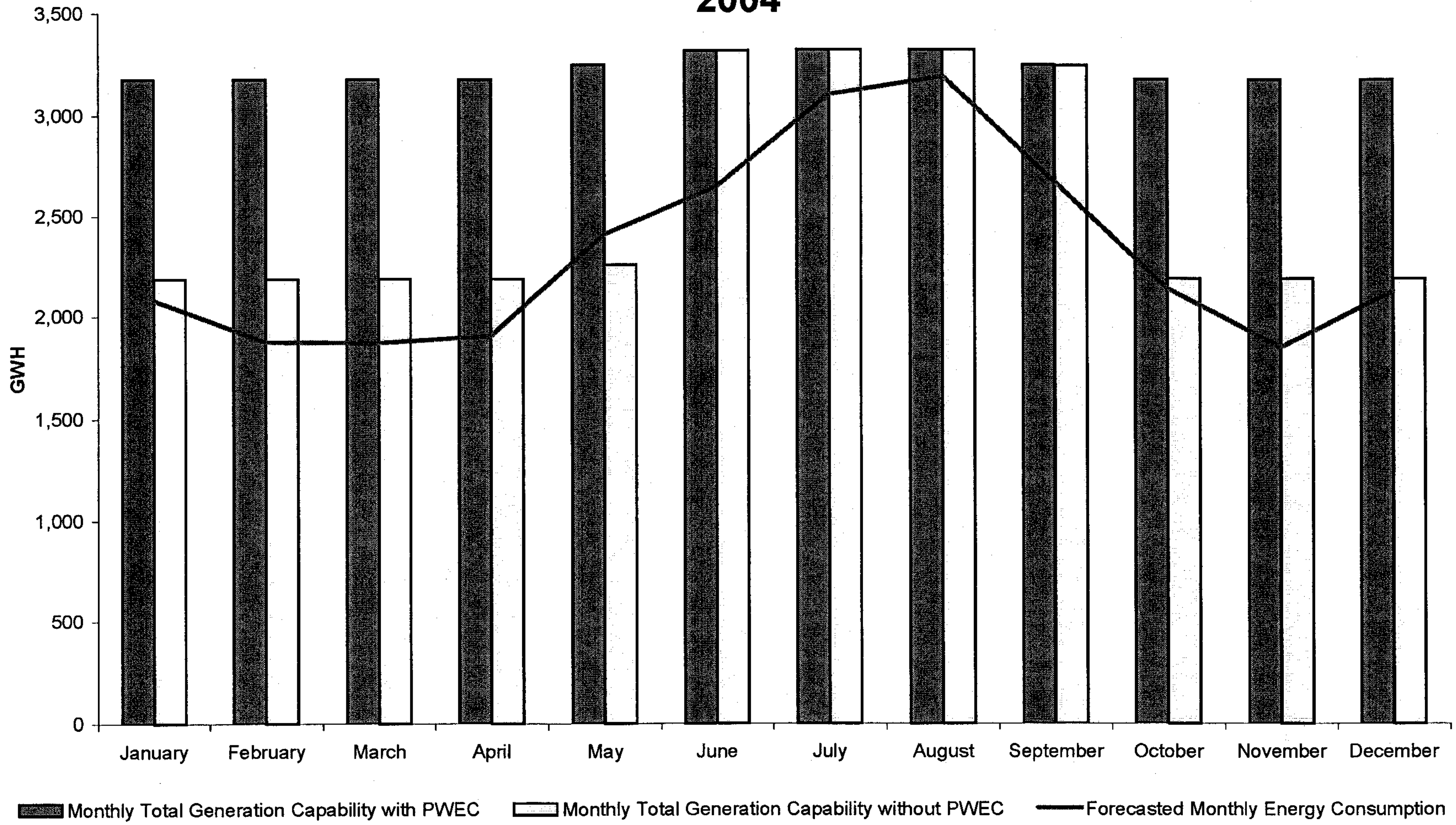
3) Pacificorp exchange allows APS access to capacity from May 15 to September 15 and allows Pacificorp access to APS capacity from October 15 to February 15. It is assumed that APS receives the capacity or retains its own capacity in agreement with its intramonth expected peak demands. (i.e. In the figure, APS receives exchange in May and September, and does not provide exchange in February and October.

4) Monthly demands include 15% reserve margin.

5) Monthly demands have not been updated to reflect any more recent hourly forecasts that APS may have developed.

Sources: APB_WP9, DR001654_0051_TRACKB_APS-EWEN-WORKPAPERS, 12/03 APS RFP

Exhibit JDT-7
WITH PWEC ASSETS, APS HAS ENORMOUS EXCESS ENERGY GENERATION CAPABILITY
2004



Notes: Monthly Production Capability of plants calculated as follows: Coal and Combined Cycle at 85% capacity factor, Oil and gas-fired steam at 60% capacity factor, Hydro and CTs are excluded, SRP contract reported at minimum historical capacity factor."With PWEC" refers to the generation capacity APS would own if the rate base request were approved. "Without PWEC" refers to the generation capacity currently owned, and available under contract by APS and therefore includes APS's Track B purchases.

Sources: EIA 861, WECC Summary of Estimated Loads and Resources, APS Response to MR 1.4, APB_WP9, RC01035.

Exhibit JDT-8
RESULTS OF VARIOUS WESTERN UTILITIES' RFPs

Utility	Date	Time period	Product	MWs	Total responses
Pacificorp	Sep-01	2 months - 12 years	capacity/energy price/tolling - various		
NorthWestern Energy	Oct-01	various terms, beginning July 2002 for up to 11 years	full requirements; base load; peaking/reserves	1,100	14
Aquila	Jun-02	Starting July 2007	capacity	300	Confidential
Xcel	Dec-01	May 2005 - 2009	power	1,000	27
Cheyenne Light Fuel and Power Co	Dec-02	Starting January 2004, 3-15 years	full requirement	~146	
Idaho Power	Feb-03	Starting April 2004	devoted dispatchable energy; construction of new capacity	200	11
APS	Mar-03	1 year	summer load	2,460	
TEP	Mar-03	1 year	summer load	760	
Pacificorp	Jun-03	2004 - 2007	June - August peaking power	225	
Pacificorp	Jun-03	2005-2012	asset-based energy contracts in 25 MW blocks, for April	175	
Pacificorp	Jun-03	online by 2005	peaking plant	200	
Pacificorp	Jun-03	online by 2007	baseload plant	570	
El Paso	Jan-03	Starting 2006, 2009		150 (2006), 250 (2009)	22
Nevada Power	Jul-03	2004		2,000	
Portland General	Jun-03	Capacity starting December 2005, energy starting October 2006	energy (600 MW) capacity (400 MW)	1,000	40
SDG&E	May-03	2005-2007	capacity; energy	1,165	22*
WAPA	Oct-03	November 2003 - September 2004	capacity	12-23 MW	
Puget Sound Energy	Dec-03	starting 2005	generation/long-term contract	355	N/A

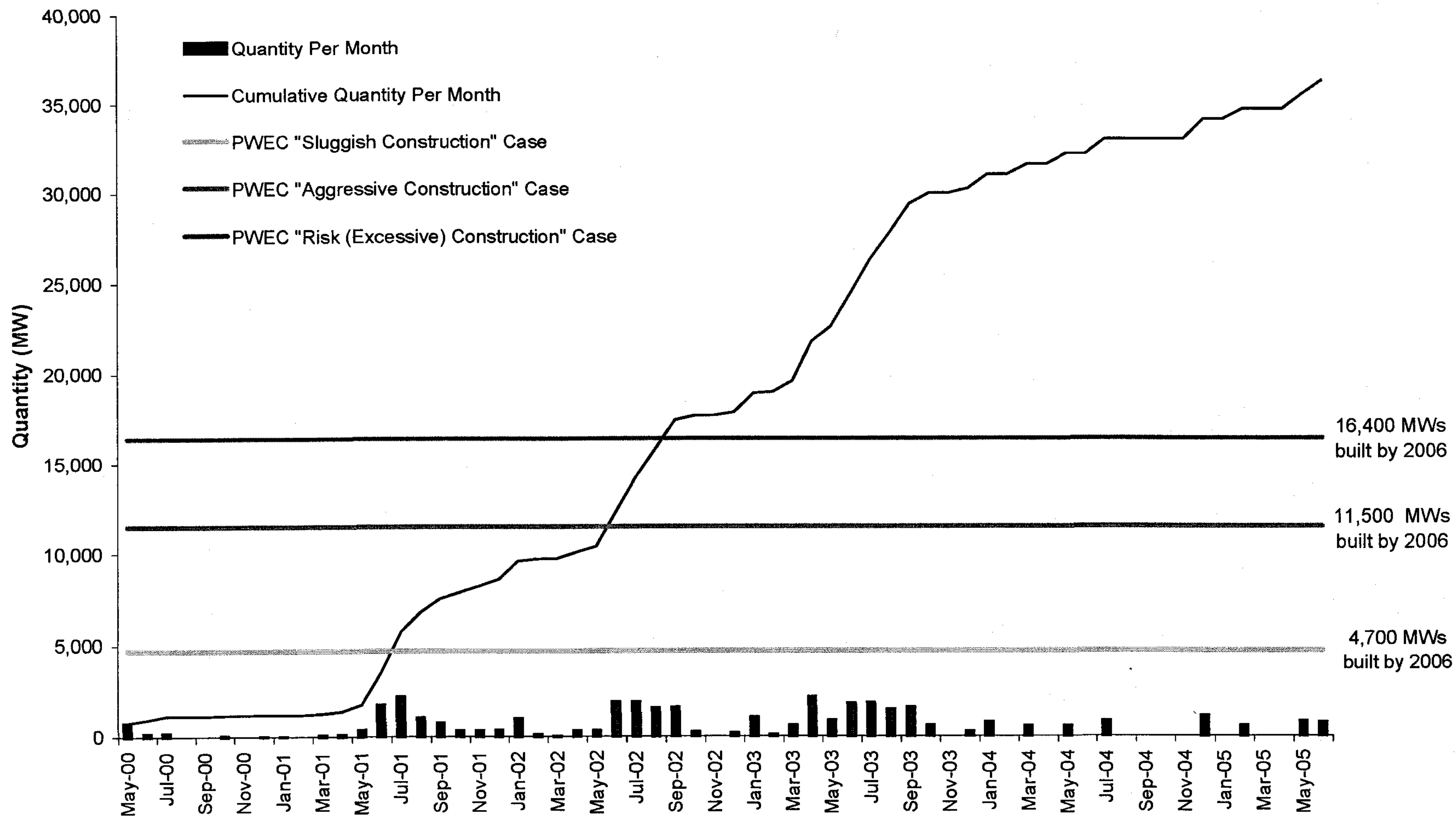
Note: Number of responses reflects number of entities responding, not total number of proposals received, where possible. A * indicates the total number of responses was the only publicly available information.

Source: Various trade press.

Exhibit JDT-9

CUMULATIVE AND MONTHLY QUANTITY OF NEW POWER GENERATION PLANTS BY ONLINE DATE v PWEC'S AUGUST 1999 NEW GENERATION RISK ASSESSMENT

Western US*



* Western US includes the WECC states: California, Arizona, Nevada, New Mexico, Utah, Idaho, Washington, Oregon, Colorado, Wyoming, and Montana.

Sources: RC02431; California Energy Commission; Second Biennial Transmission Assessment, 2002-2020; various trade press.

EXHIBIT
ACPA-3
admitted

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND FOR APPROVAL OF PURCHASED POWER CONTRACT.

DOCKET NO. E-01345A-03-0437

DIRECT TESTIMONY

OF

GREG PATTERSON

ON BEHALF OF

THE

ARIZONA COMPETITIVE POWER ALLIANCE

September 27, 2004

INTRODUCTION

Q. What is your name and by whom are you employed?

A. My name is Greg Patterson. I am employed by the Arizona Competitive Power Alliance.

Q. Would you please summarize your professional and educational background?

A. I am a CPA and graduated from the University of Arizona's Accounting Program in 1985. I worked as an accountant and accounting teacher from 1986 through 1990. In 1990 I was elected to the Arizona House of Representatives. I served on the Appropriations and Natural Resources Committees, and went on to chair the House Government Operations Committee. I later chaired the House Banking and Insurance Committee.

In 1995, I was appointed by then Governor Symington as Director of the Residential Utility Consumer Office (RUCO). As RUCO director, I participated in over 100 proceedings before the Arizona Corporation Commission. During my RUCO tenure, I also worked as a consultant for a sub contractor to the World Bank and The United States Agency for International Development (USAID), lecturing on various utility-regulation topics in Zambia, Tanzania, Albania, Egypt and Nigeria.

In 1999, I left RUCO and accepted a position with the State Senate--serving as Chief of Staff until 2001. In 2001, I accepted my current position as Director of the Arizona Competitive Power Alliance.

Q. Would you please describe your background as it relates to this proceeding?

A. As Alliance Director, I have participated in all ACC proceedings involving APS or Electric Restructuring that have occurred since 2001. These proceedings include, but are not limited to, the APS Application for Partial Variance, Track A, Track B, the APS Financing Application, and the current Rate Case. Additionally, in my former capacity as RUCO Director, I was a signatory to the 1996 and 1999 APS Settlements. In that capacity, I testified in favor of the 1999 Settlement.

Q. On whose behalf is your testimony submitted?

A. I am testifying on behalf of the Arizona Competitive Power Alliance.

Q. What companies are members of the Alliance?

A. Members of the Alliance are[1]: Calpine, Constellation New Energy, Duke Energy North America, LLC, New Harquahala Generating Company, LLC., PPL Montana, LLC, Sempra Energy Resources, Shell Trading, and Southwestern Power Group II, LLC. and Strategic Energy.

[1] The positions contained in this filing represent the views of the Alliance as an organization, but not necessarily the views of any particular member with respect to any issue. Any individual Alliance member may take different positions with respect to any issue.

Q. What generating stations have been built by Alliance members?

A. Arlington Valley Energy Facility I (AVEFI) is a 580 MW gas-fired combined cycle facility owned by Duke Energy.

South Point is a generating station owned by Calpine Western Region. It consists of a two-on one combined cycle gas fired plant producing 550 MW.

Griffith Energy is a generating project owned in equal parts by Duke Energy and PPL. It consists of a combined cycle 2X1 gas fired plant producing 600 MW.

Mesquite is a generating project developed by Sempra Energy Resources. The plant consists of two combined cycle gas fired units of a two-on-one configuration producing a total of 1,250 MW.

Harquahala is a generating station owned by PG&E National Energy Group. The station consists of three one-on-one combined cycle power blocks. The plants rating is 1,092 MW nominal.

SWPG has a CEC for a 1000 MW gas-fired, combined cycle project at Bowie, Arizona.

The Sundance Energy Project, developed by PPL has a total gross generation of 450 MW.

Q. What is the purpose of your testimony?

A. I am testifying in support of the proposed Settlement.

Q. Generally, why do you support the Settlement?

A. We believe that the Settlement represents an excellent compromise among a diverse group of parties on a large number of complex issues. All the parties face substantial risk and expense when litigating a case of this complexity. This Settlement resolves our issues in a manner that we believe is in our best interest and in the best interest of the public.

Q. Generally, why do you believe the Settlement is in the Public Interest?

A. Nearly 30 parties participated in the Settlement process and only one is opposed to the final Settlement. Parties who have endorsed the Settlement include: residential, industrial, federal and low income consumer groups, environmental groups, The IBEW, the merchant community, retail providers, Staff and APS. A group this diverse represents the people of Arizona in multiple capacities. I believe that a global settlement that is agreed to by a group this diverse is by definition in the public interest.

Q. Why was the Alliance a party in this case and what were the Alliance's overall objectives.

A. The Alliance's central objective in this case--and in the litigation filed since the Variance--is to achieve an environment in which there exists a viable and effective wholesale market into which we can sell power. This Settlement provides certainty, clarity and predictability concerning that market, and provides a post Track A and B platform from which a viable and effective wholesale market can develop and thrive.

Q. What message does a self-build moratorium send to the wholesale market?

A. The self-build moratorium provides a strong signal that the Arizona Corporation Commission believes that independent power production is an effective alternative to the traditional vertically integrated utility. The moratorium combined with Arizona's high growth rate provides assurance to the merchant community that independent power will be an even more integral component in Arizona's future power infrastructure.

Naturally, there are protections built into the Settlement in the unlikely case that the wholesale market is unable to meet Arizona's growing power needs. If the Company's efforts to secure adequate and reasonably-priced long-term resources from the competitive wholesale market are unsuccessful, the ACC may expressly authorize the Company to self-build prior to 2015 as to a particular demonstrated need.

Q. What benefit does a 1,000 megawatt RFP in 2005 provide the wholesale market?

A. The 1,000 megawatt RFP in 2005 provides a degree of certainty as to the timing of an initial increment of APS' future needs that will be met from the wholesale market. Knowing the specific amount of capacity needed and the timing of its purchase allows the individual members of the merchant community to effectively plan for the most efficient way to meet that particular need.

Naturally, there are protections built into this provision of the Settlement as well. If the company/Commission does not believe the results of the RFP are in the best interest of its customers they have the ability to reject all offers and pursue bilateral contracts. Additionally, all renewable resources, distributed generation, and DSM will be invited to compete in the RFP and will be evaluated in a consistent manner with all other bids, including their life-cycle costs compared to alternatives of comparable duration and quality.

Q. Does this conclude your testimony in support of the settlement agreement?

A. Yes.

Summary Statement of Greg Patterson

General Summary

We believe that the Settlement represents an excellent compromise among a diverse group of parties on a large number of complex issues. All the parties face substantial risk and expense when litigating a case of this complexity. This Settlement resolves our issues in a manner that we believe is in our best interest and in the best interest of the public.

Response to Commissioner Mayes

The Alliance's central objective in this case is to achieve an environment in which there exists a viable and effective wholesale market into which we can sell power.

In our original litigation position we attempted to achieve this central objective by opposing the proposed transfer of the PWEC assets to APS. Had we been successful, Alliance members would have earned the right to bid against the PWEC assets in an effort to provide low-cost power to APS customers. Within the limited framework of the Rate Case, we believed that this was our best hope of creating a viable and effective wholesale market. Yet, we recognized that broader issues of overall market structure, self-build guidelines and future RFPs would have to be litigated at a later date and in a more comprehensive venue. This proposed settlement, however, provides a venue in which we have an opportunity to solve these global market issues.

Two provisions of the proposed settlement provide a more comprehensive resolution to our goal of creating a viable and effective wholesale market than we could have achieved through litigation.

The self-build moratorium provides a strong signal that the Arizona Corporation Commission believes that independent power production is an effective alternative to the traditional vertically integrated utility. The moratorium combined with Arizona's high growth rate provides assurance to the merchant community that independent power will be an even more integral component in Arizona's future power infrastructure.

The 1,000 megawatt RFP in 2005 provides a degree of certainty as to the timing of an initial increment of APS' future needs that will be met from the wholesale market. Knowing the specific amount of capacity needed and the timing of its purchase allows the individual members of the merchant community to effectively plan for the most efficient way to meet that particular need.

Admitted

EXHIBIT

ACPA-4

LB 12/02/04

Arizona Competitive Power Alliance

EXHIBIT LIST
DOCKET NO. 01345A-03-0437

ACPA-1	Direct testimony of Joseph P. Kalt
ACPA-2	Direct testimony of Jeffrey D. Tranen
ACPA-3	Settlement direct testimony of Greg Patterson
ACPA-4	Summary of Greg Patterson Testimony

AECC

DIRECT TESTIMONY OF KEVIN C. HIGGINS

On Behalf of Arizonans for Electric Choice & Competition

Docket No. E-01345A-03-0437

February 3, 2004

TABLE OF CONTENTS

DIRECT TESTIMONY OF KEVIN C. HIGGINS

Introduction

Q. Please state your name and business address.

A. Kevin C. Higgins, 39 Market Street, Suite 200, Salt Lake City, Utah, 84101.

Q. By whom are you employed and in what capacity?

A. I am a Principal in the firm of Energy Strategies, LLC. Energy Strategies is a private consulting firm specializing in economic and policy analysis applicable to energy production, transportation, and consumption.

Q. On whose behalf are you testifying in this proceeding?

A. My testimony is being sponsored by Arizonans for Electric Choice and Competition ("AECC"), a business coalition that advocates on behalf of retail electric customers, and which supports the advancement of retail electric competition. AECC is a party to the Arizona Public Service Company ("APS") Settlement Agreement that has governed APS Standard Offer rates since 1999, and established the basis for implementing the Commission's Electric Competition Rules in the APS service territory.

Q. Were you personally involved in the negotiations that resulted in the APS Settlement Agreement?

A. Yes, I was closely involved in the negotiations on behalf of AECC.

Q. Please describe your professional experience and qualifications.

A. My academic background is in economics, and I have completed all coursework and field examinations toward the Ph.D. in Economics at the University of Utah. In addition, I have served on the adjunct faculties of both the University of Utah and Westminster College, where I taught undergraduate and graduate courses in economics. I joined Energy Strategies in 1995, where I assist private and public sector clients in the areas of energy-related economic and policy analysis, including evaluation of electric and gas utility rate matters.

Prior to joining Energy Strategies, I held policy positions in state and local government. From 1983 to 1990, I was economist, then assistant director, for the Utah Energy Office, where I helped develop and implement state energy policy. From 1991 to 1994, I was chief of staff to the chairman of the Salt Lake County Commission, where I was responsible for development and implementation of a broad spectrum of public policy at the local government level.

Q. Have you previously testified before this Commission?

A. Yes. I have testified in a number of proceedings before this Commission, including the generic proceeding on retail electric competition (1998),[1] the hearings on the APS and TEP settlement agreements (1999),[2] the AEPCO transition charge hearings (1999),[3] the Commission's Track A proceeding

[1] Docket No. RE-00000C-94-0165.
[2] Docket Nos. RE-00000C-94-0165, E-01345A-98-0473, E-01933A-97-0773, E-01345A-98-0471, and E-01933A-97-0772.
[3] Docket No. E-01773A-98-0470.

(2002),[4] the APS adjustment mechanism proceeding (2003),[5] and the Arizona ISA proceeding (2003).[6]

Q. Have you testified before utility regulatory commissions in other states?

A. Yes. I have testified numerous times on the subjects of electric utility rates and industry restructuring before state utility regulators in Colorado, Georgia, Indiana, Michigan, Nevada, New York, Oregon, South Carolina, Utah, Washington, and Wyoming.

A more detailed description of my qualifications is contained in Attachment KCH-1, attached to this testimony.

PHASE I: REVENUE REQUIREMENTS

<u>Overview and conclusions – Revenue Requirements</u>

Q. What is the purpose of your testimony in the Revenue Requirements phase of the proceeding?

A. I have been asked to evaluate the merits of APS' general rate case filing with respect to revenue requirements. I also have been asked to recommend any adjustments to the Company's proposed revenue requirements that might be necessary to ensure results that are just and reasonable. Given the wide scope of this general rate proceeding, I have concentrated my efforts on a limited number of significant issues. Absence of comment on my part regarding a particular

[4] Docket Nos. E-00000A-02-0051; E-01345A-01-0822; E-00000A-01-0630; E-01933A-02-0069; E-01933A-98-0471.
[5] Docket No. E-01345A-02-0403.
[6] Docket No. E-00000A-01-0630.

revenue issue does not signify support (or opposition) toward the Company's filing with respect to the non-discussed issue.

Q. What conclusions have you reached in your analysis of APS' revenue requirements proposals?

A. (1) The Commission should reject in its entirety APS' request to reverse the so-called "$234 million write-off" the Company took in 1999. Acquiescence to this proposal would be tantamount to granting APS a gift of at least $375 million spread over 15 years. The write-off in 1999 was an accounting matter related to projections of stranded costs. It ultimately had no meaningful impact on APS' revenues from retail ratepayers, either in 1999 or in the years that have followed. In a logical sense, APS' request to "reverse" the 1999 write-off is a non-sequitur, as there was never any harm from the write-off to be "undone". The Company's proposal is merely an attempt to take back a significant part of the rate reductions granted in the Settlement Agreement – a reversal that is entirely without merit. Rejecting this proposal would eliminate $33 million of the Company's $175 million rate increase request.

(2) The Commission should deny APS' request to place into rate base 1700 MW of new generating units owned by Pinnacle West Energy Company ("PWEC"). The units were built as merchant plants and are currently providing power to APS under contract through 2006. Moving the units into rate base would cost ratepayers a premium of $107 million per year relative to the status quo. This added cost to ratepayers is simply not reasonable. Moreover, selecting one company's generating units for inclusion into rate base would run counter to

Arizona's efforts to encourage development of a competitive wholesale market. Rejecting this proposal would eliminate $107 million of the Company's $175 million rate increase request.

(3) The Commission should deny APS' request to include $10 million per year in rates to recover costs associated with the Company's 2002 severance program. The severance program is a non-recurring cost that will have already been recouped by APS shareholders through labor cost savings by the time the rate-effective period begins. Rejecting this proposal would eliminate $10 million of the Company's $175 million rate increase request.

My three recommended revenue adjustments are summarized in Table KCH-1 below. As the table shows, the cumulative impact of these recommendations is to lower APS' proposed revenue requirements by approximately $150 million per year.

Table KCH-1
Summary of AECC Revenue Requirement Adjustments

Adjustment	**Revenue requirement impact**
1. Deny reversal of 1999 write-off	$ (33,215,060)
2. Deny inclusion of PWEC units in rate base	$(106,648,000)
3. Deny amortization of 2002 severance costs	$ (9,960,548)
TOTAL	$(149,823,608)

Q. Are there any special factors the Commission should bear in mind with respect to the underlying framework of this rate proceeding?

A. Yes, there is one factor in particular the Commission should bear in mind. APS rates currently incorporate a very substantial regulatory asset component, representing costs that were incurred many years ago, but which were not collected from customers at the time, and instead were deferred for later recovery. In 1996, the Commission agreed to allow APS to recover these costs on an accelerated basis. They will be fully amortized by June 30, 2004. To meet this timetable, current rates recover about $120 million in regulatory asset costs per year.[7] By the start of the rate-effective period for this proceeding, this substantial regulatory asset cost burden will have been completely paid off, a fact that is recognized in the Company's filing. Therefore, the proper starting point for this rate proceeding is the very substantial rate *reduction* coming to customers because the regulatory asset burden of the past will have been eliminated. Final rates should only increase if APS' prudent costs have grown more rapidly than the underlying cost reduction associated with the elimination of the Company's historic regulatory asset balance.

Reversal of 1999 write-off

Q. What is APS' proposal regarding the treatment of the write-off the Company took in 1999 following the approval of the Settlement Agreement?

A. As described in the direct testimony of Company witnesses Steven M. Wheeler and Donald G. Robinson, APS is asking the Commission for a special increase in rate base in the net amount of $142 million in order to "reverse" a write-off the Company took in 1999 following approval of the Settlement Agreement. The net effect of this proposal would be to raise retail rates $33 million per year.

Q. What is the rationale for APS' request?

[7] See pre-filed direct testimony of Donald G. Robinson, Attachment DGR-4, p. 2 (which provides the basis for recovery of carrying charges) and Attachment DGR-5, p. 20 (which provides amortization costs).

A. In 1999, following approval of the Settlement Agreement, APS recorded a $140 million after-tax charge to its income statement, the basis for which is addressed in my testimony below. APS depicts this charge as the "$234 million write-off." In this proceeding, APS justifies its request for additional rate base because the Company believes it is entitled to "reverse" the write-off it took following approval of the Settlement Agreement, due to the Company's "detrimental reliance" on that agreement. The alleged detrimental reliance is related to the Commission's Track A decision in September 2002 prohibiting divestiture of APS' generating assets to PWEC.[8]

Q. What is your assessment of APS' request?

A. I recommend against adoption of APS' request in the strongest possible terms. Acquiescence to this proposal would be tantamount to granting APS a gift of at least $375 million spread over 15 years. This cost to ratepayers would result from the amortization of the initial $142 million net increase in rate base plus the return earned each year on the net balance, as shown in Attachment KCH-2. As a practical matter, the benefit to APS would be even greater than $375 million, as the revenue requirements impact from the Company's proposal is greatest in the first year, and the initial-year rate impact of $33 million would remain in place until and unless there are subsequent rate cases.

Q. Why are you so strongly opposed to the Company's proposal?

A. I was closely involved in the negotiations that led to the Settlement Agreement in 1999 and I am very familiar with the terms of that agreement, including the basis for the write-off. The write-off in 1999 was an accounting

[8] Pre-filed direct testimony of Steven M. Wheeler, p. 4, lines 7-12.

matter related to projections of stranded costs. It ultimately had no meaningful impact on APS' revenues from retail ratepayers, either in 1999 or in the years that have followed.[9] Nor was the write-off related in any way to the rate reductions granted to Standard Offer customers as a result of the Settlement Agreement. Simply put, the write-off did not result in any reduction in revenues recovered by APS from its customers. To "reverse" the write-off today would be to commit an act that has no logical basis.

Q. If the write-off had no impact on revenues from retail ratepayers, why was it taken?

A. In 1998 and 1999, APS was projecting stranded costs due to retail access in the amount of $533 million in present value terms.[10] APS' calculation represented the net revenues the Company would theoretically lose due to retail customers switching to direct access service. This "lost revenue" constituted the Company's stranded cost, which it was entitled to recover via the Competitive Transition Charge ("CTC").

The Company's stranded cost calculation, made from the perspective of 1998, assumed that *all* of APS' load would switch to direct access service as soon as it was eligible to do so (e.g., 100 percent switching by 1/1/01). According to this calculation, the impact of retail access would cause the present value of the Company's revenues to decline by $533 million over the period 1999-2004. This

[9] A relatively small number of customers took direct access service in APS' territory prior to the western price spike in 2000. Theoretically, there could be some small amount of un-recovered stranded cost associated with these sales, but at most it would be on the order of two-tenths of one percent of the "$234 million reversal" APS is seeking.

[10] This calculation was filed by APS on June 4, 1999 as Schedule JED-3, attached to the direct testimony of APS witness Jack E. Davis in the APS Settlement Agreement proceeding, Docket Nos. E-01345A-98, E-

forecasted decline in revenues took into account APS' projected sales of its "freed up" generation into a competitive market. Put another way, APS calculated that its cost of providing state-regulated generation service was going to be $533 million more expensive (in present value terms) than what the Company could sell that same generation for in the competitive market. Thus, APS considered its stranded cost to be $533 million, in accordance with the "revenues lost" methodology.

This calculation was very important because the Electric Competition Rules provide for the recovery of net stranded cost. That is, for the period 1999-2004, a customer switching to direct access service has been (and continues to be) required to pay the APS Competitive Transition Charge to recover the Company's stranded costs.[11]

Certain parties to the Settlement Agreement, such as AECC, believed the $533 million stranded cost estimate was much too high, and would not agree to base the CTC on that amount. After extensive negotiations, as a compromise, the parties agreed to base the CTC on a stranded cost of $350 million (present value).

This compromise set in motion the write-off. Because APS believed its stranded cost to be $533 million, the Company was required, in compliance with financial accounting standards, to make an accounting adjustment to write off the present value of any future revenues not expected to be recovered from regulated rates. This amount was the difference between the $533 million the Company projected in stranded cost and the $350 million it would be allowed to collect

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01345A-0773, and RE-00000C-94-0165. The calculation was originally filed by APS with the Commission on August 21, 1998.

[11] Note that for Standard Offer customers, stranded cost recovery is built into existing rates.

through the CTC. This difference had a present value of $183 million, which was the basis for the write-off.

Q. If the basis for the write-off was $183 million, why does APS refer to it as a "$234 million" write-off?

A. $183 million is a present value amount. APS elected to apply the write-off to a stream of regulatory assets that were being amortized during the 1999-2004 period. The nominal value of the regulatory assets that were "foregone" equaled $234 million.

Q. You stated that the write-off was based on future revenues not expected to be recovered from regulated rates. Wasn't that a revenue loss to APS?

A. No, as I have stated already, APS ultimately did not experience any meaningful loss of revenue related to the write-off.

Q. Why didn't APS lose any revenue?

A. Because even though APS recovered $234 million less in regulatory assets than it would have otherwise, the Company still received the same revenues it would have absent the write-off: instead of being attributed to recovery of regulatory assets, the revenues simply added to APS' profits.

To understand this point, it is important to bear in mind that the write off – an accounting action – was based on a *forecast* of future revenues that were not expected to be recovered under regulated rates due to un-recovered stranded costs, i.e., the $183 million discussed above. That forecast was based on assumptions made in 1998 by APS about the future – assumptions that turned out to be very, very wrong. As things actually turned out, APS did *not* experience any un-recovered stranded cost, and hence, did *not* experience the revenue shortfall that was the basis of the write-off.

Q. What turned out differently than expected to preclude the revenue loss from occurring?

For one thing, APS' stranded cost calculation of $533 million assumed that *all* of its retail customers – industrial, commercial, residential – moved to direct access service as soon as they legally could. Of course, this did not happen (nor was it ever remotely likely to happen). In fact, due to high wholesale prices (combined with stranded cost charges), relatively few customers have actually taken direct access service between 1999 and today. Thus, the projected revenue loss due to the less-than-full-recovery of stranded cost never actually took place.

This point is illustrated conceptually in Attachment KCH-3. In the left-hand panel, I show the basis for the write-off, which was the present value difference between APS' projected stranded cost of $533 million and the stranded cost recovery of $350 million that would have been collected under the CTC, had all of APS' retail customers switched to direct access service. Under this scenario, once 100 percent of customer load moved to direct access service on January 1, 2001, the Company's generation-related revenues would equal the market price plus the CTC, which together were expected to fall short of the Company's cost of generation under regulation (which is depicted by the uppermost curve). This $183 million shortfall is labeled "Area A" in the diagram.

In the right-hand panel, I show conceptually what actually happened. Note that, due to the nearly complete absence of direct access transactions, the

Company's actual revenues turned out to be based on its regulated Standard Offer rates – the uppermost curve in the diagram – meaning that the Company wound up recovering its regulated generation costs. Consequently, there was never a "shortfall" of $183 million in present value revenues.

The write-off took place, but the revenue shortfall that was its basis never happened. That is, even though the Settlement Agreement package obligated APS to absorb – potentially – a $183 million shortfall, the revenue loss did not materialize. <u>In hindsight, with respect to this aspect of the Settlement Agreement, APS got a better deal than it bargained for, as the Company was obligated to absorb a potential revenue shortfall of $183 million – but ultimately did not have to.</u>

Q. What else turned out differently than expected to preclude the revenue loss from occurring?

A. In retrospect, APS' stranded cost projection of $533 million turned out to be completely wrong. Rather than its regulated cost of generation being $533 million *more expensive* than the competitive market value, for much of the intervening period, APS' generation has actually been *cheaper*. As a result, APS' stranded costs actually turned out to be *negative* over the period 1999-2003. This outcome is illustrated in Attachment KCH-4.[12] In hindsight, then, even the compromise stranded cost amount of $350 million turned out to be much too high.

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[12] The calculation in Attachment KCH-4 uses the original generation cost forecast employed by APS in calculating the $533 million stranded cost figure, but updates the 1998 forecast prices with actual Palo Verde prices. Arguably, APS' own generation costs may have also increased since the 1998 forecast, but comparable cost data was not available from the Company for the years in question. Given APS' resource mix, it is extremely unlikely that higher APS fuel costs would have resulted in positive stranded cost calculation, considering the *negative* $1.4 billion present value that results from the figures in Attachment KCH-4.

As a result, even if customers *had* taken significant advantage of retail access service, APS' revenue loss due to un-recovered stranded cost would have been significantly less than the write-off, or even negligible.

There is a significant irony here. If, in 1999, APS' stranded cost calculation had been less aggressive – and, in hindsight, more accurate – the Company would not have been required to take a write-off in the first place. For instance, had APS projected stranded costs of $350 million, no write-off would have been needed, as that amount was assured recovery through the CTC even if 100 percent of customers switched to direct access. Indeed, given the fact that customers have overwhelmingly remained on Standard Offer service, APS' revenues would have turned out to be the same irrespective of whether the Company projected stranded costs of $533 million or $350 million: the only difference was whether a write-off was required.

Q. Are you advocating for some type of retroactive adjustment to stranded cost?

A. No, I am not. AECC agreed to a fixed-charge CTC in 1999, and has never sought to undo the terms of that deal, despite the obvious changes in market prices from prior expectations. But neither is APS entitled to a retroactive negation of the rate reductions in the Settlement Agreement through the "write-off reversal" claim it is pursuing in this proceeding. APS should not be rewarded now for having over-estimated stranded cost in 1998 – particularly since the write-off it incurred as a result of that over-estimation did not result in any actual reductions in APS revenues between 1999 and the present time.

Q. Does APS acknowledge that the 1999 write-off was based on projections of stranded costs?

A. Yes, but APS tries to downplay this connection. I assume this because the facts pertaining to stranded cost recovery are entirely unsupportive of APS' claim to have the write-off reversed. So, despite acknowledging stranded cost as the *basis* of the 1999 write-off, Mr. Wheeler nevertheless asserts that the *restoration* of the write-off has "nothing to do" with stranded cost.[13]

In my opinion, there is a serious disconnection here. In a logical sense, APS' request to "reverse" the 1999 write-off is a non-sequitur. Indeed, there was never any harm from the write-off to be "undone". The "reversal" story is merely a vehicle that APS is apparently employing to seek compensation from customers for unrelated damages that APS believes it has incurred due to the Commission's Track A decision prohibiting divestiture of APS' generating assets to PWEC. The problem with this story, though, is that APS tries to give the impression that the write-off in 1999 actually cost the Company money – when in fact, it did not.

Q. On page 19 of his pre-filed direct testimony Mr. Wheeler states that "if APS had not written off this $234 million, it would have continued to recover that amount in rates during the years 1999 through 2004." Is that a correct statement?

A. In a narrow sense it is correct, but it is also misleading, because it gives the impression that because of the write-off, the $234 million was somehow not recovered. APS does not point out that it is *equally true* to state:

[13] Pre-filed direct testimony of Steven M. Wheeler, 19, lines 9-13.

> Although it had written off this $234 million, APS continued to recover that amount in rates during the years 1999 through 2004.

A more complete version of Mr. Wheeler's assertion would read as follows:

Because almost all customers remained on Standard Offer service, APS would have recovered the $234 million in rates during the years 1999 through 2004 <u>*with or without*</u> *the write-off.*

Q. Was the write-off related to the rate reductions for Standard Offer customers that were implemented as part of the Settlement Agreement?

A. No. As I stated above, the write-off was solely related to stranded cost, which had nothing to do with the rate reductions to Standard Offer customers. All other things equal, reducing regulated rates for bundled customers lowers a utility's return; it does *not* cause a write-off.

Q. Do you believe it would be appropriate for APS to "take back" any part of the rate reductions that customers experienced from 1999-2004?

A. Absolutely not. Mr. Wheeler even states that it is not APS' intent to take back the rate decreases it agreed to as part of the 1999 settlement.[14] However, in defending the Company's proposal for a "reversal" of the write-off, APS states that the Company would not have agreed to the write-off *or the rate reductions* in the settlement, but for the other terms of the agreement, including divestiture.[15] <u>So, in a very real sense, APS' proposal does amount to an attempt to "take back" part of the prior rate reductions.</u> The Company did not receive the benefit of

[14] Pre-filed direct testimony of Steven M. Wheeler., p. 21, lines 5-6.

divestiture in the Settlement Agreement, and as compensation, it seeks an artificial increase in rates of $33 million per year. This is equivalent to a 1.8 percent rate increase – and it would result in higher rates for 15 years.

Q. Do you believe APS is entitled to any consideration with respect to the change in the divestiture provision in the 1999 settlement?

A. I am not opposed to APS receiving some consideration for this change. However, "reversing" the write-off to artificially raise rates $33 million per year is not an appropriate consideration. As I pointed out above, with respect to the write-off issue, APS actually wound up with a *better deal than it bargained for* in the settlement. That is because the settlement obligated APS to absorb a potential shortfall of $183 million in stranded cost – but the shortfall never materialized. This improved position of the Company should be factored in to any assessment of the damages it may have suffered from the reversal of the divestiture provision.

Q. What about APS' contention that it would not have agreed to the rate reductions absent the divestiture provision in the settlement?

A. I am not in a position to second-guess the Company's strategic tradeoffs. However, it is important to bear in mind that the Settlement Agreement was not the sole means to effect a rate reduction. Expectations about divestiture notwithstanding, APS' Standard Offer rates were always intended to be fully regulated, and therefore were always subject to reduction through a general rate case. In my opinion, the rate reductions that emerged from the Settlement

[15] APS Response to AECC 1.2a.: "APS would not have agreed to any write-off or the resulting rate reductions but for the other promises made in the Settlement, including divestiture."

Agreement were not unfair to the Company and should not be "undone" going forward to compensate APS for the change in the divestiture provision.

Q. What is the basis for your conclusion?

A. A review of the Company's earnings from 1999 through 2002 shows that APS has posted very solid returns despite the rate reductions. The Company's returns-on-equity for these years are shown in Table KCH-2 below. Indeed, in 2000, APS' return-on-equity was nearly 15 percent. While I certainly give credit to APS management for producing these returns in the face of rate reductions, it is simply not credible for the Company to insinuate that, for the purpose of advancing its "write-off reversal" argument, the rates that have prevailed since the Settlement Agreement have been in any way unjust and unreasonable to the utility. By extension, it is equally incredible to argue that those prior rate reductions should be "taken back" in this proceeding *for any reason.*

Table KCH-2
APS Return on Equity
1999-2002 [16]

1999	13.5%
2000	14.9%
2001	13.1%
2002	9.2%

Q. What consideration ought to be granted to APS in light of the reversal of the divestiture provision?

A. Section 2.6 of the Settlement Agreement establishes the basis for the Competition Rules Compliance Charge ("CRCC"), which is intended to recover costs associated with compliance with the Electric Competition Rules. In approving the Settlement Agreement, the Commission limited APS to recovery of 67 percent of the reasonable and prudent costs associated with effecting divestiture of its generation.[17] Given that APS was not permitted to implement that divestiture, I agree with APS that it should be allowed to recover 100 percent of the reasonable and prudent divestiture-related costs contemplated by Section 2.6. This higher level of cost recovery is already included in the CRCC proposed by APS, and represents about $3 million of the total CRCC spread over five years.

<u>**Rate basing of PWEC units**</u>

Q. What is APS' proposal with respect to the rate-basing of certain PWEC units?

A. APS is proposing to place five new generating units currently owned by PWEC into rate base as part of this proceeding. The units in question are Red Hawk Units 1 and 2, West Phoenix Units 4 and 5, and Saguaro CT Unit 3, which have an aggregate nameplate rating of approximately 1700 MW. APS' proposal would result in a net increase in rate base of $895 million,[18] which as shown in Attachment KCH-5, would raise rates $107 million per year. As such, this proposal represents over 60 percent of the $175 million rate increase being proposed by APS in this proceeding.

Q. What is APS' rationale for this proposal?

A. APS devotes a considerable amount of direct testimony to defending this proposal. The Company's argument, at its essence, is two-pronged: (1) that rate-

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[16] Moody's Analysis of APS, June 2003, p. 7 [Provided in APS Response to Utilitech 1-14.]
[17] ACC Decision No. 61973, p. 10, lines 2-8.
[18] Pre-filed direct testimony of Donald G. Robinson, p. 11, lines 20-21.

basing these units is a fair reward to Pinnacle West for having invested in Arizona generation during a critical time, and (2) that it is in ratepayers' long-term interests for these plants to be in rate base, where they will be priced at cost-of-service, and shielded from market volatility.

Q. What is your assessment of the Company's proposal?

A. The Company's proposal to rate base the PWEC units should not be adopted. The units were built as merchant plants and are currently providing power to APS under contract through 2006. Moving the units into rate base would cost ratepayers a premium of $107 million per year relative to the status quo. This added cost to rate payers is simply not reasonable. Moreover, Arizona has had a substantial amount of merchant generation constructed since the adoption of the Electric Competition Rules in 1996, with over 8800 MW added since 2001 (including PWEC). Selecting one company's generating units for inclusion into rate base would run counter to Arizona's efforts to encourage development of a competitive wholesale market.

Q. Is there any circumstance in which any of the PWEC generation should be considered for rate base treatment?

A. The only exception to excluding all of the PWEC generation from rate base treatment is the special case of generation constructed inside the Phoenix load pocket, to the extent that such generation is needed to meet load that cannot be served from competitive generation. In my opinion, that would leave open the door to possible *future* rate base treatment of some portion of the West Phoenix units. However, as those units were constructed at-risk and are currently under contract through 2006, I do not believe it is appropriate to include them in rate base at this time.

Q. Please address APS' argument that rate basing the PWEC units is a fair reward for having invested in Arizona generation.

A. When the Commission approved the 1998 version of the Electric Competition Rules it was abundantly clear that any new generation constructed in Arizona (other than by SRP) would be built "at risk." That is, there was absolutely no presumption that new generation would enter rate base. Indeed, the opposite was the case, as the Affected Utilities were required to divest the generation they had.

Consequently, when PWEC began construction of Red Hawk, West Phoenix 4 and 5, and Saguaro CT Unit 3, some *two years after* the adoption of the 1998 Rules, there could be no mistake on the part of Pinnacle West management that these units were being constructed in the full light of market risk and return. Indeed, under the Electric Competition Rules, there was not even assurance that APS would be obliged to purchase even a single megawatt-hour from these units.

Q. What about the Commission's reversal of the divestiture requirement? Doesn't that change the situation of these units?

A. No. When the Commission reversed the divestiture requirement as part of the Track A Order in September 2002, it changed the future treatment of APS' existing fleet of units: rather than being divested into the competitive generation market, those units will remain in APS rate base. But the PWEC units were never intended for rate base. Thus, their status as at-risk units has not been changed at all.

Q. Do you believe that Arizona has benefited from the construction of the PWEC facilities?

A. I have no reason to doubt that the construction of these units has been a benefit to Arizona. The best indication is that these units are supplying power to APS pursuant to the Track B solicitation. In my opinion, it is essential that these units continue to supply power to APS under their current contracts, at prices that were bid at arm's length. That way, customers continue to receive the benefit of competitively bid generation as envisioned by the Commission in establishing the Track B process.

Q. Do you believe that it is in ratepayers' interest that the PWEC units be brought into rate base now, in order to protect against future market volatility?

A. No, I do not. APS' "rate base proposal" for hedging against future market volatility is an expensive deal for customers. The $107 million incremental annual cost relative to purchasing the requisite power pursuant to the Track B solicitation is simply too hefty, and should be rejected.

Q. How should APS acquire the additional power needed to serve its Standard Offer customers after the Track B contract with PWEC expires?

A. Consistent with the Commission's Procedural Order on January 8, 2003, APS has sought competitive bids for the needed generation, including the 1700 MW now being provided by PWEC under contract. According to APS, these bids are currently being evaluated. To the extent that the results of the solicitation demonstrate that there will be a shortfall in delivering power to the Phoenix load pocket after 2006, it would be reasonable to consider rate base treatment for that portion of the West Phoenix generation needed to serve the load pocket. In my opinion, such rate base treatment, to the extent warranted, should not start before 2007, and should only be reflected in rates in the context of a future rate case.

Responses to questions posed by Commissioner Gleason

Q. Are you familiar with the questions raised by Commissioner Gleason relating to the rate basing of merchant generation in his letter of September 5, 2003?

A. Yes, I am. Commissioner Gleason has asked parties to respond to questions concerning the determination of market value for power plants, the presence of other power plants on the market that could serve Arizona, precedence in other jurisdictions for incorporating merchant assets into rate base, and the impact on the Track B process from including the PWEC assets into rate base.

Q. Do you have any comments you wish to make in response to these questions?

A. Yes. Commissioner Gleason's inquiry into market valuation speaks to the question of whether net book value (i.e., original cost net of depreciation and accumulated deferred income taxes) or market value should be used as the basis for additions to rate base, in the that event APS' proposal to place PWEC assets into rate base is approved in whole or part.

While, as I have discussed above, I am opposed to bringing any of the PWEC assets into rate base at this time, I believe Commissioner Gleason's question is an important inquiry to the extent that APS' proposal is considered. Ultimately, the question boils down to the Commission's assessment of what is just and reasonable. If the Commission is inclined to allow a merchant plant into rate base, it would not be unreasonable for the Commission to consider whether the plant's book value exceeded its market value, and to deny inclusion in rate base of any portion that was excess. If the Company felt the results of such an approach was unacceptable, it could withdraw its application.

Unfortunately, the mechanics of such an assessment of market value would be problematic, and would likely require an assessment by asset valuation experts, who would consider such factors as discounted net cash flow, cost-of-capital, and net salvage value in making a determination. Such an analysis would be needed because the assets are owned by an affiliate and any asset transfer would not be presumed to occur at an arm's length price.

In the case of generation constructed in the Phoenix load pocket, net book value can be given more weight, in my opinion. I have had a long involvement in addressing load pocket issues in Arizona, both in the Arizona ISA process, as well as in RTO negotiations, and am of the view that load pocket generation must be subject to price regulation during periods of import constraint. One of the guidelines to use in such regulation is cost-of-service. It is essential, however, that to the extent that any consideration is given to including the West Phoenix units into rate base, a condition of such approval be that the output of those units be made available at cost-of-service prices to competitive ESPs to serve any ESP retail load in the load pocket during periods of import constraint. Such a condition would be equivalent to requiring the generating units to be subject to the Arizona ISA Local Generation Requirement protocol, or any successor protocol adopted by an RTO.

Q. Turning to another of Commissioner Gleason's questions, are you personally familiar with instances in other jurisdictions in which merchant generation has been brought into rate base?

A. In one recent case in which I am familiar, PSI Energy, a vertically-integrated utility located in Indiana, purchased the 700 MW Madison and Henry County Generating Stations from subsidiaries of Cinergy, which is an affiliated company. PSI Energy then requested inclusion of those units in rate base based on the purchase price. It is my understanding that the transfer took place pursuant to the terms of a contested settlement agreement between PSI Energy, Indiana regulatory staff, and the Indiana utility consumer advocate office that was ultimately approved by the Indiana Utility Regulatory Commission. The transfer price was based on the net book value of the plant, with some adjustments. Apparently, in that instance, the Indiana Commission determined that net book value was a reasonable measure of the facilities' worth.

Q. Are you aware of any other power plants in Arizona that are available to be purchased at this time?

A. I am not personally aware of any specific power plants that are for sale in Arizona at the current time.

Q. What would be the likely impact on the Track B process from including the PWEC assets in rate base?

A. Adopting the Company's proposal to put the PWEC assets into rate base would undermine the Track B process. At the most fundamental level, it would replace power that was contracted through the Track B process and replace it with rate base generation (from the same power plants) that is significantly more expensive. Moreover, rate basing the 1700 MW of PWEC generation in question would short-circuit the Track B bidding process for this amount of contestable load in the future. As I recommended above, with respect to the Track B process, APS should be required to purchase power from the PWEC units under their current contracts, at prices that were bid at arm's length. For the period following the expiration of these contracts, APS should be required to continue the Track B process by seeking competitive bids for its contestable load, including the 1700 MW now being provided by PWEC. If the results of the solicitation demonstrate that there will be a shortfall in delivering power to the Phoenix load pocket after 2006, as APS claims will happen, then it would be appropriate to consider alternative approaches, including rate basing some portion of the West Phoenix generation after the current PWEC contract expires.

Q. Do you have any other issues you would like to bring to the attention of the Commission regarding APS' proposal to place the PWEC units in rate base?

A. Yes. I am concerned that the introduction of PWEC units could give rise to a future generation of stranded cost claims by APS. Militating against this possibility is the fact that the Electric Competition Rules make it clear that resources added after 1996 are not eligible for stranded cost recovery. Moreover, AECC entered into the 1999 Settlement Agreement with the expectation that the matter of stranded cost would be resolved permanently. In the event that the Commission gives consideration to APS' rate base proposal, I recommend that a condition of any rate base treatment be the exclusion of the PWEC resources from any future charges to recover alleged stranded cost.

Employee severance costs

Q. What has APS proposed with respect to severance costs?

A. In 2002, Pinnacle West offered an employee severance package that cost \$36 million, some \$30 million of which is allocated to APS. According to the Pinnacle West 2002 Annual Report, the severance program lowered Pinnacle West's labor costs by \$30 million per year. Embedded in APS' proposed rates is a three-year amortization of APS' share of the cost of this severance program, which would cost ratepayers about \$10 million per year.

Q. What is your assessment of the Company's proposal regarding severance costs?

A. It is not appropriate for customers in 2004-06 to pay for the cost of this severance program, which was enacted in 2002. The severance program is a non-recurring cost that will have already been fully recouped by APS shareholders through labor cost savings by the time the rate-effective period begins. Therefore, the severance costs should be excluded entirely from the revenue requirements of the rate-effective period.

Q. But won't customers benefit from the labor cost savings?

A. Yes, but APS shareholders will have already benefited handsomely first, because the initial benefit of the cost-savings from the severance program has been accruing to them. The severance program was enacted in 2002 during a period when retail rates had already been established pursuant to the 1999 Settlement Agreement. Consequently, the full benefit of the cost savings in the second half 2002, all of 2003, and the first six months of 2004 will have accrued solely to APS shareholders. As Pinnacle West has reported the savings to be $30 million per year, and as APS represents five-sixths of the program costs, some $25 million per year in APS labor cost savings are currently accruing to APS shareholders from this program. Just counting 2003 and the first half of 2004, the APS-related savings will have exceeded $37 million, completely recovering the APS-related costs, leaving over $7 million in net benefits to shareholders. There is no reason to now turn around and bill ratepayers $30 million over the next three years to recover the severance program's costs. The costs will have already been more than recovered. Therefore, I recommend that the Company's revenue requirements be reduced by the $10 million annual cost of amortizing the 2002 severance program.

<u>**Conclusion – Revenue Requirements**</u>

Q. Would you please summarize the main points in your revenue requirements testimony?

A. (1) The Commission should reject in its entirety APS' request to reverse the so-called "$234 million write-off" the Company took in 1999. The write-off in 1999 was an accounting matter related to projections of stranded costs. It ultimately had no meaningful impact on APS' revenues from retail ratepayers, either in 1999 or in the years that have followed. The Company's proposal is merely an attempt to take back a significant part of the rate reductions granted in the Settlement Agreement – a reversal that is entirely without merit. Rejecting this proposal would eliminate $33 million of the Company's $175 million rate increase request.

(2) The Commission should deny APS' request to place into rate base 1700 MW of new generating units owned by Pinnacle West Energy Company ("PWEC"). The units were built as merchant plants and are currently providing power to APS under contract through 2006. Moving the units into rate base would cost ratepayers a premium of $107 million per year relative to the status quo. This added cost to rate payers is simply not reasonable. Moreover, selecting one company's generating units for inclusion into rate base would run counter to Arizona's efforts to encourage development of a competitive wholesale market. Rejecting this proposal would eliminate $107 million of the Company's $175 million rate increase request.

(3) The Commission should deny APS' request to include $10 million per year in rates to recover costs associated with the Company's 2002 severance program. The severance program is a non-recurring cost that will have already been recouped by APS shareholders through labor cost savings by the time the rate-effective period begins. Rejecting this proposal would eliminate $10 million of the Company's $175 million rate increase request.

PHASE II: COST-OF-SERVICE, RATE SPREAD, RATE DESIGN

<u>Overview and conclusions – Cost-of-Service, Rate Spread, and Rate Design</u>

Q. What is the purpose of your testimony in the Cost-of-Service, Rate Spread, and Rate Design phase of the proceeding?

A. I have been asked to evaluate the merits of APS' general rate case filing with respect to cost-of-service, rate spread, and rate design. I also have been asked to recommend any adjustments to the Company's proposed treatment of these subjects that might be necessary to ensure results that are just and reasonable.

Q. What conclusions have you reached in your analysis of APS' treatment of cost-of-service, rate spread, and rate design?

A. (1) APS' use of the 4-CP method for allocating fixed production cost is appropriate given its system load characteristics and should be accepted by the Commission.

(2) APS' proposal to differentiate General Service rates by voltage levels is consistent with the general approach adopted in the vast majority of utility tariffs across the country and should be approved by the Commission.

(3) APS' proposal to present its rates in an unbundled format is consistent with the requirements of the Electric Competition Rules, provides better information to customers, and should be adopted.

(4) APS' cost-of-service analysis demonstrates that General Service customers are *currently* paying rates that exceed the Company's revenue requirements even after the Company's proposed $166 million base rate increase is factored in. That is, on a strict cost-of-service basis, no rate increase is warranted for this customer class. Consequently, the Company's proposed across-the board increase is not

reasonable. Instead, any rate increase should be spread in such a way the percentage increase to General Service customers is 60 percent of the system average percentage increase. In the event that rates are decreased, the decrease should be spread in such a way that the percentage decrease to General Service customers is 125 percent of the system average percentage decrease.

(5) I agree with APS' attempt to simplify the design of Rate E-32. However, *within* the E-32 customer group, the Company's proposed rate increase falls more heavily on medium-sized customers (e.g., 500 kw demand) than is appropriate. This outcome should be modified by reallocating any rate increase within the E-32 customer group such that relatively less of the increase is spread to medium-sized customers, and relatively more of it is spread to the large-sized customers (1500 kw to 3000 kw demand).

(6) APS proposes to charge transmission voltage customers an unbundled distribution charge. Transmission voltage customers should not be charged an unbundled distribution charge, as these customers do not use the distribution system. In the current tariff, the only cost in the unbundled distribution charge is the recovery of pre-1999 regulatory assets, which will be completed by June 30, 2004. Exhibit A, Schedule B of the Settlement Agreement explicitly states that transmission voltage customers will not pay distribution costs after June 30, 2004. Consistent with this provision, the APS distribution charge for transmission voltage customers should be removed from APS' proposed rates.

(7) APS' proposal to change the definition of on-peak hours for Rate E-35 should be rejected. Current E-35 customers have adapted their business operations to meet

the terms of the existing definitions in the tariff. Changing the definitions will be disruptive and potentially costly to major businesses that have planned their operations in reliance on the tariff's existing definitions.

<u>Use of the 4-CP method for allocating fixed production costs</u>

Q. Why do you agree with the Company's use of the 4-CP method for allocating fixed production costs?

A. APS' system demands are driven by summer usage. The 4-CP method allocates fixed production costs based on the average of system peak demands in the four summer months, thereby properly aligning cost allocation with cost causation. Given APS' system load characteristics, the 4-CP method is inherently reasonable.

<u>Differentiation of General Service rates by voltage level</u>

Q. Why do you agree with the Company's proposal to differentiate General Service rates by voltage level?

A. Commercial and industrial customers typically take service at one of three basic voltage levels: secondary, primary, or transmission. The cost of providing service differs according to voltage level; for instance, line losses are significantly lower for transmission service than for secondary service. Yet currently, APS' Standard Offer General Service rates do not distinguish among service at differing voltage levels (although the Company's Direct Access rates do make such a distinction). Failure to set different rates for different voltage levels causes a subsidy within the General Service class from higher-voltage customers to lower-voltage customers.

In my experience, I know of no other utility that does not differentiate its rates across secondary, primary, and transmission service. APS' proposal to make such a distinction in this proceeding is consistent with the general approach adopted in the vast majority of utility tariffs across the country and should be approved by the Commission.

Unbundling of rate components

Q. Why do you agree with the Company's proposal to present its rates in an unbundled format?

A. Separating individual rate components by function, such as generation, transmission, and distribution, is required by the Electric Competition Rules. The Company's proposal to separately identify these rate components rates conforms to the requirements of the Rules, and will provide better information to customers. In separately stating generation and transmission cost components, it will make the process of evaluating direct access opportunities more transparent for customers who wish to do so. The Company's proposal on this issue should be adopted.

Rate spread

Q. Why do you disagree with the Company's proposal to spread its proposed rate increase on an across-the-board equal percentage basis?

A. As reproduced in Table KCH-3, below, APS' cost-of-service analysis shows that at *current* rates, General Service customers are providing a 9.00 percent return on rate base to the Company, which is even higher than the return the Company is requesting in this proceeding. In other words, on a strict cost-of-service basis, *none* of the Company's claim of a $166 million base rate shortfall is attributable to General Service customers. General Service rates are sufficiently high now to enable APS to more-than-fully recover its claimed costs plus requested return from these customers.

Table KCH-3
APS Return by Customer Class
At Current Rates [19]

Residential	4.34%
General Service	9.00%
Irrigation	0.63%
Street Lighting	2.48%
Dusk-to-Dawn	3.08%
Total Retail	6.27%

In such a situation, an across-the-board percentage increase applied to General Service customers is not equitable.

Q. What rate spread do you propose instead of the Company's approach?

A. Although a straight across-the-board approach is not equitable, AECC members recognize that, if the Company's $166 million base rate increase were adopted, adhering to a rate spread based strictly on cost-of-service results would lead to significantly higher rate increases for residential customers. Therefore, I am proposing a modification to the Company's rate spread that would limit any rate increase to General Service customers to 60 percent of the system average increase. This approach would move the rate spread *in the direction* of cost-of-service results, while still significantly mitigating the impact of the Company's rate increase on residential customers. The results of this rate spread are presented

[19] APS Schedule G-1.

in Attachment KCH-6 and are summarized in Table KCH-4 below, for the case in which the Company's $166 million base rate increase is adopted. Table KCH-5 compares rate spreads for the case in which my recommended $150 million reduction to the Company's revenue requirement is adopted.

Table KCH-4
Summary of Rate Spread Results
if APS $166 million base rate increase is adopted

Customer class	Strict COS	Equal %	AECC
Residential	19.04%	9.31%	12.93%
General Service	(1.10)%	9.31%	5.59%
Irrigation	28.94%	9.34%	12.93%
Street Lighting	43.30%	9.31%	12.93%
Dusk-to-Dawn	35.75%	9.31%	12.93%
Total Retail	9.31%	9.31%	9.31%

Table KCH-5
Summary of Rate Spread Results
if APS $166 million base rate increase is reduced by $150 million

Customer class	Equal %	AECC
Residential	0.95%	1.32%
General Service	0.95%	0.57%
Irrigation	0.95%	1.32%
Street Lighting	0.95%	1.32%
Dusk-to-Dawn	0.95%	1.32%
Total Retail	0.95%	0.95%

Q. What do you recommend in the event that APS base rates are reduced?

A. If APS base rates are reduced, the decrease should be spread in such a way that the percentage decrease to General Service customers is 125 percent of the system average percentage decrease. Such a spread would move rates in the direction of cost-of-service, as General Service rates are currently providing disproportionately high returns relative to other customer classes.

Rate design for Rate E-32

Q. What are your concerns regarding the Company's proposal for Rate E-32?

A. APS is proposing to simplify the design of Rate E-32, which in its current form, is extremely complex and difficult for customers to understand. I fully support APS' intentions in this regard.

However, in spreading its proposed rate increase across E-32 customers, the Company's approach creates inequities among E-32 customers that need to be rectified. Specifically, an inordinate share of the Company's proposed 9.7 percent increase for this sub-class falls on medium-sized customers, i.e., those with billing demands around 500 kw. This can be seen by examining APS Schedule A-4, the results of which are partially reproduced in Table KCH-6 below.

Table KCH-6
Impact of Proposed Rates on Selected E-32 customers
if APS $175 million rate increase is adopted

kw	load factor	summer increase	winter increase
100	30%	19.5%	20.8%
100	60%	-4.5%	-7.5%
100	75%	-9.8%	-13.9%
500	30%	26.3%	27.6%
500	60%	17.5%	13.8%
500	75%	15.0%	9.9%
3000	30%	23.0%	22.6%
3000	60%	14.7%	9.6%
3000	75%	12.5%	6.0%

As shown in Table KCH-6, at each load factor, a customer with a 500 kw demand would experience a significantly-higher rate impact than either smaller or larger customers. This outcome is particularly inappropriate as the Company's own analysis shows that customers of this size (100 kw to 999 kw) are already recovering their costs more fully than customers in the 1000 kw to 3000 kw range.[20]

Q. What do you recommend to rectify this problem with the proposed E-32 rate?

A. The Company's proposed E-32 rate has two demand blocks in the distribution charge. The first block applies to the first 500 kw of demand and is proposed to be priced at $6.348/kw-mo. for secondary service. The second block is proposed to be priced at $4.618/kw-mo. for all kw over 500 kw for secondary service. The problem with sizing the first demand block at 500 kw is that it exacerbates the plight of customers around 500-kw in size – contributing to the inequity of their outcome relative to both smaller and larger customers.

This problem can be rectified by sizing the first demand block at a smaller kw, such as 100 kw. (100 kw is convenient because APS has filed billing determinant data that corresponds to this break-point.) Note that APS' proposed rate design will actually *reduce* rates for 100 kw customers with load factors greater than 60 percent. If we raise the price of the first block ten percent to $7.00/kw-mo., but start the second block at 100 kw, the resultant "revenue-neutral" price of the second block would be $5.054 per kw-mo. for secondary service. This calculation is shown in Attachment KCH-7. Relative to APS' proposal, this alternative would lessen the rate decrease for customers with 100

[20] Pre-filed direct testimony of Alan Propper, Attachment AP-3, shows the Medium General Service class (100 kw – 1000 kw) is currently producing a return of 8.88% and the Large General Service class (1000 kw – 3000 kw) is producing a return of 3.28 %.

kw demands. It would improve the outcome for customers in the range of 200 kw to 1200 kw, have little impact on customers in the range of 1200 kw to 1500 kw, and result in a slightly higher rates for the larger customers in the E-32 class. These outcomes are consistent with APS' cost-of-service results. The impact is summarized in Table KCH-7, below, which can be compared with Table KCH-6, which shows the results under APS' proposal.

Table KCH-7
Impact of Alternative Rate Design on Selected E-32 customers if APS $175 million rate increase is adopted

kw	load factor	summer increase	winter increase
100	30%	22.6%	24.3%
100	60%	-2.7%	-5.5%
100	75%	-8.3%	-12.2%
500	30%	21.6%	22.4%
500	60%	14.4%	10.3%
500	75%	12.3%	6.9%
3000	30%	24.2%	24.0%
3000	60%	14.2%	9.3%
3000	75%	12.1%	5.8%

Q. What is your recommendation to the Commission on this issue?

A. The Commission should order APS to change the break-point for the first demand block in the E-32 rate from 500 kw to 100 kw. The blocks should then be re-priced as described in my testimony and in accordance with the methodology shown in Attachment KCH-7. To the extent that the revenue requirement as it pertains to distribution service for E-32 customers is ultimately modified in this proceeding, the final price for the E-32 demand blocks would be scaled down (or up) accordingly.

Distribution charge for transmission voltage service

Q. Why do you object to APS' proposal to charge a distribution charge to transmission voltage customers?

A. Transmission voltage customers should not be charged an unbundled distribution charge, as these customers do not use the distribution system. In the current tariff, the only cost in the unbundled distribution charge is the recovery of pre-1999 regulatory assets, which will be completed by June 30, 2004. Exhibit A, Schedule B of the Settlement Agreement explicitly states that transmission voltage customers will not pay distribution costs after June 30, 2004. (I negotiated that language with APS as part of the Settlement Agreement.) Consistent with this provision, the APS distribution charge for transmission voltage customers should be removed from APS' proposed rates. Instead, these costs should be recovered from the customers who use the primary and secondary distribution systems.

Q. How can that be accomplished?

A. As a practical matter, this can be readily accomplished in either one of two ways. (1) To the extent that APS' proposed revenue requirement is reduced as part of this proceeding, the first dollars of the reduction that would go to transmission voltage customers could be earmarked for eliminating the distribution charge; or (2) To the extent that the rate spread is modified (as I have proposed above), the first dollars of the reduction from APS' proposal that would go to transmission voltage customers could be earmarked for eliminating the distribution charge for those customers.

__**Definition of on-peak hours for Rate E-35**__

Q. Why do you disagree with APS' proposal to change the definition of on-peak hours for Rate E-35?

A. Rate E-35 provides time-of-use pricing for customers with loads greater than 3000 kw. APS is proposing to change the definition of on-peak hours, such that the on-peak period would begin two hours earlier each week day, i.e., starting at 9 a.m. instead of 11 a.m. (The on-peak period would continue to end at 9 p.m. each week day.) The problem with this proposal is that current E-35 customers have adapted their business operations to meet the terms of the existing definitions in the tariff. Changing the definitions will be disruptive and potentially costly to major businesses that have planned their operations in reliance on the tariff's existing definitions.

For example, I have discussed this situation with representatives of Honeywell, which is a Rate E-35 customer at its Laboratory Services test site in Phoenix. Honeywell moved to Rate E-35 in 1998 at APS' urging, as a means of reducing its peak demand via load management. Because of the price signals sent by the E-35 rate, Honeywell has moved much of its testing to the overnight shift, reducing its peak demand from 17.1 MW to an average of 8.3 MW. Accomplishing this change required a significant effort in reshaping corporate culture, as it requires the most manpower and energy-intensive products to be operating on an overnight basis. Since the change to E-35, Honeywell has continued to install additional equipment and automated controls to minimize its on-peak usage in reliance on the terms of the E-35 tariff.

Honeywell plans its most energy-intensive operations such that they end just before 11 a.m. each day. Changing the definition of on-peak hours to start at 9 a.m. will completely disrupt the work schedules that Honeywell has developed in reliance on the current definition, and will cause Honeywell to seriously consider abandoning the time-of-use rate, as its benefits may be negated by the change.

Q. What is your recommendation to the Commission regarding APS' proposed change in the definition of on-peak hours?

A. The proposed change in definition should be rejected. One of the unintended consequences of the proposed change is the disruption to the operations of customers who moved to this rate in good faith and have made human and capital investments in reliance on its existing terms.

Q. Does this conclude your direct testimony?

A. Yes, it does.

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Vitae

PROFESSIONAL EXPERIENCE

Principal, Energy Strategies, L.L.C., Salt Lake City, Utah, January 2000 to present. Responsible for energy-related economic and policy analysis, regulatory intervention, and strategic negotiation on behalf of industrial, commercial, and public sector interests. Previously Senior Associate, February 1995 to December 1999.

Adjunct Instructor in Economics, Westminster College, Salt Lake City, Utah, September 1981 to May 1982; September 1987 to May 1995. Taught in the economics and M.B.A. programs. Awarded Adjunct Professor of the Year, Gore School of Business, 1990-91.

Chief of Staff to the Chairman, Salt Lake County Board of Commissioners, Salt Lake City, Utah, January 1991 to January 1995. Senior executive responsibility for all matters of county government, including formulation and execution of public policy, delivery of approximately 140 government services, budget adoption and fiscal management (over $300 million), strategic planning, coordination with elected officials, and communication with consultants and media.

Assistant Director, Utah Energy Office, Utah Department of Natural Resources, Salt Lake City, Utah, August 1985 to January 1991. Directed the agency's resource development section, which provided energy policy analysis to the Governor, implemented state energy development policy, coordinated state energy data collection and dissemination, and managed energy technology demonstration programs. Position responsibilities included policy formulation and implementation, design and administration of energy technology demonstration programs, strategic management of the agency's interventions before the Utah Public Service Commission, budget preparation, and staff development. Supervised a staff of economists, engineers, and policy analysts, and served as lead economist on selected projects.

Utility Economist, Utah Energy Office, January 1985 to August 1985. Provided policy and economic analysis pertaining to energy conservation and resource development, with an emphasis on utility issues. Testified before the state Public Service Commission as an expert witness in cases related to the above.

Acting Assistant Director, Utah Energy Office, June 1984 to January 1985. Same responsibilities as Assistant Director identified above.

Research Economist, Utah Energy Office, October 1983 to June 1984. Provided economic analysis pertaining to renewable energy resource development and utility issues. Experience includes preparation of testimony, development of strategy, and appearance as an expert witness for the Energy Office before the Utah PSC.

Operations Research Assistant, Corporate Modeling and Operations Research Department, Utah Power and Light Company, Salt Lake City, Utah, May 1983 to September 1983. Primary area of responsibility: designing and conducting energy load forecasts.

Instructor in Economics, University of Utah, Salt Lake City, Utah, January 1982 to April 1983. Taught intermediate microeconomics, principles of macroeconomics, and economics as a social science.

Teacher, Vernon-Verona-Sherrill School District, Verona, New York, September 1976 to June 1978.

EDUCATION

Ph.D. Candidate, Economics, University of Utah (coursework and field exams completed, 1981).

> Fields of Specialization: Public Finance, Urban and Regional Economics, Economic Development, International Economics, History of Economic Doctrines.

Bachelor of Science, Education, State University of New York at Plattsburgh, 1976 (cum laude).

Danish International Studies Program, University of Copenhagen, 1975.

SCHOLARSHIPS AND FELLOWSHIPS

University Research Fellow, University of Utah, Salt Lake City, Utah 1982 to 1983.
Research Fellow, Institute of Human Resources Management, University of Utah, 1980 to 1982.
Teaching Fellow, Economics Department, University of Utah, 1978 to 1980.
New York State Regents Scholar, 1972 to 1976.

EXPERT TESTIMONY

"In the Matter of Application of the Detroit Edison Company to Increase Rates, Amend Its Rate Schedules Governing the Distribution and Supply of Electric Energy, etc.," **Michigan** Public Service Commission, Case No. U-13808. Direct testimony submitted December 12, 2003 (interim request).

"In the Matter of PacifiCorp's Filing of Revised Tariff Schedules," Public Utility Commission of **Oregon**, Docket No. UE-147. Joint testimony regarding stipulation submitted August 21, 2003.

"Petition of PSI Energy, Inc. for Authority to Increase Its Rates and Charges for Electric Service, etc.," **Indiana** Utility Regulatory Commission, Cause No. 42359. Direct testimony submitted August 19, 2003. Cross examined November 5, 2003.

"In the Matter of the Application of Consumers Energy Company for a Financing Order Approving the Securitization of Certain of its Qualified Cost," **Michigan** Public Service Commission, Case No. U-13715. Direct testimony submitted April 8, 2003. Cross examined April 23, 2003.

"In the Matter of the Application of Arizona Public Service Company for Approval of Adjustment Mechanisms," **Arizona** Corporation Commission, Docket No. E-01345A-02-0403. Direct testimony submitted February 13, 2003. Surrebuttal testimony submitted March 20, 2003. Cross examined April 8, 2003.

"Re: The Investigation and Suspension of Tariff Sheets Filed by Public Service Company of Colorado, Advice Letter No. 1373 – Electric, Advice Letter No. 593 – Gas, Advice Letter No. 80 – Steam," **Colorado** Public Utilities Commission, Docket No. 02S-315 EG. Direct testimony submitted November 22, 2002. Cross-answer testimony submitted January 24, 2003.

"In the Matter of the Application of The Detroit Edison Company to Implement the Commission's Stranded Cost Recovery Procedure and for Approval of Net Stranded Cost Recovery Charges," **Michigan** Public Service Commission, Case No. U-13350. Direct testimony submitted November 12, 2002.

"Application of South Carolina Electric & Gas Company: Adjustments in the Company's Electric Rate Schedules and Tariffs," Public Service Commission of **South Carolina**, Docket No. 2002-223-E. Direct testimony submitted November 8, 2002. Surrebuttal testimony submitted November 18, 2002. Cross examined November 21, 2002.

"In the Matter of the Application of Questar Gas Company for a General Increase in Rates and Charges," **Utah** Public Service Commission, Docket No. 02-057-02. Direct testimony submitted August 30, 2002. Rebuttal testimony submitted October 4, 2002.

"The Kroger Co. v. Dynegy Power Marketing, Inc.," **Federal Energy Regulatory Commission**, EL02-119-000. Confidential affidavit filed August 13, 2002.

"In the matter of the application of Consumers Energy Company for determination of net stranded costs and for approval of net stranded cost recovery charges," **Michigan** Public Service Commission, Case No. U-13380. Direct testimony submitted August 9, 2002. Rebuttal testimony submitted August 30, 2002. Cross examined September 10, 2002.

"In the Matter of the Application of Public Service Company of Colorado for an Order to Revise Its Incentive Cost Adjustment," **Colorado** Public Utilities Commission, Docket 02A-158E. Direct testimony submitted April 18, 2002.

"In the Matter of the Generic Proceedings Concerning Electric Restructuring Issues," **Arizona** Corporation Commission, Docket No. E-00000A-02-0051, "In the Matter of Arizona Public Service Company's Request for Variance of Certain Requirements of A.A.C. R14-2-1606," Docket No. E-01345A-01-0822, "In the Matter of the Generic Proceeding Concerning the Arizona Independent Scheduling Administrator," Docket No. E-00000A-01-0630, "In the Matter of Tucson Electric Power Company's Application for a Variance of Certain Electric Competition Rules Compliance Dates," Docket No. E-01933A-02-0069, "In the Matter of the Application of Tucson Electric Power Company for Approval of its Stranded Cost Recovery," Docket No. E-01933A-98-0471. Direct testimony submitted March 29, 2002 (APS variance request); May 29, 2002 (Track A proceeding/market power issues); and July 28, 2003 (Arizona ISA). Rebuttal testimony submitted August 29, 2003 (Arizona ISA). Cross examined June 21, 2002 (Track A proceeding) and September 12, 2003 (Arizona ISA).

"In the Matter of Savannah Electric & Power Company's 2001 Rate Case," **Georgia** Public Service Commission, Docket No. 14618-U. Direct testimony submitted March 15, 2002. Cross examined March 28, 2002.

"Nevada Power Company's 2001 Deferred Energy Case," Public Utilities Commission of **Nevada**, PUCN 01-11029. Direct testimony submitted February 7, 2002. Cross examined February 21, 2002.

"2001 Puget Sound Energy Interim Rate Case," **Washington** Utilities and Transportation Commission, Docket Nos. UE-011570 and UE-011571. Direct testimony submitted January 30, 2002. Cross examined February 20, 2002.

"In the Matter of Georgia Power Company's 2001 Rate Case," **Georgia** Public Service Commission, Docket No. 1400-U. Direct testimony submitted October 12, 2001. Cross examined October 24, 2001.

"In the Matter of the Application of PacifiCorp for Approval of Its Proposed Electric Rate Schedules and Electric Service Regulations," **Utah** Public Service Commission, Docket No. 01-35-01. Direct testimony submitted June 15, 2001. Rebuttal testimony submitted August 31, 2001.

"In the Matter of Portland General Electric Company's Proposal to Restructure and Reprice Its Services in Accordance with the Provisions of SB 1149," Public Utility Commission of **Oregon**, Docket No. UE-115. Direct testimony submitted February 20, 2001. Rebuttal testimony submitted May 4, 2001. Joint testimony regarding stipulation submitted July 27, 2001.

"In the Matter of the Application of APS Energy Services, Inc. for Declaratory Order or Waiver of the Electric Competition Rules," **Arizona** Corporation Commission, Docket No.E-01933A-00-0486. Direct testimony submitted July 24, 2000.

"In the Matter of the Application of Questar Gas Company for an Increase in Rates and Charges," **Utah** Public Service Commission, Docket No. 99-057-20. Direct testimony submitted April 19, 2000. Rebuttal testimony submitted May 24, 2000. Surrebuttal testimony submitted May 31, 2000. Cross examined June 6 & 8, 2000.

"In the Matter of the Application of Columbus Southern Power Company for Approval of Electric Transition Plan and Application for Receipt of Transition Revenues," Public Utility Commission of **Ohio**, Case No. 99-1729-EL-ETP; "In the Matter of the Application of Ohio Power Company for Approval of Electric Transition Plan and Application for Receipt of Transition Revenues," Public Utility Commission of **Ohio**, Case No. 99-1730-EL-ETP. Direct testimony prepared, but not submitted pursuant to settlement agreement effected May 2, 2000.

"In the Matter of the Application of FirstEnergy Corp. on Behalf of Ohio Edison Company, The Cleveland Electric Illuminating Company, and the Toledo Edison Company for Approval of Their Transition Plans and for Authorization to Collect Transition Revenues," Public Utility Commission of **Ohio**, Case No. 99-1212-EL-ETP. Direct testimony prepared, but not submitted pursuant to settlement agreement effected April 11, 2000.

"2000 Pricing Process," **Salt River Project** Board of Directors, oral comments provided March 6, 2000 and April 10, 2000.

"Tucson Electric Power Company vs. Cyprus Sierrita Corporation," **Arizona** Corporation Commission, Docket No. E-000001-99-0243. Direct testimony submitted October 25, 1999. Cross examined November 4, 1999.

"Application of Hildale City and Intermountain Municipal Gas Association for an Order Granting Access for Transportation of Interstate Natural Gas over the Pipelines of Questar Gas Company for Hildale, Utah," **Utah** Public Service Commission, Docket No. 98-057-01. Rebuttal testimony submitted August 30, 1999.

"In the Matter of the Application by Arizona Electric Power Cooperative, Inc. for Approval of Its Filing as to Regulatory Assets and Transition Revenues," **Arizona** Corporation Commission, Docket No. E-01773A-98-0470. Direct testimony submitted July 30, 1999. Cross examined February 28, 2000.

"In the Matter of the Application of Tucson Electric Power Company for Approval of its Plan for Stranded Cost Recovery," **Arizona** Corporation Commission, Docket No. E-01933A-98-0471; "In the Matter of the Filing of Tucson Electric Power Company of Unbundled Tariffs Pursuant to A.A.C. R14-2-1601 et seq.," Docket No. E-01933A-97-0772; "In the Matter of the Competition in the Provision of Electric Service Throughout the State of Arizona," Docket No. RE-00000C-94-0165. Direct testimony submitted June 30, 1999. Rebuttal testimony submitted August 6, 1999. Cross examined August 11-13, 1999.

"In the Matter of the Application of Arizona Public Service Company for Approval of its Plan for Stranded Cost Recovery," **Arizona** Corporation Commission, Docket No. E-01345A-98-0473; "In the Matter of the Filing of Arizona Public Service Company of Unbundled Tariffs Pursuant to A.A.C. R14-2-1601 et seq.," Docket No. E-01345A-97-0773; "In the Matter of the Competition in the Provision of Electric Service Throughout the State of Arizona," Docket No. RE-00000C-94-0165. Direct testimony submitted June 4, 1999. Rebuttal testimony submitted July 12, 1999. Cross examined July 14, 1999.

"In the Matter of the Application of Tucson Electric Power Company for Approval of its Plan for Stranded Cost Recovery," **Arizona** Corporation Commission, Docket No. E-01933A-98-0471; "In the Matter of the Filing of Tucson Electric Power Company of Unbundled Tariffs Pursuant to A.A.C. R14-2-1601 et seq.," Docket No. E-01933A-97-0772; "In the Matter of the Application of Arizona Public Service Company for Approval of its Plan for Stranded Cost Recovery," Docket No. E-01345A-98-0473; "In the Matter of the Filing of Arizona Public Service Company of Unbundled Tariffs Pursuant to A.A.C. R14-2-1601 et seq.," Docket No. E-01345A-97-0773; "In the Matter of the Competition in the Provision of Electric Service Throughout the State of Arizona," Docket No. RE-00000C-94-0165. Direct testimony submitted November 30, 1998.

"Hearings on Pricing," **Salt River Project** Board of Directors, written and oral comments provided November 9, 1998.

"Hearings on Customer Choice," **Salt River Project** Board of Directors, written and oral comments provided June 22, 1998; June 29, 1998; July 9, 1998; August 7, 1998; and August 14, 1998.

"In the Matter of the Competition in the Provision of Electric Service Throughout the State of Arizona," **Arizona** Corporation Commission, Docket No. U-0000-94-165. Direct and rebuttal testimony filed January 21, 1998. Second rebuttal testimony filed February 4, 1998. Cross examined February 25, 1998.

"In the Matter of Consolidated Edison Company of New York, Inc.'s Plans for (1) Electric Rate/Restructuring Pursuant to Opinion No. 96-12; and (2) the Formation of a Holding Company Pursuant to PSL, Sections 70, 108, and 110, and Certain Related Transactions," **New York** Public Service Commission, Case 96-E-0897. Direct testimony filed April 9, 1997. Cross examined May 5, 1997.

"In the Matter of the Petition of Sunnyside Cogeneration Associates for Enforcement of Contract Provisions," **Utah** Public Service Commission, Docket No. 96-2018-01. Direct testimony submitted July 8, 1996.

"Questar Pipeline Company," **Federal Energy Regulatory Commission**, Docket No. RP95-407. Direct testimony prepared, but withheld subject to settlement. Settlement approved July 1, 1996.

"In the Matter of Arizona Public Service Company's Rate Reduction Agreement," **Arizona** Corporation Commission, Docket No. U-1345-95-491. Direct testimony prepared, but withheld consequent to issue resolution. Agreement approved April 18, 1996.

"In the Matter of the Application of PacifiCorp, dba Pacific Power & Light Company, for Approval of Revised Tariff Schedules and an Alternative Form of Regulation Plan," **Wyoming** Public Service Commission, Docket No. 2000-ER-95-99. Direct testimony submitted April 8, 1996.

"In the Matter of the Application of Mountain Fuel Supply Company for an Increase in Rates and Charges," **Utah** Public Service Commission, Case No. 95-057-02. Direct testimony submitted June 19, 1995. Rebuttal testimony submitted July 25, 1995. Surrebuttal testimony submitted August 7, 1995.

"In the Matter of the Investigation of the Reasonableness of the Rates and Tariffs of Mountain Fuel Supply Company," **Utah** Public Service Commission, Case No. 89-057-15. Direct testimony submitted July 1990. Surrebuttal testimony submitted August 1990.

"In the Matter of the Review of the Rates of Utah Power and Light Company pursuant to The Order in Case No. 87-035-27," **Utah** Public Service Commission, Case No. 89-035-10. Rebuttal testimony submitted November 15, 1989. Cross examined December 1, 1989 (rate schedule changes for state facilities).

"In the Matter of the Application of Utah Power & Light Company and PC/UP&L Merging Corp. (to be renamed PacifiCorp) for an Order Authorizing the Merger of Utah Power & Light Company and PacifiCorp into PC/UP&L Merging Corp. and Authorizing the Issuance of Securities, Adoption of Tariffs, and Transfer of Certificates of Public Convenience and Necessity and Authorities in Connection Therewith," **Utah** Public Service Commission, Case No. 87-035-27; Direct testimony submitted April 11, 1988. Cross examined May 12, 1988 (economic impact of UP&L merger with PacifiCorp).

"In the Matter of the Application of Mountain Fuel Supply Company for Approval of Interruptible Industrial Transportation Rates," **Utah** Public Service Commission, Case No. 86-057-07. Direct testimony submitted January 15, 1988. Cross examined March 30, 1988.

"In the Matter of the Application of Utah Power and Light Company for an Order Approving a Power Purchase Agreement," **Utah** Public Service Commission, Case No. 87-035-18. Oral testimony delivered July 8, 1987.

"Cogeneration: Small Power Production," **Federal Energy Regulatory Commission**, Docket No. RM87-12-000. Statement delivered March 27, 1987, on behalf of State of Utah, in San Francisco.

"In the Matter of the Investigation of Rates for Backup, Maintenance, Supplementary, and Standby Power for Utah Power and Light Company," **Utah** Public Service Commission, Case No. 86-035-13. Direct testimony submitted January 5, 1987. Case settled by stipulation approved August 1987.

"In the Matter of the Application of Sunnyside Cogeneration Associates for Approval of the Cogeneration Power Purchase Agreement," **Utah** Public Service Commission, Case No. 86-2018-01. Rebuttal testimony submitted July 16, 1986. Cross examined July 17, 1986.

"In the Matter of the Investigation of Demand-Side Alternatives to Capacity Expansion for Electric Utilities," **Utah** Public Service Commission, Case No. 84-999-20. Direct testimony submitted June 17, 1985. Rebuttal testimony submitted July 29, 1985. Cross examined August 19, 1985.

"In the Matter of the Implementation of Rules Governing Cogeneration and Small Power Production in Utah," **Utah** Public Service Commission, Case No. 80-999-06, pp. 1293-1318. Direct testimony submitted January 13, 1984 (avoided costs), May 9, 1986 (security for levelized contracts) and November 17, 1986 (avoided costs). Cross-examined February 29, 1984 (avoided costs), April 11, 1985 (standard form contracts), May 22-23, 1986 (security for levelized contracts) and December 16-17, 1986 (avoided costs).

OTHER RELATED ACTIVITY

Participant, Oregon Direct Access Task Force (UM 1081), May 2003 to present.

Participant, Michigan Stranded Cost Collaborative, March 2003 to present.

Board of Directors, ex-officio, Desert STAR RTO, September 1999 to February 2002.

Advisory Committee, Desert STAR RTO, September 1999 to February 2002. Acting Chairman, October 2000 to February 2002.

Board of Directors, Arizona Independent Scheduling Administrator Association, October 1998 to present.

Acting Chairman, Operating Committee, Arizona Independent Scheduling Administrator Association, October 1998 to June 1999.

Member, Desert Star ISO Investigation Working Groups: Operations, Pricing, and Governance, April 1997 to present. Legal & Negotiating Committee, April 1999 to December 1999.

Participant, Independent System Operator and Spot Market Working Group, Arizona Corporation Commission, April 1997 to September 1997.

Participant, Unbundled Services and Standard Offer Working Group, Arizona Corporation Commission, April 1997 to October 1997.

Participant, Customer Selection Working Group, Arizona Corporation Commission, March 1997 to September 1997.

Member, Stranded Cost Working Group, Arizona Corporation Commission, March 1997 to September 1997.

Member, Electric System Reliability & Safety Working Group, Arizona Corporation Commission, November 1996 to present.

Chairman, Salt Palace Renovation and Expansion Committee, Salt Lake County/State of Utah/Salt Lake City, multi-government entity responsible for implementation of planning, design, finance, and construction of an $85 million renovation of the Salt Palace Convention Center, Salt Lake City, Utah, May 1991 to December 1994.

State of Utah Representative, Committee on Regional Electric Power Cooperation, a joint effort of the Western Interstate Energy Board and the Western Conference of Public Service Commissioners, January 1987 to December 1990.

Member, Utah Governor's Economic Coordinating Committee, January 1987 to December 1990.

Chairman, Standard Contract Task Force, established by Utah Public Service Commission to address contractual problems relating to qualifying facility sales under PURPA, March 1986 to December 1990.

Chairman, Load Management and Energy Conservation Task Force, Utah Public Service Commission, August 1985 to December 1990.

Alternate delegate for Utah, Western Interstate Energy Board, Denver, Colorado, August 1985 to December 1990.

Articles Editor, Economic Forum, September 1980 to August 1981.

Rate Impact of Reversal of Regulatory Asset Write-Off over 15 Years

Ln #		Year 0	Year 1	Year 2	Year 3	Year 4	Year 5
	Rate Base Impacts:						
1	Rate Base Additions:						
2	APS Generation Asset Pre-tax Write-Off Ending Balance ($000s)	$ 234,000	$ 218,400	$ 202,800	$ 187,200	$ 171,600	$ 156,000
3	Rate Base Deductions:						
4	Acc. Deferred Income Tax Benefit Ending Balance ($000s)	$ 92,430	$ 86,268	$ 80,106	$ 73,944	$ 67,782	$ 61,620
5	Acc. DIT Balance Annual Amortization ($000s)	$ 6,162	$ 6,162	$ 6,162	$ 6,162	$ 6,162	$ 6,162
6	Total Rate Base ($000s)	$ 141,570	$ 132,132	$ 122,694	$ 113,256	$ 103,818	$ 94,380
7	Return on Rate Base (%)	8.67%	8.67%	8.67%	8.67%	8.67%	8.67%
8	Required Return on Rate Base ($000s)	$ 12,274	$ 11,456	$ 10,638	$ 9,819	$ 9,001	$ 8,183
9	Effective Tax Rate (%)	39.50%	39.50%	39.50%	39.50%	39.50%	39.50%
10	Tax Gross Up Factor	1.65289	1.65289	1.65289	1.65289	1.65289	1.65289
11	Revenue Gross Up for Tax Impact ($000s)	$ 20,288	$ 18,935	$ 17,583	$ 16,230	$ 14,878	$ 13,525
	Operating Expense Adjustment (Assuming 15 Year Amortization of Write-Off):						
12	Depreciation & Amortization Expense ($000s)	$ -	$ 15,600	$ 15,600	$ 15,600	$ 15,600	$ 15,600
13	Interest Impact:						
14	Cost of Debt	5.81%	5.81%	5.81%	5.81%	5.81%	5.81%
15	Debt Ratio	50%	50%	50%	50%	50%	50%
16	Weighted Cost of Debt	2.89%	2.89%	2.89%	2.89%	2.89%	2.89%
17	Interest Expense ($000s):	$ -	$ 4,094	$ 3,821	$ 3,548	$ 3,275	$ 3,002
18	Effective Tax Rate (%)	39.50%	39.5%	39.5%	39.5%	39.5%	39.5%
19	Amortization Income Tax Impact ($000s)	$ -	$ (6,162)	$ (6,162)	$ (6,162)	$ (6,162)	$ (6,162)
20	Interest Expense Income Tax Impact ($000s)	$ -	$ (1,617)	$ (1,509)	$ (1,401)	$ (1,294)	$ (1,186)
21	Income Tax Impact ($000s)	$ -	$ (7,779)	$ (7,671)	$ (7,563)	$ (7,456)	$ (7,348)
22	Operating Income After Tax	$ -	$ 7,821	$ 7,929	$ 8,037	$ 8,144	$ 8,252
23	Tax Gross Up Factor	1.65289	1.65289	1.65289	1.65289	1.65289	1.65289
24	Income Grossed Up for Taxes ($000s)	$ -	$ 12,927	$ 13,105	$ 13,284	$ 13,462	$ 13,640
	Total Rev. Req't Impact:						
25	Return on Rate Base Component ($000s)	$ 20,288	$ 18,935	$ 17,583	$ 16,230	$ 14,878	$ 13,525
26	Amortization Expense Impact ($000s)	$ -	$ 12,927	$ 13,105	$ 13,284	$ 13,462	$ 13,640
27	Total Rev. Req't Impact ($000s)	$ 20,288	$ 31,863	$ 30,688	$ 29,514	$ 28,340	$ 27,165

Rate Impact of Reversal of Regulatory Asset Write-Off over 15 Years

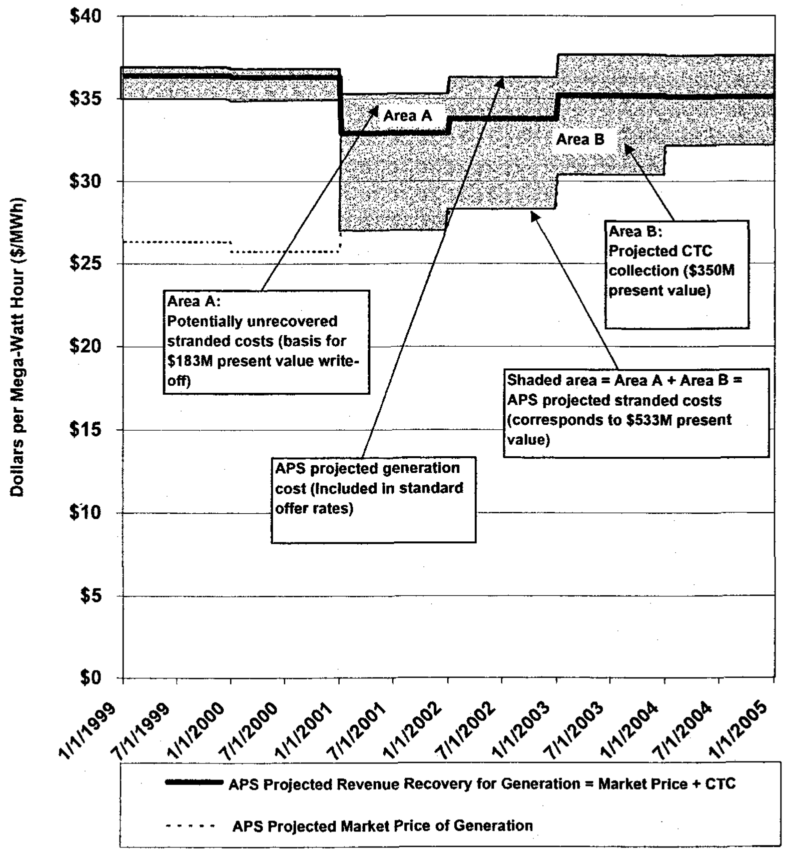
Ln #		Year 6	Year 7	Year 8	Year 9	Year 10
	Rate Base Impacts:					
1	Rate Base Additions:					
2	APS Generation Asset Pre-tax Write-Off Ending Balance ($000s)	$ 140,400	$ 124,800	$ 109,200	$ 93,600	$ 78,000
3	Rate Base Deductions:					
4	Acc. Deferred Income Tax Benefit Ending Balance ($000s)	$ 55,458	$ 49,296	$ 43,134	$ 36,972	$ 30,810
5	Acc. DIT Balance Annual Amortization ($000s)	$ 6,162	$ 6,162	$ 6,162	$ 6,162	$ 6,162
6	Total Rate Base ($000s)	$ 84,942	$ 75,504	$ 66,066	$ 56,628	$ 47,190
7	Return on Rate Base (%)	8.67%	8.67%	8.67%	8.67%	8.67%
8	Required Return on Rate Base ($000s)	$ 7,364	$ 6,546	$ 5,728	$ 4,910	$ 4,091
9	Effective Tax Rate (%)	39.50%	39.50%	39.50%	39.50%	39.50%
10	Tax Gross Up Factor	1.65289	1.65289	1.65289	1.65289	1.65289
11	Revenue Gross Up for Tax Impact ($000s)	$ 12,173	$ 10,820	$ 9,468	$ 8,115	$ 6,763
	Operating Expense Adjustment (Assuming 15 Year Amortization of					
12	Depreciation & Amortization Expense ($000s)	$ 15,600	$ 15,600	$ 15,600	$ 15,600	$ 15,600
13	Interest Impact:					
14	Cost of Debt	5.81%	5.81%	5.81%	5.81%	5.81%
15	Debt Ratio	50%	50%	50%	50%	50%
16	Weighted Cost of Debt	2.89%	2.89%	2.89%	2.89%	2.89%
17	Interest Expense ($000s):	$ 2,729	$ 2,456	$ 2,183	$ 1,910	$ 1,637
18	Effective Tax Rate (%)	39.5%	39.5%	39.5%	39.5%	39.5%
19	Amortization Income Tax Impact ($000s)	$ (6,162)	$ (6,162)	$ (6,162)	$ (6,162)	$ (6,162)
20	Interest Expense Income Tax Impact ($000s)	$ (1,078)	$ (970)	$ (862)	$ (755)	$ (647)
21	Income Tax Impact ($000s)	$ (7,240)	$ (7,132)	$ (7,024)	$ (6,917)	$ (6,809)
22	Operating Income After Tax	$ 8,360	$ 8,468	$ 8,576	$ 8,683	$ 8,791
23	Tax Gross Up Factor	1.65289	1.65289	1.65289	1.65289	1.65289
24	Income Grossed Up for Taxes ($000s)	$ 13,818	$ 13,996	$ 14,175	$ 14,353	$ 14,531
	Total Rev. Req't Impact:					
25	Return on Rate Base Component ($000s)	$ 12,173	$ 10,820	$ 9,468	$ 8,115	$ 6,763
26	Amortization Expense Impact ($000s)	$ 13,818	$ 13,996	$ 14,175	$ 14,353	$ 14,531
27	Total Rev. Req't Impact ($000s)	$ 25,991	$ 24,817	$ 23,642	$ 22,468	$ 21,294

Rate Impact of Reversal of Regulatory Asset Write-Off over 15 Years

Ln #		Year 11	Year 12	Year 13	Year 14	Year 15	Total	Source
	Rate Base Impacts:							
1	Rate Base Additions:							
2	APS Generation Asset Pre-tax Write-Off Ending Balance ($000s)	$ 62,400	$ 46,800	$ 31,200	$ 15,600	$ -		APS Data Response Attachment RC02337
3	Rate Base Deductions:							
4	Acc. Deferred Income Tax Benefit Ending Balance ($000s)	$ 24,648	$ 18,486	$ 12,324	$ 6,162	$ -		APS Data Response Attachment RC02337
5	Acc. DIT Balance Annual Amortization ($000s)	$ 6,162	$ 6,162	$ 6,162	$ 6,162			$92.4M ÷ 15 years
6	Total Rate Base ($000s)	$ 37,752	$ 28,314	$ 18,876	$ 9,438	$ -		Ln 2 - Ln 4
7	Return on Rate Base (%)	8.67%	8.67%	8.67%	8.67%	8.67%		APS Data Response Attachment RC02337
8	Required Return on Rate Base ($000s)	$ 3,273	$ 2,455	$ 1,637	$ 818	$ -		Ln 6 x Ln 7
9	Effective Tax Rate (%)	39.50%	39.50%	39.50%	39.50%	39.50%		SFR_SCH_C3
10	Tax Gross Up Factor	1.65289	1.65289	1.65289	1.65289	1.65289		SFR_SCH_C3
11	Revenue Gross Up for Tax Impact ($000s)	$ 5,410	$ 4,058	$ 2,705	$ 1,353	$ -	$ 162,302	Ln 8 x Ln 10
	Operating Expense Adjustment (Assuming 15 Year Amortization of							
12	Depreciation & Amortization Expense ($000s)	$ 15,600	$ 15,600	$ 15,600	$ 15,600	$ 15,600	$ 234,000	$234M ÷ 15 years
13	Interest Impact:							
14	Cost of Debt	5.81%	5.81%	5.81%	5.81%	5.81%	5.81%	APS Data Response Attachment RC02337
15	Debt Ratio	50%	50%	50%	50%	50%	50%	APS Data Response Attachment RC02337
16	Weighted Cost of Debt	2.89%	2.89%	2.89%	2.89%	2.89%	2.89%	APS Data Response Attachment RC02337
17	Interest Expense ($000s):	$ 1,365	$ 1,092	$ 819	$ 546	$ 273		Ln $6_{(yr-1)}$ x Ln 16
18	Effective Tax Rate (%)	39.5%	39.5%	39.5%	39.5%	39.5%	39.5%	= Ln 9
19	Amortization Income Tax Impact ($000s)	$ (6,162)	$ (6,162)	$ (6,162)	$ (6,162)	$ (6,162)	$ (92,430)	Ln 12 x Ln 18
20	Interest Expense Income Tax Impact ($000s)	$ (539)	$ (431)	$ (323)	$ (216)	$ (108)	$ -	Ln 17 x Ln 18
21	Income Tax Impact ($000s)	$ (6,701)	$ (6,593)	$ (6,485)	$ (6,378)	$ (6,270)	$ (92,430)	Ln 19 + Ln 20
22	Operating Income After Tax	$ 8,899	$ 9,007	$ 9,115	$ 9,222	$ 9,330	$ 141,570	Ln 12 + Ln 20
23	Tax Gross Up Factor	1.65289	1.65289	1.65289	1.65289	1.65289	1.65289	= Ln 10
24	Income Grossed Up for Taxes ($000s)	$ 14,709	$ 14,887	$ 15,065	$ 15,244	$ 15,422	$ 234,000	Ln 22 x Ln 23
	Total Rev. Req't Impact:							
25	Return on Rate Base Component ($000s)	$ 5,410	$ 4,058	$ 2,705	$ 1,353	$ -	$ 162,302	= Ln 11
26	Amortization Expense Impact ($000s)	$ 14,709	$ 14,887	$ 15,065	$ 15,244	$ 15,422	$ 212,618	= Ln 24
27	Total Rev. Req't Impact ($000s)	$ 20,119	$ 18,945	$ 17,770	$ 16,596	$ 15,422	$ 374,920	Ln 25 + Ln 26

Basis for 1999 APS Write-Off, 1999 - 2004

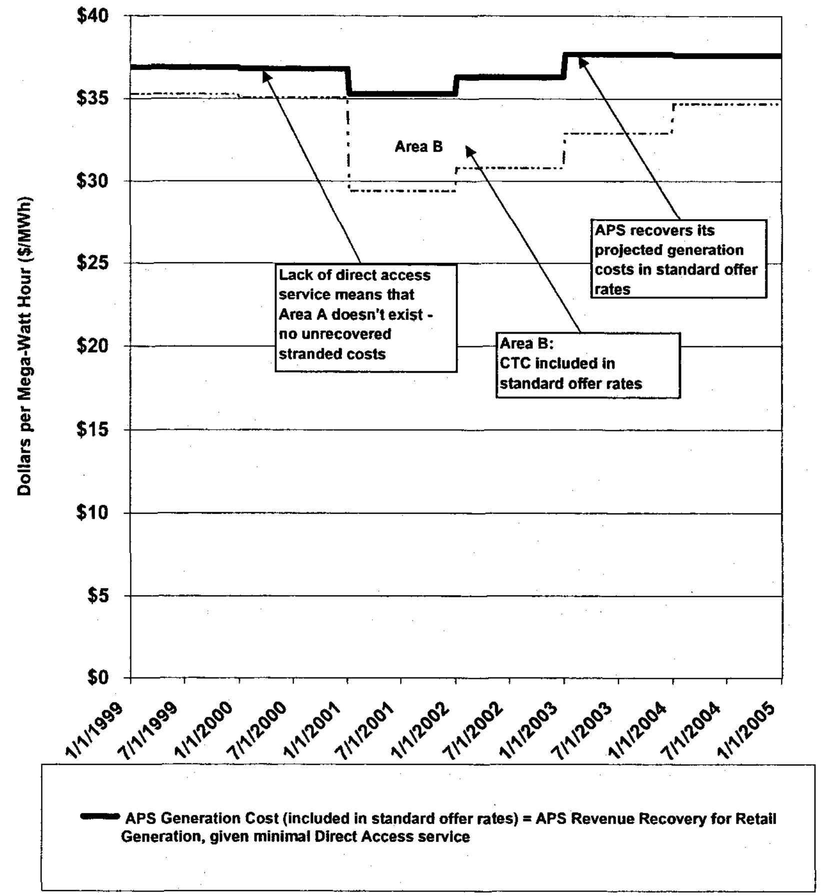
Note: Assumes 20% direct access penetration from 1-1-99 to 12-31-00 & 100% direct access service starting 1-1-01



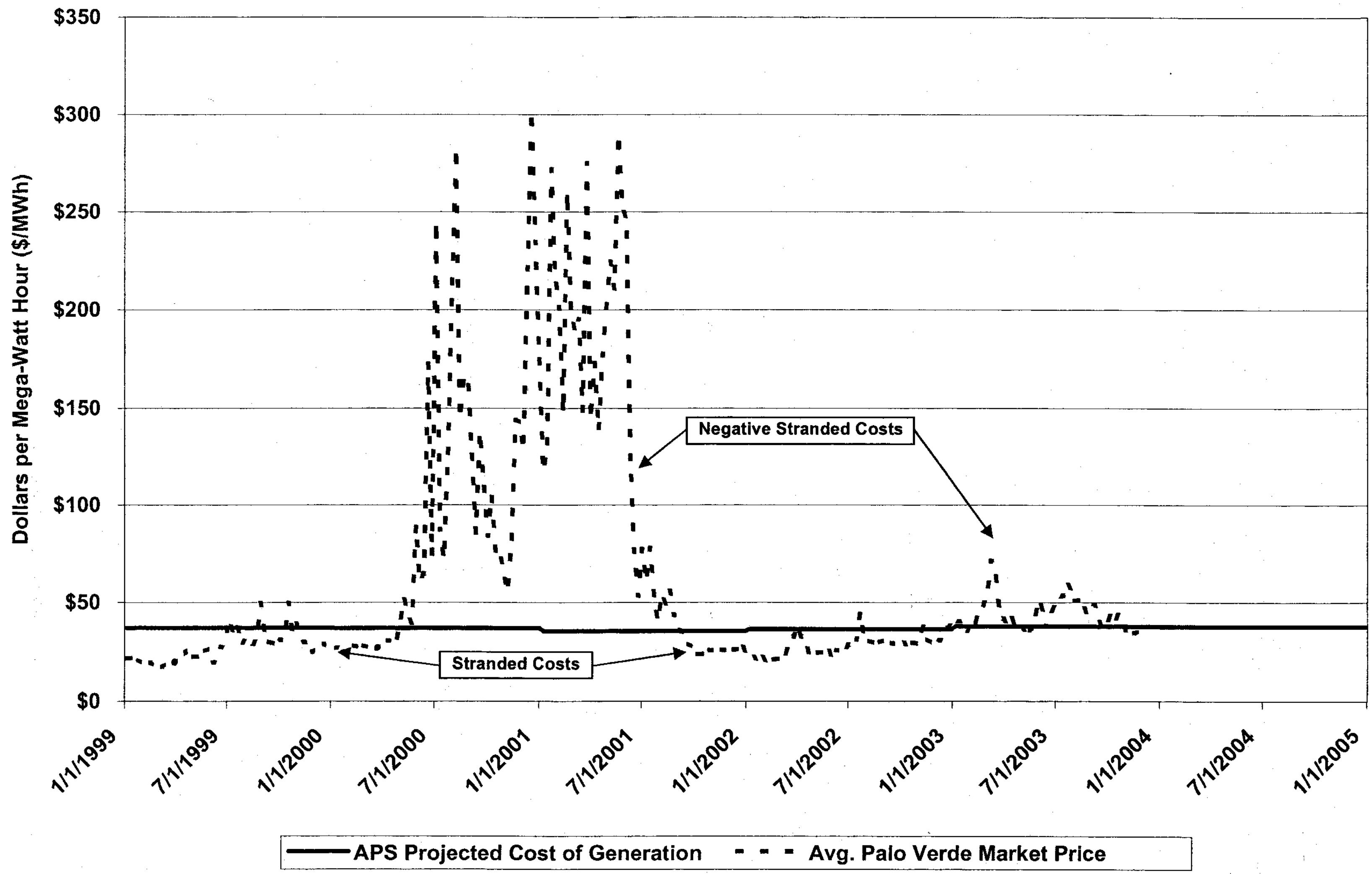
Data Source: APS market price forecast & generation cost forecasts from APS Attachment JED-3 in Docket No. E-01345A-98-0473

Basis for Actual Revenue Recovery, 1999 - 2004

Note: Vast majority of customers served under standard offer rates



APS' Actual Stranded Cost 1999 - 2003



Stranded Cost Calculation 1999 - 2003

Year	Energy Production (GWh)	APS Generation Costs (¢/kWh)	Palo Verde Avg Market Price (¢/kWh)	% Eligible for Shopping	Stranded Costs ($ Millions)	1999 NPV @ 8.8% ($ Millions)
1999	23,152	3.69	2.71	20%	45	42
2000	23,652	3.68	9.36	20%	-269	-227
2001	24,571	3.53	10.70	100%	-1,761	-1,367
2002	23,374	3.63	2.83	100%	186	133
2003	23,374	3.77	4.40	100%	-148	-97
Total					-1,946	-1,517
ACC Jurisdictional @ 93.5%					-1,820	-1,418

Palo Verde Market Price: Annual average of published weekly weighted index price at Palo Verde

Calculation Methodology: Same as APS original $533 million calculation (Attachment JED-3 in Docket No. E-01345A-98-0473), except actual market prices used instead of 1998 APS market price forecast.

Rate Impact of Including PWEC Assets in Rate Base

Ln #		Amount	Source
	Rate Base Impact:		
1	Total Rate Base - ACC Jurisdiction ($000s)	$ 889,237	Schedule B-2, p. 1 of 3
2	APS Requested Return on Rate Base for 12/31/02	8.67%	Schedule D1
3	Required Return on Rate Base	$ 77,097	Ln 1 x Ln 2
	Operating Income Impact:		
4	Change in Operating Income	$ 12,575	Schedule C-2, p. 3 of 10
	Overall Revenue Requirement Impact:		
5	Total Required Revenue Change	$ 64,522	Ln 3 - Ln 4
6	Revenue Conversion Factor	1.6529	Schedule C-3
7	Total Annual Revenue Requirement Impact	$ 106,648	Ln 5 x Ln 6

ARIZONA PUBLIC SERVICE COMPANY
Cost of Service Summary - Present Rates
Rates of Return by Customer Classification
Adjusted Test Year Ending December 31, 2002
(As filed by APS)
($000)

Ln #		Total Company (A)	Total ACC Jurisdiction (B)	All Other (C)	Total ACC Jurisdiction: Residential (D)	General Service (E)	Irrigation (F)	Street Lighting (G)	Dusk to Dawn (H)
1.a	Revenues by Rates	1,827,189	1,791,584	35,605	889,898	883,595	2,099	10,794	5,198
1.b	Other Revenues	150,987	148,562	2,425	71,187	74,249	215	2,582	329
2.	Expenses	1,626,563	1,590,132	36,432	839,733	730,686	2,360	12,439	4,914
3.	Operating Income Before Income Taxes	351,613	350,014	1,598	121,352	227,158	(46)	937	613
4.	Income Taxes	86,608	86,144	463	18,616	67,806	(75)	(195)	(7)
5.	Net Operating Income	265,005	263,870	1,135	102,736	159,352	29	1,132	620
6.	Rate Base	4,221,019	4,207,476	13,543	2,367,112	1,769,998	4,571	45,676	20,118
7.	Rate of Return	6.28%	6.27%	8.38%	4.34%	9.00%	0.63%	2.48%	3.08%

Data Source: APS Schedule G-1, Page 1 of 1

ARIZONA PUBLIC SERVICE COMPANY
SUMMARY OF BASE REVENUES BY CUSTOMER CLASSIFICATION
APS PROPOSED RATES USING APS PROPOSED RATE INCREASE
TEST YEAR ENDING DECEMBER 31, 2002, ADJUSTED
(As Filed by APS)

		Base Revenues in the Test Year		APS Proposed Increase			
		(A)	(B)	(C)	(D)	(E)	(F)
Line No.	Customer Classification	Present Rates ($000)	Proposed Rates ($000)	Amount ($000)	%	Proposed CRCC ($000)	Proposed Increase with CRCC %
1	Residential	889,898	972,747	82,849	9.31%	3,717	9.73%
2	General Service	883,595	965,868	82,273	9.31%	4,485	9.82%
3	Irrigation	2,099	2,295	196	9.34%	11	9.86%
4	Outdoor Lighting	10,794	11,799	1,005	9.31%	36	9.64%
5	Dusk to Dawn Lighting Service	5,198	5,682	484	9.31%	14	9.58%
6	Total Sales to Ultimate Retail Customers	1,791,584	1,958,391	166,807	9.31%	8,263	9.77%

Data Source: APS Schedule H-1, Page 1 of 1

ARIZONA PUBLIC SERVICE COMPANY
Cost of Service Summary - Class Revenues Adjusted by AECC to Match Overall APS Requested ACC Jurisdiction Rate of Return
Rates of Return by Customer Classification
Adjusted Test Year Ending December 31, 2002
($000)

					Total ACC Jurisdiction				
Ln #		Total Company (A)	Total ACC Jurisdiction (B)	All Other (C)	Residential (D)	General Service (E)	Irrigation (F)	Street Lighting (G)	Dusk to Dawn (H)
1.a	Revenues by Rates	1,993,995	1,958,390	35,605	1,059,308	873,853	2,706	15,468	7,056
1.b	Other Revenues	150,987	148,562	2,425	71,187	74,249	215	2,582	329
2.	Expenses	1,626,564	1,590,132	36,432	839,733	730,686	2,360	12,439	4,914
3.	Operating Income Before Income Taxes	518,418	516,820	1,598	290,762	217,416	561	5,611	2,471
4.	Interest Expense	NA	131,928	NA	74,222	55,500	143	1,432	631
5.	Income Taxes	152,495	152,032	463	85,533	63,957	165	1,650	727
6.	Net Operating Income	365,923	364,788	1,135	205,229	153,459	396	3,960	1,744
7.	Rate Base	4,221,019	4,207,476	13,543	2,367,112	1,769,998	4,571	45,676	20,118
8	Rate of Return	8.67%	8.67%	8.38%	8.67%	8.67%	8.67%	8.67%	8.67%

Data Source: APS Schedule G-1, Page 1 of 1 modified such that class return matches APS requested ACC jurisdiction return

ARIZONA PUBLIC SERVICE COMPANY
SUMMARY OF BASE REVENUES BY CUSTOMER CLASSIFICATION
COST-OF-SERVICE BASED RATES USING APS PROPOSED INCREASE
TEST YEAR ENDING DECEMBER 31, 2002, ADJUSTED

		Base Revenues in the Test Year		Proposed Increase			
		(A)	(B)	(C)	(D)	(E)	(F)
Line No.	Customer Classification	Present Rates ($000)	Proposed Rates ($000)	Amount ($000)	%	Proposed CRCC ($000)	Proposed Increase with CRCC %
1	Residential	889,898	1,059,308	169,410	19.04%	3,717	19.45%
2	General Service	883,595	873,853	(9,742)	-1.10%	4,485	-0.59%
3	Irrigation	2,099	2,706	607	28.94%	11	29.47%
4	Outdoor Lighting	10,794	15,468	4,674	43.30%	36	43.63%
5	Dusk to Dawn Lighting Service	5,198	7,056	1,858	35.75%	14	36.02%
6	Total Sales to Ultimate Retail Customers	1,791,584	1,958,390	166,806	9.31%	8,263	9.77%

Data Source: APS Schedule H-1, Page 1 of 1 as modified in Attachment KCH-6, p. 3 to match strict cost of service results

ARIZONA PUBLIC SERVICE COMPANY
SUMMARY OF BASE REVENUES BY CUSTOMER CLASSIFICATION
AECC PROPOSED RATES USING APS PROPOSED INCREASE
TEST YEAR ENDING DECEMBER 31, 2002, ADJUSTED

		Base Revenues in the Test Year		AECC Proposed Increase			
		(A)	(B)	(C)	(D)	(E)	(F)
Line No.	Customer Classification	Present Rates ($000)	Proposed Rates ($000)	APS Amount ($000)	%	Proposed CRCC ($000)	Proposed Increase with CRCC %
1	Residential	889,898	1,005,004	115,106	12.93%	3,717	13.35%
2	General Service @ 60% of Overall %	883,595	932,956	49,361	5.59%	4,485	6.09%
3	Irrigation	2,099	2,371	272	12.93%	11	13.46%
4	Outdoor Lighting	10,794	12,190	1,396	12.93%	36	13.27%
5	Dusk to Dawn Lighting Service	5,198	5,870	672	12.93%	14	13.20%
6	Total Sales to Ultimate Retail Customers	1,791,584	1,958,391	166,807	9.31%	8,263	9.77%

Data Source: APS Schedule H-1, Page 1 of 1 modified to limit General Service class to 60% of overall retail percentage increase

ARIZONA PUBLIC SERVICE COMPANY
SUMMARY OF BASE REVENUES BY CUSTOMER CLASSIFICATION
EQUAL PERCENTAGE RATE INCREASE USING AECC REVENUE ADJUSTMENTS TO APS REQUESTED RATE INCREASE
TEST YEAR ENDING DECEMBER 31, 2002, ADJUSTED

		Base Revenues in the Test Year		AECC Proposed Increase			
		(A)	(B)	(C)	(D)	(E)	(F)
Line No.	Customer Classification	Present Rates ($000)	Proposed Rates ($000)	AECC Amount ($000)	%	Proposed CRCC ($000)	Proposed Increase with CRCC %
1	Residential	889,898	898,334	8,436	0.95%	3,717	1.37%
2	General Service	883,595	891,971	8,376	0.95%	4,485	1.46%
3	Irrigation	2,099	2,119	20	0.95%	11	1.47%
4	Outdoor Lighting	10,794	10,896	102	0.95%	36	1.28%
5	Dusk to Dawn Lighting Service	5,198	5,247	49	0.95%	14	1.22%
6	Total Sales to Ultimate Retail Customers	1,791,584	1,808,567	16,983	0.95%	8,263	1.41%

Data Source: APS Schedule H-1, Page 1 of 1 modified to spread AECC proposed revenue increase on equal percentage basis

ARIZONA PUBLIC SERVICE COMPANY
SUMMARY OF BASE REVENUES BY CUSTOMER CLASSIFICATION
AECC PROPOSED RATES USING AECC REVENUE ADJUSTMENTS TO APS REQUESTED RATE INCREASE
TEST YEAR ENDING DECEMBER 31, 2002, ADJUSTED

		Base Revenues in the Test Year		AECC Proposed Increase			
		(A)	(B)	(C)	(D)	(E)	(F)
Line No.	Customer Classification	Present Rates ($000)	Proposed Rates ($000)	AECC Amount ($000)	%	Proposed CRCC ($000)	Proposed Increase with CRCC %
1	Residential	889,898	901,617	11,719	1.32%	3,717	1.73%
2	General Service @ 60% of Overall %	883,595	888,621	5,026	0.57%	4,485	1.08%
3	Irrigation	2,099	2,127	28	1.32%	11	1.84%
4	Outdoor Lighting	10,794	10,936	142	1.32%	36	1.65%
5	Dusk to Dawn Lighting Service	5,198	5,266	68	1.32%	14	1.59%
6	Total Sales to Ultimate Retail Customers	1,791,584	1,808,567	16,983	0.95%	8,263	1.41%

Data Source: APS Schedule H-1, Page 1 of 1 modified to spread AECC proposed revenue increase and to limit General Service class to 60% of overall retail percentage increase

Adjustments To E-32 Rate Design

Arizona Public Service Company Adjusted 2002 Test Year E-32 Billing Determinants					
E-32, 20 < kW < 100 Small GS	Billing Determinants	AECC Proposed Charge	AECC kW $	APS kW $	Difference kW $
Winter (Jan-Apr, Nov-Dec)					
1st 100 kW	3,599,159	$7.000	$25,194,113	$22,847,458	$2,346,655.00
			$25,194,113		
Summer (May-Oct)					
1st 100 kW	4,134,380	$7.000	$28,940,660	$26,245,046	$2,695,614.00
			$28,940,660		
Total E-32, 20 < kW < 100 Small GS, kW $			**$54,134,773**	**$49,092,504**	**$5,042,269**

AECC - Total E-32, 20 < kW < 100 Small GS - kW $	**$54,134,773**
APS - Total E-32, 20 < kW < 100 Small GS - kW $	**$49,092,504**
Difference	**$5,042,269**

Arizona Public Service Company Adjusted 2002 Test Year E-32 Billing Determinants					
E-32, 100 <= kW < 1000 Med GS	Billing Determinants	AECC Proposed Charge	AECC kW $	APS kW $	Difference kW $
Winter (Jan-Apr, Nov-Dec)					
1st 100 kW	2,168,000	$7.000	$15,176,000	$32,506,750	($17,330,750)
over 100 kW	3,340,655	$5.054	$16,884,804	$1,791,181	$15,093,623
			$32,060,804	**$34,297,931**	**($2,237,127)**
Summer (May-Oct)					
1st 100 kW	2,682,200	$7.000	$18,775,400	$40,704,220	($21,928,820)
over 100 kW	4,229,774	$5.054	$21,378,714	$2,308,265	$19,070,449
			$40,154,114	**$43,012,485**	**($2,858,371)**
Total E-32, 100 <= kW < 1000 Med GS, kW $			**$72,214,918**	**$77,310,416**	**($5,095,498)**

E-32, kW > 1000 Lg GS	Billing Determinants	AECC Proposed Charge	AECC kW $	APS kW $	Difference kW $
Winter (Jan-Apr, Nov-Dec)					
1st 100 kW	87,800	$7.000	$614,600	$2,667,567	($2,052,967)
over 100 kW	1,244,613	$5.054	$6,290,697	$4,212,496	$2,078,201
			$6,905,297	**$6,880,063**	**$25,234**
E-32, kW > 1000 Lg GS					
Summer (May-Oct)					
1st 100 kW	106,200	$7.000	$743,400	$3,320,353	($2,576,953)
over 100 kW	1,558,214	$5.054	$7,875,742	$5,270,794	$2,604,948
			$8,619,142	**$8,591,147**	**$27,995**
Total E-32, kW > 1000 Lg GS kW $			**$15,524,439**	**$15,471,210**	**$53,229**

AECC - Total Med GS and Lg GS - kW $	**$87,739,357**
APS - Total Med GS and Lg GS - kW $	**$92,781,626**
Difference	**($5,042,269)**

AECC - Total Sm, Med, Lg - kW $	**$141,874,130**
APS - Total Sm, Med, Lg - kW $	**$141,874,130**
Difference	**$0**

EXHIBIT
AECC-2
Admitted

REBUTTAL TESTIMONY OF KEVIN C. HIGGINS

On Behalf of Arizonans for Electric Choice & Competition

Docket No. E-01345A-03-0437

March 30, 2004

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REBUTTAL TESTIMONY OF KEVIN C. HIGGINS

Introduction

Q. Please state your name and business address.

A. Kevin C. Higgins, 39 Market Street, Suite 200, Salt Lake City, Utah, 84101.

Q. By whom are you employed and in what capacity?

A. I am a Principal in the firm of Energy Strategies, LLC.

Q. On whose behalf are you testifying in this proceeding?

A. My testimony is being sponsored by Arizonans for Electric Choice and Competition ("AECC").

Q. Are you the same Kevin C. Higgins who has previously filed direct testimony in this case?

A. Yes, I am.

Q. What recommendations do you make in your rebuttal testimony?

A. My rebuttal testimony supports the following recommendations:

(1) I recommend that the Commission reject RUCO witnesses Marylee Diaz Cortez's and Richard A. Rosen's proposals to eliminate the right to direct access service, as well as Ms. Diaz Cortez's recommendation that the Commission find the 1999 Settlement Agreement "expired" and "void";

(2) I recommend that the Commission reject RUCO's proposal to raise rates by $35 million to fund Demand-Side Management ("DSM") programs;

(3) I offer an alternative rate design to the Environmental Portfolio Surcharge proposed by Staff witness Barbara Keene; however, I note that Ms. Keene's proposal retains important aspects of the balance of interests contained in the design of the current surcharge. Therefore, if my preferred option of a strictly proportional increase is not adopted, then I support approval of Ms. Keene's rate design for the Environmental Portfolio Surcharge;

(4) I support APS' use of the 4-CP method for allocating fixed production costs and recommend against adoption of alternatives to that method. I also recommend against allocating a portion of distribution system costs based on energy, as proposed by RUCO witness John Stutz.

Direct Access and the 1999 Settlement Agreement

Q. What does Ms. Diaz Cortez recommend with respect to direct access and the 1999 Settlement Agreement?

A. Testifying on behalf of RUCO, Ms. Diaz Cortez recommends that the Commission eliminate the right to direct access service for all APS customers. She further recommends that the Commission declare the 1999 Settlement Agreement "expired" and "voided."[1]

Q. What is your assessment of Ms. Diaz Cortez's proposal?

A. Ms. Diaz Cortez's proposal should be rejected. Retail access is an issue of statewide importance. The Commission has already established a process for evaluating the Electric Competition Rules. Ms. Diaz Cortez is attempting to circumvent that process by forcing the issue of retail access into this rate case.

[1] Pre-filed direct testimony of Marylee Diaz Cortez, p. 9, lines 6-15.

This rate case has important issues of its own to be decided and is not the right venue for addressing the totality of the Electric Competition Rules.

Moreover, in her discussion of the 1999 Settlement Agreement, Ms. Diaz Cortez grossly mischaracterizes the benefits of the bargain that was struck under the settlement. Her testimony on this point is nothing short of disingenuous. Her proposal to eliminate direct access rights for *all APS customers* demonstrates bad faith toward AECC, which was a partner with RUCO in negotiating the settlement with APS.

Q. Did you help negotiate the 1999 Settlement Agreement?

A. Yes, I did, on behalf of AECC.

Q. Did Ms. Diaz Cortez ever participate in those negotiations?

A. No.

Q Please explain your view that Ms. Diaz Cortez grossly mischaracterizes the benefits of the bargain that was struck under the settlement.

A. The overriding objective of the 1999 Settlement Agreement was to remove the obstacles to implementing the Commission's Electric Competition Rules. This is what AECC sought to achieve, while building in features that protected customers against uncertainty and provided tangible savings in the form of regularly-scheduled Standard Offer rate reductions. The Electric Competition Rules, while certainly subject to continued Commission jurisdiction, were not fashioned as a "pilot project" or an "experiment." The fundamental premise was the establishment of a permanent right for customers to shop for power if they so chose. This is a long-run proposition, and AECC negotiated with the long view in mind.

Q. What is an example of taking the long-view in the 1999 Settlement Agreement?

A. The agreement provided for stranded cost payments to be paid by shopping customers to APS during a transition period that stretched from 1999 through 2004. Stranded cost payments are an impediment to shopping, but were part of the package in the Electric Competition Rules, and therefore a necessary part of the solution. AECC agreed to six years of stranded cost charges, starting in 1999, in the belief that it was best for Arizona customers to address this legal obligation head on, agree to a stipulated level of obligation, and retire it once and for all. With stranded cost charges scheduled (initially) to be retired at the end of 2004[2], customers seeking to shop could one day expect to enjoy a more level playing field. Now – before stranded cost charges are even ended – RUCO seeks to have the Settlement Agreement declared "expired" and have the Commission wipe out the primary benefit of AECC's bargain: the right to shop for power.

Q. What is another example of taking the long view in the Settlement Agreement?

A. The parties to the Settlement Agreement did not propose to establish any shopping credit subsidies to assist the retail competitive market in getting started. While it may have been tempting to support the initiation of retail access in such a manner, my view was that one of the major problems facing Arizona ratepayers in

[2] In this proceeding, APS has proposed to move up the date of ending its stranded cost charge (or CTC) to June 30, 2004.

1999 was a staggering burden of deferred costs. Hundreds of millions of dollars worth of APS expenses since the 1980s had been deferred and booked as regulatory assets. Paying off this gigantic debt has been costing APS customers around $120 million per year, a burden that will not be paid off until June 30, 2004. Understandably, AECC did not advocate for any implementation approach that would have subsidized retail access and added to APS' regulatory assets. This was another example of taking the long view.

Q. In what way is Ms. Diaz Cortez's testimony on the Settlement Agreement disingenuous?

A. On page 17 of her direct testimony, Ms. Diaz Cortez testifies that voiding the 1999 Settlement Agreement and eliminating the right to shop will not result in the non-performance of any of the agreement's terms. She justifies this conclusion by stating that "the distribution system was opened to direct access per section 1.1 of the agreement."[3] It is disingenuous to assert that *closing* the distribution system now to direct access would not result in non-performance under the agreement, on the grounds that the distribution system had been opened for a limited period of time. Direct access was not established merely for a four-year window. Confiscating the right to shop from customers would rob AECC of the primary benefit of its bargain from the 1999 Settlement Agreement and would clearly result in non-performance under the agreement. Ms. Diaz Cortez's cavalier

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[3] Pre-filed direct testimony of Marylee Diaz Cortez, p. 17, line 21 – p. 18, line 14.

declaration that "no party will be left unwhole by the expiration of the agreement"[4] is simply false.

Q. Has having the right to shop been harmful to Arizona customers?

A. No. Arizona designed its direct access program in a manner that protected customers from the severe market volatility experienced in the West in 2000 and 2001. While this volatility negatively impacted customers' *exercise* of their right to shop, the mere *possession* of the right has not been a problem. Direct access has taken hold in other parts of the country when the underlying economics have been supportive.[5] Arizona customers who wish to exercise their right to shop in the future should not be deprived of that opportunity. Given the extreme difficulty in securing this right, it would be rash and unnecessary to take it away.

Q. What about Ms. Diaz Cortez's assertion that residential customers are unlikely to benefit from retail access?

A. I agree that residential customers are not main focus of Electric Service Providers (ESPs), although residential aggregation programs have been successful in places such as Ohio. It was in recognition that residential customers would be less likely to participate in direct access service that the Settlement Agreement provided a larger cumulative Standard Offer rate reduction for residential customers than for large customers, 7.5 percent versus 5.0 percent. But even if residential customers are less likely to take direct access service than a commercial or industrial customer, it does not warrant taking this option away from residential customers.

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[4] Ibid., p. 18, lines 20-21.

Q. In the event that the Commission decides to act on RUCO's proposal, what do you recommend?

A. In such event, any rollback of the right to shop should be limited to residential customers. In association with such a limitation, the Commission could also eliminate any residential customer responsibility for forward-going costs associated with direct access service. This should satisfy RUCO.

But there is no reason to deny *non-residential* customers the right to shop. Non-residential customers are not asking the Commission to have this right taken away from them.

Q. What about small commercial customers? Should their right to shop be taken away?

A. Absolutely not. Based on my experience in other parts of the country, smaller commercial customers often have some of the best opportunities for savings from direct access.

Q. What about Dr. Rosen's recommendation to eliminate the right to shop in order to minimize the degree of FERC's authority over transmission in Arizona?

A. From a customer perspective, there are two principal issues to address concerning federal jurisdiction. The first is the reasonableness of transmission rates based on cost-of-service regulation. This is unlikely to be a problem for customers. Transmission service is a relatively small portion of customers' bills, and there is little reason to expect a material difference in electric power rates to

[5] Texas, Illinois, Michigan, Ohio, Maine, Massachusetts, and New York are some examples of states with significant direct access activity.

customers that would result from FERC-determined versus state-determined transmission rates.

The second principal issue is the assurance of an economic priority to the use of that part of the transmission system built to deliver power to native load customers – both bundled and direct access customers. Dr. Rosen raises the fear of losing priority, through FERC usurpation, as one of the main reasons to abandon direct access.[6]

I agree with Dr. Rosen that retaining transmission priority for native load customers is an important objective. To that end, I spent years – and hundreds of hours – negotiating with other RTO stakeholders the terms of the "congestion management" protocol that the southwestern utilities, including APS, filed with FERC. That protocol is contained in Appendix A of the WestConnect tariff. Through the terms of its allocation of Firm Transmission Rights ("FTR") auction proceeds and its "tiebreaking" provisions, Appendix A ensures an economic and reliability priority for native load customers. This protocol was painstakingly put together to protect native load customers and to ensure non-discriminatory treatment between bundled and direct access customers. It has already been approved by FERC. Dr. Rosen's apparent belief that it is necessary to take the drastic step of abrogating direct access rights in order to ensure native load transmission priority is misplaced. The hard work to establish such assurance has already been performed. His recommendation to sweep away direct access rights

[6] Pre-filed direct testimony of Richard A. Rosen, p. 11, lines 7-17.

in order to address a concern that has been thoroughly addressed elsewhere should be rejected.

Demand Side Management

Q. What is your assessment of RUCO's proposal to raise rates $35 million to fund Demand-Side Management (DSM) programs?

A. I recommend against adoption of this proposal, which is presented in the direct testimony of Ms. Diaz Cortez.[7] RUCO's proposal would raise rates an average of 2 percent by imposing a 1.5 mill per-kwh DSM charge. While energy conservation and load management have value, the program proposed by RUCO would have a significant rate impact and is likely to exacerbate the substantial cross-subsidies between rate classes that are already present in APS' rates.

The first step in sending the right message for energy conservation is to remove the cross-subsidies in rates that mask energy price signals. A far more reasonable approach to DSM is contained in Staff's overall rate proposal, which combines a significant and appropriate movement toward cost-of-service rates[8] with a more modest DSM rate impact of $4 million.[9] If a DSM program is mandated, it should be based on Staff's overall approach, not RUCO's.

Q. Do you have any other concerns regarding RUCO's DSM proposal?

A. Yes. Given that the residential advocate is championing this significant cost increase, to the extent that the Commission wishes to pursue it, consideration

[7] Pre-filed direct testimony of Marylee Diaz Cortez, p. 27, line 4 – p. 29, line 2.
[8] Pre-filed direct testimony of Erinn A.Andreason, p. 4, line 16 – p. 5, line 10.
[9] Pre-filed direct testimony of Barbara Keene, p. 10, lines 4-6.

should be given to limiting program funding and participation to residential customers.

If, to the contrary, funding requirements are imposed on non-residential customers, then customers whose cumulative charges reach a reasonable critical mass should have the ability to self-direct any DSM funds that are collected; that is, if non-residential customers are required to pay a DSM charge, then those funds should accrue in an account in that customer's name, and the customer should be able to use the funds for DSM purposes in its own facilities. A reasonable threshold for self-direction would be any customer with a multi-site aggregated use of 4 million kwh per year, which is equivalent to an average demand of approximately 450 kw. Such a customer would pay $6000 per year in DSM charges under RUCO's proposal. If this level of funding is to be collected from individual customers, they should be allowed to direct it to investments in their own facilities, rather than having it spent on somebody else's.

Q. Do you have any comments on the rate design for DSM?

A. Yes. The flat 1.5 mills-per-kwh charge proposed by RUCO would place an unfair cost burden on high-load-factor customers, whose energy usage does not fluctuate significantly relative to their peaks, and who, on the average, cost less to serve because they make efficient use of utility assets. If a DSM charge is adopted, alternative rate designs, such as percentage of bill, or demand charges for customers with necessary meters, should be considered.

Environmental Portfolio Standard

Q. Do you have any comments on Staff's recommendation for funding the Environmental Portfolio Standard ("EPS")?

A. Yes. Staff witness Barbara Keene proposes changes to the Environmental Portfolio Surcharge that would raise an additional $4.4 million in funding for EPS-related projects. This is about a 67 percent increase over current funding levels. Ms. Keene's proposed change would not affect the 0.875 mill/kwh charge, but would raise the cap on the monthly per-meter charge from 35 cents to 99 cents for residential customers, from $13 to $25 for most non-residential customers, and from $39 to $100 for customers with billing demands of 3000 kw or greater.

The current structure of charges strikes an important balance between meeting the funding goals of the EPS program and limiting the subsidy cost imposed on individual customers, which is accomplished through the per-meter cap. My recommendation for meeting the targeted increase in EPS funding would be to retain this current structure by increasing all billing components – i.e., the energy charge and the per-meter caps, by an equal percentage: in this case, 67 percent.[10]

Although Ms. Keene's proposal does not adhere to a strictly proportional increase, it otherwise retains important aspects of the balance of interests contained in the design of the current surcharge. Therefore, if my preferred option of a strictly proportional increase is not adopted, then I recommend that Ms. Keene's rate design for the Environmental Portfolio Surcharge be approved.

[10] This would result in an EPS energy charge of 1.461 mills/kwh, a residential cap of 58 cents/month, a non-residential cap of $21.71/month, and a large customer cap of $65.14/month.

Cost allocation methodology

Q. Do you have any comments on testimony that addresses cost allocation methodology?

A. Yes. In my direct testimony, I supported APS' use of the 4-CP method for allocating fixed production cost. Staff witness Lee Smith and RUCO witness John Stutz have challenged APS' use of this method, and argue for alternatives that would classify more costs as energy-related and less as demand-related, resulting in a re-allocation of cost responsibility from lower-load-factor customer classes to higher-load-factor customer classes.[11]

While, typically, a case can be made for more than one cost allocation method, I believe the 4-CP method is particularly appropriate for the APS territory. The APS system is not a static state, but is characterized by substantial load growth, which has important implications for future costs. The major driver of the need for additional generating resources is the growth in APS' summer peak demand. It is important that APS' cost allocation methodology reflect this underlying cost dynamic. I believe this is best captured by using the 4-CP approach, which reflects the demands put on the system in the peak summer months.

Moreover, placing increased cost responsibility on higher-load-factor customers is particularly inappropriate given that APS energy costs are allocated to customer classes without regard to seasonality or time-of-use, despite

[11] See pre-filed direct testimony of Lee Smith (Staff), p. 33, line 18 – p. 35, line 5 and pre-filed direct testimony of John Stutz (RUCO), p. 19, line 1 – p. 23, line 16.

significant differences in seasonal and time-of-use costs.[12] This means that high-load-factor customer classes – which generally use a higher-than-average portion of their energy in cheaper off-peak periods – are allocated the same average cost of energy as low-load factor customer classes, which generally consume more of their energy requirements during the more expensive on-peak periods. In other words, the allocation of energy costs to classes without regard to seasonality or time-of-use already shifts costs unduly to high-load-factor customers. Moving away from the 4-CP method to one of the proposed alternatives will only exacerbate this problem. Therefore, the Commission should not approve the alternatives proposed to APS' 4-CP method. Instead, ASP' cost-of-service analysis should be accepted.

Q. Do you have any comments on testimony that addresses allocation of distribution costs?

A. Yes. RUCO witness John Stutz recommends allocating a portion of distribution system costs based on energy, rather than exclusively on demand. This would result in a greater allocation of distribution costs to high-load-factor customers and a smaller allocation to low-load-factor customers.[13]

I disagree with Dr. Stutz's recommendation. While the distribution system certainly is used for the delivery of energy, the investment in distribution system facilities is driven by demand. A low-load-factor customer requires essentially the same investment in distribution facilities as a high-load factor customer, and

[12] Note that the allocation of costs to customer classes is distinct from the inclusion of seasonal or time-of-use features in rate design. APS' rates provide for seasonal and optional time-of-use pricing, which are rate design features applicable to individual rate schedules. However, the allocation of APS energy costs to customer classes in the first instance is not differentiated by seasonality or time-of-use. See AP__WP21.

should pay the same cost for the investment required. A high-load factor customer simply uses the distribution system more efficiently. These high-load factor customers would be unfairly penalized by switching to a methodology that allocates distribution system costs on an energy basis. Therefore, I recommend that Dr. Stutz's proposal not be adopted.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

[13] Pre-filed direct testimony of John Stutz, p.23, line 18 – p. 24, line 10.

AECC/PD/FEA/K

Admitted
EXHIBIT
AECC/PD 1
FEA/K

DIRECT TESTIMONY OF KEVIN C. HIGGINS

On Behalf of Arizonans for Electric Choice & Competition,

Phelps Dodge Mining Company, Federal Executive Agencies, and The Kroger Co.

Docket No. E-01345A-03-0437

September 27, 2004

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DIRECT TESTIMONY OF KEVIN C. HIGGINS

Introduction

Q. Please state your name and business address.

A. Kevin C. Higgins, 39 Market Street, Suite 200, Salt Lake City, Utah, 84101.

Q. By whom are you employed and in what capacity?

A. I am a Principal in the firm of Energy Strategies, LLC. Energy Strategies is a private consulting firm specializing in economic and policy analysis applicable to energy production, transportation, and consumption.

Q. On whose behalf are you testifying in this phase of the proceeding?

A. With respect to the Settlement Agreement that has been put forward to resolve the issues in this proceeding, I am testifying on behalf of Arizonans for Electric Choice and Competition ("AECC"), Phelps Dodge Mining Company ("Phelps Dodge"), Federal Executive Agencies ("FEA"), and The Kroger Co. ("Kroger"). AECC, Phelps Dodge Mining, FEA, and Kroger represent retail customer interests in the General Service class. Each of these parties supports and has signed the Settlement Agreement.

Q. Have you previously filed testimony in this proceeding?

A. Yes, I filed both direct and rebuttal testimony on behalf of AECC.

Q. Please describe your professional experience and qualifications.

A. My academic background is in economics, and I have completed all coursework and field examinations toward the Ph.D. in Economics at the

University of Utah. In addition, I have served on the adjunct faculties of both the University of Utah and Westminster College, where I taught undergraduate and graduate courses in economics. I joined Energy Strategies in 1995, where I assist private and public sector clients in the areas of energy-related economic and policy analysis, including evaluation of electric and gas utility rate matters.

Prior to joining Energy Strategies, I held policy positions in state and local government. From 1983 to 1990, I was economist, then assistant director, for the Utah Energy Office, where I helped develop and implement state energy policy. From 1991 to 1994, I was chief of staff to the chairman of the Salt Lake County Commission, where I was responsible for development and implementation of a broad spectrum of public policy at the local government level.

Q. Have you previously testified before this Commission?

A. Yes. I have testified in a number of proceedings before this Commission, including the generic proceeding on retail electric competition (1998),[1] the hearings on the APS and TEP settlement agreements implementing the Electric Competition Rules (1999),[2] the AEPCO transition charge hearings (1999),[3] the Commission's Track A proceeding (2002),[4] the APS adjustment mechanism proceeding (2003),[5] and the Arizona ISA proceeding (2003).[6]

Q. Have you testified before utility regulatory commissions in other states?

[1] Docket No. RE-00000C-94-0165.
[2] Docket Nos. RE-00000C-94-0165, E-01345A-98-0473, E-01933A-97-0773, E-01345A-98-0471, and E-01933A-97-0772.
[3] Docket No. E-01773A-98-0470.
[4] Docket Nos. E-00000A-02-0051; E-01345A-01-0822; E-00000A-01-0630; E-01933A-02-0069; E-01933A-98-0471.
[5] Docket No. E-01345A-02-0403.
[6] Docket No. E-00000A-01-0630.

A. Yes. I have testified numerous times on the subjects of electric utility rates and industry restructuring before state utility regulators in Colorado, Georgia, Idaho, Indiana, Michigan, Nevada, New York, Ohio, Oregon, South Carolina, Utah, Washington, and Wyoming.

A more detailed description of my qualifications is contained in Attachment KCH-1, attached to my direct testimony.

<u>Overview and conclusions</u>

Q. What is the purpose of your testimony with respect to the Settlement Agreement?

A. I am testifying in support of the Settlement Agreement as proposed by the Stipulating Parties on August 18, 2004.

Q. Did you personally participate in the negotiations that led to the Settlement Agreement?

A. Yes, I participated throughout the negotiation process.

Q. What is your assessment of the Settlement Agreement?

A. The Settlement Agreement is a comprehensive treatment of wide-ranging, complex, and interrelated issues. It was carefully crafted over a period of months and represents a balancing of interests among diverse Parties who have negotiated and compromised in good faith to produce a result that is in the public interest. In my opinion, the Settlement Agreement, taken as a whole, produces rates, terms, conditions, and policies that are just and reasonable. Because of the complex tradeoffs among multiple issues and multiple parties, it is essential that the

Settlement Agreement be viewed as a total package. The Stipulating Parties have each made concessions in reliance on the advancement of the complete Agreement as negotiated. I strongly recommend adoption of the Settlement Agreement in the form presented by the Parties, as any alterations to the package are highly likely to deprive some Parties of the benefits of their bargains.

Q. How is your testimony organized?

A. My testimony is organized by the following topics:

- Revenue requirements
- Rate spread/Environmental Portfolio Standard surcharge rate design
- Rate design (pertaining to base rates)
- Demand-Side Management (DSM), and
- Direct access service.

Q. Why have you combined Rate Spread and the Environmental Portfolio Standard surcharge rate design into a single topic?

A. From the standpoints of AECC, Phelps Dodge, FEA, and Kroger, the Settlement Agreement's treatment of rate spread and the Environmental Portfolio Standard ("EPS") surcharge rate design are closely interrelated and most effectively addressed in tandem.

<u>Revenue requirements</u>

Q. What are the revenue requirements features of the settlement agreement?

A. Paragraph 1 of the Settlement Agreement provides that APS will receive a rate increase of $75.5 million, of which $67.5 million is in base rates and $8 million is in the Competition Rules Compliance Charge ("CRCC"). This translates into an average base rate increase of 3.77 percent, plus .44 percent for the CRCC.

Q. How do the revenue requirements in the Settlement Agreement compare with the initial request by APS in its application?

A. In its Application, APS requested an overall rate increase of $175 million, or 9.75 percent. Of this amount, $167 million was in base rates, and $8 million was in the CRCC. In addition, in rebuttal testimony, APS revised its base revenue requirement upward by an additional 1 percent to $185 million, although the Company did not seek to recover this additional amount in rates.

The Settlement Agreement reduces the initial overall increase requested by APS by approximately 57 percent.

Q. How do the revenue requirements in the Settlement Agreement compare with the recommendations in your direct testimony?

A. In my direct testimony, I recommended adjustments that reduced APS' proposed increase of $175 million by approximately $150 million. One of these adjustments – denial of the reversal of the $234 million write-down – is explicitly incorporated into the Settlement results.

Another adjustment I had recommended – denial of including certain PWEC assets in APS rate base – was resolved through a compromise that allows these units into rate base, but at a lesser value than was initially sought by APS. Specifically, Paragraph 7 of the Settlement Agreement provides that PWEC assets will have an original cost rate base of $700 million. This represents a $148 million disallowance from the original cost of the assets as of December 31, 2004. In addition, APS has agreed to forego any present or future stranded cost claims on the PWEC assets coming into rate base [Paragraph 8].

Q. Should the revenue requirements elements of the Settlement Agreement be adopted?

A. Yes. The revenue requirements elements of the Settlement Agreement are integral parts of a comprehensive agreement. They reflect reasonable compromises that resulted from extensive negotiations among the parties. I recommend that the revenue requirements be adopted as part of the entire settlement package.

Rate spread/EPS surcharge rate design

Q. What are the rate spread provisions in the Settlement Agreement?

A. Section XIX of the Settlement Agreement identifies rate increases for the various rate schedules. The Residential class as a whole would see a base rate increase of 3.94 percent. Schedules E-32, E-32R, E-34, E-35, E-53, E-54 – which are in the General Service class – and certain contracts would each experience base rate increases of 3.5 percent. Schedules E-20, E-21, E-22, E-23, E-24, E-30, E-38. E-38T, E-40, E-47, E-51, E-59, E-67, and E-221 would experience base rate increases of 5 percent.

Q. What accounts for the differences in rate increases among the various rate schedules?

A. As AECC, FEA, and Kroger discussed in their previously-filed direct testimony, and as shown in APS' initial application, the APS General Service class is paying rates that subsidize all of the other customer classes. It is important, on the grounds of both equity and efficiency, to take steps to remove such subsidies from rates, while recognizing that it may not be pragmatic to eliminate all subsidies at once, due to the potential rate impact on the subsidized classes. In this situation, it is appropriate for the General Service class to experience a less-than-average increase, and for classes being subsidized to experience a greater-than-average increase. The rate spread in the Settlement Agreement takes a very modest step in the direction of reducing cross-subsidies by moving rates in the direction of cost-of-service.

Q. Do you believe that the rate spread in the Settlement Agreement is just and reasonable?

A. Yes, but only insofar as the rate spread is an integral component of the larger Agreement. Absent other key provisions in the Settlement Agreement, the Settlement rate spread would *not* be acceptable to AECC, Phelps Dodge, FEA, and Kroger, as these parties otherwise view the base rate increase for General Service as being too high, in light of the subsidy this class is currently paying. These parties have accepted the Settlement rate spread in light of other considerations in the Settlement Agreement.

Q. What are examples of Settlement provisions that were essential to General Service customers in accepting the Settlement rate spread?

A. As the Settlement Agreement is a comprehensive document with many interrelated considerations, I will not attempt to provide an exhaustive listing of such provisions, but relevant provisions include General Service rate design as well as the Environmental Portfolio Standard ("EPS") surcharge rate design.

Q. Please explain the connection of the EPS surcharge rate design to the acceptance of the Settlement rate spread by AECC, Phelps Dodge, FEA, and Kroger.

A. The EPS surcharge is currently set at $.00875 per kWh. In addition, there are monthly caps in place for three categories of customers. For residential customers, the cap is $0.35 per month. For non-residential customers with loads greater than 3 MW in size, the cap is $39 per month. For all other non-residential customers, the cap is $13 per month.

Section VIII of the Settlement Agreement addresses the EPS surcharge. Paragraph 63 in that section states:

> APS shall also recover costs for EPS-eligible renewables through the EPS surcharge, which shall be established in this case as an adjustment mechanism to allow for specific Commission-approved changes to APS' EPS funding. The initial charge will be the same as contained in the current EPS surcharge tariff, including caps. If the Commission amends the EPS surcharge set forth in Rule 1618 or approves additional EPS funding pursuant to paragraph 64 of this Agreement, *any change in EPS funding requirements resulting from such actions shall be collected from APS' customers in a manner that maintains the proportions between customer categories embodied in the current EPS surcharge*. These adjustments may be made outside a rate case. [Emphasis added.]

As laid out in Paragraph 63, the Settlement Agreement establishes rate design parameters for the EPS surcharge. The Settlement Agreement does *not* cap the total funding of the EPS program, nor does it require retention of the current caps if EPS funding is increased from current levels. However, Paragraph 63 does require that changes in EPS funding levels be collected in a manner that maintains the proportions between customer categories embodied in the current EPS surcharge. In other words, if the EPS funding is increased from current levels, the most straightforward means of collecting the increased revenues consistent with the Settlement would be to increase all EPS surcharge rate elements proportionally – the per-kWh charge plus each category of cap.

Maintaining the proportionality of the current EPS surcharge among the three categories of customers is a key provision of the Settlement Agreement for AECC, Phelps Dodge, FEA, and Kroger. The presence of this provision in the Agreement, among others, makes it possible for these General Service parties to accept the Settlement Agreement's rate spread provisions, despite the level of subsidy payment to the other customer classes built into General Service base rates.

Q. Can you provide a simple example of how this proportionality principle would work?

A. Yes. For example, if EPS funding requirements were to double from the level collected under the current EPS surcharge, this additional funding could be realized, consistent with the Settlement Agreement, by doubling the per kWh charge of $.00875, *and* doubling each of the three customer caps.

Q. What type of approach to funding the EPS surcharge would violate the Settlement Agreement?

A. It would violate the Settlement Agreement to attempt to raise additional EPS funds by raising one of the customer caps in a manner that altered the proportions among the customer categories embodied in the current EPS surcharge.

Q. There is currently an open docket that is considering changes to Rule 1618, which governs the EPS. Do you think it is appropriate to address EPS rate design in the context of the general rate case Settlement Agreement?

A. Yes, absolutely. In fact, it would be highly *inappropriate* from a rate making and overall public policy standpoint to address EPS rate design outside a general rate case. Issues of equitable rates among customer classes (or categories) should not be decided in isolation from the breadth of facts available in a general rate case. It would be wrong to set the EPS surcharge rate design in a vacuum that ignored pertinent facts, such as the level of subsidies paid by APS General Service customers in base rates. The proper forum for considering the full spectrum of customer equity considerations is a general rate case, as opposed to a single-issue docket. Accordingly, the EPS surcharge rate design is properly incorporated into the comprehensive package developed in the Settlement Agreement.

Q. Does the Settlement Agreement restrict the Commission's ability to increase total funding for the EPS?

A. No. As I indicated above, the Settlement Agreement does not cap the total funding that the Commission may make available for the EPS program.

Q. Does the Settlement Agreement cap the EPS surcharge at current levels?

A. If the Commission does not alter the current level of EPS funding, then the Agreement retains the caps at their current levels. However, as I indicated above, if the Commission *increases* the level of funding for the EPS program, then the Settlement Agreement does *not* require retention of the current caps. It simply requires that the *proportions* among the customer categories be retained.

Q. What is your recommendation to the Commission concerning the Settlement Agreement's treatment of rate spread and the EPS surcharge?

A. These provisions of the Settlement Agreement are an integral part of the comprehensive agreement. They were painstakingly crafted through intense negotiations among the parties. I recommend that these provisions be adopted exactly as proposed as part of the entire settlement package. Changing any aspect of these provisions is certain to deny some parties the benefit of their bargains.

Rate design (pertaining to base rates)

Q. What other aspects of rate design do you wish to address?

A. I wish to address three rate design issues pertaining to base rates that are incorporated into the Settlement Agreement: (1) voltage differentiation; (2) unbundled rates; and (3) specific design issues pertaining to General Service Schedules E-32, E-34, and E-35.

Q. How is voltage differentiation treated in the Settlement Agreement?

A. The Settlement Agreement provides for rates that are differentiated according to the voltage at which each customer takes service. The Settlement Agreement adopts the basic approach proposed by APS in its Application, with some modifications. AECC, FEA, and Kroger each supported APS' general approach to voltage differentiation (with selected modifications) in previously-filed direct testimony.

Customers typically take service at one of three basic voltage levels: secondary, primary, or transmission. The cost of providing service differs according to voltage level; for instance, customers taking service at transmission voltage do not use any of the primary and secondary components of the distribution system, and so do not require the utility to make any investment in these components. Yet, currently, APS' Standard Offer General Service rates do not distinguish among service at differing voltage levels (although the APS' Direct Access rates do make such a distinction). Failure to set different rates for different voltage levels causes a subsidy within the General Service class from higher-voltage customers to lower-voltage customers.

In my experience, I know of no utility, except APS, that does not differentiate its rates across secondary, primary, and transmission service. The Settlement Agreement's incorporation of this distinction in this proceeding is consistent with the general approach adopted in the vast majority of utility tariffs across the country.

Q. What modifications were made to APS' initial proposal?

A. The Settlement Agreement modifies APS' initial proposal to recognize two additional facts concerning the costs on the APS system:

(1) Paragraph 120 recognizes that military base customers served directly from an APS substation will not be charged for the cost of APS' primary line and

secondary distribution investments, and establishes a cost-based voltage discount applicable to military base customers with this service configuration; and

(2) The rate design of Schedule E-32 recognizes that customers with demands of 100 kW and greater do not utilize APS' secondary feeders. This cost-of-service consideration is recognized in the design of the E-32 demand charge in the Settlement Agreement.

Q. In your opinion, is the Settlement Agreement's treatment of voltage differentiated rates just and reasonable?

A. Yes, it is.

Q. Turning now to rate unbundling, how does the Settlement Agreement treat this issue?

A. The Settlement Agreement adopts the basic approach to unbundling each schedule's rate components that APS proposed in its Application – an approach that AECC, FEA, and Kroger supported in previously-filed direct testimony. Separating individual rate components by function, such as generation, transmission, and distribution, is required by the Electric Competition Rules, and will provide better information to customers.

As the Settlement Agreement rates are lower than the rates APS proposed in its Application, it was necessary for the Parties to negotiate the treatment of the individual unbundled rate components at the stipulated revenue requirement, particularly for the rate schedules for which future direct access would be most relevant. This approach is explained in Paragraph 119, which states that "with regard to Schedules E-32, E-34, and E-35, the non-systems-benefits revenue requirement assigned to the General Service class will be used to establish first the unbundled component of generation at cost and then the unbundled component of revenue cycle services at cost." In this manner, the generation component is set at a rate that is neither below nor above cost, so as not to distort the economics of shopping.

Q. In your opinion, is the Settlement Agreement's treatment of unbundling rate components just and reasonable?

A. Yes. In separately stating generation and transmission cost components, it will make the process of evaluating direct access opportunities more transparent for customers who wish to do so. At the same time, APS' rates will also continue to be provided on a bundled basis for Standard Offer service. Customers who are not interested in evaluating direct access service can choose to ignore the unbundled detail in the tariff, and simply continue to focus on the bundled rates on their bill.

Q. Turning now to the specific General Service rate designs, do you have any overall comments you wish to make regarding the Settlement Agreement?

A. Yes. Specific rates for Schedules E-32, E-34, and E-35 are included in Appendix J of the Settlement Agreement. Whereas the Settlement Agreement summarizes the design objectives negotiated by the parties, it is the negotiated rates themselves, as they appear in Appendix J, that constitute the ultimate basis in reaching agreement for AECC, Phelps Dodge, FEA, and Kroger. Each element of these rate designs was the subject of negotiation over an extended period of time. The relationship between demand and energy charges, the designation of rate blocks, the differentiation of rates by voltage, the demarcation of unbundled components – in short, every component of the General Service rates in Appendix J – is an integral part of the Settlement Agreement and was of material interest in reaching settlement to at least one of the signatory Parties.

Q. Are there specific aspects of the E-32 rate design that you wish to point out?

A. Yes. As Paragraph 121 states, Schedule E-32 was modified in an effort to simplify the design, to make it more cost-based, and to smooth out the rate impact across customers of varying sizes within the rate schedule. The E-32 rate design in the Settlement Agreement is vastly improved relative to the design in the current tariff.

In particular, the Settlement Agreement's treatment of Schedule E-32 strikes a proper balance between demand and energy charges. In a system such as APS', in which new distribution infrastructure and new generation resources must be added to meet a growing system peak, it is critical on grounds of both fairness and efficiency to levy a demand charge that sufficiently places cost responsibility on those customers responsible for the costs incurred in meeting the system peak. The demand charge performs this function. Failure to properly weight demand cost responsibility would cause an improper subsidy among the customers within the E-32 rate schedule, which would result in higher-load-factor customers subsidizing the peak-related costs caused by lower-load-factor customers. The Settlement Agreement achieves a proper balancing of costs through the setting of the demand and energy charges.

In addition, the Settlement Agreement provides for an optional time-of-use rate that is open to all E-32 customers, increasing the pricing options available to customers on this rate schedule.

Q. Are there specific aspects of the E-35 rate design that you wish to point out?

A. Yes. In addition to the general design issues discussed above, Paragraph 118 of the Settlement Agreement retains the existing 11:00 AM to 9:00 PM on-peak time periods in the current tariff. In its initial Application, APS had proposed to modify the definition of this time period, by starting the on-peak period two hours earlier each day. The proposed change would have caused unintended problems for E-35 customers that have adapted their business operations to meet the terms of the existing definitions in the tariff. The Settlement Agreement averts this problem.

Q. In your opinion, is the Settlement Agreement's treatment of the specific rate designs of Schedules E-32, E-34, and E-35 just and reasonable?

A. Yes. The rates in Appendix J of the Settlement Agreement reflect a proper treatment of the relationship between demand and energy charges, the designation of rate blocks, the differentiation of rates by voltage, and the demarcation of unbundled components, among other things. Every component of the General Service rates in Appendix J is an integral part of the Settlement Agreement and should be adopted by the Commission.

Demand-Side Management

Q. What aspects of the Settlement Agreement's treatment of DSM do you wish to address?

A. I have a few limited comments on the DSM provisions in the Settlement Agreement. Specifically, I will address the rate design of the DSM adjustment mechanism for General Service customers, and I will comment on the provision in the Settlement Agreement that provides a process for evaluating the merits of allowing large customers to self-direct any DSM investments.

Q. How does the Settlement Agreement treat rate design for the DSM adjustment mechanism, as it applies to General Service customers?

A. Paragraph 43 establishes a DSM adjustment mechanism for any approved DSM expenditures in excess of the $10 million base rate DSM allowance. General Service customers that are demand-billed will pay a per-kW charge instead of a per kWh charge. This allocation *within* the General Service class does not impact the allocation *across* classes, which is performed on a per-kWh basis.

Q. In your opinion, what is the rationale for providing a process to evaluate the merits of allowing large customers to self-direct any DSM investments?

A. If the DSM adjustment mechanism grows to a significant size, larger customers may be required to contribute tens of thousands of dollars to this program. In my opinion, it is far more equitable for these customers – who are primarily businesses and public sector entities – to be able first to direct the funds they contribute to their own DSM opportunities, rather than have their contributions used to subsidize other businesses and public sector customers.

Paragraph 55 provides a forum for evaluating the merit of self-direction, which I believe is an important component of any mandatory DSM funding.

<u>**Direct access service**</u>

Q. What does the Settlement Agreement state with respect to direct access service?

A. The Settlement Agreement makes no changes to direct access service. Paragraph 82 of the Agreement states that changes to retail access shall be addressed through the Electric Competition Advisory Group or other similar process.

Q. Do any of the provisions of the Settlement Agreement have implications for direct access service?

A. Yes. There are a number of provisions of the Settlement Agreement that have implications for direct access service. To the best of my knowledge, all are salutary.

Q. Please elaborate.

A. As I discussed above, the rates incorporated in the Settlement Agreement include unbundled rate components. This feature will make the process of evaluating direct access opportunities more transparent for customers who wish to do so. In addition, in moving to the stipulated revenue requirement, the generation component for Schedules E-32, E-34, and E-35 is moved first to cost, in order not to distort the economics of shopping.

Further, as part of moving the West Phoenix PWEC assets into rate base, Paragraph 15 provides that these units shall be deemed "local generation" as that term is used in the AISA protocol or any successor FERC-approved protocol. During must-run conditions, generation from the West Phoenix facility shall be available at FERC-approved cost-of-service prices to electric service providers serving direct access load in the Phoenix load pocket. This provision ensures that electric service providers serving direct access customers in the Phoenix load pocket can have access to this local generation without being subject to pricing that is distorted by exercise of market power.

Finally, as I discussed above, APS has agreed to forego any present or future stranded cost claims on the PWEC assets coming into rate base. This provision prevents direct access service from being undercut by a future stranded cost claim resulting from the Settlement Agreement's inclusion of these assets in rate base.

Q. In stipulating to this provision, are AECC, Phelps Dodge, FEA, or Kroger acknowledging that any future APS stranded cost claims on other assets are valid?

A. Absolutely not. This provision of the Settlement Agreement simply removes the PWEC assets from the realm of any future debate on this topic.

<u>Conclusion</u>

Q. Do you have any summary conclusions you would like to offer to the Commission?

A. Yes. The Settlement Agreement is a comprehensive stipulation that took months to craft. It represents a compromise among a diverse set of Parties who were able to reach agreement through good-faith negotiations. The Settlement Agreement, in its complete from, produces an outcome that I believe is just, reasonable, and in the public interest. I strongly recommend that the Commission approve it in the form it has been submitted.

Q. Does this conclude your direct testimony on this matter?

A. Yes, it does.

Admitted

EXHIBIT

AECC / PD 2
FEA / K

RESPONSIVE / CLARIFYING TESTIMONY

AND EXHIBIT

OF KEVIN C. HIGGINS

On Behalf of Arizonans for Electric Choice and Competition,

Phelps Dodge Mining Corp., Federal Executive Agencies, and The Kroger Co.

Docket No. E-01345A-03-0437

October 25, 2004

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RESPONSIVE / CLARIFYING TESTIMONY
OF KEVIN C. HIGGINS

Introduction

Q. Please state your name and business address.

A. Kevin C. Higgins, 39 Market Street, Suite 200, Salt Lake City, Utah, 84101.

Q. By whom are you employed and in what capacity?

A. I am a Principal in the firm of Energy Strategies, LLC. Energy Strategies is a private consulting firm specializing in economic and policy analysis applicable to energy production, transportation, and consumption.

Q. Are you the same Kevin C. Higgins who previously provided direct and rebuttal testimony on behalf of Arizonans for Electric Choice and Competition ("AECC"), and subsequently provided direct testimony regarding the proposed Settlement Agreement on behalf of AECC, Phelps Dodge Mining Corp., Federal Executive Agencies, and The Kroger Co.?

A. Yes, I am.

Q. What is the purpose of your responsive testimony?

A. My responsive testimony addresses certain arguments in the direct testimony concerning the proposed Settlement Agreement that was pre-filed by Peter F. Chamberlain on behalf of Arizona Cogeneration Association ("AzCA").

Q. What conclusions and recommendations do you make in your responsive testimony?

A. The AzCA witnesses are advocating for policies that promote distributed generation. To that end, Mr. Chamberlain proposes rate design changes that would: (1) lower the cost of partial requirements service, which self-generators typically require for meeting their standby and supplemental energy needs; and (2) *raise* the power rates to the higher-load-factor retail customers who constitute the likely market for the cogeneration products AzCA is promoting.

A significant portion of Mr. Chamberlain's testimony is a critique of Rate E-32, and the companion Rate E-32R, which is an *optional* rate for partial requirements service. Mr. Chamberlain's testimony mischaracterizes the economic basis of Rate E-32, and the related Rates E-32R and E-32-TOU. Remarkably, Mr. Chamberlain's testimony contains no substantive discussion of Rate E-52, which is designed exclusively for partial requirements service. In addition, Mr. Chamberlain's testimony contains serious factual errors, as well as a number of irrelevant comparisons.

The rate components proposed for Rate E-32 are an integral part of the Settlement Agreement. Altering the E-32 rate design as suggested by Mr. Chamberlain would constitute an adverse material change for several parties to the Agreement. Furthermore, as a matter of public policy, it makes no sense to re-design a rate intended for thousands of *full* requirements customers in an attempt to address special design needs for a relative handful of *partial* requirements customers – when a rate designed specifically for partial requirements service is already available.

Mr. Chamberlain's recommendations to modify Rate E-32 should be rejected in their entirety.

APS rates for partial requirements service

Q. What is the basic criticism asserted by Mr. Chamberlain regarding APS rates for partial requirements service?

A. Mr. Chamberlain focuses his attention on rates for partial requirements service applicable to customers with demands below 3000 kW. In Table KCH-SR1 below, I list the rate schedules that are relevant to this discussion.

Table KCH-SR1
Selected APS Rate Schedules for General Service Customers below 3000 kW

Full Requirements Service	Partial Requirements Service
E-32	E-32R w/ E-32 basis
E-32-TOU	E-32R w/ E-32-TOU basis
	E-52

Note that APS customers actually have a *choice* of partial requirements rates under which they can take service. Despite this fact, Mr. Chamberlain chooses to focus on only one of these options: E-32R, with an E-32 basis. He appears to be unaware that partial requirements customers have the full range of choices shown in Table KCH-SR1.

Mr. Chamberlain testifies that Rate E-32R is not appropriate for partial requirements service. His criticism is centered primarily on the demand charge, a rate component that Mr. Chamberlain appears to oppose generally, but most particularly in the context of partial requirements service. A major theme in Mr. Chamberlain's testimony is his assertion that a customer taking service under Rate E-32 (or E-32R) has no economic incentive to shift load from peak to off-peak periods. He uses this conclusion to argue for dramatic changes to Rate E-32. While his recommendations are not very specific, it is clear that he supports a drastic reduction (or indeed elimination) of the demand-related rate elements in Rates E-32 (and E-32R), as well as an increase in the energy charges in the tailblock of Rate E-32.

Q. Is Mr. Chamberlain's critique valid?

A. No. Mr. Chamberlain's testimony mischaracterizes the economic basis of Rate E-32, as well as related Rates E-32R and E-32-TOU. He completely ignores certain options available to partial requirements customers, such as Rate E-32R with a time-of-use ("TOU") basis, and makes only a passing reference to Rate E-52, which is designed specifically for partial requirements service. In addition, Mr. Chamberlain's testimony contains a number of serious factual errors.

Q. How does Mr. Chamberlain mischaracterize the economic basis of Rates E-32, E-32-TOU, and E-32R?

A. Mr. Chamberlain states that "the rates developed for partial requirements customers are not based on the cost of providing the service to customers they purport to serve."[1] In making this claim, Mr. Chamberlain focuses solely on Rate E-32R, which is derived from Rate E-32. He launches an attack on the design of Rate E-32, a *full* requirements rate, but never addresses the rates or costs of the rate schedule designed exclusively for *partial* requirements service, Rate E-52.

[1] Direct testimony of Peter F. Chamberlain, p. 2, lines 23-24.

Mr. Chamberlain argues that the E-32 demand charge overstates the cost to serve partial requirements customers. By focusing on Rate E-32 in the context of partial requirements service, Mr. Chamberlain mischaracterizes the economic basis of the rate. Rate E-32 has over 78,000 full requirements customers on it. The demand-related charges in Rate E-32 are necessary for properly pricing the capacity-related costs of the APS system for these full requirements customers. These charges are critical for properly assigning fixed distribution, transmission, and generation costs to these thousands of customers, to ensure that they are appropriately charged for the costs they cause to be incurred. Indeed, the demand charge is a fundamental pricing component for non-residential electricity sales throughout the United States, with virtually universal application.

Mr. Chamberlain would turn rate design on its head by subordinating the design needs of Rate E-32 – and its 78,000 *full* requirements customers – in order to satisfy his objectives for *partial* requirements service. Meanwhile, he provides no substantive analysis of Rate E-52, which is designed exclusively for partial requirements service.

Q. Are there other ways in which Mr. Chamberlain mischaracterizes the economics of taking service under Rates E-32, E-32-TOU, and E-32R?

Yes. Mr. Chamberlain also states that the "rate structures proposed for partial requirements customers produce perverse incentives to increase on peak energy usage and do nothing to encourage (and may, in fact, penalize) load management efforts to shift load to off peak periods."[2]

This statement is simply incorrect. Mr. Chamberlain fails to consider that a partial requirements customer has the option of receiving service under Rate 32R with a time-of-use basis. Under this option, off-peak demand charges are significantly lower than on-peak charges. Moreover, off-peak demand charges do not have a ratchet provision; that is, if the customer incurs off-peak demand charges in a given month, it does not create a cost obligation to the customer for subsequent months, unlike demand charges incurred for on-peak periods. This is a significant incentive for a partial requirements customer to use the APS system during off-peak, rather than on-peak, periods.

It appears to me that Mr. Chamberlain is simply unaware of the TOU option for E-32R. This is revealed in his response to APS Data request 4-15, in which Mr. Chamberlain states: "Consider a 500 kw partial requirements customer taking service under E-32R. Should that customer experience an unplanned outage of its generation at 3 a.m. on a Sunday morning, he will be forced to pay charges as if he needed service at the hour of the system's monthly coincident peaks." For an E-32R customer taking service on a TOU basis, this statement is simply incorrect. The off-peak residual demand charge is $7.14 cheaper than the on-peak demand charge, and has no ratchet. Indeed, the off-peak generation component for E-32-TOU is only $0.25 per kW-month. In addition, the off-peak

[2] *Ibid.*, p. 2, lines 25-28.

charges for the energy required by this customer are $.01 per kWh less than during the on-peak period.

Mr. Chamberlain's characterization of the incentives and disincentives facing a partial requirements customer with respect to on-peak and off-peak usage is simply wrong. His recommendations pertaining to Rate E-32 should be rejected in their entirety.

<u>Other design issues pertaining to Rate E-32</u>

Q. On page 6 of his direct testimony, Mr. Chamberlain states that "an E-32 customer operating solely during off-peak hours with a peak load of 500 kw would pay the same total demand and non-fuel energy charges as a customer operating during only on-peak hours." Can you respond to this statement?

A. Mr. Chamberlain's reference to "non-fuel energy charges" is not entirely clear, as APS has no such charge. But the gist of Mr. Chamberlain's statement is an assertion that an E-32 customer with a peak demand of 500 kW, who operated solely during off-peak hours, would not see any rate savings relative to operating exclusively during on-peak hours.

Such an assertion is wrong. Under the terms of the Settlement Agreement, an E-32 customer is free to take service under E-32-TOU.[3] An E-32-TOU customer with a peak demand of 500 kW, who operated solely during off-peak hours, would save 40 percent on rates during the winter and 36 percent during the summer, relative to operating solely during on-peak hours under Rate E-32. This analysis is shown in Settlement Attachment KCH-SR1.

[3] Obviously, for an E-32 customer who does not elect TOU option, there is no difference between peak and off-peak pricing, as by definition the non-TOU version of Rate E-32 has no time-of-use features.

Q. On page 11 of his direct testimony. Mr. Chamberlain states that it is likely that the tailblock energy rate for Rate E-32 will not recover the actual variable fuel costs of generation. Can you respond to this statement?

A. Mr. Chamberlain's assertion is incorrect. The proposed energy tailblock rate for Rate E-32 is $.03182 per kWh during the winter and $.04175 during the summer. The base cost of APS fuel and purchased power established in the Settlement Agreement is $.020743 per kWh.[4] The winter tailblock rate for Rate E-32 is over 50 percent higher than APS' base energy cost, and the summer tailblock rate is more than double APS' base energy cost.

Mr. Chamberlain buttresses his argument with references to natural gas prices – in essence arguing that retail customers should pay the marginal cost of energy, as opposed to the traditional regulatory approach of average cost pricing. The issue of marginal versus average cost pricing in regulated monopolies has been extensively discussed in the regulatory literature. The upshot is that charging marginal cost for energy is almost certain to result in a mismatch between utility costs and revenues, and for this reason is seldom adopted by regulatory authorities.

Adopting Mr. Chamberlain's recommendation to raise the tailblock rate for E-32 customers would result in a significant increase in APS rates for higher-load factor customers, who incidentally, constitute the likely market for the cogeneration products AzCA is promoting. The economic harm to these customers is not inconsequential to the interests of cogeneration equipment vendors, as higher energy rates make gas-fired cogeneration equipment more competitive. The Commission should reject AzCA's attempt to create an undue pricing advantage for distributed generation by means of raising the APS rates of higher-load-factor customers.

Q. On page 6 of his direct testimony, Mr. Chamberlain states that Rate E-32 has been designed to take costs that have been "functionalized" as energy and make them "demand-based." Is this a correct characterization?

A. No. Generation costs have a significant demand (or capacity) component to them. But an examination of the unbundled components of proposed Rate E-32 shows that there is no separate demand charge for generation for this rate schedule. Instead, demand-related generation costs are collected in the initial energy block as a function of load factor, i.e., the first 200 kWh per kW. These costs are not being "re-functionalized" (or more properly, "re-classified") – they are demand-related at the outset, and they are being collected via a demand-related pricing mechanism. Ironically, it is Mr. Chamberlain who proposes to de-link cost classification from rate design: he wants costs that are properly classified as demand-related to be ignored in the design of the rate.

Q. On page 9 of his direct testimony, Mr. Chamberlain states that Rate E-32 collects transmission costs through a kW charge. Is this correct?

A. No. An examination of the unbundled rate for Schedule E-32 shows that under the Settlement Agreement, it is proposed that transmission costs be collected on a per-kWh basis, the opposite of what Mr. Chamberlain contends. Mr. Chamberlain's detailed depiction of how the APS retail tariff supposedly

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[4] Settlement Agreement, paragraph 31.

assigns transmission cost responsibility based on the highest fifteen minute period any time during the month is entirely incorrect.[5]

I also note that as part of Mr. Chamberlain's discussion of transmission costs, he makes numerous references to the proposed rate design for WestConnect, the proposed RTO. These references are not terribly relevant. WestConnect has not yet been implemented, and it is likely to be years before any WestConnect transmission rate design is ever in use. In addition, the WestConnect tariff is intended for wholesale transactions, whereas Rate E-32 is designed for retail service, and there are analytical hazards in attempting the kind of direct comparisons made by Mr. Chamberlain.

<u>Clarification pertaining to Rate E-32-TOU residual demand charge</u>

Q. Do you wish to make any clarifications with respect to the Rate E-32-TOU rate components in the proposed Settlement Agreement?

A. Yes. There is an omission in the rate table for Rate E-32-TOU, attached to the Settlement Agreement. The table should show a reduction in the delivery-related demand charge after the first 100 kW of load for residual off-peak demand. However, this reduction was inadvertently omitted. Instead of remaining at the initial level of $7.722 per kW-month (e.g., for secondary), the residual off-peak demand charge for delivery should step down exactly as occurs for on-peak hours, and for E-32 generally. Note also that the initial rate block for residual off-peak delivery will only apply to the first 100 kW of *combined* on-peak and residual off-peak load.

[5] Direct testimony of Peter F. Chamberlain, p. 10, lines 9-19.

Q. Does this conclude your responsive / clarifying testimony?

A. Yes, it does.

E-32 versus E-32 TOU Bill Comparison

for a 500kW customer under two different load characteristics

Scenario 1 - All usage on-peak @ E-32 rate

Ln #	Load Characteristics:		
1	Monthly Load On-Peak	500	kW
2	Monthly Load Off-Peak	0	kW
3	On-Peak Load Factor	70%	On-P LF
4	Off-Peak Load Factor	0%	Off-P LF
5	Load Factor	21%	LF
6	Monthly Demand	500	kW
7	Avg Monthly Usage	75,250	kWh
8	Avg Summer Monthly Usage	75,833	kWh
9	Avg Winter Monthly Usage	74,667	kWh

Demand Blocks		Rate
1) <=100 kW	100	7.722 $/kW
2) 100 < kW <500	400	3.497 $/kW
3) >500 kW	0	3.497 $/kW
Total	500	

Basic Service Charge - Instrument-Rated Meter	1.134 $/day

Usage Block	Value	Rate
Summer:		
1) <=200 kWh per kW	75,833	0.07938 $/kWh
2) All Additional kWh	0	0.04175 $/kWh
Total Avg Summer	75,833	
Winter:		
1) <=200 kWh per kW	74,667	0.06945 $/kWh
2) All Additional kWh	0	0.03182 $/kWh
Total Avg Winter	74,667	

Billing Summary:

Ln #		(A)	(B)	(C)	(D)	(E)
			E-32 Bundled			
			Base	CRCC	Franchise	Total
				kWhx$0.000338	[(B)+(C)]x0.0144	
10	Avg. Summer	Basic Service Charge	$34			
11		Demand Charges	$2,171			
12		Energy Charges	$6,020			
13		Total @ Secondary Voltage	$8,225	$26	$119	$8,369
14	Avg. Winter	Basic Service Charge	$34			
15		Demand Charges	$2,171			
16		Energy Charges	$5,186			
17		Total @ Secondary Voltage	$7,391	$25	$107	$7,523

Scenario 2 - All usage off-peak @ E-32 TOU rate

Ln #	Load Characteristics:		
18	Monthly Load On-Peak	0	kW
19	Monthly Load Off-Peak	500	kW
20	On-Peak Load Factor	0%	On-P LF
21	Off-Peak Load Factor	29%	Off-P LF
22	Load Factor	21%	LF
23	Monthly Demand	500	kW
24	Avg Monthly Usage	75,250	kWh
25	Avg Summer Monthly Usage	75,833	kWh
26	Avg Winter Monthly Usage	74,667	kWh
27			

TOU Demand Blocks	Value	Rate1
1) <=100 kW On-Peak	0	15.112 $/kW
2) 100 < kW <500 On-Peak	0	10.887 $/kW
3) >500 kW On-Peak	0	10.887 $/kW
Total	0	
First 100 Residual kW Off-Peak, if applicable	100	7.972 $/kW
Over 100 Residual kW Off-Peak, if applicable	400	3.747 $/kW
Total	500	

Basic Service Charge - Instrument-Rated Meter	1.134 $/day

Energy Usage	Value	Rate
Summer:		
Avg On-Peak kWh	0	0.04815 $/kWh
Avg Off-Peak kWh	75,833	0.03815 $/kWh
Winter:		
Avg On-Peak kWh	0	0.03822 $/kWh
Avg Off-Peak kWh	74,667	0.02822 $/kWh

Billing Summary:

Ln #		(A)	(B)	(C)	(D)	(E)
			E-32 TOU			
			Base	CRCC	Franchise	Total
				kWhx$0.000338	[(B)+(C)]x0.0144	
28	Avg. Summer	Basic Service Charge	$34			
29		Demand Charges	$2,296			
30		Energy Charges	$2,893			
31		Total @ Secondary Voltage	$5,223	$26	$76	$5,324
32	Avg. Winter	Basic Service Charge	$34			
33		Demand Charges	$2,296			
34		Energy Charges	$2,107			
35		Total @ Secondary Voltage	$4,437	$25	$64	$4,527

E-32 TOU Savings compared to E-32

	(F)	(G)
Avg. Summer	Amt ($)	Percent (%)
	$3,045	36%
Avg. Winter	Amt ($)	Percent (%)
	$2,996	40%

Note 1: E-32 TOU rates reflect a reduction in the delivery-related demand charge after the first 100 kW of combined on-peak and residual off-peak load as noted in testimony.

SUMMARY OF THE TESTIMONY OF

KEVIN C. HIGGINS

On Behalf of Arizonans for Electric Choice & Competition,

Phelps Dodge Mining Co., Federal Executive Agencies, and The Kroger Co.

Docket No. E-01345A-03-0437

November 3, 2004

EXHIBIT
AECC/PD/
FEA/K-3
Admitted

SUMMARY OF THE DIRECT TESTIMONY OF KEVIN C. HIGGINS

With respect to the Settlement Agreement that has been put forward to resolve the issues in this proceeding, I am testifying on behalf of Arizonans for Electric Choice and Competition ("AECC"), Phelps Dodge Mining Company ("Phelps Dodge"), Federal Executive Agencies ("FEA"), and The Kroger Co. ("Kroger"). AECC, Phelps Dodge, FEA, and Kroger represent retail customer interests in the General Service class. AECC, FEA, and Kroger put forward separate cases in the initial phase of this proceeding, but have elected to consolidate their testimony as it pertains to the Settlement Agreement. Each of these parties supports and has signed the Settlement Agreement.

I am testifying in support of the Settlement Agreement as proposed by the Stipulating Parties on August 18, 2004.

In my opinion, the Settlement Agreement, taken as a whole, produces rates, terms, conditions, and policies that are just and reasonable. Because of the complex tradeoffs among multiple issues and multiple parties, it is essential that the Settlement Agreement be viewed as a total package. The Stipulating Parties have each made concessions in reliance on the advancement of the complete Agreement as negotiated. I strongly recommend adoption of the Settlement Agreement in the form presented by the Parties, as any alterations to the package are highly likely to deprive some Parties of the benefits of their bargains.

Revenue requirements

Paragraph 1 of the Settlement Agreement provides that APS will receive a rate increase of $75.5 million, of which $67.5 million is in base rates and $8 million is in the Competition Rules Compliance Charge ("CRCC"). This translates into an average base rate increase of 3.77 percent, plus .44 percent for the CRCC.

The Settlement Agreement reduces the initial overall increase requested by APS by approximately 57 percent.

In my initial direct testimony, I recommended adjustments that reduced APS' proposed increase of $175 million by approximately $150 million. One of these adjustments – denial of the reversal of the $234 million write-down – is explicitly incorporated into the Settlement results.

Another adjustment I had recommended – denial of including certain PWEC assets in APS rate base – was resolved through a compromise that allows these units into rate base, but at a lesser value than was initially sought by APS. The compromise on this issue explains much of the difference in the revenue requirements recommended in my initial testimony and the Settlement result.

Rate spread/EPS surcharge rate design

Section XIX of the Settlement Agreement identifies rate increases for the various rate schedules. The Residential class as a whole would see a base rate increase of 3.94 percent. Schedules E-32, E-32R, E-34, E-35, E-53, E-54 – which are in the General Service class – and certain contracts would each experience base rate increases of 3.5 percent.

As AECC, FEA, and Kroger discussed in their initial direct testimony, the APS General Service class is paying rates that subsidize all of the other customer classes. In this situation, it is appropriate for the General Service class to experience a less-than-average increase, and for classes being subsidized to experience a greater-than-average increase. The rate spread in the Settlement Agreement takes a very modest step in the direction of reducing cross-subsidies by moving rates in the direction of cost-of-service.

In their respective initial testimonies, AECC, FEA, and Kroger recommended a greater movement toward cost-of-service parity than is provided in the Settlement Agreement. These parties have accepted the Settlement rate spread in light of other considerations in the Settlement Agreement, including, in particular, the Environmental Portfolio Standard ("EPS") surcharge rate design.

Section VIII of the Settlement Agreement addresses the EPS surcharge. Paragraph 63 in that section states, in part:

> If the Commission amends the EPS surcharge set forth in Rule 1618 or approves additional EPS funding pursuant to paragraph 64 of this Agreement, *any change in EPS funding requirements resulting from such actions shall be collected from APS' customers in a manner that maintains the proportions between customer categories embodied in the current EPS surcharge.* [Emphasis added.]

As laid out in Paragraph 63, the Settlement Agreement establishes rate design parameters for the EPS surcharge. The Settlement Agreement does *not* cap the total funding of the EPS program, nor does it require retention of the current caps if EPS funding is increased from current levels. However, Paragraph 63 does require that changes in EPS funding levels be collected in a manner that maintains the proportions between customer categories embodied in the current EPS surcharge. In other words, if the EPS funding is increased from current levels, the most straightforward means of collecting the increased revenues consistent with the Settlement would be to increase all EPS surcharge rate elements proportionally – the per-kWh charge plus each category of cap.

Maintaining the proportionality of the current EPS surcharge among the three categories of customers is a key provision of the Settlement Agreement for AECC, Phelps Dodge, FEA, and Kroger. The presence of this provision in the Agreement, among others, makes it possible for these General Service parties to accept the Settlement Agreement's rate spread provisions.

Rate design (pertaining to base rates)

The Settlement Agreement provides for rates that are differentiated according to the voltage at which each customer takes service. The Settlement Agreement adopts the basic approach proposed by APS in its Application, with some modifications. AECC, FEA, and Kroger each supported APS' general approach to voltage differentiation (with selected modifications) in previously-filed direct testimony. The Settlement Agreement's incorporation of this distinction in this proceeding is consistent with the general approach adopted in the vast majority of utility tariffs across the country.

The Settlement Agreement modifies APS' initial proposal to recognize two additional facts concerning the costs on the APS system, which were addressed in the initial direct testimonies of AECC, FEA, and Kroger:

(1) Paragraph 120 recognizes that military base customers served directly from an APS substation will not be charged for the cost of APS' primary line and secondary distribution investments, and establishes a cost-based voltage discount applicable to military base customers with this service configuration; and

(2) The rate design of Schedule E-32 recognizes that customers with demands of 100 kW and greater do not utilize APS' secondary feeders. This cost-of-service consideration is recognized in the design of the E-32 demand charge in the Settlement Agreement.

The Settlement Agreement also adopts the basic approach to unbundling each schedule's rate components that APS proposed in its Application – an approach that AECC, FEA, and Kroger supported in their initial direct testimonies. Separating individual rate components by function, such as generation, transmission, and distribution, is required by the Electric Competition Rules, and will provide better information to customers. It will make the process of evaluating direct access opportunities more transparent for customers who wish to do so.

Specific rates for Schedules E-32, E-34, and E-35 are included in Appendix J of the Settlement Agreement. Whereas the Settlement Agreement summarizes the design objectives negotiated by the parties, it is the negotiated rates themselves, as they appear in Appendix J, that constitute the ultimate basis in reaching agreement for AECC, Phelps Dodge, FEA, and Kroger. Each element of these rate designs was the subject of negotiation over an extended period of time. The relationship between demand and energy charges, the designation of rate blocks, the differentiation of rates by voltage, the demarcation of unbundled components – in short, every component of the General Service rates in Appendix J – is an integral part of the Settlement Agreement and was of material interest in reaching settlement to at least one of the signatory Parties.

As Paragraph 121 states, Schedule E-32 was modified in an effort to simplify the design, to make it more cost-based, and to smooth out the rate impact across customers of varying sizes within the rate schedule. The E-32 rate design in the Settlement Agreement is vastly improved relative to the design in the current tariff.

In particular, the Settlement Agreement's treatment of Schedule E-32 strikes a proper balance between demand and energy charges. In a system such as APS', in which new distribution infrastructure and new generation resources must be added to meet a growing system peak, it is critical on grounds of both fairness and efficiency to levy a demand charge that sufficiently places cost responsibility on those customers responsible for the costs incurred in meeting the system peak. The demand charge performs this function. Failure to properly weight demand cost responsibility would cause an improper subsidy among the customers within the E-32 rate schedule, which would result in higher-load-factor customers subsidizing the peak-related costs caused by lower-load-factor customers. The Settlement Agreement achieves a proper balancing of costs through the setting of the demand and energy charges.

In addition, the Settlement Agreement provides for an optional time-of-use rate that is open to all E-32 customers, increasing the pricing options available to customers on this rate schedule. I offer a clarification regarding some omitted information regarding this rate in my responsive / clarifying testimony.

In addition to the general design issues discussed above, Paragraph 118 of the Settlement Agreement retains the existing 11:00 AM to 9:00 PM on-peak time periods in the current tariff. In its initial Application, APS had proposed to modify the definition of this time period, by starting the on-peak period two hours earlier each day. The proposed change would have caused unintended problems for E-35 customers that have adapted their business operations to meet the terms of the existing definitions in the tariff. The Settlement Agreement averts this problem.

<u>Demand-Side Management</u>

Paragraph 43 establishes a DSM adjustment mechanism for any approved DSM expenditures in excess of the $10 million base rate DSM allowance. General Service customers that are demand-billed will pay a per-kW charge instead of a per kWh charge. This allocation *within* the General Service class does not impact the allocation *across* classes, which is performed on a per-kWh basis.

Paragraph 55 provides a forum for evaluating the merit of self-direction, which I believe is an important component of any mandatory DSM funding.

<u>Direct access service</u>

The Settlement Agreement makes no changes to direct access service. Paragraph 82 of the Agreement states that changes to retail access shall be addressed through the Electric Competition Advisory Group or other similar process.

APS has agreed to forego any present or future stranded cost claims on the PWEC assets coming into rate base. This provision prevents direct access service from being undercut by a future stranded cost claim resulting from the Settlement Agreement's inclusion of these assets in rate base.

SUMMARY OF THE RESPONSIVE / CLARIFYING TESTIMONY OF KEVIN C. HIGGINS

My responsive testimony addresses certain arguments in the direct testimony concerning the proposed Settlement Agreement that was pre-filed by Peter F. Chamberlain on behalf of Arizona Cogeneration Association ("AzCA").

A significant portion of Mr. Chamberlain's testimony is a critique of Rate E-32, and the companion Rate E-32R, which is an *optional* rate for partial requirements service. Mr. Chamberlain's testimony mischaracterizes the economic basis of Rate E-32, and the related Rates E-32R and E-32-TOU. Notably, Mr. Chamberlain's testimony contains no substantive discussion of Rate E-52, which is designed exclusively for partial requirements service. In addition, Mr. Chamberlain's testimony contains serious factual errors, as well as a number of irrelevant comparisons.

Among the factual errors in Mr. Chamberlains testimony is his claim that rate structures proposed for partial requirements customers produce perverse incentives to <u>increase</u> on peak energy usage and do nothing to encourage (and may, in fact, penalize) load management efforts to shift load to off peak periods. It appears to me that Mr. Chamberlain is simply unaware of the TOU option for E-32R. I demonstrate in my testimony that this statement is simply incorrect.

Mr. Chamberlain also claims that it is likely that the tailblock energy rate for Rate E-32 will not recover the actual variable fuel costs of generation. This assertion is also incorrect. The proposed energy tailblock rate for Rate E-32 is $.03182 per kWh during the winter and $.04175 during the summer. The base cost of APS fuel and purchased power established in the Settlement Agreement is $.020743 per kWh. The winter tailblock rate for Rate E-32 is over 50 percent higher than APS' base energy cost, and the summer tailblock rate is more than double APS' base energy cost.

Mr. Chamberlain also states that Rate E-32 collects transmission costs through a kW charge. This claim is also incorrect. An examination of the unbundled rate for Schedule E-32 shows that under the Settlement Agreement, it is proposed that transmission costs be collected on a per-kWh basis, the opposite of what Mr. Chamberlain contends.

The rate components proposed for Rate E-32 are an integral part of the Settlement Agreement. Altering the E-32 rate design as suggested by Mr. Chamberlain would constitute an adverse material change for several parties to the Agreement. Furthermore, as a matter of public policy, it makes no sense to re-design a rate intended for 78,000 *full* requirements customers in an attempt to address special design needs for a relative handful of *partial* requirements customers – when a rate designed specifically for partial requirements service is already available. Mr. Chamberlain's recommendations to modify Rate E-32 should be rejected in their entirety.

In my clarifying testimony I point out that there is an omission in the rate table for Rate E-32-TOU, attached to the Settlement Agreement. The table should show a reduction in the delivery-related demand charge after the first 100 kW of load for residual off-peak demand. However, this reduction was inadvertently omitted. Instead of remaining at the initial level of $7.722 per kW-month (e.g., for secondary), the residual off-peak demand charge for delivery should step down exactly as occurs for on-peak hours, and for E-32 generally. The initial rate block for residual off-peak delivery will only apply to the first 100 kW of *combined* on-peak and residual off-peak load.

APS-1

EXHIBIT
APS-1
admitted

NEW APPLICATION

RECEIVED

BEFORE THE ARIZONA CORPORATION COMMISSION

2003 JUN 27 P 3: 44

AZ CORP COMMISSION
DOCUMENT CONTROL

COMMISSIONERS

MARC SPITZER, Chairman
JIM IRVIN
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
MIKE GLEASON

E-01345A-03-0437

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND FOR APPROVAL OF PURCHASED POWER CONTRACT	DOCKET NO. E-01345A-03-0437 **APPLICATION**

Pursuant to A.R.S. § 40-250, *et seq.*; A.A.C. R14-2-103; and Decision No. 61973 (October 6, 1999), Arizona Public Service Company ("APS" or "Company") hereby files an Application for a permanent increase of at least $175 million on annualized test year sales, or 9.8 percent on average, for its jurisdictional electric operations, to become effective on July 1, 2004.

The rate increase sought herein is required to enable the Company to maintain its credit ratings and attract new capital on reasonable terms, recover its costs of service, and permit APS to earn a fair rate of return on the fair value of its assets devoted to public service, which return will recover the Company's capital costs necessarily and prudently incurred in rendering adequate utility service to customers. The requested increase is necessary for APS to continue as the type of financially strong utility that can ensure APS customers continued reliable service, on demand, and at reasonable prices into the future.

APS is requesting that the Arizona Corporation Commission ("Commission") recognize the higher fuel and purchased power expenses that are being incurred by the Company; allow APS to include in rates at cost of service certain generation assets of Pinnacle West Energy Corporation ("PWEC");[1] permit APS to recover the $234 million write off taken under the 1999 Settlement Agreement, which was approved in Decision No. 61973; and provide for the recovery of all prudently incurred costs to comply with the Commission's Retail Electric Competition Rules, A.A.C. R14-2-1601, *et seq*. (the "Electric Competition Rules"), including the one-third of costs associated with the planned divestiture of generation from APS to PWEC that was not previously deferred pursuant to Decision No. 61973. Such amounts are included in the $175 million increase requested by this Application.

In addition, APS requests that the Commission approve depreciation and amortization rates and classifications for certain of the Company's tangible and intangible property and approve a specific accounting and ratemaking treatment of costs associated with asset retirement obligations under the recently implemented Statement of Financial Accounting Standards No. 143 ("SFAS 143").

Finally, APS is requesting Commission review of its long-term purchased power contract with PWEC, which was previously submitted to the Commission. This request is required by Section 5.3 of such contract. However, the need for such review and any subsequent Commission approval would be moot if the PWEC units are rate based as requested in this Application.

In support of this Application, the Company respectfully states as follows:

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[1] These units are Redhawk Combined Cycle Units 1 and 2, West Phoenix Combined Cycle Units 4 and 5, and Saguaro Combustion Turbine Unit 3 (collectively, the "PWEC Units").

I.

The Company is a corporation duly organized, existing and in good standing under the laws of the State of Arizona. Its principal place of business is 400 North Fifth Street, Phoenix, Arizona, 85004, and its post office address is P.O. Box 53999, Phoenix, Arizona 85072-3999.

II.

The Company is a public service corporation principally engaged in the generation, transmission and distribution of electricity for sale in Arizona. In conducting such business, the Company operates an interconnected and integrated electric utility system.

III.

All communications and correspondence concerning this Application, as well as communications and pleadings with respect thereto filed by other parties, should be served upon the following:

Thomas L. Mumaw
Karilee S. Ramaley
Pinnacle West Capital Corporation Law Department
P.O. Box 53999
Phoenix, Arizona 85072-3999
Attorneys for Arizona Public Service Company

Jeffrey B. Guldner
Faraz Sanei
Snell & Wilmer L.L.P.
400 East Van Buren
Phoenix, Arizona 85004-2202
Attorneys for Arizona Public Service Company

IV.

This Commission has jurisdiction to conduct public hearings to determine the fair value of the property of a public service corporation, to fix a just and reasonable rate of return thereon, and thereafter, to approve rate schedules designed to develop such return.

Further, the Commission has jurisdiction to establish the practices and procedures to govern the conduct of such hearing, including, but not limited to, such matters as notice, intervention, filing, service, exhibits, discovery and other prehearing and hearing matters.

V.

Accompanying this Application are all of the relevant standard filing requirements ("SFRs") and rate design schedules described in A.A.C. R14-2-103[2] and the direct testimony and attachments of the following witnesses:

- Steven M. Wheeler
- Donald G. Robinson
- Ajit P. Bhatti
- Chris N. Froggatt
- Laura L. Rockenberger
- Charles E. Olson, Ph.D.
- William H. Hieronymus, Ph.D.
- John H. Landon, Ph.D.
- Alan Propper
- David J. Rumolo
- Kenneth Gordon, Ph.D.

VI.

The Company respectfully requests that this Commission set a date for a hearing on this Application such that new rates for the Company will become effective July 1, 2004. At the hearing conducted pursuant to this rate request, APS will establish and hereby alleges that:

(1) its current rates and charges do not permit the Company to earn a fair return on the fair value of its assets devoted to public service and are therefore no longer just and reasonable;

[2] This Application does not include SFR Schedule E-6 because such schedule applies only to a "combination utility" within the meaning of A.A.C. R14-2-103(A)(3)(q) which does not include APS.

(2) the requested increase is the minimum amount necessary to allow the Company an opportunity to earn a fair return on the fair value of its assets devoted to public service, for preservation of the Company's financial integrity and for the attraction of new capital investment on reasonable terms;

(3) the Company requires additional permanent revenue of at least $175 million based on annualized test period sales in order to continue to provide adequate and reliable electric service to its customers as required by law;

(4) the PWEC Units were prudently planned and constructed and are used and useful, and the acquisition of the PWEC Units and their inclusion in rates at cost of service is appropriate and in the best interests of APS customers;

(5) the recovery by APS of the $234 million write off taken pursuant to Decision No. 61973 and the recovery by APS of all prudently incurred costs to comply with the Commission's Electric Competition Rules, including the one-third of costs associated with the planned divestiture of generation from APS to PWEC that was not previously deferred pursuant to Decision No. 61973, is appropriate and warranted;

(6) Section 3.4 of the APS-PWEC Track B contract[3] requires APS to file an application for approval and full cost recovery within 60 days of contract execution because deliveries are contemplated to occur after January 1, 2006; to the extent that further action by APS is required, this Application constitutes such action as is required by Section 3.4 of

[3] This contract was submitted to the Commission in APS' May 27, 2003 Report on the Track B Solicitation Process and is discussed in the Independent Monitor's Final Report on Track B Solicitation filed on June 13, 2003.

the contract, and APS requests that any Commission order regarding such contract be consistent with the Company's rate application; and

(7) the requested increase and associated approvals fairly balance the interests of both APS' customers and its investors.

WHEREFORE, THE COMPANY RESPECTFULLY REQUESTS that the Commission:

A. Issue a procedural order establishing a date for hearing evidence concerning the Application and prescribing the time and form of notice to APS customers;

B. Issue a final order granting the Company the permanent rate increase sought herein;

C. Issue a final order authorizing APS' depreciation and amortization rates and classifications, and authorizing the requested treatment of asset retirement obligations resulting from SFAS 143; and

D. Grant the Company such other relief as the Commission deems just and proper.

RESPECTFULLY SUBMITTED this 27th day of June 2003.

PINNACLE WEST CAPITAL CORP.
Law Department
Thomas L. Mumaw
Thomas L. Mumaw
Karilee S. Ramaley

SNELL & WILMER L.L.P.
Jeffrey B. Guldner
Faraz Sanei

Attorneys for Arizona Public Service Company

ORIGINAL AND 13 COPIES OF THE FOREGOING filed this 27th day of June 2003, with:

Docket Control
Arizona Corporation Commission
1200 West Washington
PHOENIX, AZ 85007

1367385.1

REVISED
B-1 & G-1
FILED
7/14/03

Jana Van Ness
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Regulatory Compliance

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Mail Station 9908
P.O. Box 53999
Phoenix, AZ 85072-3999

July 14, 2003

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

RE: Arizona Public Service Company's Application for General Rate Increase
Docket No. E-01345A-03-0437

To Whom It May Concern:

At the request of Arizona Corporation Commission (Commission) Staff, Arizona Public Service Company (APS) hereby submits Revised Schedules B-1 and G-7 (page 4 of 4) of the Commission's Standard Filing Requirements (SFR). The changes to Schedule B-1 are format changes only and do not change the substance of either that Schedule or the balance of the SFRs. The changes to Schedule G-7 affect only lines 17, 18 and 23. They do not impact the APS cost-of-service study or any other of the SFRs.

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

Sincerely,

Jana Van Ness

Jana Van Ness
Manager
Regulatory Compliance

JVN/vld

Docket Control (Original + 13 copies)

ARIZONA PUBLIC SERVICE COMPANY
Summary of Original Cost and RCND Rate Base Elements
Total Company and ACC Jurisdictional
Test Year Ended 12/31/2002
(Dollars in Thousands)

		Original Cost						
		Total Company			ACC			
Line No.	Description	Unadjusted Test Year (a)	Pro Forma (a)	Adjusted Test Year (a)	Unadjusted Test Year (b)	Pro Forma (b)	Adjusted Test Year (b)	Line No.
1.	Gross Utility Plant in Service	$ 8,486,874	$ (242,704)	$ 8,244,170	$ 8,203,305	$ 13,895	$ 8,217,200	1.
2.	Less: Accumulated Depreciation & Amort.	3,542,547	(426,560)	3,115,987	3,405,509	(307,558)	3,097,951	2.
3.	Net Utility Plant in Service	4,944,327	183,856	5,128,183	4,797,796	321,453	5,119,249	3.
	Deductions:							
4.	Deferred Taxes	1,292,375	(9,553)	1,282,822	1,268,546	12,698	1,281,244	4.
5.	Investment Tax Credits	4,040	-	4,040	4,033	-	4,033	5.
6.	Customer Advances for Constr.	45,513	-	45,513	45,513	-	45,513	6.
7.	Customer Deposits	39,865	-	39,865	39,865	-	39,865	7.
8.	Pension Liability	49,511	-	49,511	48,751	-	48,751	8.
9.	Other Deferred Credits	124,050	-	124,050	123,798	-	123,798	9.
10.	Unamortized Gain-sale of Utility Plant	59,484	-	59,484	59,381	-	59,381	10.
11.	Total Deductions	1,614,838	(9,553)	1,605,285	1,589,887	12,698	1,602,585	11.
	Additions:							
12.	Regulatory Assets/Liabilities Net	166,268	134,321	300,589	165,564	134,258	299,822	12.
13.	Miscellaneous Deferred Debits	27,379	-	27,379	26,959	-	26,959	13.
14.	Depreciation Fund - Decommissioning	194,440	-	194,440	191,608	-	191,608	14.
15.	Allowance for Working Capital (c)	175,713	-	175,713	172,423	-	172,423	15.
16.	Total Additions	563,800	134,321	698,121	556,554	134,258	690,812	16.
17.	Total Rate Base	$ 3,893,289	$ 327,730	$ 4,221,019	$ 3,764,463	$ 443,013	$ 4,207,476 (d)	17.

Supporting Schedules:
(a) B-2
(b) B-3
(c) B-5

Recap Schedules:
(d) A-1

ARIZONA PUBLIC SERVICE COMPANY
Summary of Original Cost and RCND Rate Base Elements
Total Company and ACC Jurisdictional
Test Year Ended 12/31/2002
(Dollars in Thousands)

		RCND						
		Total Company			ACC			
Line No.	Description	Unadjusted Test Year (a)	Pro Forma (a)	Adjusted Test Year (a)	Unadjusted Test Year (b)	Pro Forma (b)	Adjusted Test Year (b)	Line No.
1.	Gross Utility Plant in Service	$ 13,596,926	$ (994,763)	$ 12,602,163	$ 13,142,617	$ (581,418)	$ 12,561,199	1.
2.	Less: Accumulated Depreciation & Amort.	5,677,664	(726,993)	4,950,671	5,458,032	(536,061)	4,921,971	2.
3.	Net Utility Plant in Service	7,919,262	(267,770)	7,651,492	7,684,585	(45,357)	7,639,228	3.
	Deductions:							
4.	Deferred Taxes	1,292,375	(9,553)	1,282,822	1,268,546	12,698	1,281,244	4.
5.	Investment Tax Credits	4,040	-	4,040	4,033	-	4,033	5.
6.	Customer Advances for Constr.	45,513	-	45,513	45,513	-	45,513	6.
7.	Customer Deposits	39,865	-	39,865	39,865	-	39,865	7.
8.	Pension Liability	49,511	-	49,511	48,751	-	48,751	8.
9.	Other Deferred Credits	124,050	-	124,050	123,798	-	123,798	9.
10.	Unamortized Gain-sale of Utility Plant	59,484	-	59,484	59,381	-	59,381	10.
11.	Total Deductions	1,614,838	(9,553)	1,605,285	1,589,887	12,698	1,602,585	11.
	Additions:							
12.	Regulatory Assets/Liabilities Net	166,268	134,321	300,589	165,564	134,258	299,822	12.
13.	Miscellaneous Deferred Debits	27,379	-	27,379	26,959	-	26,959	13.
14.	Depreciation Fund - Decommissioning	194,440	-	194,440	191,608	-	191,608	14.
15.	Allowance for Working Capital (c)	175,713	-	175,713	172,423	-	172,423	15.
16.	Total Additions	563,800	134,321	698,121	556,554	134,258	690,812	16.
17.	Total Rate Base	$ 6,868,224	$ (123,896)	$ 6,744,328	$ 6,651,252	$ 76,203	$ 6,727,455 (d)	17.

Supporting Schedules:
(a) B-2
(b) B-3
(c) B-5

Recap Schedules:
(d) A-1

ARIZONA PUBLIC S[illegible]E COMPANY
Cost of Service Study
Development of Allocation Factors
Adjusted Test Year Ending December 31, 2002

Factor	Definition and Application of Allocation Factor	General Service	Small General Service	Medium General Service	Large General Service	Extra-Large General Service	Residential	Residential E-10	Residential E-12	Residential EC-1	Residential ET-1	Residential ECT-1
16. DEMDIST7	Individual Maximum Demand @ Secondary TXF Level w/losses (KW)	3,056,779	1,300,052	1,363,985	257,332	135,410	5,938,353	553,239	2,103,504	231,787	2,557,185	492,638
	Distribution UG Line Transformers	33.82%	14.38%	15.09%	2.85%	1.50%	65.69%	6.12%	23.27%	2.56%	28.29%	5.45%
17. CUSTOH1	Weighted Customer Costs for Distribution Services ($)	43,430	39,828	3,602	0	0	404,336	46,279	188,197	12,234	136,454	21,172
	Distribution OH Services	9.69%	8.88%	0.80%	0.00%	0.00%	90.17%	10.32%	41.97%	2.73%	30.43%	4.72%
18. CUSTUG1	Weighted Customer Costs for Distribution Services ($)	40,878	33,450	4,064	2,828	536	415,485	47,555	193,386	12,572	140,216	21,756
	Distribution UG Services	8.96%	7.33%	0.89%	0.62%	0.12%	91.04%	10.42%	42.38%	2.75%	30.72%	4.77%
19. DEMDIST10	NCP Demand @ Primary Line Level w/losses (KW)	2,596,964	950,468	1,157,321	270,617	218,558	3,257,955	299,996	946,125	152,894	1,519,427	339,513
	Distribution Rents	43.76%	16.02%	19.50%	4.56%	3.68%	54.90%	5.05%	15.94%	2.58%	25.60%	5.72%
20. ENERGY1	Customer Class Energy @ Generation (MWH)	13,391,465	3,766,696	5,288,514	1,754,953	2,581,302	11,215,488	1,020,291	3,356,182	635,131	4,917,386	1,286,498
	Production - Energy	53.22%	14.97%	21.02%	6.97%	10.26%	44.57%	4.05%	13.34%	2.52%	19.54%	5.11%
21. ENERGY2	Customer Class Energy @ Generation (MWH)	13,391,465	3,766,696	5,288,514	1,754,953	2,581,302	11,215,488	1,020,291	3,356,182	635,131	4,917,386	1,286,498
	Production - Energy (Fuel and Purchase Power)	53.22%	14.97%	21.02%	6.97%	10.26%	44.57%	4.05%	13.34%	2.52%	19.54%	5.11%
22. ENERGY4	Customer Class Energy @ Generation (MWH)	13,391,465	3,766,696	5,288,514	1,754,953	2,581,302	11,215,488	1,020,291	3,356,182	635,131	4,917,386	1,286,498
	Production - Energy - Ancillary Service - Must Run	53.22%	14.97%	21.02%	6.97%	10.26%	44.57%	4.05%	13.34%	2.52%	19.54%	5.11%
23. CUST370	Weighted Costs for Distribution Meters ($)	298,900	259,684	32,608	3,818	2,790	819,821	62,460	254,001	36,255	404,364	62,741
	Distribution Meters	26.39%	22.93%	2.88%	0.34%	0.25%	72.38%	5.51%	22.42%	3.20%	35.70%	5.54%
24. CUST371	Dusk to Dawn Customer Class Specific	0	0	0	0	0	0	0	0	0	0	0
	Dusk to Dawn	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
25. CUST373	Street Lighting Customer Class Specific	0	0	0	0	0	0	0	0	0	0	0
	Street Lighting	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
26. CUSTNUM	Number of Customer Accounts	100,134	95,717	4,112	244	61	819,821	93,834	381,583	24,806	276,670	42,928
	Customer Accounts	10.76%	10.29%	0.44%	0.03%	0.01%	88.12%	10.09%	41.01%	2.67%	29.74%	4.61%
27. CUST910	Number of Customer Accounts	100,134	95,717	4,112	244	61	819,821	93,834	381,583	24,806	276,670	42,928
	Customer Service and Information	10.78%	10.30%	0.44%	0.03%	0.01%	88.25%	10.10%	41.07%	2.67%	29.78%	4.62%
28. CUST916	Number of Customer Accounts	100,134	95,717	4,112	244	61	819,821	93,834	381,583	24,806	276,670	42,928
	Sales Expense	10.76%	10.29%	0.44%	0.03%	0.01%	88.12%	10.09%	41.01%	2.67%	29.74%	4.61%
29. DEMREGAST	4-CP Demand @ Generation (KW)	2,451,981	828,460	994,764	285,615	343,142	2,642,653	232,966	766,305	141,521	1,240,307	261,554
	Regulatory Asset - Demand Related	47.97%	16.21%	19.46%	5.59%	6.71%	51.70%	4.56%	14.99%	2.77%	24.26%	5.12%
30. ERGREGAST	Customer Class Energy @ Generation (MWH)	13,391,465	3,766,696	5,288,514	1,754,953	2,581,302	11,215,488	1,020,291	3,356,182	635,131	4,917,386	1,286,498
	Regulatory Asset - Energy Related	53.22%	14.97%	21.02%	6.97%	10.26%	44.57%	4.05%	13.34%	2.52%	19.54%	5.11%
31. ERGSYSBEN	Customer Class Energy @ Generation (MWH)	13,391,465	3,766,696	5,288,514	1,754,953	2,581,302	11,215,488	1,020,291	3,356,182	635,131	4,917,386	1,286,498
	System Benefits - Energy Related	53.22%	14.97%	21.02%	6.97%	10.26%	44.57%	4.05%	13.34%	2.52%	19.54%	5.11%

Jana Van Ness
Manager
Regulatory Compliance

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Mail Station 9908
P.O. Box 53999
Phoenix, AZ 85072-3999

July 14, 2003

Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

RE: Arizona Public Service Company's Application for General Rate Increase
Docket No. E-01345A-03-0437

To Whom It May Concern:

Arizona Public Service Company (APS) is hereby providing revised copies of Schedules B-1 and G-7 (page 4 of 4) of the Arizona Corporation Commission's Standard Filing Requirement (SFR) schedules to those who have requested them. The changes to Schedule B-1 are format changes only and do not change the substance of either that Schedule or the balance of the SFRs. The changes to Schedule G-7 (page 4 of 4) affect only lines 17, 18 and 23. They do not impact the APS cost-of-service study or any other of the SFRs. The SFR discs provided originally should be replaced with these revised discs.

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

Sincerely,

Jana Van Ness

Jana Van Ness
Manager
Regulatory Compliance

JVN/vld

Attachment

SCHEDULES

A-1

ARIZONA PUBLIC SERVICE COMPANY
Computation of Increase in Gross Revenue Requirements
ACC Jurisdictional
Adjusted Test Year Ended 12/31/2002
(Dollars in Thousands)

Line No.	Description	Electric: Original Cost	RCND	Fair Value	Line No.
1.	Adjusted Rate Base	$ 4,207,476 (a)	$ 6,727,455 (a)	5,467,466	1.
2.	Adjusted Operating Income	263,870 (b)	263,870 (b)	263,870	2.
3.	Current Rate of Return	6.27%	3.92%	4.83%	3.
4.	Required Operating Income	364,788	364,788	364,788	4.
5.	Required Rate of Return	8.67%	5.42%	6.67%	5.
6.	Operating Income Deficiency	100,918	100,918	100,918	6.
7.	Gross Revenue Conversion Factor	1.6529 (c)	1.6529 (c)	1.6529 (c)	7.
8.	Increase in Base Revenue Requirements	$ 166,807	$ 166,807	$ 166,807	8.
9.	CRCC Surcharge (d)	8,283	8,283	8,283	9.
10.	Total Increase in Revenue Requirements	$ 175,090	$ 175,090	$ 175,090	10.

Line No.	Customer Classification	Projected Revenue Increase Due to Rates	% Increase	Line No.
11.	Residential	86,586	9.73%	11.
12.	General Service	86,758	9.82%	12.
13.	Irrigation	207	9.86%	13.
14.	Outdoor Lighting	1,041	9.64%	14.
15.	Dusk-to-Dawn	498	9.58%	15.
16.	Total	$ 175,090	9.77%	16.
17.	Total Sales to Ultimate Retail Customers	$ 1,791,584 (d)		17.

Supporting Schedules
(a) B-1 (c) C-3
(b) C-1, page 2 (d) H-1

A-2

ARIZONA PUBLIC SERVICE COMPANY
Summary Results of Operations
Two Prior Years, Test Year and Projected Years
(Thousands of Dollars)

Line No.	Description	Prior Years Year Ending 2000 (a)	Prior Years Year Ending 2001 (a)	Test Year Actual 12/31/2002 (a)	Test Year Adjusted 12/31/2002 (b)	Projected Year Present Rates 12/31/2003 (c)	Projected Year Present Rates 12/31/2004 (c)	Projected Year Proposed Rates 12/31/2004 (c)	Projected Year Present Rates 12/31/2005 (c)	Projected Year Proposed Rates 12/31/2005 (c)	Line No.
1.	Gross Revenues	$ 2,934,142	$ 3,111,328	$ 2,093,393	$ 1,978,176	$ 1,969,996	$ 2,148,301	$ 2,263,598	$ 2,205,210	$ 2,405,450	1.
2.	Revenue Deductions & Operating Expenses	2,487,906	2,712,350	1,764,393	1,713,172	1,667,927	1,798,414	1,837,180	1,872,584	1,954,397	2.
3.	Operating Income	446,236	398,978	329,000	265,004	302,069	349,887	426,418	332,626	451,053	3.
4.	Other Income and (Deductions)	(6,545)	(15,280)	(8,041)	(8,041)	960	(1,667)	(1,667)	(8,411)	(8,411)	4.
5.	Interest Expense	133,097	118,211	121,616	121,616	132,689	148,175	145,810	165,971	156,562	5.
6.	Net Income	$ 306,594	$ 265,487	$ 199,343	$ 135,347	$ 170,340	$ 200,045	$ 278,941	$ 158,244	$ 286,080	6.
7.	Earned Per Average Common Share*	$ 4.30	$ 3.73	$ 2.80	$ 1.90	N/A	N/A	N/A	N/A	N/A	7.
8.	Dividends Per Common Share*	$ 2.39	$ 2.39	$ 2.39	$ 2.39	N/A	N/A	N/A	N/A	N/A	8.
9.	Payout Ratio*	55.6%	64.1%	85.4%	125.8%	N/A	N/A	N/A	N/A	N/A	9.
10.	Return on Average Invested Capital	11.1%	9.3%	7.6%	6.3%	6.9%	7.1%	8.6%	6.2%	8.3%	10.
11.	Return on Year End Capital	10.7%	9.1%	7.7%	6.4%	6.6%	6.8%	8.2%	6.0%	8.1%	11.
12.	Return on Average Common Equity	15.2%	12.4%	9.2%	6.6%	7.9%	8.4%	11.5%	6.0%	10.4%	12.
13.	Return on Year End Common Equity	14.5%	12.3%	9.2%	6.6%	7.9%	7.7%	10.4%	6.0%	10.1%	13.
14.	Times Bond Interest Earned- Before Income Taxes	3.8	3.6	2.9	2.6	2.5	2.7	3.4	2.2	3.3	14.
15.	Times Total Interest & Preferred Dividends Earned- After Income Taxes	2.6	2.5	2.1	1.8	1.9	2.0	2.4	1.7	2.4	15.
16.	Adjusted Return on Avg. Common Equity	12.4%	8.0%	7.9%	5.4%	6.7%	7.8%	11.0%	6.0%	10.4%	16.

Supporting Schedules:
(a) E-2
(b) C-1
(c) F-1

*Optional for projected year

A-3

ARIZONA PUBLIC SERVICE COMPANY
Summary of Capital Structure
Two Prior Years, Test Year and Projected Years
(Thousands of Dollars)

Line No.	Description	Prior Years Year Ending 2000 (a)	Prior Years Year Ending 2001 (a)	Actual Test Year Ending 12/31/2002 (a)	Projected Year Present Rates Year Ending 12/31/2003 (b)	Projected Year Present Rates Year Ending 12/31/2004 (b)	Projected Year Proposed Rates Year Ending 12/31/2004 (b)	Line No.
1.	Short-term Debt	82,100	171,162	-	59,428	67,003	67,003	1.
2.	Long-Term Debt	2,057,174	2,074,525	2,220,843	2,637,848	2,710,162	2,630,656	2.
3.	TOTAL DEBT	2,139,274	2,245,687	2,220,843	2,697,276	2,777,165	2,697,659	3.
4.	Preferred Stock	-	-	-	-	-	-	4.
5.	Common Equity	2,119,768	2,150,690	2,159,312	2,162,314	2,612,299	2,690,969	5.
6.	Total Capital	4,259,042	4,396,377	4,380,155	4,859,590	5,389,464	5,388,628	6.
	Capitalization Ratios:							
7.	Short-term Debt	1.93%	3.89%	0.00%	1.22%	1.24%	1.24%	7.
8.	Long-Term Debt	48.30%	47.19%	50.70%	54.28%	50.29%	48.82%	8.
9.	TOTAL DEBT	50.23%	51.08%	50.70%	55.50%	51.53%	50.06%	9.
10.	Preferred Stock	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	10.
11.	Common Equity	49.77%	48.92%	49.30%	44.50%	48.47%	49.94%	11.
		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	
12.	Weighted Cost of Short-Term Debt	0.10%	0.07%	0.00%	0.02%	0.04%	0.04%	12.
13.	Weighted Cost of Long-Term Debt	3.31%	3.00%	3.06%	3.17%	2.91%	2.91%	13.
14.	Weighted Cost of Senior Capital	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	14.

Supporting Schedules:

(a) E-1
(b) D-1

A-4

ARIZONA PUBLIC SERVICE COMPANY
Construction Expenditures, Net Plant Placed in Service and Gross Utility Plant in Service
Two Prior Years, Test Year and Projected Years
(Thousands of Dollars)

Line No.	Year	Construction Expenditures (a)	Net Plant Placed In Service (b) (c)	Gross Utility Plant in Service (c)	Line No.
1.	Year Ended 2000	$ 463,768	$ 259,123	$ 7,772,330	1.
2.	Year Ended 2001	473,545	322,390	8,094,720	2.
3.	Test Year - Year Ended 12/31/2002	498,285	392,154	8,486,874	3.
4.	Projected Year - Year Ended 12/31/2003	407,642	335,463	8,822,337	4.
5.	Projected Year - Year Ended 12/31/2004	382,898	1,476,239	10,298,576	5.
6.	Projected Year - Year Ended 12/31/2005	523,325	447,724	10,746,300	6.

Supporting Schedules:

(a) F-3 (Includes nuclear fuel costs.)
(b) E-5 (Test Year only.)

(c) Includes acquisition of Pinnacle West Energy Corporation ("PWEC") units in 2004.

A-5

ARIZONA PUBLIC SERVICE COMPANY
Summary Changes in Financial Position
Two Prior Years, Test Year and Projected Years
(Thousands of Dollars)

		Prior Years		Actual	Projected Year	Projected Year		Projected Year		
Line No.	Year	Year Ending 2000	Year Ending 2001	Test Year Ending 12/31/2002	Present Rates Year Ending 12/31/2003	Present Rates Year Ending 12/31/2004	Proposed Rates Year Ending 12/31/2004	Present Rates Year Ending 12/31/2005	Proposed Rates Year Ending 12/31/2005	Line No.
		(a)	(a)	(a)	(b)	(b)	(b)	(b)	(b)	
	Sources of Funds:									
1.	Operations	$ 723,671	$ 605,075	$ 704,512	$ 641,263	$ 504,076	$ 583,582	$ 505,208	$ 634,380	1.
2.	Outside financing	(181,088)	(68,613)	(218,396)	300,096	(90,111)	(169,617)	50,083	(79,089)	2.
3.	Total funds Provided	542,583	536,462	486,116	941,359	413,965	413,965	555,291	555,291	3.
	Application of Funds:									
4.	Construction Expenditures	464,368	465,360	490,156	411,899	386,883	386,883	528,710	528,710	4.
5.	Other	83,083	56,890	(29,768)	529,460	27,082	27,082	26,581	26,581	5.
6.	Total Funds Applied	$ 547,451	$ 522,250	$ 460,388	$ 941,359	$ 413,965	$ 413,965	$ 555,291	$ 555,291	6.

Supporting Schedules:

(a) E-3
(b) F-2

B-1

ARIZONA PUBLIC SERVICE COMPANY
Summary of Original Cost and RCND Rate Base Elements
Total Company and ACC Jurisdictional
Test Year Ended 12/31/2002
(Dollars in Thousands)

Line No.	Description	Original Cost Total Company (a)	Original Cost ACC (a)		RCND Total Company (b)	RCND ACC (b)		Line No.
1.	Gross Utility Plant in Service	$ 8,486,874	$ 8,203,305		$ 13,596,926	$ 13,142,617		1.
2.	Less: Accumulated Depreciation & Amort.	3,542,547	3,405,509		5,677,664	5,458,032		2.
3.	Net Utility Plant in Service	4,944,327	4,797,796		7,919,262	7,684,585		3.
	Deductions:							
4.	Deferred Taxes	1,292,375	1,268,546		1,292,375	1,268,546		4.
5.	Investment Tax Credits	4,040	4,033		4,040	4,033		5.
6.	Customer Advances for Constr.	45,513	45,513		45,513	45,513		6.
7.	Customer Deposits	39,865	39,865		39,865	39,865		7.
8.	Pension Liability	49,511	48,751		49,511	48,751		8.
9.	Other Deferred Credits	124,050	123,798		124,050	123,798		9.
10.	Unamortized Gain-sale of Utility Plant	59,484	59,381		59,484	59,381		10.
11.	Total Deductions	1,614,838	1,589,887		1,614,838	1,589,887		11.
	Additions:							
12.	Regulatory Assets/Liabilities Net	166,268	165,564		166,268	165,564		12.
13.	Miscellaneous Deferred Debits	27,379	26,959		27,379	26,959		13.
14.	Depreciation Fund - Decommissioning	194,440	191,608		194,440	191,608		14.
15.	Allowance for Working Capital (d)	175,713	172,423		175,713	172,423		15.
16.	Total Additions	563,800	556,554		563,800	556,554		16.
17.	Total Rate Base Before Proforma Adjust.	3,893,289	3,764,463		6,868,224	6,651,252		17.
18.	Proforma Adjustments	327,730	443,013		(123,896)	76,203		18.
19.	Total Rate Base	$ 4,221,019	$ 4,207,476	(e)	$ 6,744,328	$ 6,727,455	(e)	19.

Supporting Schedules:
(a) B-2
(b) B-3
(c) B-5

Recap Schedules:
(e) A-1

B-2

ARIZONA PUBLIC SERVICE COMPANY
Original Cost Rate Base
Pro Forma Adjustments
(Dollars in Thousands)

		(1)		(2)		(3)	
		Actual at End of Test Year 12/31/2002 (a)		PWEC Units		Remove Regulatory Assets Amortized under Prior Settlement	
Line No.	Description	Total Co. (A)	ACC (B)	Total Co. (C)	ACC (D)	Total Co. (E)	ACC (F)
1.	Gross Utility Plant in Service	$ 8,486,874	$ 8,203,305	$ 1,021,886	$ 1,015,393	$ -	$ -
2.	Less: Accumulated Depreciation & Amort.	3,542,547	3,405,509	73,395	73,045	-	-
3.	Net Utility Plant in Service	4,944,327	4,797,796	948,491	942,348	-	-
4.	Less: Total Deductions	1,614,838	1,589,887	53,382	53,111	(41,080)	(41,080)
5.	Total Additions	563,800	556,554	-	-	(104,000)	(104,000)
6.	Total Rate Base	$ 3,893,289	$ 3,764,463	$ 895,109	$ 889,237	$ (62,920)	$ (62,920)

(2) Adjustment to Test Year rate base to include the Pinnacle West Energy Units including West Phoenix Combined Cycle Unit No. 4, West Phoenix Combined Cycle No. 5, Redhawk Combined Cycle No. 1, Redhawk Combined Cycle No. 2 and Saguaro Combustion Turbine No. 3.

(3) Adjustment to Test Year rate base to exclude certain net regulatory assets which, pursuant to the terms of the 1999 Settlement Agreement, will be fully amortized by June 30, 2004.

Supporting Schedules:
(a) E-1

ARIZONA PUBLIC SERVICE COMPANY
Original Cost Rate Base
Pro Forma Adjustments
(Dollars in Thousands)

		(4)		(5)		(6)	
		Independent Spent Fuel Storage Installation ("ISFSI")		Reversal of Settlement Write-Off		Transmission Assets	
Line No.	Description	Total Co. (G)	ACC (H)	Total Co. (I)	ACC (J)	Total Co. (K)	ACC (L)
1.	Gross Utility Plant in Service	$ -	$ -	$ -	$ -	$ (1,264,590)	$ (1,001,498)
2.	Less: Accumulated Depreciation & Amort.	-	-	-	-	(499,955)	(380,603)
3.	Net Utility Plant in Service	-	-	-	-	(764,635)	(620,895)
4.	Less: Total Deductions	1,707	1,682	92,430	92,430	(115,992)	(93,445)
5.	Total Additions	4,321	4,258	234,000	234,000	-	-
6.	Total Rate Base	$ 2,614	$ 2,576	$ 141,570	$ 141,570	$ (648,643)	$ (527,450)

(4) Adjustment to Test Year rate base to include the amount of System Benefits related ISFSI costs anticipated to be accrued between the end of the Test Year and June 30, 2004.

(5) Adjustment to Test Year rate base to restore the pre-tax $234 million deduction taken by the Company in consideration of benefits previously agreed to under the 1999 Settlement.

(6) Adjustment to Test Year rate base to remove transmission assets and generation plant functionalized to ancillary services consistent with FERC rules requiring APS to take transmission service and related ancillary services for the APS Standard Offer customers under the APS OATT.

ARIZONA PUBLIC SERVICE COMPANY
Original Cost Rate Base
Pro Forma Adjustments
(Dollars in Thousands)

		(7)		(8)		
		Total Original Cost Rate Base Pro Forma Adjustments (b)		Adjusted at End of Test Year 12/31/2002 (b)		
Line No.	Description	Total Co. (M)	ACC (N)	Total Co. (O)	ACC (P)	Line No.
1.	Gross Utility Plant in Service	$ (242,704)	$ 13,895	$ 8,244,170	$ 8,217,200	1.
2.	Less: Accumulated Depreciation & Amort.	(426,560)	(307,558)	3,115,987	3,097,951	2.
3.	Net Utility Plant in Service	183,856	321,453	5,128,183	5,119,249	3.
4.	Less: Total Deductions	(9,553)	12,698	1,605,285	1,602,585	4.
5.	Total Additions	134,321	134,258	698,121	690,812	5.
6.	Total Rate Base	$ 327,730	$ 443,013	$ 4,221,019	$ 4,207,476	6.

Recap Schedules:
(b) B-1

B-3

ARIZONA PUBLIC SERVICE COMPANY
RCND Cost Rate Base
Pro Forma Adjustments
(Dollars in Thousands)

Line No.	Description	(1) Actual at End of Test Year 12/31/2002 (a)		(2) PWEC Units		(3) Remove Regulatory Assets Amortized under Prior Settlement	
		Total Co. (A)	ACC (B)	Total Co. (C)	ACC (D)	Total Co. (E)	ACC (F)
1.	Gross Utility Plant in Service	$ 13,596,926	$ 13,142,617	$ 1,023,292	$ 1,016,790	$ -	$ -
2.	Less: Accumulated Depreciation & Amort.	5,677,664	5,458,032	74,288	73,934	-	-
3.	Net Utility Plant in Service	7,919,262	7,684,585	949,004	942,856	-	-
4.	Less: Total Deductions	1,614,838	1,589,887	53,382	53,111	(41,080)	(41,080)
5.	Total Additions	563,800	556,554	-	-	(104,000)	(104,000)
6.	Total Rate Base	$ 6,868,224	$ 6,651,252	$ 895,622	$ 889,745	$ (62,920)	$ (62,920)

(2) Adjustment to Test Year rate base to include the Pinnacle West Energy Units including West Phoenix Combined Cycle Unit No. 4, West Phoenix Combined Cycle No. 5, Redhawk Combined Cycle No. 1, Redhawk Combined Cycle No. 2 and Saguaro Combustion Turbine No. 3.

(3) Adjustment to Test Year rate base to exclude certain net regulatory assets which, pursuant to the terms of the 1999 Settlement Agreement, will be fully amortized by June 30, 2004.

Supporting Schedules:
(a) B-4

ARIZONA PUBLIC SERVICE COMPANY
RCND Cost Rate Base
Pro Forma Adjustments
(Dollars in Thousands)

		(4)		(5)		(6)	
		Independent Spent Fuel Storage Installation ("ISFSI")		Reversal of Settlement Write-Off		Transmission Assets	
Line No.	Description	Total Co.	ACC	Total Co.	ACC	Total Co.	ACC
		(G)	(H)	(I)	(J)	(K)	(L)
1.	Gross Utility Plant in Service	$ -	$ -	$ -	$ -	$ (2,018,055)	$ (1,598,208)
2.	Less: Accumulated Depreciation & Amort.	-	-	-	-	(801,281)	(609,995)
3.	Net Utility Plant in Service	-	-	-	-	(1,216,774)	(988,213)
4.	Less: Total Deductions	1,707	1,682	92,430	92,430	(115,992)	(93,445)
5.	Total Additions	4,321	4,258	234,000	234,000	-	-
6.	Total Rate Base	$ 2,614	$ 2,576	$ 141,570	$ 141,570	$ (1,100,782)	$ (894,768)

(4) Adjustment to Test Year rate base to include the amount of System Benefits related ISFSI costs anticipated to be accrued between the end of the Test Year and June 30, 2004.

(5) Adjustment to Test Year rate base to restore the pre-tax $234 million deduction taken by the Company in consideration of benefits previously agreed to under the 1999 Settlement.

(6) Adjustment to Test Year rate base to remove transmission assets and generation plant functionalized to ancillary services consistent with FERC rules requiring APS to take transmission service and related ancillary services for the Standard Offer customers under the APS OATT.

ARIZONA PUBLIC SERVICE COMPANY
RCND Cost Rate Base
Pro Forma Adjustments
(Dollars in Thousands)

Line No.	Description	(7) Total RCND Rate Base Pro Forma Adjustments Total Co. (M)	(7) Total RCND Rate Base Pro Forma Adjustments ACC (N)	(8) Adjusted at End of Test Year 12/31/2002 (b) Total Co. (O)	(8) Adjusted at End of Test Year 12/31/2002 (b) ACC (P)	Line No.
1.	Gross Utility Plant in Service	$ (994,763)	($581,418)	$ 12,602,163	$ 12,561,199	1.
2.	Less: Accumulated Depreciation & Amort.	(726,993)	(536,061)	4,950,671	4,921,971	2.
3.	Net Utility Plant in Service	(267,770)	(45,357)	7,651,492	7,639,228	3.
4.	Less: Total Deductions	(9,553)	12,698	1,605,285	1,602,585	4.
5.	Total Additions	134,321	134,258	698,121	690,812	5.
6.	Total Rate Base	$ (123,896)	$ 76,203	$ 6,744,328	$ 6,727,455	6.

Recap Schedules:
(b) B-1

B-4

ARIZONA PUBLIC SERVICE COMPANY
RCND by Major Plant Accounts
Test Year Ended 12/31/02
(Thousands of Dollars)

Line No.	Function	Plant Account	Description	RCN (a)	Condition Percent (b)	RCND (c)	Line No.
1.	INTANGIBLES	301	Organization	$ 74	100.00%	$ 74	1.
2.		302	Franchises and consents	884	40.18%	355	2.
3.		303	Miscellaneous intangible plant	201,550	50.53%	101,843	3.
4.			Subtotal	202,508		102,272	4.
5.	PRODUCTION	310	Land and Land Rights	3,206	100.00%	3,206	5.
6.		310	Limit Term Land Rights	89	45.33%	40	6.
7.		311	Structures and improvements	212,692	44.27%	94,159	7.
8.		312	Boiler plant equipment	1,763,288	44.65%	787,308	8.
9.		314	Turbogenerator units	527,950	33.91%	179,028	9.
10.		315	Accessory electric equipment	355,546	34.74%	123,516	10.
11.		316	Miscellaneous power plant equip.	88,665	59.33%	52,605	11.
12.		320	Land and land rights	3,400	100.00%	3,400	12.
13.		321	Structures and improvements	879,393	59.55%	523,679	13.
14.		322	Reactor plant equipment	1,352,385	57.19%	773,430	14.
15.		323	Turbogenerator units	492,053	59.73%	293,903	15.
16.		324	Accessory electric equipment	473,585	57.58%	272,690	16.
17.		325	Misc power plant equip	189,250	49.03%	92,790	17.
18.		330	Limit Term Land Rights	65	40.00%	26	18.
19.		331	Structures and improvements	1,163	0.00%	0	19.
20.		332	Reservoirs, dams, and waterways	10,601	0.00%	0	20.
21.		333	Water wheels, turbines and generators	1,943	0.00%	0	21.
22.		334	Accessory electric equipment	1,605	0.00%	0	22.
23.		335	Miscellaneous power plant equip.	259	0.00%	0	23.
24.		336	Roads, railroads and bridges	734	0.00%	0	24.
25.		340	Land and land rights	28	100.00%	28	25.
26.		341	Structures and improvements	16,529	43.20%	7,141	26.
27.		342	Fuel holders, products, and accessories	40,195	70.33%	28,269	27.
28.		343	Prime movers	116,835	11.86%	13,857	28.
29.		344	Generators	148,230	77.01%	114,152	29.
30.		345	Accessory electric equipment	44,549	52.24%	23,272	30.
31.		346	Miscellaneous power plant equip.	10,334	35.22%	3,640	31.
32.			Subtotal	6,734,572		3,390,139	32.
33.	TRANSMISSION	350	Land and land rights	32,009	100.00%	32,009	33.
34.		350	Limit Term Land Rights	18,799	57.02%	10,719	34.
35.		352	Structures and improvements	44,277	69.92%	30,958	35.
36.		353	Station equipment	799,655	58.66%	469,077	36.
37.		354	Towers and fixtures	271,421	44.93%	121,949	37.
38.		355	Poles and fixtures	316,497	67.90%	214,901	38.
39.		356	Overhead conductors and devices	560,601	58.80%	329,633	39.
40.		357	Underground conduit	17,941	71.38%	12,806	40.
41.		358	Underground conductors and devices	36,134	65.84%	23,791	41.
42.			SUBTOTAL	2,097,334		1,245,843	42.
43.	DISTRIBUTION	360	Land and land rights	26,030	100.00%	26,030	43.
44.		360	Limit Term Land Rights	725	25.24%	183	44.
45.		361	Structures and improvements	42,131	69.46%	29,265	45.
46.		362	Station equipment	322,369	66.66%	214,891	46.
47.		364	Poles, towers, and fixtures	529,061	70.64%	373,729	47.
48.		365	Overhead conductors and devices	363,653	73.08%	265,757	48.
49.		366	Underground conduit	516,658	87.90%	454,143	49.
50.		367	Underground conductors and devices	986,319	71.79%	708,078	50.
51.		368	Line transformers	585,096	61.30%	358,664	51.
52.		369	Services	320,772	64.44%	206,705	52.
53.		370	Meters	189,272	67.48%	127,722	53.
54.		371	Installations on customers' premises	44,452	65.60%	29,161	54.
55.		373	Street lighting and signal systems	88,382	65.69%	58,058	55.
56.			Subtotal	4,014,920		2,852,386	56.

ARIZONA PUBLIC SERVICE COMPANY
RCND by Major Plant Accounts
Test Year Ended 12/31/02
(Thousands of Dollars)

Line No.	Function	Plant Account	Description	RCN (a)	Condition Percent (b)	RCND (c)	Line No.
57.	GENERAL	389	Land and land rights	7,327	100.00%	7,327	57.
58.		390	Structures and improvements	164,648	66.32%	109,195	58.
59.		391	Office furniture and equipment	90,009	57.35%	51,620	59.
60.		391	Capitalized Lease-Computer Equipment	5,941	81.62%	4,849	60.
61.		392	Transportation equipment	34,941	27.47%	9,598	61.
62.		392	Capitalized Lease-Transportation Equip.	19,553	100.00%	19,554	62.
63.		393	Stores equipment	5,452	31.68%	1,727	63.
64.		394	Tools, shop and garage equipment	17,505	73.97%	12,948	64.
65.		395	Laboratory equipment	2,731	22.71%	620	65.
66.		396	Power operated equipment	38,790	33.43%	12,968	66.
67.		397	Communication equipment	158,534	61.25%	97,102	67.
68.		398	Miscellaneous equipment	2,161	51.57%	1,114	68.
69.			Subtotal	547,592		328,622	69.
70.			Total Plant	$ 13,596,926		$ 7,919,262	70.

Supporting Schedules
RCND Study

Recap Schedules
(a) B-3

B-4a

ARIZONA PUBLIC SERVICE COMPANY
Computation of RCND Rate Base Elements
Test Year Ended 12/31/02
(Dollars in Thousands)

Line No.		Description	Total * Company (b + c) (a)	ACC (b)	All Other (d + e) (c)	SCE 500KV (d)	Other (e)
1.	A.	ORIGINAL COST:					
2.		Gross Utility Plant in Service	$ 8,486,874	$ 8,203,305	$ 283,569	$ 51,829	$ 231,740
3.		Accumulated Depreciation & Amortization	3,542,547	3,405,509	137,038	45,235	91,803
4.		Net Utility Plant in Service	4,944,327	4,797,796	146,531	6,594	139,937
5.	B.	RCND:					
6.		Reproduction Cost New	13,596,926	13,142,617	454,309	213,611	240,698
7.		Accumulated Depreciation from Sch B-1	5,677,664	5,458,032	219,632	186,434	33,198
8.		Total RCND Plant in Service at 12/31/02	7,919,262	7,684,585	234,677	27,177	207,500
9.		Deductions:					
10.		Deferred Taxes	1,292,375	1,268,546	23,829	-	23,829
11.		Investment Tax Credits	4,040	4,033	7	-	7
12.		Total Deferred Taxes and ITC	1,296,415	1,272,579	23,836	-	23,836
13.		Customer Advances for Construction	45,513	45,513	-	-	-
14.		Customer Deposits	39,865	39,865	-	-	-
15		Pension Liability	49,511	48,751	760	-	760
16		Other Deferred Credits	124,050	123,798	252	-	252
17		Deferred Gains for Sale of Util. Plant	59,484	59,381	103	-	103
18		Total Deductions	1,614,838	1,589,887	24,951	-	24,951
19		Additions:					
20		Regulatory Assets/Liabilities Net	166,268	165,564	704	-	704
21		Miscellaneous Deferred Debits	27,379	26,959	420	-	420
22		Depreciation Fund - Decommissioning	194,440	191,608	2,832	-	2,832
23		Allowance for Working Capital	175,713	172,423	3,290	-	3,290
24		Total Additions	563,800	556,554	7,246	-	7,246
25		Total RCND Rate Base Before Proforma Adj.	6,868,224	6,651,252	216,972	27,177	189,795
26		Proforma Adjustments	(123,896)	76,203	(200,099)	(27,177)	(172,922)
27		Total RCND Rate Base	$ 6,744,328	$ 6,727,455	$ 16,873	$ -	$ 16,873

Supporting Schedules:
For Lines 2, 3, 9-23, Col. (a): See Schedule B-1, Column (a).
For Lines 2, 3, 9-23, Col. (b): See Schedule B-1, Column (b).
For Line 6, Col. (a): See Schedule b-4, Column (a) page 2 of 2.
For Line 8, Col. (a): See Schedule b-4, Column (c) page 2 of 2.

* - Includes SCE 500KV

B-5

ARIZONA PUBLIC SERVICE COMPANY
Computation of Working Capital
Test Year Ended 12/31/02
(Dollars in Thousands)

Line No.	Description		Amount	Line No.
1.	Cash Working Capital (a)	$	54,098	1.
2.	Materials and Supplies (b)		79,985	2.
3.	Fuel - Coal and Oil (b)		28,185	3.
4.	Fuel - Nuclear, Net (b) (c)		7,466	4.
5.	Prepayments (b)		5,979	5.
6.	Total Working Capital Allowance (d)	$	175,713	6.

Supporting Schedules:
(a) Lead-Lag Study.
(b) E-1
(c) B-5, Page 2 of 2

Recap Schedules:
(d) B-1

ARIZONA PUBLIC SERVICE COMPANY
Nuclear Fuel Balances
Test Year Ended 12/31/02

Line No.	Description	Amount	Line No.
1.	Nuclear Fuel in Reactor:		1.
2.	Palo Verde Unit 1	$ 36,407,633	2.
3.	Palo Verde Unit 2	36,598,656	3.
4.	Palo Verde Unit 3	35,483,712	4.
5.	Total Nuclear Fuel in Reactor	108,490,001	5.
6.	Amortization of Nuclear Fuel		6.
7.	Palo Verde Unit 1	15,017,693	7.
8.	Palo Verde Unit 2	19,113,964	8.
9.	Palo Verde Unit 3	24,761,771	9.
	Dry Cask Storage	43,927,988	
10.	Total Amortization of Nuclear Fuel	102,821,416	10.
11.	Nuclear Fuel in Reactor (Net of Amortization)		11.
12.	Palo Verde Unit 1	21,389,940	12.
13.	Palo Verde Unit 2	17,484,692	13.
14.	Palo Verde Unit 3	10,721,941	14.
	Dry Cask Storage (Amortization)	(43,927,988)	
15.	Total Nuclear Fuel in Reactor (Net)	5,668,585	15.
16.	Nuclear Fuel in Stock:		16.
17.	Palo Verde Unit 1	367,000	17.
18.	Palo Verde Unit 2	1,365,333	18.
19.	Palo Verde Unit 3	65,366	19.
20.	Total Nuclear Fuel in Stock	1,797,699	20.
21.	Total Nuclear Fuel - Net (a)	$ 7,466,284	21.

Supporting Schedules:
N/A

Recap Schedules:
(a) B-5, Page 1 of 2

C-1

ARIZONA PUBLIC SERVICE COMPANY
Total Company
Adjusted Test Year Statement of Income
Test Year 12 Months Ended 12/31/02

(Dollars in Thousands)

Line No.	Description	Total Company: Actual For The Test Year Ended 12/31/02 (a)	Proforma Adjustments (b)	Test Year Results After Proforma Adjustments (c)	Line No.
1.	Electric operating revenues	$ 2,093,393	$ (115,217)	$ 1,978,176	1.
2.	Purchased power and fuel costs	628,030	(59,161)	568,869	2.
3.	Operating revenues less purchased power and fuel costs	1,465,363	(56,056)	1,409,307	3.
4.	Other operating expenses:				4.
5.	Operations and maintenance	495,845	120,216	616,061	5.
6.	Depreciation and amortization	399,640	(68,148)	331,492	6.
7.	Income taxes	132,953	(46,347)	86,606	7.
8.	Other taxes	107,925	2,219	110,144	8.
9.	Total	1,136,363	7,940	1,144,303	9.
10.	Operating income	329,000	(63,996)	265,004	10.
11.	Other income (deductions):				11.
12.	Income taxes	6,148	-	6,148	12.
13.	Other income	5,149	-	5,149	13.
14.	Other expense	(19,338)	-	(19,338)	14.
15.	Total	(8,041)	-	(8,041)	15.
16.	Income before interest deductions	320,959	(63,996)	256,963	16.
17.	Interest deductions:				17.
18.	Interest on long-term debt	128,462	-	128,462	18.
19.	Interest on short-term borrowings	5,416	-	5,416	19.
20.	Debt discount, premium and expense	2,888	-	2,888	20.
21.	Capitalized interest	(15,150)	-	(15,150)	21.
22.	Total	121,616	-	121,616	22.
23.	Net income	$ 199,343	$ (63,996)	$ 135,347	23.

Supporting Schedules:
(a) E-2
(b) C-2

Recap Schedules:
(c) A-2

ARIZONA PUBLIC SERVICE COMPANY
ACC Jurisdiction
Adjusted Test Year Statement of Income
Test Year 12 Months Ended 12/31/02

(Dollars in Thousands)

Line No.	Description	ACC Jurisdiction Actual For The Test Year Ended 12/31/02	Proforma Adjustments (a)	Test Year Results After Proforma Adjustments (b)	Line No.
1.	Electric Operating Revenues	$ 2,051,730	$ (111,584)	$ 1,940,146	1.
2.	Purchased power and fuel costs	616,873	(56,994)	559,879	2.
3.	Operating revenues less purchased power and fuel costs	1,434,857	(54,590)	1,380,267	3.
4.	Other Operating Expenses:				4.
5.	Operations and maintenance	489,041	101,032	590,073	5.
6.	Depreciation and amortization	393,035	(63,052)	329,983	6.
7.	Income taxes	129,307	(43,163)	86,144	7.
8.	Other taxes	104,205	5,992	110,197	8.
9.	Total	1,115,588	809	1,116,397	9.
10.	Operating Income	$ 319,269	$ (55,399)	$ 263,870	10.

Supporting Schedules:
(a) C-2

Recap Schedules:
(b) A-1

C-2

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Twelve Months Ended 12/31/2002
(Thousands of Dollars)

		(1)		(2)		(3)	
		Exclude Regulatory Assessments and Franchise Fees		Annualize 7/1/03 ACC Rate Levels		Normalize Weather Conditions	
Line No.	Description	Total Co. (A)	ACC (B)	Total Co. (C)	ACC (D)	Total Co. (E)	ACC (F)
1.	Electric Operating Revenues	$ (31,707)	$ (31,707)	$ (37,005)	$ (37,005)	$ (5,204)	$ (5,204)
2.	Purchased Power and Fuel Costs	-	-	-	-	(827)	(827)
3.	Oper Rev Less Purch Pwr & Fuel Costs	(31,707)	(31,707)	(37,005)	(37,005)	(4,377)	(4,377)
	Other Operating Expenses:						
4.	Operations Excluding Fuel Expense	(31,707)	(31,707)	-	-	(218)	(218)
5.	Maintenance	-	-	-	-	-	-
6.	Subtotal	(31,707)	(31,707)	-	-	(218)	(218)
7.	Depreciation and Amortization	-	-	-	-	-	-
8.	Amortization of Gain	-	-	-	-	-	-
9.	Administrative and General	-	-	-	-	-	-
10.	Other Taxes	-	-	-	-	-	-
11.	Total	(31,707)	(31,707)	-	-	(218)	(218)
12.	Operating Income Before Income Tax	-	-	(37,005)	(37,005)	(4,159)	(4,159)
13.	Interest Expense	-	-	-	-	-	-
14.	Taxable Income	-	-	(37,005)	(37,005)	(4,159)	(4,159)
15.	Current Income Tax Rate - 39.5%	-	-	(14,617)	(14,617)	(1,643)	(1,643)
16.	Operating Income (line 12 - line 15)	$ -	$ -	$ (22,388)	$ (22,388)	$ (2,516)	$ (2,516)

(1) Adjustment to Test Year operations to exclude regulatory assessments and franchise fees from both operating revenue and operating expense.

(2) Adjustment to Test Year operations to reflect the annualization of ACC rate levels for the 7/1/02 and 7/1/03 rate decreases.

(3) Adjustment to Test Year operations to reflect normal weather conditions for the ten years ended December 31, 2002.

Supporting Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Twelve Months Ended 12/31/2002
(Thousands of Dollars)

Line No.	Description	(4) Annualize Customer Levels to Year-End 2002 Total Co. (G)	(4) ACC (H)	(5) Schedule 1 Changes Total Co. (I)	(5) ACC (J)	(6) Base Rate Component for EPS Total Co. (K)	(6) ACC (L)
1.	Electric Operating Revenues	$ 20,971	$ 20,971	$ 79	$ 79	$ 5,263	$ 5,263
2.	Purchased Power and Fuel Costs	4,779	4,779	-	-	-	-
3.	Oper Rev Less Purch Pwr & Fuel Costs	16,192	16,192	79	79	5,263	5,263
	Other Operating Expenses:						
4.	Operations Excluding Fuel Expense	1,622	1,622	(3)	(3)	6,000	6,000
5.	Maintenance	-	-	-	-	-	-
6.	Subtotal	1,622	1,622	(3)	(3)	6,000	6,000
7.	Depreciation and Amortization	-	-	-	-	-	-
8.	Amortization of Gain	-	-	-	-	-	-
9.	Administrative and General	-	-	-	-	-	-
10.	Other Taxes	-	-	-	-	-	-
11.	Total	1,622	1,622	(3)	(3)	6,000	6,000
12.	Operating Income Before Income Tax	14,570	14,570	82	82	(737)	(737)
13.	Interest Expense	-	-	-	-	-	-
14.	Taxable Income	14,570	14,570	82	82	(737)	(737)
15.	Current Income Tax Rate - 39.5%	5,755	5,755	32	32	(291)	(291)
16.	Operating Income (line 12 - line 15)	$ 8,815	$ 8,815	$ 50	$ 50	$ (446)	$ (446)

(4) Adjustment to Test Year operations to reflect the annualization of customer levels at December 31, 2002.

(5) Adjustment to Test Year operations to reflect proposed revenue-related changes to Schedule 1.

(6) Adjustment to Test Year operations related to the base rate component of the Company's System Benefits Charge which is used to fund the Environmental Portfolio Standard. Revenue is adjusted to reverse Test Year entries to contributions in aid of construction and to include the expenses allowed by the Commission.

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Twelve Months Ended 12/31/2002
(Thousands of Dollars)

		(7)		(8)		(9)	
		Base Fuel and Purchased Power		Normalize Off-System Sales		PWEC Units	
Line No.	Description	Total Co. (M)	ACC (N)	Total Co. (O)	ACC (P)	Total Co. (Q)	ACC (R)
1.	Electric Operating Revenues	$ -	$ -	$ (128,200)	$ (126,332)	$ 56,779	$ 56,237
2.	Purchased Power and Fuel Costs	120,584	120,584	(151,868)	(149,655)	(34,970)	(34,970)
3.	Oper Rev Less Purch Pwr & Fuel Costs	(120,584)	(120,584)	23,668	23,323	91,749	91,207
	Other Operating Expenses:						
4.	Operations Excluding Fuel Expense	-	-	-	-	14,110	14,086
5.	Maintenance	-	-	-	-	18,549	18,390
6.	Subtotal	-	-	-	-	32,659	32,476
7.	Depreciation and Amortization	-	-	-	-	41,541	41,469
8.	Amortization of Gain	-	-	-	-	-	-
9.	Administrative and General	-	-	-	-	8,797	8,782
10.	Other Taxes	-	-	-	-	11,256	11,184
11.	Total	-	-	-	-	94,253	93,911
12.	Operating Income Before Income Tax	(120,584)	(120,584)	23,668	23,323	(2,504)	(2,704)
13.	Interest Expense	-	-	-	-	36,179	35,977
14.	Taxable Income	(120,584)	(120,584)	23,668	23,323	(38,683)	(38,681)
15.	Current Income Tax Rate - 39.5%	(47,631)	(47,631)	9,349	9,213	(15,280)	(15,279)
16.	Operating Income (line 12 - line 15)	$ (72,953)	$ (72,953)	$ 14,319	$ 14,110	$ 12,776	$ 12,575

(7) Adjustment to Test Year operations to include 2003 base fuel and purchased power cents/kWh costs at adjusted 2002 consumption.

(8) Adjustment to Test Year operations to include off-system revenues consistent with the Base Fuel and Purchased Power pro forma adjustment.

(9) Adjustment to Test Year operations to include the Pinnacle West Energy Units including West Phoenix Combined Cycle No. 4, West Phoenix Combined Cycle No. 5, Redhawk Combined Cycle No. 1, Redhawk Combined Cycle No. 2 and Saguaro Combustion Turbine No. 3.

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Twelve Months Ended 12/31/2002
(Thousands of Dollars)

Line No.	Description	(10) Annualize Payroll Total Co. (S)	(10) Annualize Payroll ACC (T)	(11) Employee Severance Total Co. (U)	(11) Employee Severance ACC (V)	(12) Employee Benefits Adjustment Total Co. (W)	(12) Employee Benefits Adjustment ACC (X)
1.	Electric Operating Revenues	$ -	$ -	$ -	$ -	$ -	$ -
2.	Purchased Power and Fuel Costs	7	7	-	-	253	249
3.	Oper Rev Less Purch Pwr & Fuel Costs	(7)	(7)	-	-	(253)	(249)
	Other Operating Expenses:						
4.	Operations Excluding Fuel Expense	851	843	(23,155)	(22,800)	18,623	18,375
5.	Maintenance	173	171	-	-	5,942	5,863
6.	Subtotal	1,024	1,014	(23,155)	(22,800)	24,565	24,238
7.	Depreciation and Amortization	-	-	-	-	-	-
8.	Amortization of Gain	-	-	-	-	-	-
9.	Administrative and General	-	-	-	-	-	-
10.	Other Taxes	-	-	-	-	-	-
11.	Total	1,024	1,014	(23,155)	(22,800)	24,565	24,238
12.	Operating Income Before Income Tax	(1,031)	(1,021)	23,155	22,800	(24,818)	(24,487)
13.	Interest Expense	-	-	-	-	-	-
14.	Taxable Income	(1,031)	(1,021)	23,155	22,800	(24,818)	(24,487)
15.	Current Income Tax Rate - 39.5%	(406)	(403)	9,146	9,006	(9,803)	(9,672)
16.	Operating Income (line 12 - line 15)	$ (625)	$ (618)	$ 14,009	$ 13,794	$ (15,015)	$ (14,815)

(10) Adjustment to Test Year operations to reflect the annualization of payroll and payroll taxes to employee levels at December 31, 2002 and salary levels at March 2003.

(11) Adjustment to Test Year operations to reflect a three-year levelization of expenses incurred during the Test Year related to a voluntary severance and early retirement program offered by the Company.

(12) Adjustment to Test Year operations to reflect increased employee benefits expenses.

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Twelve Months Ended 12/31/2002
(Thousands of Dollars)

Line No.	Description	(13) On-Going Direct Access Expense Total Co. (Y)	(13) ACC (Z)	(14) On-Going Independent Spent Fuel Storage Installation ("ISFSI") Expense Total Co. (AA)	(14) ACC (BB)	(15) Transmission Expenses Total Co. (CC)	(15) ACC (DD)
1.	Electric Operating Revenues	$ -	$ -	$ -	$ -	$ (2,310)	$ -
2.	Purchased Power and Fuel Costs	-	-	2,881	2,839	-	-
3.	Oper Rev Less Purch Pwr & Fuel Costs	-	-	(2,881)	(2,839)	(2,310)	-
	Other Operating Expenses:						
4.	Operations Excluding Fuel Expense	1,477	1,477	-	-	112,362	92,266
5.	Maintenance	-	-	-	-	(610)	(483)
6.	Subtotal	1,477	1,477	-	-	111,752	91,783
7.	Depreciation and Amortization	-	-	-	-	(29,163)	(23,101)
8.	Amortization of Gain	-	-	-	-	-	-
9.	Administrative and General	-	-	-	-	(5,814)	(4,932)
10.	Other Taxes	-	-	-	-	(19,236)	(15,283)
11.	Total	1,477	1,477	-	-	57,539	48,467
12.	Operating Income Before Income Tax	(1,477)	(1,477)	(2,881)	(2,839)	(59,849)	(48,467)
13.	Interest Expense	-	-	-	-	(18,756)	(15,252)
14.	Taxable Income	(1,477)	(1,477)	(2,881)	(2,839)	(41,093)	(33,215)
15.	Current Income Tax Rate - 39.5%	(583)	(583)	(1,138)	(1,121)	(16,232)	(13,120)
16.	Operating Income (line 12 - line 15)	$ (894)	$ (894)	$ (1,743)	$ (1,718)	$ (43,617)	$ (35,347)

(13) Adjustment to Test Year operations to include on-going costs of compliance with the Electric Competition Rules. Such costs were previously deferred and therefore were not included in Test Year operating expenses.

(14) Adjustment to Test Year operations to reflect the on-going costs of ISFSI. Such System Benefits related costs were previously deferred and therefore were not included in Test Year operating expenses.

(15) Adjustment to Test Year operations to remove transmission and ancillary services-related expenses from base rates and include OATT costs as an expense consistent with FERC rules requiring APS to take transmission and related ancillary services for the APS Standard Offer customers under the APS OATT.

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Twelve Months Ended 12/31/2002
(Thousands of Dollars)

Line No.	Description		(16) Interest on Customer Deposits Total Co. (EE)	(16) ACC (FF)	(17) Normalize Non-nuclear Maintenance Expense Total Co. (GG)	(17) ACC (HH)	(18) Normalize Nuclear Maintenance Expense Total Co. (II)	(18) ACC (JJ)
1.	Electric Operating Revenues		$ -	$ -	$ -	$ -	$ -	$ -
2.	Purchased Power and Fuel Costs		-	-	-	-	-	-
3.	Oper Rev Less Purch Pwr & Fuel Costs		-	-	-	-	-	-
	Other Operating Expenses:							
4.	Operations Excluding Fuel Expense		875	875	-	-	-	-
5.	Maintenance		-	-	(6,014)	(5,933)	(945)	(935)
6.	Subtotal		875	875	(6,014)	(5,933)	(945)	(935)
7.	Depreciation and Amortization		-	-	-	-	-	-
8.	Amortization of Gain		-	-	-	-	-	-
9.	Administrative and General		-	-	-	-	-	-
10.	Other Taxes		-	-	-	-	-	-
11.	Total		875	875	(6,014)	(5,933)	(945)	(935)
12.	Operating Income Before Income Tax		(875)	(875)	6,014	5,933	945	935
13.	Interest Expense		-	-	-	-	-	-
14.	Taxable Income		(875)	(875)	6,014	5,933	945	935
15.	Current Income Tax Rate -	39.5%	(345)	(346)	2,376	2,344	373	369
16.	Operating Income (line 12 - line 15)		$ (530)	$ (529)	$ 3,638	$ 3,589	$ 572	$ 566

(16) Adjustment to Test Year operations to reflect the operating income impact of interest on customer deposits.

(17) Adjustment to Test Year operations to reflect the normalization of fossil production maintenance expense and to include the O&M costs of generators acquired for compliance with the Environmental Portfolio Standard.

(18) Adjustment to Test Year operations to reflect the normalization of nuclear production maintenance expense.

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Twelve Months Ended 12/31/2002
(Thousands of Dollars)

Line No.	Description		(19) Annualize Depreciation and Amortization Total Co. (KK)	(19) ACC (LL)	(20) Regulatory Assets Total Co. (MM)	(20) ACC (NN)	(21) ISFSI Asset Total Co. (OO)	(21) ACC (PP)
1.	Electric Operating Revenues		$ -	$ -	$ -	$ -	$ -	$ -
2.	Purchased Power and Fuel Costs		-	-	-	-	-	-
3.	Oper Rev Less Purch Pwr & Fuel Costs		-	-	-	-	-	-
	Other Operating Expenses:							
4.	Operations Excluding Fuel Expense		-	-	-	-	-	-
5.	Maintenance		-	-	-	-	-	-
6.	Subtotal		-	-	-	-	-	-
7.	Depreciation and Amortization		3,027	2,373	(111,754)	(111,760)	8,251	8,130
8.	Amortization of Gain		-	-	-	-	-	-
9.	Administrative and General		-	-	-	-	-	-
10.	Other Taxes		-	-	-	-	-	-
11.	Total		3,027	2,373	(111,754)	(111,760)	8,251	8,130
12.	Operating Income Before Income Tax		(3,027)	(2,373)	111,754	111,760	(8,251)	(8,130)
13.	Interest Expense		-	-	(1,819)	(1,819)	76	74
14.	Taxable Income		(3,027)	(2,373)	113,573	113,579	(8,327)	(8,204)
15.	Current Income Tax Rate -	39.5%	(1,196)	(937)	44,861	44,864	(3,288)	(3,241)
16.	Operating Income (line 12 - line 15)		$ (1,831)	$ (1,436)	$ 66,893	$ 66,896	$ (4,963)	$ (4,889)

(19) Adjustment to Test Year operations to reflect the requested changes to depreciation rates.

(20) Adjustment to Test Year operations to remove the amortization of regulatory assets which will be fully amortized by June 30, 2004 and to include amortization of continuing regulatory assets.

(21) Adjustment to Test Year operations to reflect the amortization of the System Benefits related ISFSI regulatory asset.

ARIZONA PUBL RVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Twelve Months Ended 12/31/2002
(Thousands of Dollars)

Line No.	Description	(22) Reversal of Settlement Write-Off Total Co. (QQ)	ACC (RR)	(23) Nuclear Decommissioning Funds Total Co. (SS)	ACC (TT)	(24) Annualize Property Tax to Year Ending 12-31-2002 Total Co. (UU)	ACC (VV)
1.	Electric Operating Revenues	$ -	$ -	$ -	$ -	$ -	$ -
2.	Purchased Power and Fuel Costs	-	-	-	-	-	-
3.	Oper Rev Less Purch Pwr & Fuel Costs	-	-	-	-	-	-
	Other Operating Expenses:						
4.	Operations Excluding Fuel Expense	-	-	-	-	-	-
5.	Maintenance	-	-	-	-	-	-
6.	Subtotal	-	-	-	-	-	-
7.	Depreciation and Amortization	15,600	15,600	7,766	7,653	-	-
8.	Amortization of Gain	-	-	-	-	-	-
9.	Administrative and General	-	-	-	-	-	-
10.	Other Taxes	-	-	-	-	10,199	10,091
11.	Total	15,600	15,600	7,766	7,653	10,199	10,091
12.	Operating Income Before Income Tax	(15,600)	(15,600)	(7,766)	(7,653)	(10,199)	(10,091)
13.	Interest Expense	4,094	4,094	-	-	-	-
14.	Taxable Income	(19,694)	(19,694)	(7,766)	(7,653)	(10,199)	(10,091)
15.	Current Income Tax Rate - 39.5%	(7,779)	(7,779)	(3,068)	(3,023)	(4,029)	(3,986)
16.	Operating Income (line 12 - line 15)	$ (7,821)	$ (7,821)	$ (4,698)	$ (4,630)	$ (6,170)	$ (6,105)

(22) Adjustment to Test Year operations to include a 15-year amortization restoring the $234 million disallowance taken by the Company in consideration of certain benefits previously agreed to under the 1999 Settlement.

(23) Adjustment to Test Year operations to increase contributions to the nuclear decommissioning trust funds.

(24) Adjustment to Test Year operations to reflect property taxes calculated using December 31, 2002 plant balances.

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Twelve Months Ended 12/31/2002
(Thousands of Dollars)

		(25)		(26)		(27)	
		Financing Application		Income Tax/Synchronized Interest on Test Year Rate Base		Miscellaneous Adjustments	
Line No.	Description	Total Co. (WW)	ACC (XX)	Total Co. (YY)	ACC (ZZ)	Total Co. (AAA)	ACC (BBB)
1.	Electric Operating Revenues	$ -	$ -	$ -	$ -	$ 6,117	$ 6,114
2.	Purchased Power and Fuel Costs	-	-	-	-	-	-
3.	Oper Rev Less Purch Pwr & Fuel Costs	-	-	-	-	6,117	6,114
	Other Operating Expenses:						
4.	Operations Excluding Fuel Expense	-	-	-	-	(699)	(707)
5.	Maintenance	-	-	-	-	-	-
6.	Subtotal	-	-	-	-	(699)	(707)
7.	Depreciation and Amortization	-	-	-	-	-	-
8.	Amortization of Gain	(3,416)	(3,416)	-	-	-	-
9.	Administrative and General	-	-	-	-	-	-
10.	Other Taxes	-	-	-	-	-	-
11.	Total	(3,416)	(3,416)	-	-	(699)	(707)
12.	Operating Income Before Income Tax	3,416	3,416	-	-	6,816	6,821
13.	Interest Expense	-	-	(12,783)	(12,363)	-	-
14.	Taxable Income	3,416	3,416	12,783	12,363	6,816	6,821
15.	Current Income Tax Rate - 39.5%	1,349	1,349	5,049	4,883	2,692	2,694
16.	Operating Income (line 12 - line 15)	$ 2,067	$ 2,067	$ (5,049)	$ (4,883)	$ 4,124	$ 4,127

(25) Adjustment to Test Year operations to reflect 264 basis point differential specified in Commission Decision No. 65796.

(26) Adjustment to Test Year operations to reflect the synchronization of interest expense using the adjusted year-end 2002 capital structure and cost of long-term debt, as well as the use of the statutory income tax rate.

(27) Adjustment to Test Year operations to eliminate non-recurring and out-of-period expenses.

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Twelve Months Ended 12/31/2002
(Thousands of Dollars)

(28)

Line No.	Description	Total Income Statement Adjustments (a) Total Co. (CCC)	Total Income Statement Adjustments (a) ACC (DDD)
1.	Electric Operating Revenues	$ (115,217)	$ (111,584)
2.	Purchased Power and Fuel Costs	(59,161)	(56,994)
3.	Oper Rev Less Purch Pwr & Fuel Costs	(56,056)	(54,590)
	Other Operating Expenses:		
4.	Operations Excluding Fuel Expense	100,138	80,109
5.	Maintenance	17,095	17,073
6.	Subtotal	117,233	97,182
7.	Depreciation and Amortization	(64,732)	(59,636)
8.	Amortization of Gain	(3,416)	(3,416)
9.	Administrative and General	2,983	3,850
10.	Other Taxes	2,219	5,992
11.	Total	54,287	43,972
12.	Operating Income Before Income Tax	(110,343)	(98,562)
13.	Interest Expense	6,991	10,711
14.	Taxable Income	(117,334)	(109,273)
15.	Current Income Tax Rate - 39.5%	(46,347)	(43,163)
16.	Operating Income (line 12 - line 15)	$ (63,996)	$ (55,399)

Recap Schedules:
(a) C-1

C-3

ARIZONA PUBLIC SERVICE COMPANY
Computation of Gross Revenue Conversion Factor
Test Year Ending December 31, 2002

Line No.	Description	Percentage of Incremental Gross Revenues	Line No.
1.	Federal Income Taxes	32.57%	1.
2.	State Income Taxes	6.93%	2.
3.	Total Tax Percentage	39.50%	3.
4.	Operating Income % = 100% - Tax Percentage	60.50%	4.
5.	1/Operating Income % = Gross Revenue Conversion Factor	1.6529	5.

Supporting Schedules:
N/A

Recap Schedules:
A-1

D-1

ARIZONA PUBLIC SERVICE COMPANY
Summary Cost of Capital
(Thousands of Dollars)

		End of Test Year 12/31/02 (f)				End of Projected Year 12/31/03				End of Projected Year 12/31/04 with Proposed Rates				
Line No.	Invested Capital	Amount	%	Cost Rate (e)	Composite Cost	Amount	%	Cost Rate (e)	Composite Cost	Amount	%	Cost Rate (e)	Composite Cost	Line No.
1.	Long-Term Debt (a)	$2,139,955	49.77%	5.81%	2.89%	$2,637,848	54.95%	5.76%	3.17%	$2,630,656	49.43%	5.89%	2.91%	1.
2.	Preferred Stock (b)	-	0.00%	0.00%	0.00%	-	0.00%	0.00%	0.00%	-	0.00%	0.00%	0.00%	2.
3.	Common Equity (c)	2,159,312	50.23%	11.50%	5.78%	2,162,314	45.05%	11.50%	5.18%	2,690,969	50.57%	11.50%	5.82%	3.
4.	Short-Term Debt (a)(g)	-	0.00%	0.00%	0.00%	-	0.00%	0.00%	0.00%	-	0.00%	0.00%	0.00%	4.
5.	Deferrals (d)	-	0.00%	0.00%	0.00%	-	0.00%	0.00%	0.00%	-	0.00%	0.00%	0.00%	5.
6.	Total	$4,299,267	100.00%		8.67%	$4,800,162	100.00%		8.35%	$5,321,625	100.00%		8.73%	6.

Supporting Schedules:
(a) D-2
(b) D-3
(c) D-4
(d) E-1

Recap Schedules:
(e) A-3

(f) Adjusted for M&R calls and PC bond rate resets announced through 6/15/03.
(g) Under FERC regulations, short-term debt is utilized as a source of financing on Construction Work In Process, therefore recoverable through AFUDC provisions.

D-2

ARIZONA PUBLIC SERVICE COMPANY
Cost of Long-Term and Short-Term Debt
(Thousands of Dollars)

Line No.	Description of Debt	End of Test Year 12/31/02 Outstanding	End of Test Year 12/31/02 Annual Interest *	End of Projected Year 12/31/2003 Outstanding	End of Projected Year 12/31/2003 Annual Interest *	End of Projected Year 12/31/2004 with Proposed Rates Outstanding	End of Projected Year 12/31/2004 with Proposed Rates Annual Interest *	Line No.
	Long-Term:							
1.	First Mortgage Bonds	$259,000	$15,910	$259,000	$15,910	-	-	1.
2.	Pollution Control Indebtedness	386,860	8,449	386,860	10,144	565,860	22,443	2.
3.	Capitalized Lease obligation	20,400	1,180	18,293	1,058	16,101	932	3.
4.	Other Long-Term Debt - Senior Notes	173,695	10,290	173,695	10,305	173,695	10,305	4.
5.	Other Long-Term Debt - Unsecured Notes	1,300,000	88,486	1,800,000	114,518	1,875,000	121,186	5.
6.	Other	-	-	-	-	-	-	6.
7.	Total Long-Term (a) **	$2,139,955 (b)	$124,315	$2,637,848	$151,935	$2,630,656	$154,866	7.
8.	Cost Rate (a)	5.81%		5.76%		5.89%		8.
	Short-term:							
9.	Commercial Paper	-	-	-	-	-	-	9.
10.	Total Short-Term (a)	- ***	-	- ***	-	- ***	-	10.
11.	Cost Rate (a)	N/A		N/A		N/A		11.

* Including amortization of discount, premium and expense.

** Excludes unamortized discount.

***Under FERC regulations, short-term debt is utilized as a source of financing on Construction Work In Process, therefore recoverable through AFUDC provisions.

Supporting Schedules:
(b) E-1 (adjusted for M&R calls and PC bond rate resets announced through 6/15/03).

Recap Schedules:
(a) D-1

Schedule D-2

D-3

ARIZONA PUBLIC SERVICE COMPANY
Cost of Preferred Stock
(Thousands of Dollars)

		End of Test Year 12/31/02			End of Projected Year 12/31/03			End of Projected Year 12/31/04 with Proposed Rates			
Line No.	Description of Issue	Shares Outstanding	Amount	Dividend Requirement	Shares Outstanding	Amount	Dividend Requirement	Shares Outstanding	Amount	Dividend Requirement	Line No.
1.	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	1.
2.	Total (a) (b)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	2.
3.	Cost Rate (a)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	3.

Supporting Schedules:
(b) E-1

Recap Schedules:
(a) D-1

D-4

ARIZONA PUBLIC SERVICE COMPANY
Cost of Common Equity

A return on average common equity of at least 11.25% to 11.75% is necessary for the Company to attract and maintain investors in its common equity capital. For purposes of this filing, the Company is willing to accept a return on common equity capital in the middle of that range of 11.50%.

Supporting Schedules	Recap Schedules
N/A	D-1

E-1

ARIZONA PUBLIC SERVICE COMPANY
Comparative Balance Sheets
Test Year 12/31/02 and Two Prior Years
(Dollars in Thousands)

Line No.	Description	Test Year Ended 12/31/2002	Prior Year Ended 12/31/2001	Prior Year Ended 12/31/2000	Line No.
	UTILITY PLANT:				
1.	Electric plant in service and held for future use	$ 8,299,131	$ 7,935,206	$ 7,638,687	1.
2.	Less accumulated depreciation and amortization	3,442,571	3,287,333	3,115,383	2.
3.	Total	4,856,560	4,647,873	4,523,304	3.
4.	Construction work in progress	329,089	321,305	245,749	4.
5.	Intangible assets, net of accumulated amortization	93,259	83,135	94,393	5.
6.	Nuclear fuel, net of amortization	7,466	6,933	7,071	6.
7.	Utility plant - net (a)	5,286,374	5,059,246	4,870,517	7.
	INVESTMENTS AND OTHER ASSETS :				
8.	Decommissioning trust accounts	194,440	202,036	204,716	8.
9.	Assets from risk management activities-long term	31,622	2,082	32,955	9.
10.	Other assets	19,964	76,322	45,841	10.
11.	Total investments and other assets	246,026	280,440	283,512	11.
	CURRENT ASSETS:				
12.	Cash and cash equivalents	42,549	16,821	2,609	12.
13.	Accounts receivable:				13.
14.	Service customers	136,945	182,749	422,012	14.
15.	Other	202,597	55,016	25,089	15.
16.	Allowance for doubtful accounts	(1,341)	(3,349)	(2,380)	16.
17.	Accrued utility revenues	72,915	76,131	74,566	17.
18.	Materials and supplies, at average cost	79,985	81,215	71,966	18.
19.	Fossil fuel, at average cost	28,185	27,023	19,405	19.
20.	Deferred Income tax	4,094	-	5,793	20.
21.	Assets from risk management activities	39,616	10,097	17,506	21.
22.	Other	45,361	42,009	38,414	22.
23.	Total current assets	650,906	487,712	674,980	23.
	DEFERRED DEBITS:				
24.	Regulatory assets	241,045	342,383	469,867	24.
25.	Unamortized debt issue costs	16,696	13,163	12,805	25.
26.	Other	80,760	42,789	37,928	26.
27.	Total deferred debits	338,501	398,335	520,600	27.
28.	TOTAL ASSETS	$ 6,521,807	$ 6,225,733	$ 6,349,609	28.

Supporting Schedules:
(a) E-5

Recap Schedules:
N/A - See Next Page

ARIZONA PUBLIC SERVICE COMPANY
Comparative Balance Sheets
Test Year 12/31/02 and Two Prior Years
(Dollars in Thousands)

Line No.	Description	Test Year Ended 12/31/2002	Year Ended 12/31/2001	Year Ended 12/31/2000	Line No.
	CAPITALIZATION:				
1.	Common stock	$ 178,162	$ 178,162	$ 178,162	1.
2.	Additional paid-in capital	1,246,804	1,246,804	1,246,804	2.
3.	Retained earnings	819,632	790,289	694,802	3.
4.	Accumulated other comprehensive loss:				4.
5.	Minimum pension liability adjustment	(61,487)	(966)	-	5.
6.	Derivative instruments	(23,799)	(63,599)	-	6.
7.	Common stock equity (b)	2,159,312	2,150,690	2,119,768	7.
8.	Long-term debt less current maturities (b)	2,217,340	1,949,074	1,806,908	8.
9.	Total capitalization	4,376,652	4,099,764	3,926,676	9.
	CURRENT LIABILITIES:				
10.	Commercial paper	-	171,162	82,100	10.
11.	Current maturities of long-term debt (b)	3,503	125,451	250,266	11.
12.	Accounts payable	118,133	98,959	267,999	12.
13.	Accrued taxes	82,557	107,595	106,515	13.
14.	Accrued interest	42,608	41,043	39,488	14.
15.	Customer deposits	39,865	28,664	24,498	15.
16.	Deferred income taxes	-	3,244	-	16.
17.	Liabilities from risk management activities	59,773	21,840	37,179	17.
18.	Other	51,820	18,798	81,325	18.
19.	Total current liabilities	398,259	616,756	889,370	19.
	DEFERRED CREDITS AND OTHER:				
20.	Deferred income taxes	1,225,552	1,023,079	1,110,437	20.
21.	Liabilities from risk management activities-long term	36,678	95,159	14,711	21.
22.	Unamortized gain - sale of utility plant	59,484	64,060	68,636	22.
23.	Customer advances for construction	45,513	69,293	40,694	23.
24.	Pension liability	156,442	30,247	62,193	24.
25.	Other	223,227	227,375	236,892	25.
26.	Total deferred credits and other	1,746,896	1,509,213	1,533,563	26.
27.	TOTAL LIABILITIES AND EQUITY	$ 6,521,807	$ 6,225,733	$ 6,349,609	27.

Supporting Schedule:
N/A - See Previous Page

Recap Schedules:
(b) A-3

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ARIZONA PUBLIC SERVICE COMPANY
Comparative Income Statements
Test Year Ended 12/31/02 and Two Prior Years
(Dollars in Thousands Except per Share Amounts)

Line No.	Description	Test Year Ended 12/31/2002	Prior Year Ended 12/31/2001	Prior Year Ended 12/31/2000	Line No.
		(a)	(b)	(c)	
1.	Electric Operating Revenues	$ 2,093,393	$ 3,111,328	$ 2,934,142	1.
2.	Purchased Power and Fuel Costs	628,030	1,541,179	1,332,628	2.
3.	Operating Revenues Less Fuel Expenses	1,465,363	1,570,149	1,601,514	3.
4.	Other Operating Expenses:				4.
5.	Operations and maintenance excluding fuel expenses	495,845	465,561	430,092	5.
6.	Depreciation and amortization	399,640	420,893	425,479	6.
7.	Income taxes	132,953	183,640	199,977	7.
8.	Other taxes	107,925	101,077	99,730	8.
9.	Total	1,136,363	1,171,171	1,155,278	9.
10.	Operating Income	329,000	398,978	446,236	10.
11.	Other Income (Deductions)				11.
12.	Income taxes	6,148	504	4,312	12.
13.	Other income	5,149	20,207	9,690	13.
14.	Other expense	(19,338)	(20,790)	(20,547)	14.
15.	Total	(8,041)	(79)	(6,545)	15.
16.	Income Before Interest Deductions	320,959	398,899	439,691	16.
17.	Interest Deductions				17.
18.	Interest on long-term debt	128,462	126,118	134,431	18.
19.	Interest on short-term borrowings	5,416	4,407	7,455	19.
20.	Debt discount, premium and expense	2,888	2,650	2,105	20.
21.	Capitalized interest	(15,150)	(14,964)	(10,894)	21.
22.	Total	121,616	118,211	133,097	22.
23.	Income Before Accounting Change	199,343	280,688	306,594	23.
24.	Cumulative effect of change in accounting for derivatives-net on income taxes	-	(15,201)	-	24.
25.	Net Income	$ 199,343	$ 265,487	$ 306,594	25.
26.	Preferred Dividends	-	-	-	26.
27.	Earnings Available for Common Stock	$ 199,343	$ 265,487	$ 306,594	27.
28.	Average Common Shares Outstanding	71,264,947	71,264,947	71,264,947	28.
29.	Earnings Per Share of Average Common Stock Outstanding	$ 2.80	$ 3.73	$ 4.30	29.

Supporting Schedules:
N/A

Recap Schedules:
A-2

E-3

ARIZONA PUBLIC SERVICE COMPANY
Comparative Statements of Cash Flows
Test Year 12/31/02 and Two Prior Years
(Dollars in Thousands)

Line No.	Description	Test Year As Of 12/31/2002	Prior Year As Of 12/31/2001	Prior Year As Of 12/31/2000	Line No.
	Cash Flows from Operating Activities:				
1.	Net income	$ 199,343	$ 265,487	$ 306,594	1.
	Items Not Requiring Cash:				
2.	Depreciation and amortization	399,640	420,893	425,479	2.
3.	Nuclear fuel amortization	31,185	28,362	30,083	3.
4.	Deferred income taxes	206,767	(26,516)	(65,726)	4.
5.	Change in mark-to-market	2,957	(100,030)	(11,752)	5.
6.	Cumulative effect of change in accounting-net of income taxes	-	15,201	-	6.
	Changes in Certain Current Assets and Liabilities:				
7.	Accounts receivable	(102,450)	302,283	(209,705)	7.
8.	Materials, supplies and fossil fuel	68	(16,867)	475	8.
9.	Other current assets	(136)	(5,160)	(26,682)	9.
10.	Accounts payable	15,372	(190,141)	101,558	10.
11.	Accrued taxes	(25,038)	1,080	43,657	11.
12.	Accrued interest	1,565	1,555	7,189	12.
13.	Other current liabilities	44,224	(58,361)	101,685	13.
14.	Increase in regulatory assets	(11,029)	(17,516)	(14,138)	14.
15.	Change in risk management - assets	(22,570)	10,730	13,181	15.
16.	Change in customer advances	(23,780)	28,599	2,544	16.
17.	Change in pension liability	5,415	(30,346)	(18,373)	17.
18.	Change in other net long-term assets	(18,923)	(14,192)	64,998	18.
19.	Change in other net long-term liabilities	1,902	(9,986)	(27,396)	19.
20.	Net cash flow provided by operating activities	704,512	605,075	723,671	20.
	Cash Flows from Investing Activities:				
21.	Capital expenditures	(490,156)	(465,360)	(464,368)	21.
22.	Capitalized interest	(15,150)	(14,964)	(10,894)	22.
23.	Other	44,918	(41,926)	(72,189)	23.
24.	Net cash flow used for investing activities	(460,388)	(522,250)	(547,451)	24.
	Cash Flows from Financing Activities:				
25.	Issuance of long-term debt	459,926	396,072	300,000	25.
26.	Short-term borrowings	(171,162)	89,062	43,800	26.
27.	Dividends paid on common stock	(170,000)	(170,000)	(170,000)	27.
28.	Repayment and reacquisition of long-term debt	(337,160)	(383,747)	(354,888)	28.
29.	Net cash flow used for financing activities	(218,396)	(68,613)	(181,088)	29.
30.	Net increase (decrease) in cash and cash equivalents	25,728	14,212	(4,868)	30.
31.	Cash and cash equivalents at beginning of period	16,821	2,609	7,477	31.
32.	Cash and cash equivalents at end of period	$ 42,549	$ 16,821	$ 2,609	32.

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ARIZONA PUBLIC SERVICE COMPANY
Statement of Changes In Stockholders' Equity
Test Year 12/31/02 and Two Prior Years
(Dollars in Thousands)

Line No.	Description	Preferred Shares	Preferred Stock Amount	Common Shares	Common Stock Amount	Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Total	Line No.
1	Balance at January 1, 2000	-	$ -	71,264,947	$178,162	$1,246,804	$ 558,208	$ -	$ 1,983,174	1
2	Net income						306,594		306,594	2
3	Preferred stock dividends		-						-	3
4	Common stock dividends						(170,000)		(170,000)	4
5	Balance at December 31, 2000	-	-	71,264,947	178,162	1,246,804	694,802	-	2,119,768	5
6	Net income						265,487		265,487	6
7	Minimum pension liability adjustment, net of tax of $634							(966)	(966)	7
8	Cumulative effect of a change in accounting for derivatives, net of tax of $47,404							72,274	72,274	8
9	Unrealized loss on derivative instruments, net of tax of $71,720							(109,346)	(109,346)	9
10	Reclassification of realized gain to income, net of tax of $17,399							(26,527)	(26,527)	10
11	Comprehensive Income						265,487	(64,565)	200,922	11
12	Preferred stock dividends		-						-	12
13	Common stock dividends						(170,000)		(170,000)	13
14	Balance at December 31, 2001	-	-	71,264,947	178,162	1,246,804	790,289	(64,565)	2,150,690	14
15	Net income						199,343		199,343	15
16	Minimum pension liability adjustment, net of tax of $39,696							(60,521)	(60,521)	16
17	Unrealized gain on derivative instruments, net of tax of $25,426							38,764	38,764	17
18	Reclassification of realized loss to income, net of tax of $679							1,036	1,036	18
19	Comprehensive Income						199,343	(20,721)	178,622	19
20	Preferred stock dividends		-						-	20
21	Common stock dividends						(170,000)		(170,000)	21
22	Balance at December 31, 2002	-	$ -	71,264,947	$178,162	$1,246,804	$ 819,632	$ (85,286)	$ 2,159,312	22

Supporting Schedules:
N/A

Recap Schedules:
N/A

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ARIZONA PUBLIC SERVICE COMPANY
Detail of Utility Plant
Test Year Ended 12/31/02 & Prior Year Ended 12/31/01
(Thousands of Dollars)

Line No.	Account Description	Account Number	Test Year Ended Bal. 12/31/2002	Prior Year Ended Bal. 12/31/2001	Line No.
	Gross Plant Includible in Rate Base:				
1.	Plant in Service	101	$ 8,486,874	$ 8,094,720	1.
2.	Less: Accum. Depreciation-Plant in Service	108	3,421,819	3,268,321	2.
3.	Accum. Amortization-Plant in Service	111	120,728	104,140	3.
4.	Net Plant Includible in Rate Base		4,944,327	4,722,259	4.
5.	Nuclear fuel, net of amortization	120.2-120.5	7,466	6,933	5.
6.	Construction Work in Progress	107	312,852	302,633	6.
7.	Nuclear Fuel in Process	120.1	16,236	18,672	7.
8.	Total Construction Work in Progress		329,088	321,305	8.
9.	Plant Held for Future Use	105	5,493	10,387	9.
10.	Less: Accum Depreciation Related to Plant Held for Future Use	108	-	1,638	10.
11.	Net Plant held for Future Use		5,493	8,749	11.
12.	Utility Plant - Net		$ 5,286,374	$ 5,059,246	12.

Supporting Schedules:
N/A

Recap Schedules:
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ARIZONA PUBLIC SERVICE COMPANY
Detail of Plant Includible in Rate Base
Test Year Ended 12/31/02 & Prior Year Ended 12/31/01
(Thousands of Dollars)

Line No.	Account No.	Account Description	Prior Year Ended Bal. 12/31/2001	Net Additions (12 Months)	Test Year Ended Bal. 12/31/2002	Line No.
		Intangible Plant:				
1.	301	Organization	$ 74	-	$ 74	1.
2.	302	Franchises and Consents	883	1	884	2.
3.	303	Miscellaneous Intangible Plant	168,943	32,607	201,550	3.
4.		Total Intangible Plant	$ 169,900	32,608	$ 202,508	4.
		Production Plant:				
		Steam Production Plant:				
5.	310	Land and Land Rights	3,294	1	3,295	5.
6.	311	Structures and Improvements	116,250	(300)	115,950	6.
7.	312	Boiler Plant Equipment	767,931	32,527	800,458	7.
8.	314	Turbogenerator Units	183,786	4,417	188,203	8.
9.	315	Accessory Electric Equipment	135,922	(899)	135,023	9.
10.	316	Miscellaneous Power Plant Equip	47,909	5,433	53,342	10.
11.		Total Steam Production Plant	$ 1,255,092	$ 41,179	$ 1,296,271	11.
		Nuclear Production Plant:				
12.	320	Land and Land Rights	3,400	-	3,400	12.
13.	321	Structures and Improvements	626,488	7,912	634,400	13.
14.	322	Boiler Plant Equipment	966,970	(63)	966,907	14.
15.	323	Turbogenerator Units	340,626	980	341,606	15.
16.	324	Accessory Electric Equipment	273,760	(139)	273,621	16.
17.	325	Miscellaneous Power Plant Equip	131,768	688	132,456	17.
18.		Total Nuclear Production Plant	$ 2,343,012	$ 9,378	$ 2,352,390	18.

Supporting Schedules:
N/A

Recap Schedule:
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ARIZONA PUBLIC SERVICE COMPANY
Detail of Plant Includible in Rate Base
Test Year Ended 12/31/02 & Prior Year Ended 12/31/01
(Thousands of Dollars)

Line No.	Account No.	Account Description	Prior Year Ended Bal. 12/31/2001	Net Additions (12 Months)	Test Year Ended Bal. 12/31/2002	Line No.
		Hydraulic Production Plant:				
1.	330	Land and Land Rights	$ 65	-	$ 65	1.
2.	331	Structures and Improvements	101	-	101	2.
3.	332	Reservoirs, Dams and Waterways	992	-	992	3.
4.	333	Water Wheels, Turbines and Generators	157	-	157	4.
5.	334	Accessory Electric Equipment	628	-	628	5.
6.	335	Miscellaneous Power Plant Equip	126	-	126	6.
7.	336	Roads, Railroads and Bridges	77	-	77	7.
8.		Total Hydraulic Production Plant	$ 2,146	-	$ 2,146	8.
		Other Production Plant:				
9.	340	Land and Land Rights	28	-	28	9.
10.	341	Structures and Improvements	6,513	3,155	9,668	10.
11.	342	Fuel Holders, Producers and Accessories	23,760	2,416	26,176	11.
12.	343	Prime Movers	32,455	329	32,784	12.
13.	344	Generators	105,476	3,851	109,327	13.
14.	345	Accessory Electric Equipment	15,273	4,110	19,383	14.
15.	346	Miscellaneous Power Plant Equip	5,141	237	5,378	15.
16.		Total Other Production Plant	$ 188,646	14,098	$ 202,744	16.
17.		Total Production Plant	$ 3,788,896	$ 64,655	$ 3,853,551	17.

Supporting Schedules:
N/A

Recap Schedule:
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ARIZONA PUBLIC SERVICE COMPANY
Detail of Plant Includible in Rate Base
Test Year Ended 12/31/02 & Prior Year Ended 12/31/01
(Thousands of Dollars)

Line No.	Account No.		Account Description	Prior Year Ended Bal. 12/31/2001	Net Additions (12 Months)	Test Year Ended Bal. 12/31/2002	Line No.
			Transmission Plant				
1.	350	(a)	Land and Land Rights	$ 48,606	$ (160)	$ 48,446	1.
2.	352	(a)	Structures and Improvements	30,336	(2,718)	27,618	2.
3.	353	(a)	Station Equipment	383,887	43,134	427,021	3.
4.	354	(a)	Towers and Fixtures	83,289	176	83,465	4.
5.	355	(a)	Poles and Fixtures	165,072	9,123	174,195	5.
6.	356	(a)	Overhead Conductors and Devices	186,973	18,798	205,771	6.
7.	357		Underground Conduit	9,401	1,043	10,444	7.
8.	358		Underground Conductors and Devices	16,526	2,025	18,551	8.
9.			Total Transmission Plant	$ 924,090	$ 71,421	$ 995,511	9.
			Distribution Plant:				
10.	360		Land and Land Rights	22,083	4,672	26,755	10.
11.	361		Structures and Improvements	24,888	1,123	26,011	11.
12.	362		Station Equipment	194,232	18,125	212,357	12.
13.	364		Poles, Towers, and Fixtures	322,305	15,815	338,120	13.
14.	365		Overhead Conductors and Devices	212,086	6,771	218,857	14.
15.	366		Underground Conduit	385,609	40,114	425,723	15.
16.	367		Underground Conductors and Devices	754,929	50,576	805,505	16.
17.	368		Line Transformers	466,808	20,209	487,017	17.
18.	369		Services	230,739	11,666	242,405	18.
19.	370		Meters	144,577	1,445	146,022	19.
20.	371		Installations on Customers' Premises	23,469	1,926	25,395	20.
21.	373		Street Lighting and Signal Systems	57,023	164	57,187	21.
22.			Total Distribution Plant	$ 2,838,748	$ 172,606	$ 3,011,354	22.

(a) Excludes SCE 500kv Transmission Line

Supporting Schedules:
N/A

Recap Schedule:
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ARIZONA PUBLIC SERVICE COMPANY
Detail of Plant Includible in Rate Base
Test Year Ended 12/31/02 & Prior Year Ended 12/31/01
(Thousands of Dollars)

Line No.	Account No.		Account Description	Prior Year Ended Bal. 12/31/2001	Net Additions (12 Months)	Test Year Ended Bal. 12/31/2002	Line No.
			General Plant				
1.	389		Land and Land Rights	$ 6,717	$ 610	$ 7,327	1.
2.	390		Structures and Improvements	89,760	18,068	107,828	2.
3.	391	(b)	Office Furniture and Equipment	60,057	12,111	72,168	3.
4.	392	(b)	Transportation Equipment	31,273	16,692	47,965	4.
5.	393		Stores Equipment	1,275	(48)	1,227	5.
6.	394		Tools, Shop and Garage Equipment	10,840	1,833	12,673	6.
7.	395		Laboratory Equipment	1,351	-	1,351	7.
8.	396		Power Operated Equipment	34,849	(6,901)	27,948	8.
9.	397	(a)	Communication Equipment	84,078	8,220	92,298	9.
10.	398		Miscellaneous Equipment	1,083	253	1,336	10.
11.			Total General Plant	$ 321,283	$ 50,838	$ 372,121	11.
			SCE 500kv Transmission Line				
12.	350		Land and Land Rights	2,362	-	2,362	12.
13.	352		Structures and Improvements	410	-	410	13.
14.	353		Station Equipment	9,437	26	9,463	14.
15.	354		Towers and Fixtures	13,753	-	13,753	15.
16.	355		Poles and Fixtures	930	-	930	16.
17.	356		Overhead Conductors and Devices	22,654	-	22,654	17.
18.			Total SCE Transmission Line	$ 49,546	$ 26	$ 49,572	18.

(a) Excludes SCE 500kv Transmission Line
(b) Includes Capitalized Leases

Supporting Schedules:
N/A

Recap Schedule:
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ARIZONA PUBLIC SERVICE COMPANY
Detail of Plant Includible in Rate Base
Test Year Ended 12/31/02 & Prior Year Ended 12/31/01
(Thousands of Dollars)

Line No.	Account No.	Account Description	Prior Year Ended Bal. 12/31/2001	Net Additions (12 Months)	Test Year Ended Bal. 12/31/2002	Line No.
		SCE 500kv - General Plant				
1.	397	Communication Equipment	$ 2,257	-	$ 2,257	1.
2.		Total SCE 500kv Line	$ 51,803	$ 26	$ 51,829	2.
3.		Total Plant in Service - 101	$ 8,094,720	$ 392,154	$ 8,486,874	3.
4.		Total Net Plant Includible in Rate Base	$ 8,094,720	$ 392,154	$ 8,486,874	4.

Supporting Schedules:
N/A

Recap Schedule:
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ARIZONA PUBLIC SERVICE COMPANY
Electric Operating Statistics
Test Year and Two Prior Years

Line No.	Description	Test Year Ended 12/31/02	Prior Year Ended 12/31/01	Prior Year Ended 12/31/00	Line No.
	kWh Sales (thousands)				
1.	Residential	10,447,596	10,320,732	9,768,654	1.
2.	Commercial	10,594,216	10,479,999	10,044,996	2.
3.	Industrial	2,195,881	2,433,122	2,510,839	3.
4.	Irrigation	30,994	28,667	86,997	4.
5.	Public Street and Highway Lighting	99,529	94,693	92,915	5.
6.	Other Sales to Public Authorities	4,474	4,933	4,730	6.
7.	Total Sales to Ultimate Consumers	23,372,690	23,362,146	22,509,131	7.
8.	Sales for Resale - Requirements Customers	493,090	1,483,509	1,045,944	8.
9.	Sales for Resale - Other Customers	5,206,324	6,965,009	10,881,910	9.
10.	Total Sales for Resale	5,699,414	8,448,518	11,927,854	10.
11.	**Total kWh Sales**	29,072,104	31,810,664	34,436,985	11.
	Average Number of Customers				
12.	Residential	801,801	776,339	749,285	10.
13.	Commercial	95,575	93,499	89,539	11.
14.	Industrial	3,325	3,320	3,243	12.
13.	Irrigation	346	366	412	13.
14.	Public Street and Highway Lighting	759	780	717	14.
15.	Other Sales to Public Authorities	223	233	217	15.
16.	Total Retail Consumers	902,029	874,537	843,413	16.
17.	Sales for Resale - Requirements Customers	16	18	16	17.
18.	**Total Customers**	902,045	874,555	843,429	18.
	Average kWh Use (Annual)				
19.	Residential	13,030	13,294	13,037	19.
20.	Commercial	110,847	112,087	112,186	20.
21.	Industrial	660,415	732,868	774,233	21.
22.	Irrigation	89,578	78,325	211,158	22.
23.	Public Street and Highway Lighting	131,132	121,401	129,589	23.
24.	Other Sales to Public Authorities	20,063	21,172	21,797	24.
25.	Sales for Resale - Requirements Customers	30,818,125	82,417,167	65,371,500	25.
	Average Annual Revenue per Residential Customer				
26.	Annual Revenue	1,139.97	1,176.85	1,174.55	26.
27.	Revenue per kWh (Cents)	8.75	8.85	9.01	27.
28.	**Direct kWh Production Expense per kWh Sold (Cents)**	2.90	5.49	4.09	28.
29.	**Direct kWh Transmission Expense per kWh Sold (Cents)**	0.09	0.08	0.07	29.

Supporting Schedules:
N/A

Recap Schedules:
N/A

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ARIZONA PUBLIC SERVICE COMPANY
Taxes Charged to Operations
Test Year 12/31/02 and Prior Two Years
(Dollars in Thousands)

Line No.	Discription	Test Year Ended 12/31/2002 (a)	Prior Year Ended 12/31/2001 (b)	Prior Year Ended 12/31/2000 (c)	Line No.
	Federal Taxes:				
1.	Income	$ (56,554)	$ 139,867	$ 188,914	1.
2.	F.I.C.A.*	29,831	27,967	27,249	2.
3.	Deferred Income Taxes	170,143	(22,221)	(28,494)	3.
4.	Environmental	-	-	-	4.
5.	Unemployment	316	323	348	5.
6.	Miscellaneous	-	-	-	6.
7.	Total	143,736	145,936	188,017	7.
	State Taxes:				
8.	Ad Valorem**	103,906	99,489	99,017	8.
9.	Sales***	130,981	125,143	113,889	9.
10.	Income	(16,825)	26,504	34,932	10.
11.	Unemployment	34	486	164	11.
12.	Deferred Income Taxes	36,191	(4,632)	(6,111)	12.
13.	Total	254,287	246,990	241,891	13.
	Local Taxes:				
14.	Sales	-	-	-	14.
15.	Total Taxes	$ 398,023	$ 392,926	$ 429,908	15.

* Includes payroll related taxes charged to others
** Includes local taxes
*** For SEC reporting purposes, sales taxes related to sales of electricity are excluded from both revenues and other taxes.

Supporting Schedules:
N/A

Recap Schedules:
N/A

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ARIZONA PUBLIC SERVICE COMPANY
Notes to Financial Statements

See the attached Arizona Public Service Company Form 10-K filed with the Securities and Exchange Commission for the fiscal year ended December 31, 2002. The notes to the financial statements are contained on pages 62 through 109 of the document.

Supporting Schedules	Recap Schedules
N/A	N/A

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-K

(Mark One)

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2002

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from _____ to _____
Commission File Number 1-4473

Arizona Public Service Company

(Exact name of registrant as specified in its charter)

ARIZONA (State or other jurisdiction of incorporation or organization)	86-0011170 (I.R.S. Employer Identification No.)
400 North Fifth Street, P.O. Box 53999 Phoenix, Arizona 85072-3999 (Address of principal executive offices, including zip code)	(602) 250-1000 (Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) or 12(g) of the Act: None.

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes X No __

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in any amendment to this Form 10-K. [X]

Indicate by check mark whether the registrant is an accelerated filer (as defined in Exchange Act Rule 12b-2). Yes __ No X

As of March 31, 2003, there were issued and outstanding 71,264,947 shares of the registrant's common stock, $2.50 par value, all of which were held beneficially and of record by Pinnacle West Capital Corporation.

The registrant meets the conditions set forth in General Instruction I1(a) and (b) and is therefore filing this document with the reduced disclosure format.

TABLE OF CONTENTS

GLOSSARY

ACC – Arizona Corporation Commission

ACC Staff – Staff of the Arizona Corporation Commission

ADEQ – Arizona Department of Environmental Quality

AISA – Arizona Independent Scheduling Administrator

ALJ – Administrative Law Judge

ANPP – Arizona Nuclear Power Project, also known as Palo Verde

APS – Arizona Public Service Company, the Company

APS Energy Services – APS Energy Services Company, Inc., a subsidiary of Pinnacle West

CC&N – Certificate of Convenience and Necessity

Cholla – Cholla Power Plant

Citizens – Citizens Communications Company

Clean Air Act – the Clean Air Act, as amended

Company – Arizona Public Service Company

CPUC – California Public Utility Commission

DOE – United States Department of Energy

EITF – the FASB's Emerging Issues Task Force

EPA – United States Environmental Protection Agency

ERMC –Energy Risk Management Committee

FASB – Financial Accounting Standards Board

FERC – United States Federal Energy Regulatory Commission

FIN – FASB Interpretation

Financing Application – our application filed with the ACC on September 16, 2002

FIP – Federal Implementation Plan

Fitch – Fitch, Inc.

Four Corners – Four Corners Power Plant

GAAP – accounting principles generally accepted in the United States of America

Interim Financing Application – our application filed with the ACC on November 8, 2002

IRS – United States Internal Revenue Service

ISO – California Independent System Operator

kW – kilowatt, one thousand watts

kWh – kilowatt – hour, one thousand watts per hour

Moody's – Moody's Investors Service

MW – megawatt, one million watts

MWh – megawatt-hours, one million watts per hour

Native Load – retail and wholesale sales supplied under traditional cost-based rate regulation

1999 Settlement Agreement – comprehensive settlement agreement related to the implementation of retail electric competition

NOV – Notice of Violation

NRC – United States Nuclear Regulatory Commission

Nuclear Waste Act – Nuclear Waste Policy Act of 1982, as amended

OCI – other comprehensive income

Palo Verde – Palo Verde Nuclear Generating Station

PG&E – PG&E Corp.

Pinnacle West – Pinnacle West Capital Corporation, parent company of the Company

Pinnacle West Energy – Pinnacle West Energy Corporation, a subsidiary of Pinnacle West

PRP – potentially responsible parties under Superfund

PX – California Power Exchange

RTO – regional transmission organization

Rules – ACC retail electric competition rules

Salt River Project – Salt River Project Agricultural Improvement and Power District

SCE – Southern California Edison Company

SEC – United States Securities and Exchange Commission

SFAS – Statement of Financial Accounting Standards

SMD – standard market design

SPE – special-purpose entity

Standard & Poor's – Standard & Poor's Corporation

SunCor – SunCor Development Company, a subsidiary of Pinnacle West

Superfund – Comprehensive Environmental Response, Compensation and Liability Act

System – non-trading energy related activities

T&D – transmission and distribution

Track A Order – ACC order dated September 10, 2002 regarding generation asset transfers and related issues

Track B Order –ACC order dated March 14, 2003 regarding competitive solicitation requirements for power purchases by Arizona's investor-owned electric utilities

Trading – energy-related activities entered into with the objective of generating profits on changes in market prices

VIE – variable interest entity

WestConnect – WestConnect RTO, LLC, a proposed RTO to be formed by owners of electric transmission lines in the southwestern United States

PART I

ITEM 1. BUSINESS

CURRENT STATUS

General

We were incorporated in 1920 under the laws of Arizona and currently have more than 902,000 customers. Pinnacle West owns all of our outstanding common stock. We provide either retail or wholesale electric service to substantially all of the state of Arizona, with the major exceptions of the Tucson metropolitan area and about half of the Phoenix metropolitan area. Electricity is delivered through a distribution system that we own. We also generate, sell and deliver electricity to wholesale customers in the western United States. Our marketing and trading division, as discussed below, sells, in the wholesale market, our and Pinnacle West Energy's generation output that is not needed for our Native Load, which includes loads for retail customers and cost-of-service wholesale customers. We do not distribute any products. During 2002, no single purchaser or user of energy (other than Pinnacle West) accounted for more than 1% of total electric revenues.

At December 31, 2002, we employed approximately 5,100 people, which includes employees assigned to joint-owned generating facilities for which we serve as the generating facility manager. Our principal executive offices are located at 400 North Fifth Street, Phoenix, Arizona 85004 (telephone 602-250-1000).

Marketing and Trading

In early 2003, the marketing and trading division was moved from Pinnacle West to us for future marketing and trading activities (existing wholesale contracts will remain at Pinnacle West) as a result of the ACC's Track A Order prohibiting the previously required transfer of our generating assets to Pinnacle West Energy (see "Overview of Arizona Regulatory Developments" below). The marketing and trading division sells, in the wholesale market, our and Pinnacle West Energy generation output that is not needed for our Native Load, which includes loads for retail customers and traditional cost-of-service wholesale customers. The division focuses primarily on managing our purchased power and fuel risks in connection with our costs of serving retail customer energy requirements. See "Management's Discussion and Analysis of Financial Condition and Results of Operations - Factors Affecting Our Financial Outlook" in Item 7 for a discussion of our implementation of an ACC-mandated process by which we must competitively procure energy. Additionally, the marketing and trading division, subject to specific parameters, markets, hedges and trades in electricity, fuels and emission allowances and credits. See "Management's Discussion and Analysis of Financial Condition and Results of Operations" in Item 7 for information about the historical and prospective contribution of the marketing and trading activities to our financial results.

Business Segments

We have two principal business segments (determined by services and the regulatory environment):

- our regulated electricity segment (98% of operating revenues in 2002), which consists of regulated traditional retail and wholesale electricity businesses and related activities, and includes electricity transmission, distribution and generation; and
- our marketing and trading segment (2% of operating revenues in 2002), which consists of our competitive energy business activities, including wholesale marketing and trading.

See Note 15 of Notes to Financial Statements in Item 8 for financial information about our business segments.

Overview of Arizona Regulatory Developments

As discussed in "Management's Discussion and Analysis of Financial Condition and Results of Operations - Factors Affecting Our Financial Outlook" in Item 7, we believe pending Arizona regulatory matters are among the key factors affecting our financial outlook.

General

On September 21, 1999, the ACC approved Rules that provided a framework for the introduction of retail electric competition in Arizona. On September 23, 1999, the ACC approved a comprehensive settlement agreement among us and various parties related to the implementation of retail electric competition in Arizona. Under the Rules, as modified by the 1999 Settlement Agreement, we were required to transfer all of our competitive electric assets and services to an unaffiliated party or parties or to a separate corporate affiliate or affiliates no later than December 31, 2002. Consistent with that requirement, we had been addressing the legal and regulatory requirements necessary to complete the transfer of our generation assets to Pinnacle West Energy on or before that date. On September 10, 2002, the ACC issued the Track A Order, which, among other things, directed us not to transfer our generation assets to Pinnacle West Energy. See Note 3 of Notes to Financial Statements in Item 8 for additional information about the 1999 Settlement Agreement, the Rules (including legal challenges to the Rules), and the Track A Order.

Financing Application

On September 16, 2002, we filed an application with the ACC requesting the ACC to allow us to borrow up to $500 million and to lend the proceeds to Pinnacle West Energy or to Pinnacle West; to guarantee up to $500 million of Pinnacle West Energy's or Pinnacle West's debt; or a combination of both, not to exceed $500 million in the aggregate. In our application, we stated that the ACC's reversal of the generation asset transfer requirement and the resulting bifurcation of generation assets between us and Pinnacle West Energy under different regulatory regimes result in Pinnacle West Energy being unable to attain investment-grade credit ratings. This, in turn, precludes Pinnacle West Energy from accessing capital markets to refinance the bridge financing that Pinnacle West provided to fund the construction of Pinnacle West Energy generation assets or from effectively competing in wholesale markets. On March 27, 2003, the ACC authorized us to lend up to $500 million to Pinnacle West Energy, guarantee up to $500 million of Pinnacle West Energy debt or a combination of both, not to exceed $500 million in the aggregate. See "ACC Applications" in Note 3 of Notes to Financial Statements in Item 8 for additional information.

Competitive Procurement Process

On September 10, 2002, the ACC issued an order that, among other things, established a requirement that we competitively procure certain power requirements. On March 14, 2003, the ACC issued the Track B Order, which documented the decision made by the ACC at its open meeting on February 27, 2003, addressing this requirement. Under the order, we will be required to solicit bids for certain estimated capacity and energy requirements for periods beginning July 1, 2003. For 2003, we will be required to solicit competitive bids for about 2,500 MW of capacity and about 4,600 gigawatt-hours of energy, or approximately 20% of our total retail energy requirements. The bid amounts are expected to increase in 2004 and 2005 based largely on growth in our retail load and retail energy sales. The Track B Order also confirmed that it was "not intended to change the current rate base status of [APS'] existing assets." The order recognizes our right to reject any bids that are unreasonable, uneconomical or unreliable.

We expect to issue requests for proposals in March 2003 and to complete the selection process by June 1, 2003. Pinnacle West Energy will be eligible to bid to supply our electricity requirements. See "Track B Order" in Note 3 of Notes to Financial Statements in Item 8 for additional information.

General Rate Case

As required by the 1999 Settlement Agreement, on or before June 30, 2003, we will file a general rate case with the ACC. In this rate case, we will update our cost of service and rate design. In addition, we expect to seek:

- rate base treatment of certain power plants currently owned by Pinnacle West Energy (specifically, Redhawk Units 1 and 2, West Phoenix Units 4 and 5 and Saguaro Unit 3);

- recovery of the $234 million pretax asset write-off recorded by us as a result of the 1999 Settlement Agreement; and

- recovery of costs incurred by us in preparation for the previously required transfer of generation assets to Pinnacle West Energy.

We assume that the ACC will make a decision in this general rate case by the end of 2004.

Forward-Looking Statements

This document contains forward-looking statements based on current expectations and we assume no obligation to update these statements or make any further statements on any of these issues, except as required by applicable law. Because actual results may differ materially from expectations, we caution readers not to place undue reliance on these statements. A number of factors could cause future results to differ materially from historical results, or from results or outcomes currently expected or sought by us. These factors include the ongoing restructuring of the electric industry, including the introduction of retail electric competition in Arizona and decisions impacting wholesale competition; the outcome of regulatory and legislative proceedings relating to the restructuring; state and federal regulatory and legislative decisions and actions, including price caps and other market constraints imposed by the FERC; regional economic and market conditions, including the California energy situation and completion of generation and transmission construction in the region, which could affect customer growth and the cost of power supplies; the cost of debt and equity capital and access to capital markets; weather variations affecting local and regional customer energy usage; the effect of conservation programs on energy usage; power plant performance; our ability to compete successfully outside traditional regulated markets (including the wholesale market); our ability to manage our marketing and trading activities and the use of derivative contracts in our business; technological developments in the electric industry; the performance of the stock market, which affects the amount of our required contributions to our pension plan and nuclear decommissioning trust funds; and other uncertainties, all of which are difficult to predict and many of which are beyond our control.

REGULATION AND COMPETITION

Retail

The ACC regulates our retail electric rates and our issuance of securities. The ACC must also approve any transfer of our utility property and certain transactions between us and affiliated parties. See "Management's Discussion and Analysis of Financial Condition and Results of Operations – Factors Affecting Our Financial Outlook" in Item 7 and Note 3 of Notes to Financial Statements in Item 8 for a discussion of the status of electric industry restructuring in Arizona.

We are subject to varying degrees of competition from other utilities in Arizona (such as Tucson Electric Power Company, Southwest Gas Corporation and Citizens Communications Company) as well as cooperatives, municipalities, electrical districts and similar types of governmental organizations (principally Salt River Project). We also face competition from low-cost hydroelectric power and parties that have access to low-priced preferential federal power and other subsidies. In addition, some customers, particularly industrial and large commercial customers, may own and operate facilities to generate their own electric energy requirements. Although some very limited retail competition existed in our service area in 1999 and 2000, there are currently no active retail competitors providing unbundled energy or other utility services to our customers. As a result, we cannot predict when, and the extent to which, additional competitors will re-enter our service territory. As competition in the electric industry continues to evolve, we will continue to evaluate strategies and alternatives that will position us to compete effectively in a restructured industry.

Wholesale

General

The FERC regulates rates for wholesale power sales and transmission services. During 2002, approximately 11% of our electric operating revenues resulted from such sales and services. In early 2003, the marketing and trading division was moved from Pinnacle West to us for all future marketing and trading activities (existing wholesale contracts will remain at Pinnacle West) as a result of the ACC's Track A Order prohibiting the previously required transfer of our generating assets to Pinnacle West Energy (see "Overview of Arizona Regulatory Developments" above). The marketing and trading division sells, in the wholesale market, our and Pinnacle West Energy's generation output that is not needed for our Native Load and, in doing so, competes with other utilities, power marketers and independent power producers. The division focuses primarily on managing our purchased power and fuel risks in connection with our costs of serving retail customer energy requirements. See "Track B Order" in Note 3 of Notes to Financial Statements in Item 8 for information regarding an ACC-mandated process by which we must competitively procure energy.

Regional Transmission Organizations

On December 20, 1999, the FERC issued its Order No. 2000 regarding regional transmission organizations. In its order, the FERC set minimum characteristics and functions that must be met by utilities that participate in RTOs. The characteristics for an acceptable RTO include independence from market participants, operational control over a region large enough to support efficient and nondiscriminatory markets and exclusive authority to maintain short-term reliability.

As stated in Order No. 2000, the FERC believes that a number of benefits will result from the formation of RTOs throughout the country, and it has moved aggressively to ensure that all public utilities participate in an RTO or demonstrate why such participation is not feasible. According to the FERC, the benefits it expects to result from RTO formation include: (1) improvements in transmission system operations with resulting enhancements to inter-regional trade, congestion management, reliability and coordination; and (2) improved performance of energy markets, including greater incentives for efficient generator performance and enhanced potential for demand response.

On October 16, 2001, we and other owners of electric transmission lines in the Southwest filed with the FERC a request for a declaratory order confirming that their proposal to form WestConnect RTO, LLC would satisfy the FERC's requirements for the formation of an RTO. We and the other filing parties have agreed to fund the start-up of WestConnect's operations, which are subject to FERC approval. WestConnect has been structured as a for-profit RTO and evolved from DesertSTAR, a not-for-profit corporation in which we participated, which was originally designed to serve as an RTO for the southwestern United States. The success of WestConnect will be largely dependent on participation by all major transmission owners in the Southwest. The success is also dependent on support from the affected state regulatory commissions.

On October 10, 2002, the FERC issued an order finding that the WestConnect proposal, if modified to address specified issues, could meet the FERC's RTO requirements and provide the basic framework for a standard market design for the Southwest. In its order, the FERC also stated that its approval of various WestConnect provisions addressed in the order would not be overturned or affected by the final rule the FERC intends to ultimately adopt in response to its July 31, 2002 Notice of Proposed Rulemaking regarding a standard market design for the electric utility industry (see "Federal" in Note 3 of Notes to Financial Statements in Item 8 for additional information regarding the Notice of Proposed Rulemaking). On November 12, 2002, we and other owners filed a request for rehearing and clarification on portions of the October 10, 2002 order.

On December 23, 2002, the FERC issued its order on rehearing. In it, the FERC clarified the RTO elements that it had approved. In its order, the FERC stated that it envisions the Seams Steering Group - Western Interconnection (SSG-WI) as the entity that will facilitate a common market design for the West. The SSG-WI consists of western transmission owners, including members of WestConnect. The FERC also noted that its prior WestConnect order did not address other elements of market design that are currently being considered in the pending SMD proposal and/or through the SSG-WI process. The FERC clarified that there are only three areas that would be subject to the final SMD rule: (1) transmission credits; (2) resource adequacy; and (3) market monitoring.

The order also stated that FERC's approval of the for-profit structure will not predetermine its decision in the final SMD rule regarding whether a for-profit independent transmission company should be permitted to perform all the functions of an independent transmission provider. To the extent that the FERC has not addressed aspects of WestConnect's for-profit proposal or WestConnect's proposed particular functions, such elements will be subject to review for consistency with Order No. 2000 and other related decisions regarding functions that may be performed by an independent transmission company. The WestConnect applicants sought further clarification of that aspect of the rehearing order. The FERC has indicated that it will issue an order on the WestConnect applicants' motion for clarification before April 14, 2003.

The ACC Rules also required the formation and implementation of an Arizona Independent Scheduling Administrator. The purpose of the AISA is to oversee the application of operating protocols to ensure statewide consistency for transmission access. The AISA is anticipated to be a temporary organization until the implementation of an independent system operator or RTO. APS participated in the creation of the AISA, a not-for-profit entity, and the filing at the FERC for approval of its operating protocols. The operating protocols were partially rejected and the remainder are currently under review. On February 8, 2002, the ACC's Chief ALJ issued a procedural order which consolidated the ACC docket relating to the AISA with several other pending ACC dockets. In its Track B Order, the ACC directed that a hearing be held on whether or not we should be required to continue funding the AISA.

Purchased Power and Generating Fuel

See "Properties – Net Accredited Capacity" in Item 2 for information about our power plants by fuel types.

2002 Energy Mix

Our sources of energy during 2002 were: purchased power – 30.4% (approximately 60% of which was for wholesale power operations); coal – 37.2%; nuclear –27.7%; gas – 4.6%; and other (includes oil, hydro and solar) – 0.1%.

Coal Supply

Cholla Cholla is a coal-fired power plant located in northeastern Arizona. It is a jointly-owned facility operated by us. We purchase most of Cholla's coal requirements from a coal supplier that mines all of the coal under a long-term lease of coal reserves owned by the Navajo Nation, the federal government and private landholders. Cholla has sufficient coal, including low sulfur coal, under current contracts to ensure a reliable fuel supply through 2007. We purchase a portion of Cholla's coal requirements on the spot market to take advantage of competitive pricing options. Following expiration of current contracts, we believe that numerous competitive fuel supply options will exist to ensure the continued operation of Cholla for its useful life.

Four Corners Four Corners is a coal-fired power plant located in the northwest corner of New Mexico. It is a jointly-owned facility operated by us. We purchase all of Four Corners' coal requirements from a supplier with a long-term lease of coal reserves owned by the Navajo Nation. Four Corners is under contract for coal through 2004, with options to extend the contract through the plant site lease expiration in 2017.

Navajo Generating Station The Navajo Generating Station is a coal-fired power plant located in northern Arizona. It is a jointly-owned facility operated by Salt River Project. The Navajo Generating Station's coal requirements are purchased from a supplier with long-term leases from the Navajo Nation and the Hopi Tribe. The Navajo Generating Station is under contract with its coal supplier through 2011, with options to extend through the plant site lease expiration in 2019. The Navajo Generating Station lease waives certain taxes through the lease expiration in 2019. The lease provides for the potential to renegotiate the coal royalty in 2007 and 2017, which may impact the fuel price.

See "Properties – Net Accredited Capacity" in Item 2 for information about our ownership interest in Cholla, Four Corners and the Navajo Generating Station. See Note 10 of Notes to Financial Statements in Item 8 for information regarding our coal mine reclamation obligations.

Natural Gas Supply

We purchase the majority of our natural gas requirements for our gas-fired plants under contracts with a number of natural gas suppliers. Our natural gas supply is transported pursuant to a firm, full requirements transportation service agreement with El Paso Natural Gas Company. The transportation agreement features a 10-year rate moratorium established in a comprehensive rate case settlement entered into in 1996.

In a pending FERC proceeding, El Paso Natural Gas Company has proposed allocating its gas pipeline capacity in such a way that our (and other companies with the same contract type) gas transportation rights could be significantly impacted. Various parties, including Pinnacle West Energy and us, have challenged this allocation as being inconsistent with El Paso Natural Gas Company's existing contractual obligations and a 1996 settlement. On May 31, 2002 the FERC issued an order requiring the conversion of all firm, full requirements contracts to contract demand contracts by November 1, 2002. In addition, the FERC order set forth procedures to encourage parties to resolve the details of such conversions through a settlement process. We and other full requirements contract holders sought rehearing of the FERC order and requested a stay of the November 1, 2002 implementation date. On September 20, 2002, the FERC issued another order clarifying the capacity allocation methodology, extending the conversion implementation date from November 1, 2002 to May 1, 2003 and approving the reallocation of costs for the transportation service. We and other full requirements contract holders have sought rehearings of this FERC order. The FERC has indicated that it intends to issue an order on the merits in this proceeding by April 14, 2003. Although we cannot predict the outcome of this matter, we currently do not expect this matter to have a material adverse impact on our financial position, results of operations or liquidity. We are continuing to analyze the market to determine the most favorable source and method of meeting our natural gas requirements.

Nuclear Fuel Supply

Palo Verde Fuel Cycle Palo Verde is a nuclear power plant located about 50 miles west of Phoenix, Arizona. It is a jointly-owned facility operated by us. The fuel cycle for Palo Verde is comprised of the following stages:

- mining and milling of uranium ore to produce uranium concentrates;
- conversion of uranium concentrates to uranium hexafluoride;
- enrichment of uranium hexafluoride;
- fabrication of fuel assemblies;
- utilization of fuel assemblies in reactors; and
- storage and disposal of spent nuclear fuel.

The Palo Verde participants have contracted for all of Palo Verde's requirements for uranium concentrates and conversion services through 2008, except for a small percentage of 2003 uranium concentrates and 2004 conversion requirements that will be obtained under contracts currently being finalized. The Palo Verde participants have also contracted for all of Palo Verde's enrichment services through 2010 and fuel assembly fabrication services until at least 2015.

Spent Nuclear Fuel and Waste Disposal Nuclear power plant operators are required to enter into spent nuclear fuel disposal contracts with the DOE, and the DOE is required to accept and dispose of all spent nuclear fuel and other high-level radioactive wastes generated by domestic power reactors. Although the Nuclear Waste Act required the DOE to develop a permanent repository for the storage and disposal of spent nuclear fuel by 1998, the DOE has announced that the repository cannot be completed before 2010 and that it does not intend to begin accepting spent nuclear fuel prior to that date. In November 1997, the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit) issued a decision preventing the DOE from excusing its own delay, but refused to order the DOE to begin accepting spent nuclear fuel. Based on this decision and the DOE's delay, a number of utilities filed damages lawsuits against the DOE in the Court of Federal Claims.

In February 2002, the U.S. Secretary of Energy recommended to President Bush that the Yucca Mountain, Nevada site be developed as a permanent repository for spent nuclear fuel. The President transmitted this recommendation to Congress and the State of Nevada vetoed the President's recommendation. In July 2002, Congress approved the development of the Yucca Mountain, Nevada site, overriding the Nevada veto. It is now expected that the DOE will submit a license application to the NRC late in 2004. The State of Nevada has filed several lawsuits relating to the Yucca Mountain site. We cannot currently predict what further steps will be taken in this area.

Facility funding is a further complication. While all nuclear utilities pay an amount calculated on the basis of the output of their respective plants into a so-called nuclear waste fund the annual Congressional appropriations for the permanent repository have been for amounts less than the amounts paid into the waste fund (the balance of which is being used for other purposes).

We have existing fuel storage pools at Palo Verde and have completed a new facility for on-site dry storage of spent nuclear fuel. With the existing storage pools and the addition of the new facility, we believe that spent nuclear fuel storage or disposal methods will be available for use by Palo Verde to allow its continued operation through the term of the operating license for each Palo Verde unit. See "Palo Verde Nuclear Generating Station" in Note 10 of Notes to Financial Statements in Item 8 for a discussion of interim spent nuclear fuel storage costs.

Although some low-level waste has been stored on-site in a low-level waste facility, we are currently shipping low-level waste to off-site facilities. We currently believe that interim low-level waste storage methods are or will be available for use by Palo Verde to allow its continued operation and to safely store low-level waste until a permanent disposal facility is available.

We believe that scientific and financial aspects of the issues of spent nuclear fuel and low-level waste storage and disposal can be resolved satisfactorily. However, we acknowledge that their ultimate resolution in a timely fashion will require political resolve and action on national and regional scales which we are less able to predict. We expect to vigorously protect and pursue our rights related to this matter.

Purchased Power Agreements

In addition to that available from our own generating capacity (see "Properties" in Item 2), we purchase electricity under various arrangements. One of the most important of these is a long-term contract with Salt River Project. The amount of electricity available to us is based in large part on customer demand within certain areas now served by us pursuant to a related territorial agreement. The generating capacity available to us pursuant to the contract was 336 MW from January through May 2002, and starting in June 2002, it changed to 343 MW. In 2002, we received approximately 1,104,973 MWh of energy under the contract and paid about $46.2 million for capacity availability and energy received. This contract may be canceled by Salt River Project on three years' notice, given no earlier than December 31, 2003. We may also cancel the contract on five years' notice, given no earlier than December 31, 2006.

In September 1990, we entered into a thirty-year seasonal capacity exchange agreement with PacifiCorp. Under this agreement, we receive electricity from PacifiCorp during the summer peak season (from May 15 to September 15) and we return electricity to PacifiCorp during the winter season (from October 15 to February 15). Until 2020, we and PacifiCorp each has 480 MW of capacity and a related amount of energy available to it under the agreement for its respective seasons. In 2002, we received approximately 571,392 MWh of energy under the capacity exchange. We must also make additional offers of energy to PacifiCorp each year through October 31, 2020. Pursuant to this requirement, during 2002, PacifiCorp received offers of 1,129,600 MWh and purchased about 115,750 MWh.

Construction Program

During the years 2000 through 2002, we incurred approximately $1.4 billion in capital expenditures. Our capital expenditures for the years 2003 through 2005 are expected to be primarily for expanding transmission and distribution capabilities to meet growing customer needs, for upgrading existing utility property and for environmental purposes. Our capital expenditures were approximately $501 million in 2002. Our capital expenditures, including expenditures for environmental control facilities, for the years 2003 through 2005 have been estimated as follows:

(dollars in millions)

By Year		By Major Facilities	
2003	$ 401	Production	$ 386
2004	379	T&D	877
2005	498	Other	15
Total	$ 1,278	Total	$ 1,278

The above amounts exclude capitalized interest costs and include capitalized property taxes and approximately $30 million per year for nuclear fuel. These amounts include only our generation (production) assets. We conduct a continuing review of our construction program.

See "Management's Discussion and Analysis of Financial Condition and Results of Operations – Capital Needs and Resources" in Item 7 for additional information about our construction program.

Mortgage Replacement Fund Requirements

So long as any of our first mortgage bonds are outstanding, we are required for each calendar year to deposit with the trustee under our mortgage cash in a formularized amount related to net additions to our mortgaged utility plant. We may satisfy all or any part of this "replacement fund" requirement by using redeemed or retired bonds, net property additions or property retirements. For 2002, the replacement fund requirement amounted to approximately $161 million. Certain of the bonds we have issued under the mortgage that are callable prior to maturity are redeemable at their par value plus accrued interest with cash we deposit in the replacement fund. These call provisions are subject in many cases to a period of time after the original issuance of the bonds during which they may not be redeemed in this manner. See Note 6 of Notes to Financial Statements in Item 8 for information regarding our first mortgage bonds.

Environmental Matters

EPA Environmental Regulation

Clean Air Act We are subject to a number of requirements under the Clean Air Act. The Clean Air Act addresses, among other things:

- "acid rain";
- visibility in certain specified areas;
- hazardous air pollutants; and
- areas that have not attained national ambient air quality standards.

With respect to "acid rain," the Clean Air Act established a system of sulfur dioxide emissions "allowances" to offset each ton of sulfur dioxide emitted by affected power plants. Based on EPA allowance allocations, we will have sufficient allowances to permit continued operation of our plants at current levels without installing additional equipment. The Clean Air Act also requires the EPA to set nitrogen oxides emissions limitations for certain coal-fired units. The EPA rule allows emissions from all units in a plant to be averaged to demonstrate compliance with the emission limitation. Currently, nitrogen oxides emissions from all of our units are within the limitations specified under the EPA's rules. We do not currently expect this rule to have a material impact on our financial position, results of operations or liquidity.

The Clean Air Act required the EPA to establish a Grand Canyon Visibility Transport Commission to complete a study on visibility impairment in sixteen "Class I Areas" (large national parks and wilderness areas) on the Colorado Plateau. The Navajo Generating Station, Cholla and Four Corners are located near several Class I Areas on the Colorado Plateau. The Visibility

Commission completed its study and on June 10, 1996 submitted its final recommendations to the EPA.

On April 22, 1999, the EPA announced final regional haze rules. These new regulations require states to submit, by 2008, implementation plans to eliminate all man-made emissions causing visibility impairment in certain specified areas, including Class I Areas in the Colorado Plateau. The 2008 implementation plans must also include consideration and potential application of best available retrofit technology for major stationary sources which came into operation between August 1962 and August 1977, such as the Navajo Generating Station, Cholla and Four Corners.

The rules allow the nine western states and tribes that participated in the Visibility Commission process to follow an alternate implementation plan and schedule for the Class I Areas considered by the Visibility Commission. Under this option, those states and tribes would submit implementation plans by 2003, which would incorporate certain regional sulfur dioxide emissions milestones for the years 2003, 2008, 2013 and 2018 (which include the application of best available retrofit technology). If the regional emissions in those years were within those milestones, there would be no further emission reduction requirements, and if they were exceeded, then an emission trading program would be implemented to maintain the emissions within those milestones.

The EPA reviewed an "Annex" to the Visibility Commission recommendations that specify the regional sulfur dioxide emission milestones. On April 26, 2002, the EPA proposed to accept the Visibility Commission's Annex, which had been submitted by the Western Regional Air Partnership (successor to Visibility Commission) in September 2000. The Annex specifies regional sulfur dioxide emission reduction milestones. The EPA's final approval of the Annex would allow the states and tribes to pursue the alternate implementation of the regional haze rules through 2018. Any states and tribes that implement this option would have to submit state implementation plans by 2003 to address visibility in areas identified in the process, and revised implementation plans in 2008 to address Class I Areas which were not included in the process. The State of Arizona is in the process of developing a State Implementation Plan to implement the provisions of the Annex. Because Four Corners is located on the Navajo Reservation and is currently regulated by EPA Region IX, the provisions of the Annex currently could become applicable to Four Corners only through a Federal Implementation Plan promulgated by EPA Region IX. At this time, it is uncertain how the State of Arizona and/or EPA Region IX will proceed to implement the Annex, so the actual impact on us cannot yet be determined.

In July 1997, the EPA promulgated final National Ambient Air Quality Standards for ozone and particulate matter. Pursuant to these rules, the ozone standard is more stringent and a new ambient standard for very fine particles has been established. Congress has enacted legislation that could delay the implementation of regional haze requirements and the particulate matter ambient standard; however, the legislation does not preclude the Visibility Commission states and tribes from implementing the alternate regional haze rules discussed above. Because the actual level of emissions controls, if any, for any unit cannot be determined at this time, we currently cannot estimate the capital expenditures, if any, which would result from the final rules. However, we do not currently expect these rules to have a material adverse effect on our financial position, results of operations or liquidity.

With respect to hazardous air pollutants emitted by electric utility steam generating units, the EPA has determined that mercury emissions and other hazardous air pollutants from coal and oil-fired power plants will be regulated. We expect that the EPA will propose specific rules for this purpose in 2003 and finalize them by 2004, with compliance required by 2008. Because the ultimate requirements that the EPA may impose are not yet known, we cannot currently estimate the capital expenditures, if any, which may be required.

Certain aspects of the Clean Air Act may require us to make related expenditures, such as permit fees. We do not expect any of these expenditures to have a material impact on our financial position, results of operations or liquidity.

Federal Implementation Plan In September 1999, the EPA proposed a FIP to set air quality standards at certain power plants, including the Navajo Generating Station and Four Corners. The comment period on this proposal ended in November 1999. The FIP is similar to current Arizona regulation of the Navajo Generating Station and New Mexico regulation of Four Corners, with minor modifications. We do not currently expect the FIP to have a material impact on our financial position, results of operations or liquidity.

Superfund The Comprehensive Environmental Response, Compensation, and Liability Act (Superfund) establishes liability for the cleanup of hazardous substances found contaminating the soil, water or air. Those who generated, transported or disposed of hazardous substances at a contaminated site are among those who are potentially responsible parties. PRPs may be strictly, and often jointly and severally, liable for clean-up. The EPA had previously advised us that the EPA considers us to be a PRP in the Indian Bend Wash Superfund Site, South Area. Our Ocotillo Power Plant is located in this area. Based on the information to date, including available insurance coverage and an EPA estimate of cleanup costs, we do not expect this matter to have a material impact on our financial position, results of operations or liquidity.

Manufactured Gas Plant Sites We are currently investigating properties which we now own or which were previously owned by us or our corporate predecessors, that were at one time sites of, or sites associated with, manufactured gas plants. The purpose of this investigation is to determine if:

- waste materials are present;
- such materials constitute an environmental or health risk; and
- we have any responsibility for remedial action.

Where appropriate, we have begun clean-up of certain of these sites. We do not expect these matters to have a material adverse effect on our financial position, results of operations or liquidity.

Arizona Department of Environmental Quality

ADEQ issued to us NOVs, dated September 25, 2001 and October 15, 2001 alleging, among other things, the burning of unauthorized materials and storage of hazardous waste without a permit at the Cholla Power Plant. Each NOV requires us to achieve and document compliance with specific environmental requirements. We have submitted responses to the NOVs as well as additional information requested by the agency. By letter dated February 28, 2003, the Arizona Attorney General notified us that the ADEQ expects to take enforcement action against us regarding the violations included in the NOVs, as well as related violations. We do not expect these matters to have a material adverse effect on our financial position, results of operations or liquidity.

Navajo Nation Environmental Issues

Four Corners and the Navajo Generating Station are located on the Navajo Reservation and are held under easements granted by the federal government as well as leases from the Navajo Nation. We are the Four Corners operating agent. We own a 100% interest in Four Corners Units 1, 2 and 3, and a 15% interest in Four Corners Units 4 and 5. We own a 14% interest in Navajo Generating Station Units 1, 2 and 3.

In July 1995, the Navajo Nation enacted the Navajo Nation Air Pollution Prevention and Control Act, the Navajo Nation Safe Drinking Water Act and the Navajo Nation Pesticide Act (collectively, the Navajo Acts). The Navajo Acts purport to give the Navajo Nation Environmental Protection Agency authority to promulgate regulations covering air quality, drinking water and pesticide activities, including those that occur at Four Corners and the Navajo Generating Station. The Four Corners and Navajo Generating Station participants dispute that purported authority, and by separate letters dated October 12 and October 13, 1995, the Four Corners participants and the Navajo Generating Station participants requested the United States Secretary of the Interior to resolve their dispute with the Navajo Nation regarding whether or not the Navajo Acts apply to operations of Four Corners and the Navajo Generating Station. On October 17, 1995, the Four Corners participants and the Navajo Generating Station participants each filed a lawsuit in the District Court of the Navajo Nation, Window Rock District, seeking, among other things, a declaratory judgment that:

- their respective leases and federal easements preclude the application of the Navajo Acts to the operations of Four Corners and the Navajo Generating Station; and
- the Navajo Nation and its agencies and courts lack adjudicatory jurisdiction to determine the enforceability of the Navajo Acts as applied to Four Corners and the Navajo Generating Station.

On October 18, 1995, the Navajo Nation and the Four Corners and Navajo Generating Station participants agreed to indefinitely stay these proceedings so that the parties may attempt to resolve the dispute without litigation. The Secretary and the Court have stayed these proceedings pursuant to a request by the parties. We cannot currently predict the outcome of this matter.

In February 1998, the EPA issued regulations identifying those Clean Air Act provisions for which it is appropriate to treat Indian tribes in the same manner as states. The EPA has announced that it has not yet determined whether the Clean Air Act would supersede pre-existing binding agreements between the Navajo Nation and the Four Corners participants and the Navajo Generating Station participants that could limit the Navajo Nation's environmental regulatory authority over the Navajo Generating Station and Four Corners. We believe that the Clean Air Act does not supersede these pre-existing agreements. We cannot currently predict the outcome of this matter.

In April 2000, the Navajo Tribal Council approved operating permit regulations under the Navajo Nation Air Pollution Prevention and Control Act. We believe that the regulations fail to recognize that the Navajo Nation did not intend to assert jurisdiction over Four Corners and the Navajo Generating Station. On July 12, 2000, the Four Corners participants and the Navajo Generating Station participants each filed a petition with the Navajo Supreme Court for review of the operating permit regulations. We cannot currently predict the outcome of this matter.

Water Supply

Assured supplies of water are important for our generating plants. At the present time, we have adequate water to meet our needs. However, conflicting claims to limited amounts of water in the southwestern United States have resulted in numerous court actions.

Both groundwater and surface water in areas important to our operations have been the subject of inquiries, claims and legal proceedings, which will require a number of years to resolve. We are one of a number of parties in a proceeding before a state court in New Mexico to adjudicate rights to a stream system from which water for Four Corners is derived. (State of New Mexico, in the relation of S.E. Reynolds, State Engineer vs. United States of America, City of Farmington, Utah International, Inc., et al., San Juan County, New Mexico, District Court No. 75-184). An agreement reached with the Navajo Nation in 1985, however, provides that if Four Corners loses a portion of its rights in the adjudication, the Navajo Nation will provide, for a then-agreed upon cost, sufficient water from our allocation to offset the loss.

A summons served on us in early 1986 required all water claimants in the Lower Gila River Watershed in Arizona to assert any claims to water on or before January 20, 1987, in an action pending in Maricopa County, Arizona, Superior Court. (In re The General Adjudication of All Rights to Use Water in the Gila River System and Source, Supreme Court Nos. WC-79-0001 through WC 79-0004 (Consolidated) [WC-1, WC-2, WC-3 and WC-4 (Consolidated)], Maricopa County Nos. W-1, W-2, W-3 and W-4 (Consolidated)). Palo Verde is located within the geographic area subject to the summons. Our rights and the rights of the Palo Verde participants to the use of groundwater and effluent at Palo Verde are potentially at issue in this action. As project manager of Palo Verde, we filed claims that dispute the court's jurisdiction over the Palo Verde participants' groundwater rights and their contractual rights to effluent relating to Palo Verde. Alternatively, we seek confirmation of such rights. Three of our other power plants and two of Pinnacle West Energy's power plants are also located within the geographic area subject to the summons. Our claims dispute the court's jurisdiction over our groundwater rights with respect to these plants. Alternatively, we seek confirmation of such rights. In November 1999, the Arizona Supreme Court issued a decision confirming that certain groundwater rights may be available to the federal government and Indian tribes. In addition, in September 2000, the Arizona Supreme Court issued a decision affirming the lower court's criteria for resolving groundwater claims. Litigation on both of these issues will continue in the trial court. No trial date concerning our water rights claims has been set in this matter.

We have also filed claims to water in the Little Colorado River Watershed in Arizona in an action pending in the Apache County, Arizona, Superior Court. (In re The General Adjudication of All Rights to Use Water in the Little Colorado River System and Source, Supreme Court No. WC-79-0006 WC-6, Apache County No. 6417). Our groundwater resource utilized at Cholla is within the geographic area subject to the adjudication and is therefore potentially at issue in the case. Our claims dispute the court's jurisdiction over our groundwater rights. Alternatively, we seek confirmation of such rights. A number of parties are in the process of settlement negotiations with respect to certain claims in this matter. Other claims have been identified as ready for litigation in motions filed with the court. No trial date concerning our water rights claims has been set in this matter.

Although the foregoing matters remain subject to further evaluation, we expect that the described litigation will not have a material adverse impact on our financial position, results of operations or liquidity.

The Four Corners region, in which Four Corners is located, has been experiencing drought conditions that may affect the water supply for the plants in 2003, as well as later years if adequate moisture is not received in the watershed that supplies the area. Various stakeholders in the San Juan Basin, including the New Mexico State Engineer, are evaluating how water rights might be affected by the drought conditions, including water rights pursuant to the New Mexico state permit that provide approximately 30,000 acre feet of water to Four Corners. We are assessing alternatives for temporary supplies of water and are working with area stakeholders to minimize the effect, if any, on operations of the plant. The effect of the drought cannot be fully assessed at this time, and we cannot predict the ultimate outcome, if any, of the drought or whether the drought will adversely affect the amount of power available, or the price thereof, from Four Corners.

ITEM 2. PROPERTIES

Net Accredited Capacity

Our present generating facilities have net accredited capacities as follows:

	Capacity(kW)
Coal:	
Units 1, 2 and 3 at Four Corners	560,000
15% owned Units 4 and 5 at Four Corners	222,000
Units 1, 2 and 3 at Cholla Plant	615,000
14% owned Units 1, 2 and 3 at the Navajo Plant	315,000
Subtotal	1,712,000
Gas or Oil:	
Two steam units at Ocotillo and two steam units at Saguaro	430,000(a)
Eleven combustion turbine units	493,000
Three combined cycle units	255,000
Subtotal	1,178,000
Nuclear:	
29.1% owned or leased Units 1, 2, and 3 at Palo Verde	1,086,300
Hydro and Solar	7,600
Total	3,983,900

(a) Does not include West Phoenix steam units (108,300 kW), which were retired in December 2002.

Reserve Margin

Our 2002 peak one-hour demand on our electric system was recorded on July 9, 2002 at 5,802,900 kW, compared to the 2001 peak of 5,687,200 kW recorded on July 2, 2001. Taking into account additional capacity then available to us under long-term purchase power contracts as well as our and Pinnacle West Energy's generating capacity, our capability of meeting system demand on July 9, 2002, amounted to 6,046,600 kW, for an installed reserve margin of 6.5%. The power actually available to us from our resources fluctuates from time to time due in part to planned outages and technical problems. The available capacity from sources actually operable at the time of the 2002 peak amounted to 3,877,600 kW, for a margin of negative 38.1%. Firm purchases totaling 2,612,000 kW, including short-term seasonal purchases and unit contingent purchases were in place at the time of the peak ensuring the ability to meet the load requirement, with an actual reserve margin of 7.1%.

See "Purchased Power Agreements" in Item 1 for information about certain of our long-term power agreements.

Plant Sites Leased from Navajo Nation

The Navajo Generating Station and Four Corners are located on land held under easements from the federal government and also under leases from the Navajo Nation. These are long-term agreements with options to extend, and we do not believe that the risk with respect to enforcement of these easements and leases is material. The majority of coal contracted for use in these plants and certain associated transmission lines are also located on Indian reservations. See "Purchased Power and Generating Fuel - Coal Supply" in Item 1.

Palo Verde Nuclear Generating Station

Palo Verde Leases

See Note 8 of Notes to Financial Statements in Item 8 for a discussion of three sale-leaseback transactions related to Palo Verde Unit 2.

Regulatory

Operation of each of the three Palo Verde units requires an operating license from the NRC. The NRC issued full power operating licenses for Unit 1 in June 1985, Unit 2 in April 1986 and Unit 3 in November 1987. The full power operating licenses, each valid for a period of approximately 40 years, authorize us, as operating agent for Palo Verde, to operate the three Palo Verde units at full power.

Nuclear Decommissioning Costs

The NRC rules on financial assurance requirements for the decommissioning of nuclear power plants provide that a licensee may use a trust as the exclusive financial assurance mechanism if the licensee recovers estimated total decommissioning costs through cost of service rates or through a "non-bypassable charge." The "non-bypassable systems benefits" charge is the charge that the ACC has approved to recover certain types of ACC-approved costs, including costs for low income programs, demand side management, consumer education, environmental, renewables, etc.

"Non-bypassable" means that if a customer chooses to take energy from an "energy service provider" other than us, the customer will still have to pay this charge to us as part of the customer's electric bill. Other mechanisms are prescribed, including prepayment, if the requirements for exclusive reliance on the external sinking fund mechanism are not met. We currently rely on the external sinking fund mechanism to meet the NRC financial assurance requirements for our interests in Palo Verde Units 1, 2 and 3. The decommissioning costs of Palo Verde Units 1, 2 and 3 are currently included in our ACC jurisdictional rates. ACC retail electric competition Rules provide that decommissioning costs would be recovered through a non-bypassable "system benefits" charge, which would allow us to maintain our external sinking fund mechanism. See Note 11 of Notes to Financial Statements in Item 8 for additional information about our nuclear decommissioning costs.

Palo Verde Liability and Insurance Matters

See "Palo Verde Nuclear Generating Station" in Note 10 of Notes to Financial Statements in Item 8 for a discussion of the insurance maintained by the Palo Verde participants, including us, for Palo Verde.

Property Not Held in Fee or Subject to Encumbrances

Jointly-Owned Facilities

We share ownership of some of our generating and transmission facilities with other companies. The following table shows our interest in those jointly-owned facilities recorded on the Balance Sheets at December 31, 2002:

	Percent Owned by Us
Generating facilities:	
Palo Verde Nuclear Generating Station Units 1 and 3	29.1%
Palo Verde Nuclear Generating Station Unit 2 (see "Palo Verde Leases" below)	17.0%
Four Corners Steam Generating Station Units 4 and 5	15.0%
Navajo Steam Generating Station Units 1, 2, and 3	14.0%
Cholla Steam Generating Station Common Facilities (a)	62.8%(b)
Transmission facilities:	
ANPP 500KV System	35.8%(b)
Navajo Southern System	31.4%(b)
Palo Verde-Yuma 500KV System	23.9%(b)
Four Corners Switchyards	27.5%(b)
Phoenix-Mead System	17.1%(b)
Palo Verde – Estrella 500KV System	50.0%(b)

(a) PacifiCorp owns Cholla Unit 4 and we operate the unit for PacifiCorp. The common facilities at the Cholla Plant are jointly-owned.

(b) Weighted average of interests.

Palo Verde Leases

In 1986, we sold about 42% of our share of Palo Verde Unit 2 and certain common facilities in three separate sale-leaseback transactions. We account for these leases as operating leases. The leases, which have terms of 29.5 years, contain options to renew the leases for two additional years and to purchase the property for fair market value at the end of the lease terms. See Notes 8 and 18 of Notes to Financial Statements in Item 8 for additional information regarding the Palo Verde Unit 2 sale-leaseback transactions.

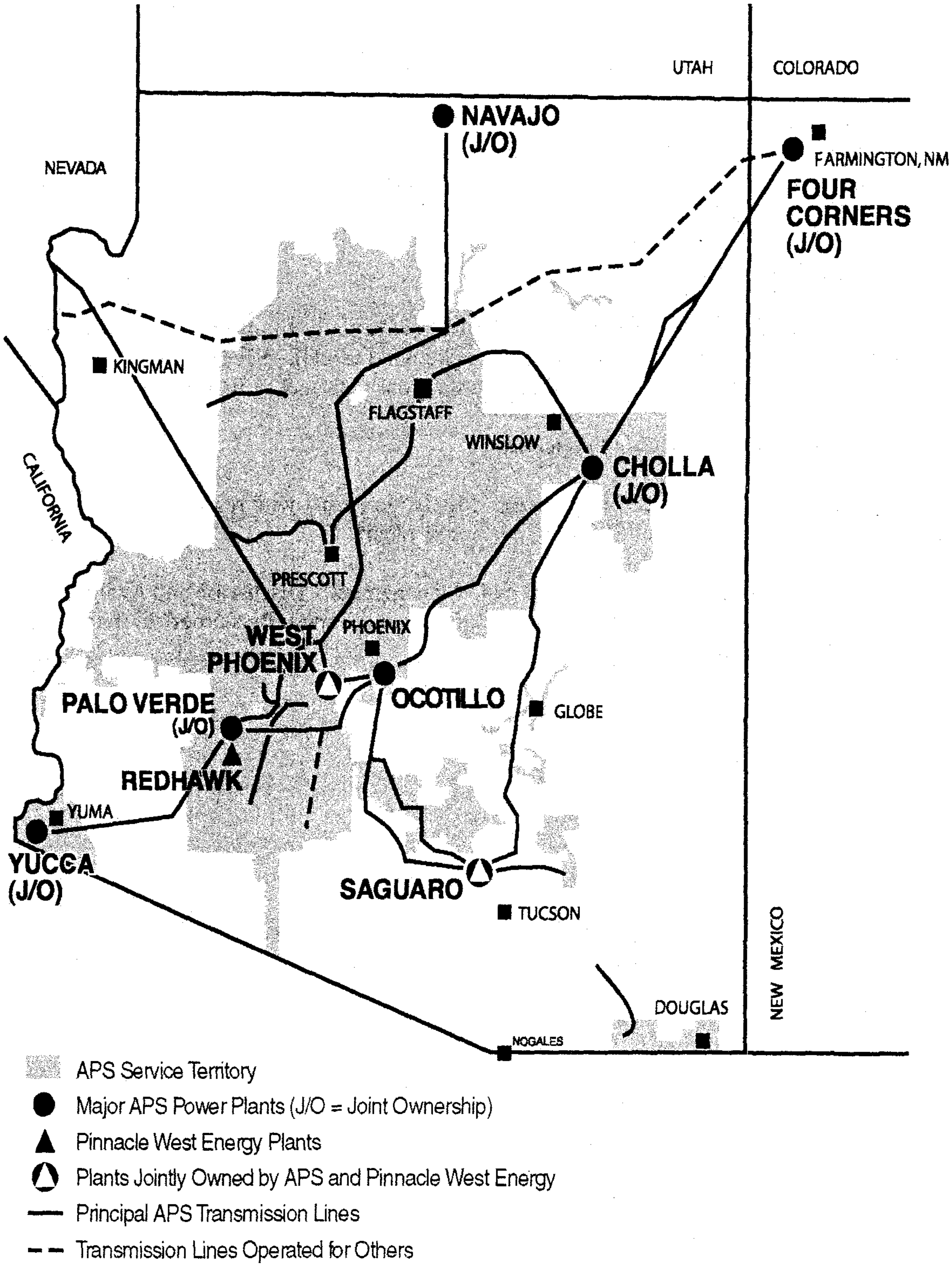
First Mortgage Lien

Our first mortgage bondholders share a lien on substantially all utility plant assets (other than nuclear fuel and transportation equipment and other excluded assets). See Note 6 of Notes to Financial Statements in Item 8 for information regarding our outstanding first mortgage bonds.

Other Information Regarding Our Properties

See "Environmental Matters" and "Water Supply" in Item 1 with respect to matters having possible impact on the operation of certain of our power plants.

See "Construction Program" in Item 1 and "Management's Discussion and Analysis of Financial Condition and Results of Operations - Liquidity and Capital Resources" in Item 7 for a discussion of our construction plans.


UTAH
COLORADO
NAVAJO
(J/O)
NEVADA
FARMINGTON, NM
FOUR
CORNERS
(J/O)
KINGMAN
FLAGSTAFF
WINSLOW
CALIFORNIA
CHOLLA
(J/O)
PRESCOTT
WEST
PHOENIX
PHOENIX
OCOTILLO
PALO VERDE
(J/O)
GLOBE
REDHAWK
YUMA
YUCCA
(J/O)
SAGUARO
TUCSON
NEW MEXICO
DOUGLAS
NOGALES
APS Service Territory
Major APS Power Plants (J/O = Joint Ownership)
Pinnacle West Energy Plants
Plants Jointly Owned by APS and Pinnacle West Energy
Principal APS Transmission Lines
Transmission Lines Operated for Others

ITEM 3. LEGAL PROCEEDINGS

See "Environmental Matters" and "Water Supply" in Item 1 in regard to pending or threatened litigation and other disputes. See Note 3 of Notes to Financial Statements in Item 8 for a discussion of the ACC retail electric competition Rules, the Track A Order and related litigation.

See Note 10 of Notes to Financial Statements in Item 8 for information relating to the FERC proceedings on California energy market issues and a claim by Citizens that we overcharged Citizens under a power service agreement.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

Not applicable.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON STOCK AND RELATED STOCKHOLDER MATTERS

Our common stock is wholly-owned by Pinnacle West and is not listed for trading on stock exchange. As a result, there is no established public trading market for our common stock.

The chart below sets forth the dividends declared on the Company's common stock for eac of the four quarters for 2002 and 2001.

Common Stock Dividends
(Dollars in Thousands)

Quarter	2002	2001
1st Quarter	$42,500	$42,500
2nd Quarter	42,500	42,500
3rd Quarter	42,500	42,500
4th Quarter	42,500	42,500

After payment or setting aside for payment of cumulative dividends and mandatory sinking fund requirements, where applicable, on all outstanding issues of preferred stock, the holders of common stock are entitled to dividends when and as declared out of funds legally available therefor. See Note 6 of Notes to Financial Statements in Item 8 for restrictions on retained earnings available for the payment of common stock dividends. As of December 31, 2002, we did not have any outstanding preferred stock.

ITEM 6. SELECTED FINANCIAL DATA

	2002	2001	2000	1999	1998
			(dollars in thousands)		
Electric operating revenues:					
Regulated electricity segment	$ 2,059,339	$ 2,562,088	$ 2,538,750	$ 1,914,722	$ 1,741,148
Marketing and trading segment	34,054	549,240	395,392	154,126	180,145
Purchased power and fuel costs:					
Regulated electricity segment	595,368	1,227,188	1,065,596	432,844	306,884
Marketing and trading segment	32,662	313,991	267,032	136,522	151,164
Operating expenses	1,136,363	1,171,171	1,155,278	1,115,664	1,097,471
Operating income	329,000	398,978	446,236	383,818	365,774
Other income/(deductions)	(8,041)	(79)	(6,545)	20,857	20,315
Interest deductions – net	121,616	118,211	133,097	136,353	130,842
Income before extraordinary charge and cumulative effect adjustment	199,343	280,688	306,594	268,322	255,247
Extraordinary charge – net of tax (a)	--	--	--	(139,885)	--
Cumulative effect of change in accounting – net of tax (b)	--	(15,201)	--	--	--
Net income	199,343	265,487	306,594	128,437	255,247
Preferred dividends	--	--	--	1,016	9,703
Earnings for common stock	$ 199,343	$ 265,487	$ 306,594	$ 127,421	$ 245,544
Total Assets	$ 6,521,807	$ 6,225,733	$ 6,349,609	$ 6,079,307	$ 6,356,534
Capital Structure:					
Common stock equity	$ 2,159,312	$ 2,150,690	$ 2,119,768	$ 1,983,174	$ 1,975,755
Non-redeemable preferred stock	--	--	--	--	85,840
Redeemable preferred stock	--	--	--	--	9,401
Long-term debt less current maturities	2,217,340	1,949,074	1,806,908	1,997,400	1,876,540
Total capitalization	4,376,652	4,099,764	3,926,676	3,980,574	3,947,536
Commercial paper	--	171,162	82,100	38,300	178,830
Current maturities of long-term debt	3,503	125,451	250,266	114,711	164,378
Total	$ 4,380,155	$ 4,396,377	$ 4,259,042	$ 4,133,585	$ 4,290,744

(a) Changes associated with a regulatory disallowance. See "Regulatory Accounting" in Note 1.

(b) Change in accounting standards related to derivatives in 2001. See Note 16

See "Management's Discussion and Analysis of Financial Condition and Results of Operations" in Item 7 for a discussion of certain information in the table above.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

INTRODUCTION

In this Item, we explain our results of operations, general financial condition, and outlook including:

- the changes in our earnings from 2001 to 2002 and from 2000 to 2001;
- our capital needs, liquidity and capital resources;
- our critical accounting policies;
- our business outlook and major factors that affect our financial outlook; and
- our management of market risks.

Throughout this Item, we refer to specific "Notes" in the Notes to Financial Statements in Item 8 of this report. These Notes add further details to the discussion.

BUSINESS OVERVIEW

We are an electric utility that provides either retail or wholesale electric service to substantially all of the state of Arizona, with the major exceptions of the Tucson metropolitan area and about half of the Phoenix metropolitan area. Electricity is delivered through a distribution system that we own. We also generate, sell and deliver electricity to wholesale customers in the western United States. Our marketing and trading division sells, in the wholesale market, our and Pinnacle West Energy's generation output that is not needed for our Native Load, which includes loads for retail customers and traditional cost-of-service wholesale customers. We do not distribute any products. Pinnacle West owns all of our outstanding common stock.

SUMMARY OF KEY FACTORS AFFECTING OUR FINANCIAL OUTLOOK

We believe the following are among the key factors affecting our financial outlook:

- The following ACC regulatory matters:
  - Our $500 million financing application, which the ACC approved on March 27, 2003;
  - The implementation of the ACC-mandated process by which we must competitively procure energy; and
  - Our general rate case to be filed in 2003.
- Wholesale power market conditions in the western United States.

We discuss each of these, and other, factors in detail below in the section entitled "Factors Affecting Our Financial Outlook."

BUSINESS SEGMENTS

We have two principal business segments (determined by services and the regulatory environment):

- our regulated electricity segment, which consists of regulated traditional retail and wholesale electricity businesses and related activities, and includes electricity transmission, distribution and generation; and

- our marketing and trading segment, which consists of our competitive energy business activities, including wholesale marketing and trading.

The following is a summary of earnings by business segment for the years ended December 31, 2002, 2001, and 2000 (dollars in millions):

	2002	2001	2000
Regulated electricity	$ 198	$ 138	$ 228
Marketing and trading	1	142	79
Income before accounting change	199	280	307
Cumulative effect of change in accounting – net of income taxes (a)	--	(15)	--
Net income	$ 199	$ 265	$ 307

(a) We recorded a $15 million after-tax charge in 2001 for the cumulative effect of a change in accounting for derivatives related to the adoption of SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities." See Note 16.

See Note 15 for additional financial information regarding our business segments.

RESULTS OF OPERATIONS

General

Throughout the following explanations of our results of operations, we refer to "gross margin." With respect to our regulated electricity segment and marketing and trading segment, gross margin refers to electric operating revenues less purchased power and fuel costs.

2002 Compared with 2001

Our net income for the year ended December 31, 2002 was $199 million compared with $265 million for the prior year. In 2001, we recognized a $15 million after-tax charge for the cumulative effect of a change in accounting for derivatives, as required by SFAS No. 133 (see Note 16).

Our income before accounting change for the year ended December 31, 2002 was $199 million compared with $281 million for the prior year. The period-to-period comparison was lower due to reduced marketing and trading segment gross margin due to our transfer of the marketing and trading activities to Pinnacle West in 2001 and severance costs of $34 million in the second half of 2002 relating to voluntary workforce reductions. These decreases were partially offset by increased earnings contributions from our regulated electricity activities, reflecting lower replacement power costs for power plant outages, retail customer growth and higher average usage per customer, and lower purchased power costs related to 2001 generation reliability program (the addition of generating capability to enhance reliability for the summer of 2001). These increases were partially offset by the effects of milder weather, retail electricity price decreases and higher costs for purchased power and gas due to higher hedged gas and power prices.

For additional details, see the following discussion.

The major factors that increased (decreased) income before accounting change were as follows (dollars in millions):

	Increase (Decrease)
Regulated electricity segment gross margin:	
Lower replacement power costs for plant outages due to lower market prices and fewer unplanned outages	$ 127
Increased purchased power and fuel costs due to higher hedged gas and power prices, partially offset by improved hedge management, net of mark-to-market reversals	(24)
Lower purchased power and fuel costs related to the 2001 generation reliability program	30
Higher retail sales volumes due to customer growth and higher average usage, excluding weather effects	38
2001 charges related to purchased power contracts with Enron and its affiliates	13
Retail price reductions effective July 1, 2001 and July 1, 2002	(28)
Effects of milder weather on retail sales	(27)
Net increase in regulated electricity segment gross margin	129
Marketing and trading segment gross margin:	
Decrease in generation sales other than Native Load due to lower market prices partially offset by higher sales volumes	(78)
Decrease in marketing and trading segment margin resulting from our transfer of marketing and trading activities to Pinnacle West in 2001	(156)
Net decrease in marketing and trading segment gross margin	(234)
Net decrease in regulated electricity and marketing and trading segments' gross margins	(105)
Higher operations and maintenance expense related to 2002 severance costs of approximately $34 million, partially offset by lower generation reliability costs	(30)
Lower depreciation and amortization expense primarily related to lower regulatory asset amortization	21
Higher taxes other than income taxes	(7)
Lower other income primarily due to a 2001 insurance recovery of environmental remediation costs	(15)
Higher net interest expense primarily due to higher debt balances and lower capitalized interest	(3)
Miscellaneous factors, net	2
Net decrease in income before income taxes	(137)
Lower income taxes primarily due to lower income	56
Net decrease in income before accounting change	$ (81)

Regulated Electricity Segment Gross Margin

Regulated electricity segment revenues related to our regulated retail and wholesale electricity businesses were $503 million lower in the year ended December 31, 2002, compared with the prior year as a result of:

- decreased revenues related to traditional wholesale sales as a result of lower sales volumes and lower prices ($64 million);
- decreased revenues related to retail load hedge management wholesale sales, primarily as a result of lower prices and lower sales volumes ($421 million);
- decreased retail revenues related to milder weather ($60 million);
- increased retail revenues related to customer growth and higher average usage, excluding weather effects ($69 million);
- decreased retail revenues related to reductions in retail electricity prices ($28 million); and
- other miscellaneous factors ($1 million net increase).

Regulated electricity segment purchased power and fuel costs were $632 million lower in the year ended December 31, 2002, compared with the prior year as a result of:

- decreased costs related to traditional wholesale sales as a result of lower sales volumes and lower prices ($64 million);
- decreased costs related to retail load hedge management wholesale sales, primarily as a result of lower prices and lower sales volumes ($426 million);
- increased costs related to higher prices for hedged natural gas and purchased power, net of mark-to-market reversals ($29 million);
- lower purchased power costs related to the 2001 generation reliability program ($30 million);
- decreased costs related to the effects of milder weather on retail sales ($33 million);
- increased costs related to retail sales growth, excluding weather effects ($31 million);
- charges in 2001 related to purchased power contracts with Enron and its affiliates ($13 million net decrease);
- decreased replacement power costs for power plant outages due to lower market prices and fewer unplanned outages ($127 million); and
- other miscellaneous factors ($1 million net increase).

Marketing and Trading Segment Gross Margin

Marketing and trading segment revenues were $515 million lower in the year ended December 31, 2002, compared with the prior year as a result of:

- decreased revenues from generation sales other than Native Load primarily due to lower market prices partially offset by higher sales volumes ($128 million); and
- lower marketing and trading revenues as a result of our transfer of marketing and trading activities to Pinnacle West in 2001 ($387 million).

Marketing and trading segment purchased power and fuel costs were $281 million lower in the year ended December 31, 2002, compared with the prior year as a result of:

- decreased fuel costs related to generation sales other than Native Load primarily because of lower natural gas prices partially offset by higher sales volumes ($50 million); and

- lower marketing and trading purchased power and fuel costs as a result of our transfer of marketing and trading activities to Pinnacle West in 2001 ($231 million).

Other Income Statement Items

The increase in operations and maintenance expense of $30 million was primarily due to severance costs of $34 million related to a 2002 voluntary workforce reduction, partially offset by lower costs related to generation reliability, plant outages and maintenance costs.

The increase in taxes other than income taxes of $7 million is primarily due to increased property taxes on higher property balances.

Other income decreased $15 million primarily due to an insurance recovery recorded in 2001 related to environmental remediation costs and other costs (see Note 17).

The decrease in depreciation and amortization expense of $21 million primarily related to lower regulatory asset amortization, in accordance with the 1999 Settlement Agreement, partially offset by increased depreciation and amortization on higher property, plant and equipment balances.

2001 Compared with 2000

Our net income for the year ended December 31, 2001 was $265 million compared with $307 million for the year ended December 31, 2000. In 2001, we recognized a $15 million after-tax charge in net income as a cumulative effect of a change in accounting for derivatives, as required by SFAS No. 133 (see Note 16).

Income before accounting change for the year ended December 31, 2001 was $281 million compared with $307 million for the year ended December 31, 2000. The year-to-year comparison benefited from strong marketing and trading results and retail customer growth. These factors were partially offset by higher purchased power and fuel costs, due in part to increased power plant maintenance; generation reliability measures; continuing retail electricity price decreases; and a charge related to Enron and its affiliates.

For additional details, see the following discussion.

The major factors that increased (decreased) income before accounting change were as follows (dollars in millions):

	Increase (Decrease)
Regulated electricity segment gross margin:	
Higher replacement power costs for plant outages related to higher market prices	$ (70)
Retail price reductions effective July 1, 2001 and July 1, 2000	(27)
Charges related to purchased power contracts with Enron and its affiliates (a)	(13) (a)
Higher purchased power costs related to the 2001 generation reliability program	(30)
Miscellaneous revenues	1
Net decrease in regulated electricity segment gross margin	(139)
Marketing and trading segment gross margin:	
Increase from generation sales other than Native Load due to higher market prices	25
Higher realized wholesale margin net of related mark-to-market reversals	11
Increase in mark-to-market value related to future periods	71
Net increase in marketing and trading segment gross margin	107
Net increase in regulated electricity and marketing and trading segments' gross margins	(32)
Higher operations and maintenance expense related to the 2001 generation reliability program	(12)
Higher operations and maintenance expense related primarily to employee benefits, plant outage and maintenance and other costs	(23)
Lower net interest expense primarily due to higher capitalized interest	15
Higher other income primarily due to a 2001 insurance recovery of environmental remediation costs	11
Miscellaneous factors, net	2
Net decrease in income before income taxes	(39)
Lower income taxes primarily due to lower income	13
Net decrease in income before accounting change	$ (26)

(a) We recorded charges totaling $13 million before income taxes for exposure to Enron and its affiliates in the fourth quarter of 2001.

Regulated Electricity Segment Gross Margin

Regulated electricity segment revenues related to our regulated retail and wholesale electricity businesses were $23 million higher in the year ended December 31, 2001 compared with the prior year as a result of:

- decreased revenues related to other wholesale sales and miscellaneous revenues as a result of lower sales volumes ($28 million);
- increased retail revenues primarily related to higher sales volumes primarily due to customer growth ($78 million); and

- decreased retail revenues related to reductions in retail electricity prices ($27 million).

Regulated electricity segment purchased power and fuel costs were $162 million higher in the year ended December 31, 2001 compared with the prior year as a result of:

- decreased costs related to other wholesale sales as a result of lower volumes ($29 million);
- higher replacement power costs primarily due to higher market prices and increased plant outages ($70 million), including costs of $12 million related to a Palo Verde outage extension to replace fuel control element assemblies;
- higher purchase power costs related to the 2001 generation reliability program ($30 million);
- higher costs related to retail sales volumes due to customer growth ($78 million); and
- charges related to purchased power contracts with Enron and its affiliates ($13 million).

Marketing and Trading Segment Gross Margin

Marketing and trading segment revenues were $154 million higher in the year ended December 31, 2001 compared with the prior year as a result of:

- increased revenues related to generation sales other than Native Load as a result of higher average market prices ($32 million);
- increased realized wholesale revenues net of related mark-to-market reversals primarily due to more transactions ($40 million);
- increased prior period mark-to-market value for losses transferred to realized margin in current period ($11 million); and
- increased mark-to-market value for future periods primarily as a result of more forward sales volumes ($71 million).

Marketing and trading segment purchased power and fuel costs were $47 million higher in the year ended December 31, 2001 compared with the prior year as a result of:

- increased fuel costs related to generation sales other than Native Load as a result of higher fuel prices ($7 million); and
- increased purchased power and fuel costs net of related mark-to-market reversals primarily due to more transactions ($40 million).

Other Income Statement Items

The increase in operations and maintenance expenses of $35 million primarily related to the 2001 generation reliability program (the addition of generating capability to enhance reliability for the summer of 2001) ($12 million) and increased employee benefit costs, plant outage and maintenance and other costs ($23 million).

Interest expense decreased by $15 million primarily because of lower interest rates and increased capitalized interest resulting from higher construction project balances.

Net other income increased $11 million primarily because of insurance recovery of environmental remediation costs (see Note 17).

See "Regulatory Matters – 1999 Settlement Agreement" in Note 3 for a discussion of the 1999 Settlement Agreement under which, among other things, we agreed to five annual retail electricity price reductions of 1.5%, with the last decrease to take effect July 1, 2003.

LIQUIDITY AND CAPITAL RESOURCES

Capital Needs and Resources

Capital Expenditure Requirements

The following table summarizes the actual capital expenditures for the year ended December 31, 2002 and estimated capital expenditures for the next three years.

CAPITAL EXPENDITURES
(dollars in millions)

	(Actual)	(Estimated)		
	2002	2003	2004	2005
Delivery	$ 369	$ 273	$ 275	$ 329
Generation (a)	132	123	99	164
Other (b)	--	5	5	5
Total	$ 501	$ 401	$ 379	$ 498

(a) As discussed below under "Factors Affecting Our Financial Outlook," as part of our 2003 general rate case, we intend to seek rate base treatment of certain power plants currently owned by Pinnacle West Energy (specifically, Redhawk Units 1 and 2, West Phoenix Units 4 and 5 and Saguaro Unit 3).

(b) The other amounts relate to capital expenditures for our marketing and trading segment. These costs were in the parent company for 2002.

Delivery capital expenditures are comprised of T&D infrastructure additions and upgrades, capital replacements, new customer construction and related information systems and facility costs. Examples of the types of projects included in the forecast include T&D lines and substations, line extensions to new residential and commercial developments and upgrades to customer information systems. In addition, we began several major transmission projects in 2001. These projects are periodic in nature and are driven by strong regional customer growth. We expect to spend about $105 million on major transmission projects during the 2003 to 2005 time frame, and these amounts are included in "Delivery" in the table above.

Generation capital expenditures are comprised of various improvements for our existing fossil and nuclear plants and the replacement of Palo Verde steam generators. Examples of the types of projects included in this category are additions, upgrades and capital replacements of various power plant equipment such as turbines, boilers and environmental equipment. Generation also contains nuclear fuel expenditures of approximately $30 million annually for 2003 to 2005.

Replacement of the steam generators in Palo Verde Unit 2 is presently scheduled for completion during the fall outage of 2003. The Palo Verde owners have approved the manufacture of two additional sets of steam generators. We expect that these generators will be installed in Units 1 and 3 in the 2005 to 2008 time frame. Our portion of steam generator expenditures for Units 1, 2 and 3 is approximately $145 million, which will be spent from 2003 through 2008. In 2003 through 2005, $94 million of the costs are included in the generation capital expenditures table above and would be funded with internally-generated cash or external financings.

Contractual Obligations

Our capital requirements consist primarily of capital expenditures and optional and mandatory redemptions of long-term debt. See "Factors Affecting Our Financial Outlook - Regulatory Matters" below and Note 3 for discussion of the $500 million financing arrangement between us and Pinnacle West Energy recently approved by the ACC. On November 22, 2002 the ACC approved our request (Interim Financing Application), to permit us to (a) make short-term advances to Pinnacle West in the form of an inter-affiliate line of credit in the amount of $125 million, or (b) guarantee $125 million of Pinnacle West's short-term debt, subject to certain conditions. As of December 31, 2002, there were no borrowings outstanding under the inter-affiliate financing arrangement. See the table below for our contractual requirements, including our debt repayment obligations. The table does not take into account any funds that we intend to lend to Pinnacle West Energy or Pinnacle West consistent with the foregoing financing arrangements.

We pay for our capital requirements with cash from operations and, to the extent necessary, external financings. We have historically paid for our dividends to Pinnacle West with cash from operations.

In 2002, we issued $375 million in long-term debt, refinanced $90 million in long-term debt and redeemed approximately $247 million in long-term debt (see Note 6). On April 7, 2003, we will redeem $33 million of our first mortgage bonds.

Our outstanding debt was approximately $2.2 billion at December 31, 2002. At December 31, 2002, we had credit commitments from various banks totaling about $250 million, which were available either to support the issuance of commercial paper or to be used as bank borrowings. At December 31, 2002, we had no outstanding commercial paper or bank borrowings.

Although provisions in our first mortgage bond indenture, articles of incorporation and ACC financing orders establish maximum amounts of additional first mortgage bonds, debt and preferred stock that we may issue, we do not expect any of these provisions to limit our ability to meet our capital requirements.

We are part of a multi-employer pension plan sponsored by Pinnacle West. Pinnacle West contributes at least the minimum amount required under IRS regulations, but no more than the maximum tax-deductible amount. The minimum required funding takes into consideration the value of the fund assets and the pension obligation. Pinnacle West elected to contribute cash to the pension plan in each of the last five years; the minimum required contributions during each of those years was zero. Specifically, Pinnacle West contributed $27 million for 2002, $24 million for 2001, $44 million for 2000, $25 million for 1999 and $14 million for 1998. We fund our share of the pension contribution. We represent approximately 90% of the total funding amounts described above. The assets in the plan are mostly domestic common stocks, bonds and real estate. Pinnacle West currently forecasts a pension contribution in 2003 of approximately $50 million, all or part of which may be required. If the fund performance continues to decline as a result of a continued decline in equity markets, larger contributions may be required in future years.

As a result of a change in IRS guidance, we claimed a tax deduction related to a tax accounting method change on the 2001 Pinnacle West federal consolidated income tax return. The accelerated deduction has resulted in a $200 million reduction in the current income tax liability. In 2002, we received an income tax refund of approximately $115 million related to the 2001 Pinnacle West federal consolidated income tax return.

The following table summarizes actual contractual requirements for the year ended December 31, 2002 and estimated contractual commitments for the next five years and thereafter (dollars in millions):

	Actual	Estimated					
	2002	2003	2004	2005	2006	2007	Thereafter
Long-term debt payments	$ 337	$ --	$ 205	$ 400	$ 84	$ --	$ 1,518
Capital lease payments	--	4	3	3	3	2	5
Operating lease payments	60	59	59	59	59	59	456
Fuel and purchase power commitments	307	135	82	28	31	17	162
Total contractual commitments	$ 704	$ 198	$ 349	$ 490	$ 177	$ 78	$ 2,141

Off-Balance Sheet Arrangements

In January 2003, the FASB issued FIN No. 46, "Consolidation of Variable Interest Entities." FIN No. 46 requires that we consolidate a VIE if we have a majority of the risk of loss from the VIE's activities or we are entitled to receive a majority of the VIE's residual returns or both. A VIE is a corporation, partnership, trust, or any other legal structure that either does not have equity investors with voting rights or has equity investors that do not provide sufficient financial resources for the entity to support its activities. FIN No. 46 is effective immediately for any VIE created after January 31, 2003 and is effective July 1, 2003 for VIEs created before February 1, 2003.

In 1986, we entered into agreements with three separate SPE lessors in order to sell and lease back interests in Palo Verde Unit 2. The leases are accounted for as operating leases in accordance with GAAP. See Note 8 for further information about the sale-leaseback transactions. Based on our preliminary assessment of FIN No. 46, we do not believe we will be required to consolidate the Palo Verde SPEs. However, we continue to evaluate the requirements of the new guidance to determine what impact, if any, it will have on our financial statements.

We are exposed to losses under the Palo Verde sale-leaseback agreements upon the occurrence of certain events that we do not consider to be reasonably likely to occur. Under certain circumstances (for example, the NRC issuing specified violation orders with respect to Palo Verde or the occurrence of specified nuclear events), we would be required to assume the debt associated with the transactions, make specified payments to the equity participants and take title to the leased Unit 2 interests, which if appropriate, may be required to be written down in value. If such an event had occurred as of December 31, 2002, we would have been required to assume approximately $285 million of debt and pay the equity participants approximately $200 million.

Credit Ratings

The ratings of our securities as of March 28, 2003 are shown below and are considered "investment-grade" ratings. The ratings reflect the respective views of the rating agencies, from which an explanation of the significance of their ratings may be obtained. There is no assurance that these ratings will continue for any given period of time. The ratings may be revised or withdrawn entirely by the rating agencies, if, in their respective judgments, circumstances so warrant. Any downward revision or withdrawal may adversely affect the market price of our securities and serve to increase our cost of and access to capital.

	Moody's	Standard & Poor's	Fitch
Senior secured	A3	A-	A-
Senior unsecured	Baa1	BBB	BBB+
Secured lease obligation bonds	Baa2	BBB	BBB
Commercial paper	P-2	A-2	F-2

On November 4, 2002 Standard & Poor's affirmed our debt ratings in the above chart. On that same date, Standard & Poor's lowered our corporate credit rating from BBB+ to BBB. Standard & Poor's assigned a stable outlook to the ratings. All of our credit ratings remain investment grade. In December 2002, Fitch placed certain of our debt on Ratings Watch Negative. The ratings watch affects all of our debt ratings with the exception of our commercial paper rating.

On December 31, 2002, Moody's affirmed the ratings set forth above.

Debt Provisions

Our significant debt covenants include a debt-to-total-capitalization ratio and an interest coverage test. We are in compliance with such covenants and anticipate that we will continue to meet all the significant covenant requirement levels. The ratio of debt to total capitalization cannot exceed 65%. At December 31, 2002, our ratio is approximately 48%. The provisions regarding interest coverage require a minimum cash coverage of two times the interest requirements. The coverage is approximately 5 times for our bank agreements and 15 times for our mortgage indenture.

Failure to comply with such covenant levels would result in an event of default which, generally speaking, would require the immediate repayment of the debt subject to the covenants.

Our financing agreements do not contain "ratings triggers" that would result in an acceleration of the required interest and principal payments in the event of a ratings downgrade. However, in the event of a ratings downgrade, we may be subject to increased interest costs under certain financing agreements.

All of our bank agreements contain "cross-default" provisions that would result in defaults and the potential acceleration of payment under these bank agreements if we were to default under other agreements. Our credit agreements generally contain provisions under which the lenders could refuse to advance loans in the event of a material adverse change in our financial condition or financial prospects.

CRITICAL ACCOUNTING POLICIES

In preparing the financial statements in accordance with GAAP, management must often make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, expenses and related disclosures at the date of the financial statements and during the reporting period. Some of those judgments can be subjective and complex, and actual results could differ from those estimates. We consider the following accounting policies to be our most critical because of uncertainties, judgments and complexities of the underlying accounting standards and operations involved.

- Regulatory Accounting – Regulatory accounting allows for the actions of regulators, such as the ACC and the FERC, to be reflected in the financial statements. Their actions may cause us to capitalize costs that would otherwise be included as an expense in the current period by unregulated companies.

- Pensions and Other Postretirement Benefit Accounting - Changes in our actuarial assumptions used in calculating our pension and other postretirement benefit liability and expense can have a significant impact on our earnings and financial position. The most relevant actuarial assumptions are the discount rate used to measure our liability and the expected long-term rate of return on plan assets used to estimate earnings on invested funds over the long-term.

- Derivative Accounting – Derivative accounting requires evaluation of rules that are complex and subject to varying interpretations. Our evaluation of these rules, as they apply to our contracts, will determine whether we use accrual accounting or fair value (mark-to-market) accounting. Mark-to-market accounting requires that changes in fair value be recorded in earnings or, if certain hedge accounting criteria are met, in other comprehensive income.

- Mark-to-Market Accounting – The market value of our derivative contracts is not always readily determinable. In some cases, we use models and other valuation techniques to determine fair value. The use of these models and valuation techniques sometimes requires subjective and complex judgment. Actual results could differ from the results estimated through application of these methods.

See the discussion below for further details on our critical accounting policies.

Regulatory Accounting

For our regulated operations, we prepare our financial statements in accordance with SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation." SFAS No. 71 requires a cost-based, rate-regulated enterprise to reflect the impact of regulatory decisions in its financial statements. As a result, we capitalize certain costs that would be included as expense in the current period by unregulated companies. Regulatory assets represent incurred costs that have been deferred because they are probable of future recovery in customer rates. Regulatory liabilities generally represent obligations to make refunds to customers for previous collections of costs not likely to be incurred.

We are required to discontinue applying SFAS No. 71 when deregulatory legislation is passed or a rate order is issued that contains sufficient detail to determine its effect on the portion of the business being deregulated. In 1999, we discontinued the application of SFAS No. 71 for our generation operations due to the 1999 Settlement Agreement with the ACC. See Note 3 for a discussion of the 1999 Settlement Agreement.

In 2002, the ACC directed us not to transfer our generation assets, as previously required by the 1999 Settlement Agreement (see "Track A Order" in Note 3). Accordingly, we now consider our generation to be cost-based, rate-regulated and subject to the requirements of SFAS No. 71. The impact of this change was immaterial to our financial statements.

Management continually assesses whether our regulatory assets are probable of future recovery by considering factors such as applicable regulatory environment changes and recent rate orders to other regulated entities in the same jurisdiction. This determination reflects the current political and regulatory climate in the state and is subject to change in the future. If future recovery of costs ceases to be probable, the assets would be written off as a charge to current period earnings. We had $241 million of regulatory assets included on the Balance Sheets at December 31, 2002. See Notes 1 and 3 for more information.

Pensions and Other Postretirement Benefit Accounting

Pinnacle West sponsors a qualified defined benefit pension plan and a non-qualified supplemental excess benefit retirement plan for employees of Pinnacle West and its subsidiaries. In 2002, we represented 87% of the total costs of this plan. Our reported costs of providing defined pension and other postretirement benefits are dependent upon numerous factors resulting from actual plan experience and assumptions of future experience. Pension and other postretirement benefit costs, for example, are impacted by actual employee demographics (including age, compensation levels and employment periods), the level of contributions we make to the plans and earnings on plan assets. Changes made to the provisions of the plans may also impact current and future pension and other postretirement benefit costs. Pension and other postretirement benefit costs may also be significantly affected by changes in key actuarial assumptions, including the expected long-term rate of return on plan assets and the discount rates used in determining the projected benefit obligation and pension and other postretirement benefit costs.

Pinnacle West's pension and other postretirement plan assets are primarily made up of equity and fixed income investments. Fluctuations in actual equity market returns as well as changes in general interest rates may result in increased or decreased pension and other postretirement benefit costs in future periods. Likewise, changes in assumptions regarding current discount rates and the expected long-term rate of return on plan assets could also increase or decrease recorded pension and other postretirement benefit costs.

We account for our defined benefit pension plans in accordance with SFAS No. 87, "Employers' Accounting for Pensions," which requires amounts recognized in our financial statements to be determined on an actuarial basis. Changes in pension obligations associated with these factors may not be immediately recognized as pension costs on the income statement, but generally are recognized in future years over the remaining average service period of plan participants. As such, significant portions of pension costs recorded in any period may not reflect the actual level of cash benefits provided to plan participants.

The following chart reflects the sensitivities associated with a one percent increase or decrease in certain actuarial assumptions related to our defined benefit pension plans. Each sensitivity below reflects the impact of changing only that assumption. The chart shows the increase (decrease) each change in assumption would have on the 2002 Pinnacle West projected benefit obligation, the 2002 reported pension liability on the Pinnacle West Consolidated Balance Sheets and the 2002 reported annual pension expense, after consideration of amounts capitalized or billed to electric plant participants, on the Pinnacle West Consolidated Statements of Income (dollars in millions). In 2002, we represented 87% of the total cost of the plans.

	Increase/(Decrease)		
Actuarial Assumption	Impact on Projected Benefit Obligation	Impact on Pension Liability	Impact on Pension Expense
Discount rate:			
Increase 1%	$(143)	$(107)	$(4)
Decrease 1%	177	130	9
Expected long-term rate of return on plan assets:			
Increase 1%	-	-	(4)
Decrease 1%	-	-	4

At the end of each year, we determine the discount rate to be used to calculate the present value of plan liabilities. The discount rate is an estimate of the current interest rate at which the pension liabilities could be effectively settled at the end of the year. The discount rate is selected by comparison to current yields on high-quality, long-term bonds. We changed our discount rate assumption from 7.5% at December 31, 2001 to 6.75% at December 31, 2002.

In 2002, we assumed that the expected long-term rate of return on plan assets would be 10%. However, the plan assets have earned a rate of return substantially less than 10% in the last three years due to sharp declines in the equity markets. For 2003, we decreased our expected long-term rate of return on plan assets to 9%, as a result of continued declines in general equity and bond market returns.

The following chart reflects the sensitivities associated with a one percent increase or decrease in certain actuarial assumptions related to our other postretirement benefit plans. Each sensitivity below reflects the impact of changing only that assumption. The chart shows the increase (decrease) each change in assumption would have on the 2002 Pinnacle West accumulated other postretirement benefit obligation and the 2002 reported other postretirement benefit expense, after consideration of amounts capitalized or billed to electric plant participants, on the Pinnacle West Consolidated Statements of Income (dollars in millions). In 2002, we represented 87% of the total cost of this plan.

	Increase/(Decrease)	
Actuarial Assumption	Impact on Accumulated Postretirement Benefit Obligation	Impact on Other Postretirement Benefit Expense
Discount rate:		
Increase 1%	$(38)	$(2)
Decrease 1%	43	2
Health care cost trend rate (a):		
Increase 1%	54	5
Decrease 1%	(43)	(4)
Expected long-term rate of return on plan assets – pretax:		
Increase 1%	-	(1)
Decrease 1%	-	1

(a) This assumes a 1% change in the initial and ultimate health care cost trend rate.

The discount rate is selected by comparison to current yields on high-quality, long-term bonds. We changed our discount rate assumption from 7.5% at December 31, 2001 to 6.75% at December 31, 2002.

In selecting our health care cost trend rate, we consider past performance and forecasts of health care costs. In 2002, we increased our initial health care cost trend rate to 8% from 7% based on an analysis of our actual plan experience. We also assume an ultimate health care cost trend rate of 5% is reached in 2007.

In selecting the pretax expected long-term rate of return on plan assets, we consider past performance and economic forecasts for the types of investments held by the plan. The market value of the plan assets has been affected by sharp declines in the equity markets. For 2003, we decreased our expected long-term rate of return on plan assets from 10% to 9%, as a result of continued declines in general equity and bond market returns.

Pension and other postretirement benefit costs and cash funding requirements may increase in future years without a substantial recovery in the equity markets. Due to the actual investment performance of the pension and other postretirement benefit funds and the changes in the actuarial assumptions discussed above, we expect an increase of approximately $29 million before income taxes in 2003 expense over 2002. See Note 7 for further details about our pension and other postretirement benefit plans.

Derivative Accounting

We are exposed to the impact of market fluctuations in the price and transportation costs of electricity, natural gas, coal and emissions allowances. We manage risks associated with these market fluctuations by utilizing various commodity derivatives, including exchange-traded futures and options and over-the-counter forwards, options and swaps. As part of our risk management program, we enter into derivative transactions to hedge purchases and sales of electricity, fuels and emissions allowances and credits. The changes in market value of such contracts have a high correlation to price changes in the hedged commodities. In addition, subject to specified risk parameters monitored by the ERMC, we engage in marketing and trading activities intended to profit from market price movements.

We examine contracts at inception to determine the appropriate accounting treatment. If a contract does not meet the derivative criteria or if it qualifies for a SFAS No. 133 scope exception, we account for the contract on an accrual basis with associated revenues and costs recorded at the time the contracted commodities are delivered or received. SFAS No. 133 provides a scope exception for contracts that meet the normal purchases and sales criteria specified in the standard. Most of our non-trading electricity purchase and sales agreements qualify as normal purchases and sales and are exempted from recognition in the financial statements until the electricity is delivered.

For contracts that qualify as a derivative and do not meet a SFAS No. 133 scope exception, we further examine the contract to determine if it will qualify for hedge accounting. Changes in the fair value of the effective portion of derivative instruments that qualify for cash flow hedge accounting treatment are recognized as either an asset or liability and in common stock equity (as a component of accumulated other comprehensive income (loss)). Gains and losses related to derivatives that qualify as cash flow hedges of expected transactions are recognized in revenue or purchased power and fuel expense as an offset to the related item being hedged when the underlying hedged physical transaction impacts earnings. If a contract does not meet the hedging criteria in SFAS No. 133, we recognize the changes in the fair value of the derivative instrument in income each period through mark-to-market accounting.

On October 1, 2002, we adopted EITF 02-3, which rescinded EITF 98-10. As a result, our energy trading contracts that are derivatives continue to be accounted for at fair value under SFAS No. 133. Contracts that were previously marked-to-market as trading activities under EITF 98-10 that do not meet the accounting definition of a derivative are now accounted for on an accrual basis with the associated revenues and costs recorded at the time the contracted commodities are delivered or received. Additionally, all gains and losses (realized and unrealized) on energy trading contracts that qualify as derivatives are included in marketing and trading segment revenues on the Statements of Income on a net basis. The rescission of EITF 98-10 has no effect on the accounting for derivative instruments used for non-trading activities, which continue to be accounted for in accordance with SFAS No. 133. See "Other Accounting Matters – Accounting for Derivative and Trading Activities" below for details on the change in accounting for energy trading contracts. See Note 16 for further discussion on derivative accounting.

Mark-to-Market Accounting

Under mark-to-market accounting, the purchase or sale of energy commodities is reflected at fair market value, net of valuation adjustments, with resulting unrealized gains and losses recorded as assets and liabilities from risk management and trading activities in the Balance Sheets.

We determine fair market value using actively-quoted prices when available. We consider quotes for exchange-traded contracts and over-the-counter quotes obtained from independent brokers to be actively-quoted.

When actively-quoted prices are not available, we use prices provided by other external sources. This includes quarterly and calendar year quotes from independent brokers. We shape quarterly and calendar year quotes into monthly prices based on historical relationships.

For options, long-term contracts and other contracts for which price quotes are not available, we use models and other valuation methods. The valuation models we employ utilize spot prices, forward prices, historical market data and other factors to forecast future prices. The primary valuation technique we use to calculate the fair value of contracts where price quotes are not available is based on the extrapolation of forward pricing curves using observable market data for more liquid delivery points in the same region and actual transactions at the more illiquid delivery points. We also value option contracts using a variation of the Black-Scholes option-pricing model.

For non-exchange traded contracts, we calculate fair market value based on the average of the bid and offer price, and we discount to reflect net present value. We maintain certain valuation adjustments for a number of risks associated with the valuation of future commitments. These include valuation adjustments for liquidity and credit risks based on the financial condition of counterparties. The liquidity valuation adjustment represents the cost that would be incurred if all unmatched positions were closed-out or hedged.

A credit valuation adjustment is also recorded to represent estimated credit losses on our overall exposure to counterparties, taking into account netting arrangements; expected default experience for the credit rating of the counterparties; and the overall diversification of the portfolio. Counterparties in the portfolio consist principally of major energy companies, municipalities and local distribution companies. We maintain credit policies that management believes minimize overall credit risk. Determination of the credit quality of counterparties is based upon a number of factors, including credit ratings, financial condition, project economics and collateral requirements. When applicable, we employ standardized agreements that allow for the netting of positive and negative exposures associated with a single counterparty. See "Factors Affecting Our Financial Outlook – Market Risks – Commodity Price Risk" below and Note 16 for further discussion on credit risk.

The use of models and other valuation methods to determine fair market value often requires subjective and complex judgment. Actual results could differ from the results estimated through application of these methods. Our practice is to hedge within timeframes established by the ERMC.

OTHER ACCOUNTING MATTERS

Accounting for Derivative and Trading Activities

During 2002, the EITF discussed EITF 02-3 and reached a consensus on certain issues. EITF 02-3 rescinded EITF 98-10 and was effective October 25, 2002 for any new contracts, and on January 1, 2003 for existing contracts, with early adoption permitted. As a result, our energy trading contracts that are derivatives continue to be accounted for at fair value under SFAS No. 133. Contracts that were previously marked-to-market as trading activities under EITF 98-10 that do not meet the definition of a derivative are now accounted for on an accrual basis with the associated revenues and costs recorded at the time the contracted commodities are delivered or received. Additionally, all gains and losses (realized and unrealized) on energy trading contracts that qualify as derivatives are included in marketing and trading segment revenues on the Statements of Income on a net basis. The rescission of EITF 98-10 has no effect on the accounting for derivative instruments used for non-trading activities, which continue to be accounted for in accordance with SFAS No. 133. We adopted the EITF 02-3 guidance for all contracts in the fourth quarter of 2002. The impact of the guidance was immaterial to our financial statements.

EITF 02-3 requires derivatives held for trading purposes, whether settled financially or physically, be reported in the income statement on a net basis. Previous guidance under EITF 98-10 permitted physically settled energy trading contracts to be reported either gross or net in the income statement. Beginning in the third quarter of 2002, we netted all of our energy trading activities on the Statements of Income and restated prior year amounts for all periods presented. Reclassification of such trading activity to a net basis of reporting resulted in reductions in both revenues and purchased power and fuel costs, but did not have any impact on our financial condition, results of operations or cash flows.

In 2001, we adopted SFAS No. 133 and recorded a $15 million after-tax charge in net income and a $72 million after-tax credit in common stock equity (as a component of other comprehensive income), both as a cumulative effect of a change in accounting for derivatives. See Notes 1 and 16 for further information on accounting for derivatives under SFAS No. 133.

Asset Retirement Obligations

On January 1, 2003 we adopted SFAS No. 143, "Accounting for Asset Retirement Obligations." The standard requires the fair value of asset retirement obligations to be recorded as a liability, along with an offsetting plant asset, when the obligation is incurred. Accretion of the liability due to the passage of time will be an operating expense and the capitalized cost is depreciated over the useful life of the long-lived asset. (See Note 1 for more information regarding our previous accounting for removal costs.)

We determined that we have asset retirement obligations for our nuclear facilities (nuclear decommissioning) and certain other generation, transmission and distribution assets. On January 1, 2003 we recorded a liability of $219 million for our asset retirement obligations including the accretion impacts; a $67 million increase in the carrying amount of the associated assets; and a net reduction of $192 million in accumulated depreciation related primarily to the reversal of previously recorded accumulated decommissioning and other removal costs related to these obligations. Additionally, we recorded a regulatory liability of $40 million for our asset retirement obligations related to our regulated utility. This regulatory liability represents the difference between the amount currently being recovered in regulated rates and the amount calculated under SFAS No. 143. We believe we can recover in regulated rates the transition costs and ongoing current period costs calculated in accordance with SFAS No. 143.

Stock-Based Compensation

In the third quarter of 2002, we began applying the fair value method of accounting for stock-based compensation, as provided for in SFAS No. 123, "Accounting for Stock-Based Compensation." We recorded approximately $333,000 in stock option expense before income taxes in our Statements of Income for 2002. See Notes 1 and 14 for further information on the impacts of adopting the fair value method provided in SFAS No. 123.

Variable Interest Entities

See "Liquidity and Capital Resources – Off-Balance Sheet Arrangements" and Note 18 for discussion of VIEs.

Other

See Note 2 for discussion of other new accounting standards that are not expected to have a material impact on the Company.

FACTORS AFFECTING OUR FINANCIAL OUTLOOK

Regulatory Matters

General

On September 21, 1999, the ACC approved Rules that provide a framework for the introduction of retail electric competition in Arizona. On September 23, 1999, the ACC approved a comprehensive settlement agreement among us and various parties related to the implementation of retail electric competition in Arizona. Under the Rules, as modified by the 1999 Settlement Agreement, we were required to transfer all of our competitive electric assets and services to an unaffiliated party or parties or to a separate corporate affiliate or affiliates no later than December 31, 2002. Consistent with that requirement, we had been addressing the legal and regulatory requirements necessary to complete the transfer of our generation assets to Pinnacle West Energy on or before that date. On September 10, 2002, the ACC issued the Track A Order, which, among other things, directed us not to transfer our generation assets to Pinnacle West Energy.

1999 Settlement Agreement

The 1999 Settlement Agreement has affected, and will affect, our results of operations. As part of the 1999 Settlement Agreement, we agreed to reduce retail electricity prices for standard-offer, full-service customers with loads less than three megawatts in a series of annual decreases of 1.5% on July 1, 1999 through July 1, 2003, for a total of 7.5%. For customers with loads three megawatts or greater, standard-offer rates were reduced in annual increments totaling 5% in the years 1999 through 2002.

The 1999 Settlement Agreement also removed, as a regulatory disallowance, $234 million before income taxes ($183 million net present value) from ongoing regulatory cash flows. We recorded this regulatory disallowance as a net reduction of regulatory assets and reported it as a $140 million after-tax extraordinary charge on the 1999 Statement of Income. As discussed under "General Rate Case" below, we intend to seek recovery of this $234 million write-off in our next general rate case.

Prior to the 1999 Settlement Agreement, the ACC accelerated the amortization of substantially all of our regulatory assets to an eight-year period that would have ended June 30, 2004. The regulatory assets to be recovered under the 1999 Settlement Agreement are currently being amortized as follows (dollars in millions):

1999	2000	2001	2002	2003	2004	Total
$164	$158	$145	$115	$86	$18	$686

See Note 3 for additional information regarding the 1999 Settlement Agreement.

Financing Application

On September 16, 2002, we filed an application with the ACC requesting the ACC to allow us to borrow up to $500 million and to lend the proceeds to Pinnacle West Energy or to Pinnacle West; to guarantee up to $500 million of Pinnacle West Energy's or Pinnacle West's debt; or a combination of both, not to exceed $500 million in the aggregate. In our application, we stated that the ACC's reversal of the generation asset transfer requirement and the resulting bifurcation of generation assets between us and Pinnacle West Energy under different regulatory regimes results in Pinnacle West Energy being unable to attain investment-grade credit ratings. This, in turn, precludes Pinnacle West Energy from accessing capital markets to refinance the bridge financing that Pinnacle West provided to fund the construction of Pinnacle West Energy generation assets or from effectively competing in the wholesale markets. On March 27, 2003, the ACC authorized APS to lend up to $500 million to Pinnacle West Energy, guarantee up to $500 million of Pinnacle West Energy debt, or a combination of both, not to exceed $500 million in the aggregate. See "ACC Applications" in Note 3 for further discussion of the approval and related conditions.

Track A Order

On September 10, 2002, the ACC issued the Track A Order. See "Track A Order" in Note 3.

Competitive Procurement Process

On September 10, 2002, the ACC issued an order that, among other things, established a requirement that we competitively procure certain power requirements. On March 14, 2003, the ACC issued the Track B Order, which documented the decision made by the ACC at its open meeting on February 27, 2003 addressing this requirement. Under the ACC's Track B Order, we will be required to solicit bids for certain estimated capacity and energy requirements for periods beginning July 1, 2003. For 2003, we will be required to solicit competitive bids for about 2,500

MW of capacity and about 4,600 gigawatt-hours of energy, or approximately 20% of our total retail energy requirements. The bid amounts are expected to increase in 2004 and 2005 based largely on growth in our retail load and our retail energy sales. The Track B Order also confirmed that it was "not intended to change the current rate base status of [APS'] existing assets." The order recognizes our right to reject any bids that are unreasonable, uneconomical or unreliable.

We expect to issue requests for proposals in March 2003 and to complete the selection process by June 1, 2003. Pinnacle West Energy will be eligible to bid to supply our electricity requirements. See "Track B Order" in Note 3 for additional information.

General Rate Case

As required by the 1999 Settlement Agreement, on or before June 30, 2003, we will file a general rate case with the ACC. In this rate case, we will update our cost of service and rate design. In addition, we expect to seek:

- rate base treatment of certain power plants currently owned by Pinnacle West Energy (specifically, Redhawk Units 1 and 2, West Phoenix Units 4 and 5 and Saguaro Unit 3);
- recovery of the $234 million pretax asset write-off recorded by us as part of the 1999 Settlement Agreement ($140 million extraordinary charge recorded on the 1999 Statement of Income); and
- recovery of costs incurred by us in preparation for the previously required transfer of generation assets to Pinnacle West Energy.

We assume that the ACC will make a decision in this general rate case by the end of 2004.

Wholesale Power Market Conditions

The marketing and trading division, which was moved to us in early 2003 for future marketing and trading activities (existing wholesale contracts will remain at Pinnacle West) as a result of the ACC's Track A Order prohibiting our transfer of generating assets to Pinnacle West Energy, focuses primarily on managing our purchased power and fuel risks in connection with our costs of serving retail customer demand. Additionally, the marketing and trading division, subject to specified parameters, markets, hedges and trades in electricity, fuels and emission allowances and credits. Earnings contributions from Pinnacle West's marketing and trading division were lower in 2002 compared to 2001 due to weak wholesale power market conditions in the western United States, which included a lack of market liquidity, fewer creditworthy counterparties, lower wholesale market prices and resulting decreases in sales volumes. Our 2003 earnings will be affected by the strength (or weakness) of the wholesale power market.

Factors Affecting Operating Revenues

General Electric operating revenues are derived from sales of electricity in regulated retail markets in Arizona and from competitive retail and wholesale bulk power markets in the western

United States. These revenues are expected to be affected by electricity sales volumes related to customer mix, customer growth and average usage per customer as well as electricity prices and variations in weather from period to period.

Customer Growth Customer growth in our service territory averaged about 3.6% a year for the three years 2000 through 2002; we currently expect customer growth to average about 3.5 % per year from 2003 to 2005. We currently estimate that retail electricity sales in kilowatt-hours will grow 3.5% to 5.5% a year in 2003 through 2005, before the retail effects of weather variations. The customer growth and sales growth referred to in this paragraph applies to energy delivery customers. As previously noted, under the 1999 Settlement Agreement, we agreed to retail electricity price reductions of 1.5% annually through July 1, 2003 (see Note 3).

Other Factors Affecting Future Financial Results

Purchased Power and Fuel Costs Purchased power and fuel costs are impacted by our electricity sales volumes, existing contracts for purchased power and generation fuel, our power plant performance, prevailing market prices and our hedging program for managing such costs.

Operations and Maintenance Expenses Operations and maintenance expenses are expected to be affected by sales mix and volumes, power plant additions and operations, inflation, outages, higher trending pension and other postretirement benefit costs and other factors. In July 2002, we implemented a voluntary workforce reduction as part of our cost reduction program. We recorded $34 million before taxes in voluntary severance costs in the second half of 2002. In addition, we are expecting to produce annual operating expense savings of approximately $30 million beginning in 2003 as a result of this workforce reduction.

Depreciation and Amortization Expenses Depreciation and amortization expenses are expected to be affected by net additions to existing utility plant and other property and changes in regulatory asset amortization. The regulatory assets to be recovered under the 1999 Settlement Agreement are currently being amortized as follows (dollars in millions):

1999	2000	2001	2002	2003	2004	Total
$164	$158	$145	$115	$86	$18	$686

Property Taxes Taxes other than income taxes consist primarily of property taxes, which are affected by tax rates and the value of property in-service and under construction. The average property tax rate was 9.7% of assessed value for 2002 and 9.3% for 2001. We expect property taxes to increase primarily due to our additions to existing facilities.

Interest Expense Interest expense is affected by the amount of debt outstanding and the interest rates on that debt. The primary factors affecting borrowing levels in the next several years are expected to be our capital requirements and our internally-generated cash flow. Capitalized interest offsets a portion of interest expense while capital projects are under construction. We stop recording capitalized interest on a project when it is placed in commercial operation. Interest expense is affected by interest rates on variable-rate debt. We are continuing to evaluate our construction program.

Retail Competition The regulatory developments and legal challenges to the Rules discussed in Note 3 have raised considerable uncertainty about the status and pace of retail electric competition in Arizona. Although some very limited retail competition existed in our service area in 1999 and 2000, there are currently no active retail competitors providing unbundled energy or other utility services to our customers. As a result, we cannot predict when, and the extent to which, additional competitors will re-enter our service territory.

General Our financial results may be affected by a number of broad factors. See "Forward-Looking Statements" below for further information on such factors, which may cause our actual future results to differ from those we currently seek or anticipate.

Market Risks

Our operations include managing market risks related to changes in interest rates, commodity prices and investments held by the nuclear decommissioning trust fund and the pension plans.

Interest Rate and Equity Risk

Our major financial market risk exposure is changing interest rates. Changing interest rates will affect interest paid on variable-rate debt and interest earned by our pension plan (see Note 7) and nuclear decommissioning trust fund (see Note 11). Our policy is to manage interest rates through the use of a combination of fixed-rate and floating-rate debt. The pension plan and nuclear decommissioning fund also have risks associated with changing market values of equity investments. Pension and nuclear decommissioning costs are recovered in regulated electricity prices. See "Critical Accounting Policies – Pension and Other Postretirement Benefit Accounting" for a sensitivity analysis on the long-term rate of return on plan assets.

The tables below present contractual balances of our long-term debt and commercial paper at the expected maturity dates as well as the fair value of those instruments on December 31, 2002 and 2001. The interest rates presented in the tables below represent the weighted average interest rates for the years ended December 31, 2002 and 2001.

Expected Maturity/Principal Repayment
December 31, 2002
(dollars in thousands)

	Short-Term Debt		Variable-Rate Long-Term Debt		Fixed-Rate Long-Term Debt	
	Interest Rates	Amount	Interest Rates	Amount	Interest Rates	Amount
2003		$ --		$ --	5.86%	$ 3,503
2004		--		--	6.16%	208,300
2005		--		--	7.27%	403,300
2006		--		--	6.72%	86,517
2007		--		--	5.78%	2,227
Years thereafter		--	3.17%	386,860	6.08%	1,136,473
Total		$ --		$ 386,860		$ 1,840,320
Fair Value		$ --		$ 386,860		$ 1,937,244

Expected Maturity/Principal Repayment
December 31, 2001
(dollars in thousands)

	Short-Term Debt		Variable-Rate Long-Term Debt		Fixed-Rate Long-Term Debt	
	Interest Rates	Amount	Interest Rates	Amount	Interest Rates	Amount
2002	4.72%	$ 171,162		$ --	8.10%	$ 125,451
2003	--	--		--	6.18%	337
2004	--	--		--	6.08%	205,185
2005	--	--		--	7.59%	400,185
2006	--	--		--	6.77%	83,880
Years thereafter	--	--	2.60%	476,860	6.73%	787,894
Total		$ 171,162		$ 476,860		$ 1,602,932
Fair Value		$ 171,162		$ 476,860		$ 1,621,937

Commodity Price Risk

We are exposed to the impact of market fluctuations in the commodity price and transportation costs of electricity, natural gas, coal and emissions allowances. We manage risks associated with these market fluctuations by utilizing various commodity derivatives, including exchange-traded futures and options and over-the-counter forwards, options and swaps. The ERMC, consisting of senior officers, oversees company-wide energy risk management activities and monitors the results of marketing and trading activities to ensure compliance with our stated energy risk management and trading policies. As part of our risk management program, we enter into derivative transactions to hedge purchases and sales of electricity, fuels and emissions allowances and credits. The changes in market value of such contracts have a high correlation to price changes in the hedged commodities. In addition, subject to specified risk parameters monitored by the ERMC, we engage in marketing and trading activities intended to profit from market price movements.

Prior to October 1, 2002, we accounted for our energy trading contracts at fair value in accordance with EITF 98-10. On October 1, 2002, we adopted EITF 02-3, which rescinded EITF 98-10. As a result, our energy trading contracts that are derivatives continue to be accounted for at fair value under SFAS No. 133. Contracts that were previously marked-to-market as trading activities under EITF 98-10 that do not meet the definition of a derivative are now accounted for on an accrual basis with the associated revenues and costs recorded at the time the contracted commodities are delivered or received. Additionally, all gains and losses (realized and unrealized) on energy trading contracts that qualify as derivatives are included in marketing and trading segment revenues on the Statements of Income on a net basis. The rescission of EITF 98-10 has no effect on the accounting for derivative instruments used for non-trading activities, which continue to be accounted for in accordance with SFAS No. 133. See Note 16 for details on the change in accounting for energy trading contracts and further discussion regarding derivative accounting.

Both non-trading and trading derivatives are classified as assets and liabilities from risk management and trading activities in the Balance Sheets. For non-trading derivative instruments that qualify for hedge accounting treatment, changes in the fair value of the effective portion are recognized in common stock equity (as a component of accumulated other comprehensive income (loss)). Non-trading derivatives, or any portion thereof, that are not effective hedges are adjusted to fair value through income. Gains and losses related to non-trading derivatives that qualify as cash flow hedges of expected transactions are recognized in revenue or purchased power and fuel expense as an offset to the related item being hedged when the underlying hedged physical transaction impacts earnings. If it becomes probable that a forecasted transaction will not occur, we discontinue the use of hedge accounting and recognize in income the unrealized gains and losses that were previously recorded in other comprehensive income (loss). In the event a non-trading derivative is terminated or settled, the unrealized gains and losses remain in other comprehensive income (loss), and are recognized in income when the underlying transaction impacts earnings.

Derivatives associated with trading activities are adjusted to fair value through income. Derivative commodity contracts for the physical delivery of purchase and sale quantities transacted in the normal course of business are exempt from the requirements of SFAS No. 133 under the normal purchase and sales exception and are not reflected on the balance sheet at fair value. Most of our non-trading electricity purchase and sales agreements qualify as normal purchases and sales and are exempted from recognition in the financial statements until the electricity is delivered.

Our assets and liabilities from risk management and trading activities are presented in two categories consistent with our business segments:

- System - our regulated electricity business segment, which consists of non-trading derivative instruments that hedge our purchases and sales of electricity and fuel for our Native Load requirements; and

- Marketing and Trading - our non-regulated, competitive business segment, which includes both non-trading and trading derivative instruments.

The following tables show the changes in mark-to-market of our system and marketing and trading derivative positions in 2002 and 2001 (dollars in millions):

	System	Marketing and Trading
Mark-to-market of net positions at December 31, 2001	$ (107)	$ --
Change in mark-to-market losses for future period deliveries	(22)	--
Changes in cash flow hedges recorded in OCI	64	--
Ineffective portion of changes in fair value recorded in earnings	8	--
Mark-to-market losses realized during the year	7	--
Mark-to-market of net positions at December 31, 2002	$ (50)	$ --

	System	Marketing and Trading
Mark-to-market of net positions at December 31, 2000	$ --	$ 12
Cumulative effect adjustment due to adoption of SFAS No. 133	95	--
Change in mark-to-market (losses)/gains for future period deliveries	(12)	85
Changes in cash flow hedges recorded in OCI	(166)	--
Ineffective portion of changes in fair value recorded in earnings	(6)	--
Mark-to-market (gains)/losses realized during the year	(18)	7
Transfer of marketing and trading balance to Pinnacle West marketing and trading	--	(104)
Mark-to-market of net positions at December 31, 2001	$ (107)	$ --

As of December 31, 2002, a hypothetical adverse price movement of 10% in the market price of our risk management and trading assets and liabilities would have decreased the fair market value of these contracts by approximately $16 million, compared to a $23 million decrease that would have been realized as of December 31, 2001. A hypothetical favorable price movement of 10% would have increased the fair market value of these contracts by approximately $18 million, compared to a

$23 million increase that would have been realized as of December 31, 2001. These contracts are hedges of our forecasted purchases of natural gas. The impact of these hypothetical price movements would substantially offset the impact that these same price movements would have on the physical exposures being hedged.

Credit Risk

We are exposed to losses in the event of nonperformance or nonpayment by counterparties. We use a risk management process to assess and monitor the financial exposure related to our counterparties. Despite the fact that the great majority of trading counterparties are rated as investment grade by the credit rating agencies, there is still a possibility that one or more of these companies could default, resulting in a material impact on earnings for a given period. Counterparties in the portfolio consist principally of major energy companies, municipalities and local distribution companies. We maintain credit policies that we believe minimize overall credit risk to within acceptable limits. Determination of the credit quality of our counterparties is based upon a number of factors, including credit ratings and our evaluation of their financial condition. In many contracts, we employ collateral requirements and standardized agreements that allow for the netting of positive and negative exposures associated with a single counterparty. Valuation adjustments are established representing our estimated credit losses on our overall exposure to counterparties. See "Critical Accounting Policies - Mark-to-Market Accounting" above for a discussion of our credit valuation adjustment policy.

Risk Factors

Exhibit 99.3, which is hereby incorporated by reference, contains a discussion of risk factors affecting the Company.

Forward-Looking Statements

The above discussion contains forward-looking statements based on current expectations and we assume no obligation to update these statements or make any further statements on any of these issues, except as required by applicable laws. Because actual results may differ materially from expectations, we caution readers not to place undue reliance on these statements. A number of factors could cause future results to differ materially from historical results, or from results or outcomes currently expected or sought by us. These factors include the ongoing restructuring of the electric industry, including the introduction of retail electric competition in Arizona and decisions impacting wholesale competition; the outcome of regulatory and legislative proceedings relating to the restructuring; state and federal regulatory and legislative decisions and actions, including price caps and other market constraints imposed by the FERC; regional economic and market conditions, including the California energy situation and completion of generation construction in the region, which could affect customer growth and the cost of power supplies; the cost of debt and equity capital and access to capital markets; weather variations affecting local and regional customer energy usage; the effect of conservation programs on energy usage; power plant performance; our ability to compete successfully outside traditional regulated markets (including the wholesale market); our ability to manage our marketing and trading activities and the use of derivative contracts in our business; technological developments in the electric industry; the performance of the stock market, which affects the amount of our required contributions to our pension plan and nuclear decommissioning trust funds; and other uncertainties, all of which are difficult to predict and many of which are beyond our control.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

See "Factors Affecting Our Financial Outlook - Market Risks" in Item 7 for a discussion of quantitative and qualitative disclosures about market risk.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO FINANCIAL STATEMENTS

See Note 12 for the selected quarterly financial data required to be presented in this Item.

INDEPENDENT AUDITORS' REPORT

To the Board of Directors and the Stockholder of
Arizona Public Service Company
Phoenix, Arizona

We have audited the accompanying balance sheets of Arizona Public Service Company (the "Company") as of December 31, 2002 and 2001, and the related statements of income, changes in common stock equity and cash flows for each of the three years in the period ended December 31, 2002. Our audits also included the financial statement schedule listed in the Index. These financial statements and the financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and the financial statement schedule based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such financial statements present fairly, in all material respects, the financial position of Arizona Public Service Company at December 31, 2002 and 2001, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2002, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

As discussed in Note 16 to the financial statements, in 2001 Arizona Public Service Company changed its method of accounting for derivatives and hedging activities in order to comply with the provisions of Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities."

Deloitte & Touche LLP

DELOITTE & TOUCHE LLP
Phoenix, Arizona
February 3, 2003 (March 14, 26 and 27, 2003 as to Note 20)

ARIZONA PUBLIC SERVICE COMPANY
STATEMENTS OF INCOME

	Year Ended December 31,		
	2002	2001	2000
Electric Operating Revenues:			
Regulated electricity segment	$ 2,059,339	$ 2,562,088	$ 2,538,750
Marketing and trading segment	34,054	549,240	395,392
Total	2,093,393	3,111,328	2,934,142
Purchased Power and Fuel Costs:			
Regulated electricity segment	595,368	1,227,188	1,065,596
Marketing and trading segment	32,662	313,991	267,032
Total	628,030	1,541,179	1,332,628
Operating Revenues less Purchased Power and Fuel Costs	1,465,363	1,570,149	1,601,514
Other Operating Expenses:			
Operations and maintenance	495,845	465,561	430,092
Depreciation and amortization	399,640	420,893	425,479
Income taxes (Note 4)	132,953	183,640	199,977
Other taxes	107,925	101,077	99,730
Total	1,136,363	1,171,171	1,155,278
Operating Income	329,000	398,978	446,236
Other Income (Deductions):			
Other income (Note 17)	5,149	20,207	9,690
Other expense (Note 17)	(19,338)	(20,790)	(20,547)
Income taxes (Note 4)	6,148	504	4,312
Total	(8,041)	(79)	(6,545)
Income Before Interest Deduction	320,959	398,899	439,691
Interest Deductions:			
Interest on long-term debt	128,462	126,118	134,431
Interest on short-term borrowings	5,416	4,407	7,455
Debt discount, premium and expense	2,888	2,650	2,105
Capitalized interest	(15,150)	(14,964)	(10,894)
Total	121,616	118,211	133,097
Income Before Accounting Change	199,343	280,688	306,594
Cumulative Effect of Change in Accounting for Derivatives – net of income taxes of $9,892	--	(15,201)	--
Net Income	$ 199,343	$ 265,487	$ 306,594

See Notes to Financial Statements.

ARIZONA PUBLIC SERVICE COMPANY
BALANCE SHEETS
ASSETS

	December 31, 2002	December 31, 2001
	(dollars in thousands)	
Utility Plant (Notes 1, 8 and 9)		
Electric plant in service and held for future use	$ 8,299,131	$ 7,935,206
Less accumulated depreciation and amortization	3,442,571	3,287,333
Total	4,856,560	4,647,873
Construction work in progress	329,089	321,305
Intangible assets, net of accumulated amortization (Note 19)	93,259	83,135
Nuclear fuel, net of accumulated amortization of $102,821 and $99,185	7,466	6,933
Utility Plant – net	5,286,374	5,059,246
Investments and Other Assets		
Decommissioning trust accounts (Note 11)	194,440	202,036
Assets from risk management and trading activities – long-term	31,622	2,082
Other assets	19,964	76,322
Total Investments and Other Assets	246,026	280,440
Current Assets:		
Cash and cash equivalents	42,549	16,821
Accounts receivable:		
Service customers	136,945	182,749
Other (Note 1)	202,597	55,016
Allowance for doubtful accounts	(1,341)	(3,349)
Accrued utility revenues	72,915	76,131
Materials and supplies (at average cost)	79,985	81,215
Fossil fuel (at average cost)	28,185	27,023
Deferred income taxes (Note 4)	4,094	--
Assets from risk management and trading activities	39,616	10,097
Other	45,361	42,009
Total Current Assets	650,906	487,712
Deferred Debits:		
Regulatory assets (Notes 1 and 3)	241,045	342,383
Unamortized debt issue costs	16,696	13,163
Other	80,760	42,789
Total Deferred Debits	338,501	398,335
Total Assets	$ 6,521,807	$ 6,225,733

See Notes to Financial Statements.

ARIZONA PUBLIC SERVICE COMPANY
BALANCE SHEETS
LIABILITIES AND EQUITY

	December 31, 2002	December 31, 2001
	(dollars in thousands)	
Capitalization:		
Common stock	$ 178,162	$ 178,162
Additional paid-in capital	1,246,804	1,246,804
Retained earnings	819,632	790,289
Accumulated other comprehensive loss:		
Minimum pension liability adjustment	(61,487)	(966)
Derivative instruments	(23,799)	(63,599)
Common stock equity	2,159,312	2,150,690
Long-term debt less current maturities (Note 6)	2,217,340	1,949,074
Total Capitalization	4,376,652	4,099,764
Current Liabilities:		
Commercial paper (Note 5)	--	171,162
Current maturities of long-term debt (Note 6)	3,503	125,451
Accounts payable	118,133	98,959
Accrued taxes	82,557	107,595
Accrued interest	42,608	41,043
Customer deposits	39,865	28,664
Deferred income taxes (Note 4)	--	3,244
Liabilities from risk management and trading activities	59,773	21,840
Other	51,820	18,798
Total Current Liabilities	398,259	616,756
Deferred Credits and Other:		
Deferred income taxes (Note 4)	1,225,552	1,023,079
Liabilities from risk management and trading activities	36,678	95,159
Unamortized gain – sale of utility plant (Note 8)	59,484	64,060
Customer advances for construction	45,513	69,293
Pension liability (Note 7)	156,442	30,247
Other	223,227	227,375
Total Deferred Credits and Other	1,746,896	1,509,213
Commitments and Contingencies (Notes 3, 10 and 11)		
Total Liabilities and Equity	$ 6,521,807	$ 6,225,733

See Notes to Financial Statements.

ARIZONA PUBLIC SERVICE COMPANY
STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2002	2001	2000
	(dollars in thousands)		
Cash Flows from Operating Activities:			
Net income	$ 199,343	$ 265,487	$ 306,594
Items not requiring cash:			
Depreciation and amortization	399,640	420,893	425,479
Nuclear fuel amortization	31,185	28,362	30,083
Deferred income taxes	206,767	(26,516)	(65,726)
Change in mark-to-market	2,957	(100,030)	(11,752)
Cumulative effect of change in accounting – net of income taxes	--	15,201	--
Changes in certain current assets and liabilities:			
Accounts receivable	(102,450)	302,283	(209,705)
Materials, supplies and fossil fuel	68	(16,867)	475
Other current assets	(136)	(5,160)	(26,682)
Accounts payable	15,372	(190,141)	101,558
Accrued taxes	(25,038)	1,080	43,657
Accrued interest	1,565	1,555	7,189
Other current liabilities	44,224	(58,361)	101,685
Increase in regulatory assets	(11,029)	(17,516)	(14,138)
Change in risk management trading – assets	(22,570)	10,730	13,181
Change in customer advances	(23,780)	28,599	2,544
Change in pension liability	5,415	(30,346)	(18,373)
Change in other net long-term assets	(18,923)	(14,192)	64,998
Change in other net long-term liabilities	1,902	(9,986)	(27,396)
Net cash provided by operating activities	704,512	605,075	723,671
Cash Flows from Investing Activities:			
Capital expenditures	(490,156)	(465,360)	(464,368)
Capitalized interest	(15,150)	(14,964)	(10,894)
Other	44,918	(41,926)	(72,189)
Net cash used for investing activities	(460,388)	(522,250)	(547,451)
Cash Flows from Financing Activities:			
Issuance of long-term debt	459,926	396,072	300,000
Short-term borrowings	(171,162)	89,062	43,800
Dividends paid on common stock	(170,000)	(170,000)	(170,000)
Repayment and reacquisition of long-term debt	(337,160)	(383,747)	(354,888)
Net cash used for financing activities	(218,396)	(68,613)	(181,088)
Net increase (decrease) in cash and cash equivalents	25,728	14,212	(4,868)
Cash and cash equivalents at beginning of year	16,821	2,609	7,477
Cash and cash equivalents at end of year	$ 42,549	$ 16,821	$ 2,609
Supplemental disclosure of cash flow information:			
Cash paid during the year for:			
Interest (excluding capitalized interest)	$ 117,081	$ 114,094	$ 123,895
Income taxes paid/(refunded) (Note 4)	$ (54,283)	$ 212,989	$ 222,866

See Notes to Financial Statements.

ARIZONA PUBLIC SERVICE COMPANY
STATEMENTS OF CHANGES IN COMMON STOCK EQUITY

For the Years Ended December 31, 2002, 2001 and 2000
(dollars in thousands)

	2002	2001	2000
COMMON STOCK	$ 178,162	$ 178,162	$ 178,162
ADDITIONAL PAID-IN CAPITAL	1,246,804	1,246,804	1,246,804
RETAINED EARNINGS			
Balance at beginning of year	790,289	694,802	558,208
Net income	199,343	265,487	306,594
Common stock dividends	(170,000)	(170,000)	(170,000)
Balance at end of year	819,632	790,289	694,802
ACCUMULATED OTHER COMPREHENSIVE LOSS			
Balance at beginning of year	(64,565)	--	--
Minimum pension liability adjustment, net of tax of $39,696 and $634	(60,521)	(966)	--
Cumulative effect of a change in accounting for derivatives, net of tax of $47,404 in 2001	--	72,274	--
Unrealized gain/(loss) on derivative instruments, net of tax of $25,426 and $71,720	38,764	(109,346)	--
Reclassification of realized (gain)/loss to income, net of tax of $679 and $17,399	1,036	(26,527)	--
Balance at end of year	(85,286)	(64,565)	--
TOTAL COMMON STOCK EQUITY	$ 2,159,312	$ 2,150,690	$ 2,119,768
COMPREHENSIVE INCOME			
Net income	$ 199,343	$ 265,487	$ 306,594
Other comprehensive loss	(20,721)	(64,565)	--
Comprehensive income	$ 178,622	$ 200,922	$ 306,594

See Notes to Financial Statements.

ARIZONA PUBLIC SERVICE COMPANY
NOTES TO FINANCIAL STATEMENTS

1. Summary of Significant Accounting Policies

Nature of Operations

We are an electric utility that provides either retail or wholesale electric service to substantially all of the state of Arizona, with the major exceptions of the Tucson metropolitan area and about half of the Phoenix metropolitan area. Electricity is delivered through a distribution system owned by us. We also generate, sell and deliver electricity to wholesale customers in the western United States. In early 2003, the marketing and trading division was moved from Pinnacle West to us for future marketing and trading activities (existing wholesale contracts will remain at Pinnacle West) as a result of the ACC's Track A Order prohibiting the previously required transfer of our generating assets to Pinnacle West Energy (see Note 3 for a discussion of the Track A Order). Our marketing and trading division sells, in the wholesale market, our and Pinnacle West Energy's generation output that is not needed for our Native Load, which includes loads for retail customers and cost-of-service wholesale customers. We do not distribute any products. Pinnacle West owns all of our outstanding stock.

During 2001, we transferred most of our marketing and trading activities to Pinnacle West, which approximated $219 million in assets and $149 million in liabilities. From time to time, we enter into transactions with Pinnacle West or Pinnacle West's subsidiaries. The following table summarizes the amounts included in the Statements of Income and Balance Sheets related to transactions with affiliated companies (dollars in millions):

	For the year ended December 31,		
	2002	2001	2000
Electric operating revenues:			
Pinnacle West – marketing and trading	$ 85	$ 50	$ --
APS Energy Services	--	15	26
Total	$ 85	$ 65	$ 26
Purchased power and fuel costs:			
Pinnacle West – marketing and trading	$ 135	$ 50	$ --
Pinnacle West Energy	--	14	--
Total	$ 135	$ 64	$ --

	As of December 31,	
	2002	2001
Net intercompany receivables/(payables):		
Pinnacle West – marketing and trading	$ 135	$ 13
Pinnacle West	(1)	(11)
Pinnacle West Energy	(1)	1
APS Energy Services	--	13
Total	$ 133	$ 16

Electric revenues include sales of electricity to affiliated companies at contract prices. Purchased power includes purchases of electricity from affiliated companies at contract prices. Intercompany receivables primarily include the amounts related to the transfer of marketing and trading activities discussed above and intercompany sales of electricity. Intercompany payables primarily include amounts related to the purchase of electricity. Intercompany receivables and payables are generally settled on a current basis in cash.

Accounting Records and Use of Estimates

Our accounting records are maintained in accordance with accounting principles generally accepted in the United States of America (GAAP). The preparation of financial statements in accordance with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements and reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. We have reclassified certain prior year amounts to conform to the current year presentation.

Derivative Accounting

We are exposed to the impact of market fluctuations in the price and transportation costs of electricity, natural gas, coal and emissions allowances. We manage risks associated with these market fluctuations by utilizing various commodity derivatives, including exchange-traded futures and options and over-the-counter forwards, options and swaps. As part of our overall risk management program, we enter into derivative transactions to hedge purchases and sales of electricity, fuels and emissions allowances and credits. The changes in market value of such contracts have a high correlation to price changes in the hedged commodities. In addition, subject to specified risk parameters monitored by the ERMC, we engage in marketing and trading activities intended to profit from market price movements.

We examine contracts at inception to determine the appropriate accounting treatment. If a contract does not meet the derivative criteria or if it qualifies for a SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," scope exception, we account for the contract on an accrual basis with associated revenues and costs recorded at the time the contracted commodities are delivered or received. SFAS No. 133 provides a scope exception for contracts that meet the normal purchases and sales criteria specified in the standard. Most of our non-trading electricity purchase and sales agreements qualify as normal purchases and sales and are exempted from recognition in the financial statements until the electricity is delivered.

For contracts that qualify as a derivative and do not meet a SFAS No. 133 scope exception, we further examine the contract to determine if it will qualify for hedge accounting. Changes in the fair value of the effective portion of derivative instruments that qualify for cash flow hedge accounting treatment are recognized as either an asset or liability and in common stock equity (as a component of accumulated other comprehensive income (loss)). Gains and losses related to derivatives that qualify as cash flow hedges of expected transactions are recognized in revenue or purchased power and fuel expense as an offset to the related item being hedged when the underlying hedged physical transaction impacts earnings. If a contract does not meet the hedging criteria in SFAS No. 133, we recognize the changes in the fair value of the derivative instrument in income each period through mark-to-market accounting.

On October 1, 2002, we adopted EITF 02-3, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities," which rescinded EITF 98-10. As a result, our energy trading contracts that are derivatives continue to be accounted for at fair value under SFAS No. 133. Contracts that were previously marked-to-market as trading activities under EITF 98-10 that do not meet the definition of a derivative are now accounted for on an accrual basis with the associated revenues and costs recorded at the time the contracted commodities are delivered or received. Additionally, all gains and losses (realized and unrealized) on energy trading contracts that qualify as derivatives are included in marketing and trading segment revenues on the Statements of Income on a net basis. The rescission of EITF 98-10 has no effect on the accounting for derivative instruments used for non-trading activities, which continue to be accounted for in accordance with SFAS No. 133. See Note 16 for more details on the change in accounting for energy trading contracts and for further discussion on derivative accounting.

Mark-to-Market Accounting

Under mark-to-market accounting, the purchase or sale of energy commodities is reflected at fair market value, net of valuation adjustments, with resulting unrealized gains and losses recorded as assets and liabilities from risk management and trading activities in the Balance Sheets.

We determine fair market value using actively-quoted prices when available. We consider quotes for exchange-traded contracts and over-the-counter quotes obtained from independent brokers to be actively-quoted.

When actively-quoted prices are not available, we use prices provided by other external sources. This includes quarterly and calendar year quotes from independent brokers. We convert quarterly and calendar year quotes into monthly prices based on historical relationships.

For options, long-term contracts and other contracts for which price quotes are not available, we use models and other valuation methods. The valuation models we employ utilize spot prices, forward prices, historical market data and other factors to forecast future prices. The primary valuation technique we use to calculate the fair value of contracts where price quotes are not available is based on the extrapolation of forward pricing curves using observable market data for more liquid delivery points in the same region and actual transactions at the more illiquid delivery points. We also value option contracts using a variation of the Black-Scholes option-pricing model.

For non-exchange traded contracts, we calculate fair market value based on the average of the bid and offer price, and we discount to reflect net present value. We maintain certain valuation adjustments for a number of risks associated with the valuation of future commitments. These include valuation adjustments for liquidity and credit risks based on the financial condition of counterparties. The liquidity valuation adjustment represents the cost that would be incurred if all unmatched positions were closed-out or hedged.

A credit valuation adjustment is also recorded to represent estimated credit losses on our overall exposure to counterparties, taking into account netting arrangements, expected default experience for the credit rating of the counterparties and the overall diversification of the portfolio. Counterparties in the portfolio consist principally of major energy companies, municipalities and local distribution companies. We maintain credit policies that management believes minimize overall credit risk. Determination of the credit quality of counterparties is based upon a number of factors, including credit ratings, financial condition, project economics and collateral requirements. When applicable, we employ standardized agreements that allow for the netting of positive and negative exposures associated with a single counterparty. See Note 16 for further discussion on credit risk.

The use of models and other valuation methods to determine fair market value often requires subjective and complex judgment. Actual results could differ from the results estimated through application of these methods. Our practice is to hedge within timeframes established by the ERMC.

Regulatory Accounting

We are regulated by the ACC and the FERC. The accompanying financial statements reflect the rate-making policies of these commissions. For regulated operations, we prepare our financial statements in accordance with SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation." SFAS No. 71 requires a cost-based, rate-regulated enterprise to reflect the impact of regulatory decisions in its financial statements. As a result, we capitalize certain costs that would be included as expense in the current period by unregulated companies. Regulatory assets represent incurred costs that have been deferred because they are probable of future recovery in customer rates. Regulatory liabilities generally represent obligations to make refunds to customers for previous collections of costs not likely to be incurred.

We are required to discontinue applying SFAS No. 71 when deregulatory legislation is passed or a rate order is issued that contains sufficient detail to determine its effect on the portion of the business being deregulated. In 1999, we discontinued the application of SFAS No. 71 for our generation operations due to the 1999 Settlement Agreement with the ACC. See Note 3 for a discussion of the 1999 Settlement Agreement.

As a result, we tested the generation assets for impairment and determined the generation assets were not impaired. Pursuant to the 1999 Settlement Agreement, a regulatory disallowance removed $234 million pretax ($183 million net present value) from ongoing regulatory cash flows and was recorded as a net reduction of regulatory assets. This reduction ($140 million after income taxes) was reported as an extraordinary charge on the 1999 Statements of Income.

In 2002, the ACC directed us not to transfer our generation assets, as previously required by the 1999 Settlement Agreement (see "Track A Order" in Note 3). Accordingly, we now consider our generation to be cost-based, rate-regulated and subject to the requirements of SFAS No. 71. The impact of this change was immaterial to our financial statements.

Management continually assesses whether our regulatory assets are probable of future recovery by considering factors such as applicable regulatory environment changes and recent rate orders to other regulated entities in the same jurisdiction. This determination reflects the current political and regulatory climate in the state and is subject to change in the future. If future recovery of costs ceases to be probable, the assets would be written off as a charge in current period earnings.

Prior to the 1999 Settlement Agreement, the ACC accelerated the amortization of substantially all of our regulatory assets to an eight-year period that would have ended June 30, 2004. The regulatory assets to be recovered under the 1999 Settlement Agreement are currently being amortized as follows (dollars in millions):

1999	2000	2001	2002	2003	2004	Total
$164	$158	$145	$115	$86	$18	$686

Regulatory assets are reported as deferred debits on the Balance Sheets. As of December 31, 2002 and 2001, they are comprised of the following (dollars in millions):

	December 31, 2002	December 31, 2001
Remaining balance recoverable under the 1999 Settlement Agreement (a)	$ 104	$ 219
Spent nuclear fuel storage (Note 10)	46	43
Electric industry restructuring transition costs (Note 3)	40	34
Other	51	46
Total regulatory assets	$ 241	$ 342

(a) The majority of our unamortized regulatory assets above relates to deferred income taxes (see Note 4) and rate synchronization cost deferrals (see "Rate Synchronization Cost Deferrals" below).

Regulatory liabilities are included in deferred credits and other on the Balance Sheets. As of December 31, 2002 and 2001, they are comprised of the following (dollars in millions):

	December 31, 2002	December 31, 2001
Deferred gains on utility property	$ 20	$ 20
Other	6	7
Total regulatory liabilities	$ 26	$ 27

Rate Synchronization Cost Deferrals

As authorized by the ACC, operating costs (excluding fuel) and financing costs of Palo Verde Units 2 and 3 were deferred from the commercial operation dates (September 1986 for Unit 2 and January 1988 for Unit 3) until the date the units were included in a rate order (April 1988 for Unit 2 and December 1991 for Unit 3). In accordance with the 1999 Settlement Agreement, we are continuing to accelerate the amortization of the deferrals over an eight-year period that will end June 30, 2004. Amortization of the deferrals is included in depreciation and amortization expense in the Statements of Income.

Utility Plant and Depreciation

Utility plant is the term we use to describe the business property and equipment that supports electric service, consisting primarily of generation, transmission and distribution facilities. We report utility plant at its original cost, which includes:

- material and labor;
- contractor costs;
- construction overhead costs (where applicable); and
- capitalized interest or an allowance for funds used during construction.

We expense the costs of plant outages, major maintenance and routine maintenance as incurred. We charge retired utility plant, plus removal costs less salvage realized, to accumulated depreciation. See Note 2 for information on a new accounting standard that impacts accounting for removal costs.

We record depreciation on utility property on a straight-line basis over the remaining useful life of the related assets. The approximate remaining average useful lives of our utility property at December 31, 2002 were as follows:

- Fossil plant – 20 years;
- Nuclear plant – 22 years
- Transmission – 34 years
- Distribution – 28 years; and
- Other utility property – 9 years

For the years 2000 through 2002 the depreciation rates, as prescribed by our regulators, ranged from a low of 1.51% to a high of 20%. The weighted-average rate was 3.35% for 2002, 3.40% for 2001 and 2000. We depreciate non-utility property and equipment over the estimated useful lives of the related assets, ranging from 3 to 30 years.

Capitalized Interest

Capitalized interest represents the cost of debt funds used to finance construction projects. Plant construction costs, including capitalized interest, are expensed through depreciation when completed projects are placed into commercial operation. Capitalized interest does not represent current cash earnings. The rate used to calculate capitalized interest was a composite rate of 5.28% for 2002, 6.26% for 2001 and 6.62% for 2000.

Electric Revenues

Revenues related to the sale of energy are generally recorded when service is rendered or energy is delivered to customers. However, the determination of energy sales to individual Native Load customers is based on the reading of their meters, which occurs on a systematic basis throughout the month. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading and the corresponding unbilled revenue are estimated. We exclude sales taxes on electric revenues from both revenue and taxes other than income taxes. Other than revenues and purchased power costs related to energy trading activities, revenues are reported on a gross basis in our Statements of Income.

All gains and losses (realized and unrealized) on energy trading contracts that qualify as derivatives are included in marketing and trading segment revenues on the Statements of Income on a net basis.

Cash and Cash Equivalents

For purposes of the Statements of Cash Flows, we consider all highly liquid debt instruments purchased with an initial maturity of three months or less to be cash equivalents.

Nuclear Fuel

We charge nuclear fuel to fuel expense by using the unit-of-production method. The unit-of-production method is an amortization method based on actual physical usage. We divide the cost of the fuel by the estimated number of thermal units we expect to produce with that fuel. We then multiply that rate by the number of thermal units produced within the current period. This calculation determines the current period nuclear fuel expense.

We also charge nuclear fuel expense for the permanent disposal of spent nuclear fuel. The DOE is responsible for the permanent disposal of spent nuclear fuel, and it charges us $0.001 per kWh of nuclear generation. See Note 10 for information about spent nuclear fuel disposal and Note 11 for information on nuclear decommissioning costs.

Income Taxes

Income taxes are provided using the asset and liability approach prescribed by SFAS No. 109, "Accounting for Income Taxes." Pinnacle West files the federal income tax return on a consolidated basis and files the state income tax returns on a consolidated or unitary basis. In accordance with our intercompany tax sharing agreement, federal and state income taxes are allocated to us as though we filed a separate income tax return. Any difference between the aforementioned allocations and the consolidated (and unitary) income tax liability is attributed to Pinnacle West.

Reacquired Debt Costs

For debt related to the regulated portion of our business, we amortize those gains and losses incurred upon early retirement over the original remaining life of the debt. In accordance with the 1999 Settlement Agreement, we are continuing to accelerate reacquired debt costs over an eight-year period that will end June 30, 2004. All regulatory asset amortization is included in depreciation and amortization expense in the Statements of Income.

Stock-Based Compensation

Pinnacle West offers stock-based compensation plans for officers and key employees of our company. In 2002, we began applying the fair value method of accounting for stock-based compensation, as provided for in SFAS No. 123, "Accounting for Stock-Based Compensation." The fair value method of accounting is the preferred method. In accordance with the transition requirements of SFAS No. 123, we applied the fair value method prospectively, beginning with 2002 stock grants. In prior years, we recognized stock compensation expense based on the intrinsic value method allowed in Accounting Principles Board Opinion (APB) No. 25, "Accounting for Stock Issued to Employees."

The following chart compares our net income and stock compensation expense to what those items would have been if we had recorded stock compensation expense based on the fair value method for all stock grants through 2002 (dollars in thousands):

	2002	2001	2000
Net income:			
As reported	$ 199,343	$ 265,487	$ 306,594
Pro forma (fair value method)	198,381	263,905	305,745
Stock compensation expense (net of tax):			
As reported	200	--	--
Pro forma (fair value method)	962	1,582	849

In order to calculate the fair value of the 2002 stock option grants and the pro forma information above, we calculated the fair value of each fixed stock option in the incentive plans using the Black-Scholes option-pricing model. The fair value was calculated based on the date the option was granted. The following weighted-average assumptions were also used in order to calculate the fair value of the stock options:

	2002	2001	2000
Risk-free interest rate	4.17%	4.08%	5.81%
Dividend yield	4.17%	3.70%	3.48%
Volatility	22.59%	27.66%	32.00%
Expected life (months)	60	60	60

See Note 14 for further discussion about our stock compensation plans.

2. Accounting Matters

On January 1, 2003 we adopted SFAS No. 143, "Accounting for Asset Retirement Obligations." The standard requires the fair value of asset retirement obligations to be recorded as a liability, along with an offsetting plant asset, when the obligation is incurred. Accretion of the liability due to the passage of time will be an operating expense and the capitalized cost is depreciated over the useful life of the long-lived asset. (See Note 1 for more information regarding our previous accounting for removal costs.)

We determined that we have asset retirement obligations for our nuclear facilities (nuclear decommissioning) and certain other fossil generation, transmission and distribution assets. On January 1, 2003 we recorded a liability of $219 million for our asset retirement obligations including the accretion impacts; a $67 million increase in the carrying amount of the associated assets; and a net reduction of $192 million in accumulated depreciation related primarily to the reversal of previously recorded accumulated decommissioning and other removal costs related to these obligations. Additionally, we recorded a net regulatory liability of $40 million for our asset retirement obligations related to our regulated utility. This regulatory liability represents the difference between the amount currently being recovered in regulated rates and the amount calculated under SFAS No. 143. We believe we can recover in regulated rates the transition costs and ongoing current period costs calculated in accordance with SFAS No. 143.

In November 2002, the EITF reached a consensus on EITF 00-21, "Revenue Arrangements with Multiple Deliverables." EITF 00-21 addresses certain aspects of the accounting by a vendor for arrangements under which it will perform multiple revenue-generating activities. EITF 00-21 specifically addresses how to determine whether an arrangement has identifiable, separable revenue-generating activities. EITF 00-21 does not address when the criteria for revenue recognition are met or provide guidance on the appropriate revenue recognition convention. EITF 00-21 is effective for revenue arrangements entered into after July 1, 2003. We are currently evaluating the impacts of this new guidance, but we do not believe it will have a material impact on our financial statements.

On January 1, 2002, we adopted SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets." This statement supersedes SFAS No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed Of," and the accounting and reporting provisions for the disposal of a segment of a business. This standard did not impact our financial statements at adoption.

In April 2002, the FASB issued SFAS No. 145, "Rescission of FASB Statements Nos. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections" which, among other things, supersedes previous guidance for reporting gains and losses from extinguishment of debt. This standard did not impact our financial statements at adoption.

In July 2002, the FASB issued SFAS No. 146, "Accounting for Costs Associated with Exit or Disposal Activities." The standard requires companies to recognize costs associated with exit or disposal activities when they are incurred rather than at the date of a commitment to an exit or disposal plan. The guidance will be applied to exit or disposal activities initiated after December 31, 2002. This standard did not impact our financial statements at adoption.

In 2001, the American Institute of Certified Public Accountants (AICPA) issued an exposure draft of a proposed Statement of Position (SOP), "Accounting for Certain Costs Related to Property, Plant, and Equipment." This proposed SOP would create a project timeline framework for capitalizing costs related to property, plant and equipment construction. It would require that property, plant and equipment assets be accounted for at the component level and require administrative and general costs incurred in support of capital projects to be expensed in the current period. In November 2002, the AICPA announced they would no longer issue general purpose SOPs. The work they have performed on the proposed SOP will be transitioned to the FASB staff. In February 2003, the FASB determined that the AICPA should continue their deliberations on certain aspects of the proposed SOP. We are waiting for further guidance from the FASB staff and the AICPA on the timing of the final guidance.

See the following Notes for other new accounting standards:

- Notes 1 and 14 for a new accounting standard (SFAS No. 148) related to stock-based compensation;
- Note 16 for a new EITF issue (EITF 02-3) related to accounting for energy trading contracts;
- Note 18 for a new interpretation (FIN No. 46) related to VIEs; and
- Note 19 for a new standard (SFAS No. 142) related to goodwill and intangible assets.

3. Regulatory Matters

Electric Industry Restructuring

State

Overview On September 21, 1999, the ACC approved Rules that provide a framework for the introduction of retail electric competition in Arizona. On September 23, 1999, the ACC approved a comprehensive settlement agreement among us and various parties related to the implementation of retail electric competition in Arizona. Under the Rules, as modified by the 1999 Settlement Agreement, we were required to transfer all of our competitive electric assets and services to an unaffiliated party or parties or to a separate corporate affiliate or affiliates no later than December 31, 2002. Consistent with that requirement, we had been addressing the legal and regulatory requirements necessary to complete the transfer of our generation assets to Pinnacle West Energy on or before that date. On September 10, 2002, the ACC issued the Track A Order, which, among other things, directed us not to transfer our generation assets to Pinnacle West Energy. See "Track A Order" below.

On September 16, 2002, we filed an application with the ACC requesting the ACC to allow us to borrow up to $500 million and to lend the proceeds to Pinnacle West Energy or to Pinnacle West; to guarantee up to $500 million of Pinnacle West Energy's or Pinnacle West's debt; or a combination of both, not to exceed $500 million in the aggregate. In our application, we stated that the ACC's reversal of the generation asset transfer requirement and the resulting bifurcation of generation assets between us and Pinnacle West Energy under different regulatory regimes result in Pinnacle West Energy being unable to attain investment-grade credit ratings. This, in turn, precludes Pinnacle West Energy from accessing capital markets to refinance the bridge financing provided by Pinnacle West to fund the construction of Pinnacle West Energy generation assets or from effectively competing in the wholesale markets. On March 27, 2003, the ACC authorized us to lend up to $500 million to Pinnacle West Energy, guarantee up to $500 million of Pinnacle West Energy debt, or a combination of both, not to exceed $500 million in the aggregate. See "ACC Applications" below.

Competitive Procurement Process

On September 10, 2002, the ACC issued an order that, among other things, established a requirement that we competitively procure certain power requirements. On March 14, 2003, the ACC issued the Track B Order which documented the decision made by the ACC at its open meeting on February 27, 2003, addressing this requirement. Under the order, we will be required to solicit bids for certain estimated capacity and energy requirements for periods beginning July 1, 2003. For 2003, we will be required to solicit competitive bids for about 2,500 megawatts of capacity and about 4,600 gigawatt-hours of energy, or approximately 20% of our total retail energy requirements. The bid amounts are expected to increase in 2004 and 2005 based largely on growth in our retail load and retail energy sales. The Track B Order also confirmed that it was "not intended to change the current rate base status of [APS'] existing assets." The order recognizes our right to reject any bids that are unreasonable, uneconomical or unreliable.

We expect to issue requests for proposals in March 2003 and to complete the selection process by June 1, 2003. Pinnacle West Energy will be eligible to bid to supply our electricity requirements. See "Track B Order" below.

These regulatory developments and legal challenges to the Rules have raised considerable uncertainty about the status and pace of retail electric competition in Arizona. These matters are discussed in more detail below.

1999 Settlement Agreement

The following are the major provisions of the 1999 Settlement Agreement, as approved by the ACC:

- We have reduced, and will reduce, rates for standard-offer service for customers with loads less than three MW in a series of annual retail electricity price reductions of 1.5% on July 1, for each of the years 1999 to 2003, for a total of 7.5%. Based on the price reductions authorized in the 1999 Settlement Agreement, there were retail price decreases of approximately $24 million ($14 million after taxes), effective July 1, 1999; approximately $28 million ($17 million after taxes), effective July 1, 2000; approximately $27 million ($16 million after taxes), effective July 1, 2001; and approximately $28 million ($17 million after taxes), effective July 1, 2002. The final price reduction is to be implemented July 1, 2003. For customers having loads of three MW or greater, standard-offer rates have been reduced in varying annual increments that total 5% in the years 1999 through 2002.

- Unbundled rates being charged by us for competitive direct access service (for example, distribution services) became effective upon approval of the 1999 Settlement Agreement, retroactive to July 1, 1999, and also became subject to annual reductions beginning January 1, 2000, that vary by rate class, through January 1, 2004.

- There will be a moratorium on retail price changes for standard-offer and unbundled competitive direct access services until July 1, 2004, except for the price reductions described above and certain other limited circumstances. Neither the ACC nor we will be prevented from seeking or authorizing rate changes prior to July 1, 2004 in the event of conditions or circumstances that constitute an emergency, such as an inability to finance on reasonable terms; material changes in our cost of service for ACC-regulated services resulting from federal, tribal, state or local laws; regulatory requirements; or judicial decisions, actions or orders.

- We will be permitted to defer for later recovery prudent and reasonable costs of complying with the Rules, system benefits costs in excess of the levels included in then-current (1999) rates, and costs associated with the "provider of last resort" and standard-offer obligations for service after July 1, 2004. These costs are to be recovered through an adjustment clause or clauses commencing on July 1, 2004.

- Our distribution system opened for retail access effective September 24, 1999. Customers were eligible for retail access in accordance with the phase-in adopted by the ACC under the Rules (see "Retail Electric Competition Rules" below), including an additional 140 MW being made available to eligible non-residential customers. We opened our distribution system to retail access for all customers on January 1, 2001. The regulatory developments and legal challenges to the Rules discussed in this note have raised considerable uncertainty about the status and pace of electric competition in Arizona. Although some very limited retail competition existed in our service area in 1999 and 2000, there are currently no active retail competitors providing unbundled energy or other utility services to our customers. As a result, we cannot predict when, and the extent to which, additional competitors will re-enter our service territory.

- Prior to the 1999 Settlement Agreement, we were recovering substantially all of our regulatory assets through July 1, 2004, pursuant to a 1996 regulatory agreement. In addition, the 1999 Settlement Agreement states that we had demonstrated that our allowable stranded costs, after mitigation and exclusive of regulatory assets, are at least $533 million net present value (in 1999 dollars). We will not be allowed to recover $183 million net present value (in 1999 dollars) of the above amounts. The 1999 Settlement Agreement provides that we will have the opportunity to recover $350 million net present value (in 1999 dollars) through a competitive transition charge that will remain in effect through December 31, 2004, at which time it will terminate. The costs subject to recovery under the adjustment clause described above will be decreased or increased by any over/under-recovery due to sales volume variances.

- We will form, or cause to be formed, a separate corporate affiliate or affiliates and transfer to such affiliate(s) our competitive electric assets and services at book value as of the date of transfer, and will complete the transfers no later than December 31, 2002. We will be allowed to defer and later collect, beginning July 1, 2004, 67% percent of our costs to accomplish the required transfer of generation assets to an affiliate. However, as noted above and discussed in greater detail below, in 2002, the ACC unilaterally modified this aspect of the 1999 Settlement Agreement by issuing an order preventing us from transferring our generation assets.

Retail Electric Competition Rules

The Rules approved by the ACC included the following major provisions:

- They apply to virtually all Arizona electric utilities regulated by the ACC, including us.

- Effective January 1, 2001, retail access became available to all of our retail electricity customers.

- Electric service providers that get CC&N's from the ACC can supply only competitive services, including electric generation, but not electric transmission and distribution.

- Affected utilities must file ACC tariffs that unbundle rates for noncompetitive services.

- The ACC shall allow a reasonable opportunity for recovery of unmitigated stranded costs.

- Absent an ACC waiver, prior to January 1, 2001, each affected utility (except certain electric cooperatives) must transfer all competitive electric assets and services to an unaffiliated party or parties or to a separate corporate affiliate or affiliates. Under the 1999 Settlement Agreement, we received a waiver to allow transfer of our competitive electric assets and services to affiliates no later than December 31, 2002. However, as noted above and discussed in greater detail below, in 2002, the ACC reversed its decision, as reflected in the Rules, to require us to transfer our generation assets.

Under the 1999 Settlement Agreement, the Rules are to be interpreted and applied, to the greatest extent possible, in a manner consistent with the 1999 Settlement Agreement. If the two cannot be reconciled, we must seek, and the other parties to the 1999 Settlement Agreement must support, a waiver of the Rules in favor of the 1999 Settlement Agreement.

On November 27, 2000, a Maricopa County, Arizona, Superior Court judge issued a final judgment holding that the Rules are unconstitutional and unlawful in their entirety due to failure to establish a fair value rate base for competitive electric service providers and because certain of the Rules were not submitted to the Arizona Attorney General for certification. The judgment also invalidates all ACC orders authorizing competitive electric service providers, including APS Energy Services, to operate in Arizona. We do not believe the ruling affects the 1999 Settlement Agreement. The 1999 Settlement Agreement was not at issue in the consolidated cases before the judge. Further, the ACC made findings related to the fair value of our property in the order approving the 1999 Settlement Agreement. The ACC and other parties aligned with the ACC have appealed the ruling to the Arizona Court of Appeals, as a result of which the Superior Court's ruling is automatically stayed pending further judicial review. That appeal is still pending. In a similar appeal concerning the issuance of competitive telecommunications CC&N's, the Arizona Court of Appeals invalidated rates for competitive carriers due to the ACC's failure to establish a fair value rate base for such carriers. That decision was upheld by the Arizona Supreme Court.

Provider of Last Resort Obligation

Although the Rules allow retail customers to have access to competitive providers of energy and energy services, we are the "provider of last resort" for standard-offer, full-service customers under rates that have been approved by the ACC. These rates are established until at least July 1, 2004. The 1999 Settlement Agreement allows us to seek adjustment of these rates in the event of emergency conditions or circumstances, such as the inability to secure financing on reasonable terms; material changes in our cost of service for ACC-regulated services resulting from federal, tribal, state or local laws; regulatory requirements; or judicial decisions, actions or orders. Energy prices in the western wholesale market vary and, during the course of the last two years, have been volatile. At various times, prices in the spot wholesale market have significantly exceeded the amount included in our current retail rates. In the event of shortfalls due to unforeseen increases in load demand or generation or transmission outages, we may need to purchase additional supplemental power in the wholesale spot market. Unless we are able to obtain an adjustment of our rates under the emergency provisions of the 1999 Settlement Agreement, there can be no assurance that we would be able to fully recover the costs of this power.

Generic Docket

In January 2002, the ACC opened a "generic" docket to "determine if changed circumstances require the [ACC] to take another look at electric restructuring in Arizona." In February 2002, the ACC docket relating to our October 2001 filing was consolidated with several other pending ACC dockets, including the generic docket. On May 2, 2002, the ACC issued a procedural order stating that hearings would begin on June 17, 2002 on various issues, including our planned divestiture of generation assets to Pinnacle West Energy and associated market and affiliate issues. The procedural order also stated that consideration of the competitive bidding process required by the Rules would proceed concurrently with the Track A issues.

Track A Order

On September 10, 2002, the ACC issued the Track A Order, which documents decisions made by the ACC at an open meeting on August 27, 2002. The major provisions of the Track A Order include, among other things:

Provisions related to the reversal of the generation asset transfer requirement:

- The ACC reversed its decision, as reflected in the Rules, to require us to transfer our generation assets either to an unrelated third party or to a separate corporate affiliate; and

- the ACC unilaterally modified the 1999 Settlement Agreement, which authorized the transfer of our generating assets, and directed us to cancel our activities to transfer our generation assets to Pinnacle West Energy.

Provisions related to the wholesale competitive energy procurement process (Track B issues):

- The ACC stayed indefinitely the requirement of the Rules that we acquire 100% of our energy needs for our standard offer customers from the competitive market, with at least 50% obtained through a competitive bid process;

- the ACC established a requirement that we competitively procure, at a minimum, any required power that we cannot produce from our existing assets in accordance with the ultimate outcome of the Track B proceedings;

- the ACC directed the parties to develop a competitive procurement ("bidding") process that can begin by March 1, 2003; and

- the ACC stated that "the [Pinnacle West Energy] generating assets that APS may acquire from [Pinnacle West Energy] shall not be counted as APS assets in determining the amount, timing and manner of the competitive solicitation" for Track B purposes, thereby bifurcating the regulatory treatment of our existing assets and the Pinnacle West Energy assets.

On November 15, 2002, we filed appeals of the Track A Order in the Maricopa County, Arizona Superior Court and in the Arizona Court of Appeals. Arizona Public Service Company v. Arizona Corporation Commission, CV2002-0222 32. Arizona Public Service Company v. Arizona Corporation Commission, 1CA CC 02-0002. On December 13, 2002, we and the ACC staff agreed to principles for resolving certain issues raised by us in our appeals of the Track A Order. We and the ACC are the only parties to the Track A Order appeals. The major provisions of this document include, among other things, the following:

- The parties agreed that it would be appropriate for the ACC to consider the following matters in our upcoming general rate case, anticipated to be filed before June 30, 2003:

- the generating assets to be included in our rate base, including the question of whether certain power plants currently owned by Pinnacle West Energy (specifically, Redhawk Units 1 and 2, West Phoenix Units 4 and 5, and Saguaro Unit 3) should be included in our rate base;

- the appropriate treatment of the $234 million pretax asset write-off agreed to by us as part of a 1999 settlement agreement approved by the ACC among us and various parties related to the implementation of retail competition in Arizona; and

- the appropriate treatment of costs incurred by us in preparation for the previously anticipated transfer of generation assets to Pinnacle West Energy.

- Upon the ACC's issuance of a final decision that is no longer subject to appeal approving the Financing Application, with appropriate conditions, our appeals of the Track A Order would be limited to the issues described in the preceding bullet points, each of which would be presented to the ACC for consideration prior to any final judicial resolution.

On February 21, 2003, a Notice of Claim was filed with the ACC and the Arizona Attorney General on behalf of Pinnacle West, Pinnacle West Energy and us to preserve their and our rights relating to the Track A Order.

Track B Order

The ACC Staff has conducted workshops on the Track B issues with various parties to determine and define the appropriate process to be used for competitive power procurement. On September 10, 2002, the ACC issued an order that, among other things, established a requirement that APS competitively procure certain power requirements. On March 14, 2003, the ACC issued the Track B Order which documented the decision made by the ACC at its open meeting on February 27, 2003, addressing this requirement. The order adopted most of the provisions of an ACC ALJ's recommendation that was issued on January 30, 2003. Under the ACC's Track B Order, we will be required to solicit bids for certain estimated capacity and energy requirements for periods beginning July 1, 2003. For 2003, we will be required to solicit competitive bids for about 2,500 megawatts of capacity and about 4,600 gigawatt-hours of energy, or approximately 20% of our total retail energy requirements. The bid amounts are expected to increase in 2004 and 2005 based largely on growth in our retail load and retail energy sales. The Track B Order also confirmed that it was "not intended to change the current rate base status of [APS'] existing assets."

The order recognizes our right to reject any bids that are unreasonable, uneconomical or unreliable. The Track B procurement process will involve the ACC Staff and an independent monitor. The Track B Order also contains requirements relating to standards of conduct between us and any of our affiliates that may participate in the competitive solicitation, requires that we treat bidders in a non-discriminatory manner and requires us to file a protocol regarding short-term and emergency procurements. The order permits the provision of corporate oversight support and governance as long as such activities do not favor Pinnacle West Energy in the procurement process or provide Pinnacle West Energy with our confidential bidding information that is not available to other bidders. The order directs us to evaluate bids on cost, reliability and reasonableness. The decision requires bidders to allow the ACC to inspect their plants and requires assurances of appropriate competitive market conduct from senior officers of such bidders. Following the solicitation, we will prepare a report evaluating environmental issues relating to the procurement and a series of workshops on environmental risk management will be commenced thereafter.

We expect to issue requests for proposals in March 2003 and to complete the selection process by June 1, 2003. Pinnacle West Energy will be eligible to bid to supply our electricity requirements.

ACC Applications

On September 16, 2002, we filed a Financing Application requesting the ACC to allow us to borrow up to $500 million and to lend the proceeds to Pinnacle West Energy or Pinnacle West; to guarantee up to $500 million of Pinnacle West Energy's or Pinnacle West's debt; or a combination of both, not to exceed $500 million in the aggregate. The loan and/or the guarantee would be used to refinance debt incurred to fund the construction of Pinnacle West Energy generation assets.

The Financing Application addressed, among other things, the following matters:

- We noted that our April 19, 2002 filing with the ACC had sought unification of "[Pinnacle West Energy] Assets" (West Phoenix Units 4 and 5, Redhawk Units 1 and 2, and Saguaro Unit 3) and our generation assets under a common financial and regulatory regime. We further noted that the Track A Order's language regarding the treatment of the Pinnacle West Energy Assets for Track B purposes appears to postpone a decision regarding the inclusion of the Pinnacle West Energy Assets in our rate base, thereby effectively precluding the consolidation of the Pinnacle West Energy Assets at APS under a common financial and regulatory regime at the present time.

- We stated that we did not intend or desire to foreclose the possibility that we would acquire all or part of the Pinnacle West Energy Assets or that we may propose that the Pinnacle West Energy Assets be included in our rate base or afforded cost-of-service regulatory treatment to the extent the Pinnacle West Energy Assets are used by our customers. We stated that these issues would be appropriate topics in our 2003 general rate case and noted that the Track A Order specifically stated that the ACC would not pre-judge the eventual rate treatment of the Pinnacle West Energy Assets.

- We stated that the Track A Order's reversal of the generation asset transfer requirement and the resulting bifurcation of generation assets between us and Pinnacle West Energy under different regulatory regimes result in Pinnacle West

Energy being unable to attain investment-grade credit ratings. This, in turn, precludes Pinnacle West Energy from accessing capital markets to refinance the bridge financing provided by Pinnacle West to fund the construction of the Pinnacle West Energy Assets or from effectively competing in the wholesale markets. We noted that Pinnacle West Energy had previously received investment-grade credit ratings contingent upon its receipt of our generation assets and that Pinnacle West's credit ratings could be adversely affected if Pinnacle West Energy is unable to finance its capital requirements. On November 4, 2002, Standard & Poor's lowered Pinnacle West's senior unsecured debt rating from "BBB" to "BBB-."

- We stated that the amount of the requested loan and/or guarantee is our present estimate of the amount of credit support necessary through us to restore Pinnacle West Energy and Pinnacle West to their credit status prior to the ACC's issuance of the Track A Order. We further stated that if the requested amount proves to be inadequate, we reserve the right to submit a second financing application seeking additional credit support.

On March 27, 2003, the ACC approved the Financing Application, subject to the following principal conditions:

- any debt issued by us pursuant to the order must be unsecured;
- we will be permitted to loan up to $500 million to Pinnacle West Energy (the "APS Loan"), guarantee up to $500 million of Pinnacle West Energy debt, or a combination of both, not to exceed $500 million in the aggregate;
- the APS Loan must be callable and secured by certain Pinnacle West Energy assets;
- the APS Loan must bear interest at a rate equal to 264 basis points above the interest rate on our debt that could be issued and sold on equivalent terms (including, but not limited to, maturity and security);
- the 264 basis points referred to in the previous bullet point will be capitalized as a deferred credit and used to offset retail rates in the future, with the deferred credit balance bearing an interest rate of six percent per annum;
- the APS Loan must have a maturity date of not more than four years, unless otherwise ordered by the ACC;
- any demonstrable increase in our cost of capital as a result of the transaction (such as from a decline in bond rating) will be excluded from future rate cases;
- we must maintain a common equity ratio of at least forty percent and may not pay common dividends if such payment would reduce our common equity ratio below that threshold, unless otherwise waived by the ACC. The ACC will process any

waiver request within sixty days, and for this sixty-day period this condition will be suspended. However, this condition, which will continue indefinitely, will not be permanently waived without an order of the ACC; and

- certain waivers of the ACC's affiliated interest rules previously granted to APS and its affiliates will be withdrawn and, during the term of the APS Loan, neither Pinnacle West nor Pinnacle West Energy may reorganize or restructure, acquire or divest assets, or form, buy or sell affiliates (each, a "Covered Transaction"), or pledge or otherwise encumber the Pinnacle West Energy assets without prior ACC approval, except that the foregoing restrictions will not apply to the following categories of Covered Transactions:
  - Covered Transactions less than $100 million, measured on a cumulative basis over the calendar year in which the Covered Transactions are made;
  - Covered Transactions by SunCor of less than $300 million through 2005, consistent with SunCor's anticipated accelerated asset sales activity during those years;
  - Covered Transactions related to the payment of ongoing construction costs for Pinnacle West Energy's (a) West Phoenix Unit 5, located in Phoenix, with an expected commercial operation date in mid-2003, and (b) Silverhawk plant, located near Las Vegas, with an expected commercial operation date in mid-2004; and
  - Covered Transactions related to the sale of 25% of the Silverhawk plant to Southern Nevada Water Authority if Southern Nevada Water Authority exercises its existing purchase option to do so.

The ACC also ordered the ACC staff to conduct an inquiry into our and our affiliates' compliance with the retail electric competition and related rules and decisions.

In mid-2003, Pinnacle West will need to refinance approximately $475 million of their indebtedness. We expect that this indebtedness will be repaid through funds borrowed by Pinnacle West Energy from us under the APS Loan.

On November 22, 2002, the ACC approved our request to permit us to (a) make short-term advances to Pinnacle West in the form of an inter-affiliate line of credit in the amount of $125 million or (b) guarantee $125 million of Pinnacle West's short-term debt, subject to certain conditions. See Note 5.

Federal

In July 2002, the FERC adopted a price mitigation plan that constrains the price of electricity in the wholesale spot electricity market in the western United States. The FERC has adopted a price cap of $250 per MWh for the period subsequent to October 31, 2002. Sales at prices above the cap must be justified and are subject to potential refund.

On July 31, 2002, the FERC issued a Notice of Proposed Rulemaking for Standard Market Design for wholesale electric markets. Voluminous comments and reply comments were filed on virtually every aspect of the proposed rule, and the FERC has announced that it will issue an additional white paper on the proposed Standard Market Design in April 2003. We are reviewing the proposed rulemaking and cannot currently predict what, if any, impact there may be to the Company if the FERC adopts the proposed rule or any modifications proposed in the comments.

General

The regulatory developments and legal challenges to the Rules discussed in this Note have raised considerable uncertainty about the status and pace of retail electric competition in Arizona. Although some very limited retail competition existed in our service area in 1999 and 2000, there are currently no active retail competitors providing unbundled energy or other utility services to our customers. As a result, we cannot predict when, and the extent to which, additional competitors will re-enter our service territory. As competition in the electric industry continues to evolve, we will continue to evaluate strategies and alternatives that will position us to compete in the new regulatory environment.

4. Income Taxes

We are included in Pinnacle West's consolidated tax return. However, when Pinnacle West allocates income taxes to us, it does so based on our taxable income or loss alone.

Certain assets and liabilities are reported differently for income tax purposes than they are for financial statements. The tax effect of these differences is recorded as deferred taxes. We calculate deferred taxes using the current income tax rates.

We have recorded a regulatory asset related to income taxes on our Balance Sheets in accordance with SFAS No. 71. This regulatory asset is for certain temporary differences, primarily the allowance for equity funds used during construction. We amortize this amount as the differences reverse. In accordance with ACC settlement agreements, we are continuing to accelerate amortization of a regulatory asset related to income taxes over an eight-year period that will end June 30, 2004 (see Note 1). Accordingly, we are including this accelerated amortization in depreciation and amortization expense on the Statements of Income.

As a result of a change in IRS guidance, we claimed a tax deduction related to a tax accounting method change on the 2001 Pinnacle West federal consolidated income tax return. The accelerated deduction has resulted in a $200 million reduction in the current income tax liability. In 2002, we received an income tax refund of approximately $115 million related to the 2001 Pinnacle West federal consolidated income tax return.

The components of income tax expense for income before accounting change are (dollars in thousands):

	Year Ended December 31,		
	2002	2001	2000
Current:			
Federal	$ (61,962)	$ 174,251	$ 211,139
State	(18,000)	35,401	50,252
Total current	(79,962)	209,652	261,391
Deferred	206,767	(26,516)	(65,726)
Total income tax expense	$ 126,805	$ 183,136	$ 195,665

The following table compares pretax income at the 35% federal income tax rate to income tax expense (dollars in thousands):

	Year Ended December 31,		
	2002	2001	2000
Federal income tax expense at 35% statutory rate	$ 114,152	$ 162,338	$ 175,791
Increases (reductions) in tax expense resulting from:			
State income tax net of federal income tax benefit	15,036	20,563	20,007
Other	(2,383)	235	(133)
Income tax expense	$ 126,805	$ 183,136	$ 195,665

The following table sets forth the net deferred income tax liability recognized on the Balance Sheets at December 31, 2002 and 2001 (dollars in thousands):

	December 31,	
	2002	2001
Current asset/(liability)	$ 4,094	$ (3,244)
Long term liability	(1,225,552)	(1,023,079)
Accumulated deferred income taxes – net	$ (1,221,458)	$ (1,026,323)

The components of the net deferred income tax liability were as follows (dollars in thousands):

	December 31, 2002	December 31, 2001
DEFERRED TAX ASSETS		
Pension liability	$ 61,966	$ 13,450
Risk management and trading activities	38,204	46,343
Deferred gain on Palo Verde Unit 2 sale-leaseback	23,562	25,374
Other	80,965	97,868
Total deferred tax assets	204,697	183,035
DEFERRED TAX LIABILITIES		
Plant-related	(1,316,636)	(1,069,207)
Regulatory asset for income taxes	(80,635)	(121,757)
Risk management and trading activities	(28,884)	(18,394)
Total deferred tax liabilities	(1,426,155)	(1,209,358)
Accumulated deferred income taxes – net	$ (1,221,458)	$ (1,026,323)

5. Lines of Credit and Short-Term Borrowings

We had committed lines of credit with various banks of $250 million at December 31, 2002 and 2001, which were available either to support the issuance of commercial paper or to be used for bank borrowings. These lines of credit mature in June 2003. The commitment fees at December 31, 2002 and 2001 for these lines of credit were 0.09% per annum. We had no bank borrowings outstanding under these lines of credit at December 31, 2002 and 2001.

We had no commercial paper borrowings outstanding at December 31, 2002 and $171 million at December 31, 2001. The weighted average interest rate on commercial paper borrowings was 2.47% for the year ended December 31, 2002 and 4.72% for the year ended December 31, 2001. By Arizona statute, our short-term borrowings cannot exceed 7% of our total capitalization unless approved by the ACC.

On November 22, 2002, the ACC approved our request to permit us to (a) make short-term advances to Pinnacle West in the form of an inter-affiliate line of credit in the amount of $125 million, or (b) guarantee $125 million of Pinnacle West's short-term debt, subject to certain conditions. This interim loan matures in December 2003. There have been no borrowings on this line.

6. Long-Term Debt

Borrowings under our mortgage bond indenture are secured by substantially all of the Company's utility plant. We also have unsecured debt. The following table presents the components of long-term debt on the Balance Sheets outstanding at December 31, 2002 and 2001 (dollars in thousands):

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	Maturity Dates (a)	Interest Rates	December 31, 2002	December 31, 2001
First mortgage bonds	2002	8.125% (b)	$ --	$ 125,000
	2004	6.625%	80,000	80,000
	2023	7.25%	54,150	54,150
	2024	8.75% (c)	--	121,668
	2025	8.0%	33,075	33,075
	2028	5.5%	25,000	25,000
	2028	5.875%	154,000	154,000
Unamortized discount and premium			(6,337)	(5,266)
Pollution control bonds	2024-2034	(d)	386,860	386,860
Pollution control bonds	2029	3.30% (e)	--	90,000
Pollution control bonds with senior notes (f)	2029	5.05%	90,000	--
Unsecured notes	2004	5.875%	125,000	125,000
Unsecured notes	2005	6.25%	100,000	100,000
Unsecured notes	2005	7.625%	300,000	300,000
Unsecured notes	2011	6.375%	400,000	400,000
Unsecured notes	2012	6.50%	375,000	--
Senior notes (g)	2006	6.75%	83,695	83,695
Capitalized lease obligations	2003-2012	5.78%	20,400	1,343
Total long-term debt			2,220,843	2,074,525
Less current maturities			3,503	125,451
Total long-term debt less current maturities			$ 2,217,340	$ 1,949,074

(a) This schedule does not reflect the timing of redemptions that may occur prior to maturity.

(b) On March 15, 2002, we redeemed at maturity, $125 million of our First Mortgage Bonds, 8.125% Series due 2002.

(c) On April 15, 2002, we redeemed $122 million of our First Mortgage Bonds, 8.75% Series due 2024.

(d) The weighted-average rate was 1.94% at December 31, 2002 and 2.55% at December 31, 2001. Changes in short-term interest rates would affect the costs associated with this debt.

(e) In November 2001, these bonds were converted to a one year fixed rate of 3.30%. These bonds were previously adjustable rate, and from January 1, 2001 until October 31, 2001, the weighted average rate was 2.72%.

(f) On November 1, 2002, Maricopa County, Arizona Pollution Control Corporation issued $90 million of 5.05% Pollution Control Revenue Refunding Bonds (Arizona Public Service Company Palo Verde Project) 2002 Series A, due 2029, and loaned the proceeds to us pursuant to a loan agreement. The bonds were issued to refinance $90 million of outstanding pollution control bonds. The bondholders were issued $90 million of first mortgage bonds (senior note mortgage bonds) as collateral.

(g) We currently have outstanding $84 million of first mortgage bonds (senior note mortgage bonds) issued to the senior note trustee as collateral for the senior notes, as well as, the $90 million issue discussed in footnote (f) above. The senior note mortgage bonds have the same interest rate, interest payment dates, maturity and redemption provisions as the senior notes. Our payments of principal, premium and/or interest on the senior notes satisfy our corresponding payment obligations on the senior note mortgage bonds. As long as the senior note mortgage bonds secure the senior notes, the senior notes will effectively rank equally with the first mortgage bonds. When we repay all of our first mortgage bonds, other than those that secure senior notes, the senior note mortgage bonds will no longer secure the senior notes and will cease to be outstanding.

Our significant debt covenants related to our financing arrangements include a debt-to-total-capitalization ratio and an interest coverage test. We are in compliance with such covenants and anticipate that we will continue to meet all the significant covenant requirement levels. Failure to comply with such covenant levels would result in an event of default which, generally speaking, would require the immediate repayment of the debt subject to the covenants.

Our financing agreements do not contain "ratings triggers" that would result in an acceleration of the required interest and principal payments in the event of a ratings downgrade. However, in the event of a ratings downgrade, we may be subject to increased interest costs under certain financing agreements.

All of our bank agreements contain "cross-default" provisions under which a default by us in a specified amount under another agreement would result in a default and the potential acceleration of payment under the agreements. Our credit agreements generally contain provisions under which the lenders could refuse to advance loans in the event of a material adverse change in the borrower's business or financial condition.

The following is a list of payments due on total long-term debt and capitalized lease requirements through 2007:

- $ 4 million in 2003;
- $ 208 million in 2004;
- $ 403 million in 2005;
- $ 87 million in 2006;
- $ 2 million in 2007; and
- $1,523 million, thereafter.

Our first mortgage bondholders share a lien on substantially all utility plant assets (other than nuclear fuel and transportation equipment and other excluded assets). The mortgage bond indenture restricts the payment of common stock dividends under certain conditions. We may pay dividends on our common stock if there is a sufficient amount "available" from retained earnings and the excess of cumulative book depreciation (since the mortgage's inception) over mortgage depreciation, which is the cumulative amount of additional property pledged each year to address collateral depreciation. As of December 31, 2002, the amount "available" under the mortgage would have allowed us to pay approximately $3 billion of dividends compared to our current annual common stock dividends of $170 million.

7. Retirement Plans and Other Benefits

Pension Plans

Pinnacle West sponsors a qualified defined benefit pension plan and a non-qualified supplemental excess benefit retirement plan for the employees of Pinnacle West and its subsidiaries. Effective January 1, 2003, Pinnacle West sponsored a new account balance pension plan for all new employees in place of the defined benefit plan, and, effective April 1, 2003, the new plan will be offered as an alternative to the defined benefit plan for all existing employees. In 2002, we represented 87% of the total cost of this plan. A defined benefit plan specifies the amount of benefits a plan participant is to receive using information about the participant. The pension plan covers nearly all of our employees. The supplemental excess benefit plan covers officers of the company and highly compensated employees designated for participation by Pinnacle West's Board of Directors. Our employees do not contribute to the plans. Generally, the benefits under these plans are calculated based on age, years of service and pay. Pinnacle West funds the qualified plan by contributing at least the minimum amount required under IRS regulations but no more than the maximum tax-deductible amount. The assets in the qualified plan at December 31, 2002 were mostly domestic common stocks and bonds and real estate.

The following table shows our contributions and pension expense, including administrative costs, and after consideration of amounts capitalized or billed to electric plant participants for 2002, 2001, and 2000 (dollars in millions):

	2002	2001	2000
Contributions	$ 26	$ 44	$ 23
Pension expense	$ 11	$ 6	$ 2

The following table shows the components of Pinnacle West's consolidated net periodic pension cost before consideration of amounts capitalized or billed to electric plant participants for the years ended December 31, 2002, 2001 and 2000 (dollars in thousands):

	2002	2001	2000
Service cost – benefits earned during the period	$ 30,333	$ 27,640	$ 26,040
Interest cost on projected benefit obligation	71,242	66,549	61,625
Expected return on plan assets	(75,652)	(77,340)	(77,231)
Amortization of:			
Transition asset	(3,227)	(3,227)	(3,227)
Prior service cost	2,912	3,008	2,370
Net actuarial loss/(gain)	1,846	907	(1,190)
Net periodic pension cost	$ 27,454	$ 17,537	$ 8,387

The following table shows a reconciliation of the funded status of the plans to the amounts recognized in Pinnacle West's Consolidated Balance Sheets at December 31, 2002 and 2001 (dollars in thousands):

	2002	2001
Funded status – pension plan assets less than projected benefit obligation	$ (348,770)	$ (166,773)
Unrecognized net transition asset	(10,327)	(13,554)
Unrecognized prior service cost	23,148	26,170
Unrecognized net actuarial losses	293,223	108,422
Accrued pension benefit liability recognized in the Consolidated Balance Sheets	$ (42,726)	$ (45,735)

The following table sets forth Pinnacle West's defined benefit pension plans' change in projected benefit obligation for the plan years 2002 and 2001 (dollars in thousands):

	2002	2001
Projected pension benefit obligation at beginning of year	$ 931,646	$ 840,485
Service cost	30,333	27,640
Interest cost	71,242	66,549
Benefit payments	(35,230)	(33,282)
Actuarial losses	71,696	21,632
Plan amendments	(110)	8,622
Projected pension benefit obligation at end of year	$ 1,069,577	$ 931,646

The following table sets forth Pinnacle West's qualified defined benefit pension plans' change in the fair value of plan assets for the plan years 2002 and 2001 (dollars in thousands):

	2002	2001
Fair value of pension plan assets at beginning of year	$ 764,873	$ 775,196
Actual loss on plan assets	(36,966)	(22,876)
Employer contributions	26,600	44,200
Benefit payments	(33,700)	(31,647)
Fair value of pension plan assets at end of year	$ 720,807	$ 764,873

The following table sets forth Pinnacle West's defined benefit pension plans' amounts recognized in Pinnacle West's Consolidated Balance Sheets at December 31, 2002 and 2001 (dollars in thousands):

	2002	2001
Accrued pension benefit liability	$ (42,726)	$ (45,735)
Additional minimum liability	(141,155)	(3,297)
Intangible asset	23,148	1,697
Accumulated other comprehensive loss – pretax	118,007	1,600

The following table shows Pinnacle West's accumulated benefit obligation in relation to the fair value of plan assets for the plan years 2002 and 2001 (dollars in thousands):

	2002	2001
Projected benefit obligation	$ 1,069,577	$ 931,646
Accumulated benefit obligation	904,687	752,230
Fair value of plan assets	720,807	764,873

The following are weighted-average assumptions as of December 31, 2002 and 2001:

	2002	2001
Discount rate	6.75%	7.50%
Rate of increase in compensation levels	4.00%	4.00%
Expected long-term rate of return on assets	9.00%	10.00%

Employee Savings Plan Benefits

Pinnacle West sponsors a defined contribution savings plan for the employees of Pinnacle West and its subsidiaries. In 2002, we represented 93% of the total cost of this plan. In a defined contribution savings plan, the benefits a participant will receive result from regular contributions they make to a participant account. Under this plan, Pinnacle West makes matching contributions in Pinnacle West stock to participant accounts. After a five-year vesting period, participants have a choice to change the employer contribution match to other investments. At December 31, 2002, approximately 25% of total plan assets were in Pinnacle West stock. We recorded expenses for this plan of approximately $4 million for 2002, $4 million for 2001, and $3 million for 2000.

Other Postretirement Benefits

Pinnacle West sponsors other postretirement benefits for the employees of Pinnacle West and its subsidiaries. In 2002, we represented 87% of the total cost of this plan. We provide medical and life insurance benefits to retired employees. Employees must retire to become eligible for these retirement benefits, which are based on years of service and age. For the medical insurance plans, retirees make contributions to cover a portion of the plan costs. For the life insurance plan, retirees do not make contributions. We retain the right to change or eliminate these benefits.

Funding is based upon actuarially determined contributions that take tax consequences into account. Plan assets consist primarily of domestic stocks and bonds.

The following table shows our contributions and postretirement benefit expense after consideration of amounts capitalized or billed to electric plant participants for 2002, 2001 and 2000 (dollars in millions):

	2002	2001	2000
Contributions	$ 7	$ 11	$ 5
Other postretirement benefit expense	$ 9	$ 6	$ 2

The following table shows the components of Pinnacle West's net periodic other postretirement benefit costs before consideration of amounts capitalized or billed to electric plant participants for the years ended December 31, 2002, 2001 and 2000 (dollars in thousands):

	2002	2001	2000
Service cost – benefits earned during the period	$ 12,036	$ 9,438	$ 8,613
Interest cost on accumulated benefit obligation	25,235	21,585	19,315
Expected return on plan assets	(21,116)	(21,985)	(22,381)
Amortization of:			
Transition obligation	4,001	7,698	7,698
Prior service credit	(75)	--	--
Net actuarial loss/(gain)	3,072	(4,066)	(7,983)
Net periodic other postretirement benefit cost	$ 23,153	$ 12,670	$ 5,262

The following table shows a reconciliation of the funded status of the plan to the amounts recognized in Pinnacle West's Consolidated Balance Sheets as of December 31, 2002 and 2001 (dollars in thousands):

	2002	2001
Funded status – other postretirement plan assets less than accumulated other postretirement benefit obligation	$ (186,400)	$ (80,544)
Unrecognized net obligation at transition	36,489	84,748
Unrecognized prior service credit	(1,673)	--
Unrecognized net actuarial loss/(gain)	148,268	(8,606)
Net other postretirement benefit liability recognized in the Consolidated Balance Sheets	$ (3,316)	$ (4,402)

The following table sets forth Pinnacle West's other postretirement benefit plan's change in accumulated postretirement benefit obligation for the plan years 2002 and 2001 (dollars in thousands):

	2002	2001
Accumulated other postretirement benefit obligation at beginning of year	$ 318,355	$ 264,006
Service cost	12,036	9,438
Interest cost	25,235	21,585
Benefit payments	(10,473)	(10,194)
Actuarial losses	108,979	33,520
Plan amendments	(44,258) (a)	--
Accumulated other postretirement benefit obligation at end of year	$ 409,874	$ 318,355

(a) The plan was amended January 1, 2002 to increase the deductibles, out of pocket maximums and prescription drug co-pays. The plan was amended in June 2002 to increase the participants' portion of premiums.

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The following table sets forth Pinnacle West's other postretirement benefit plan's change in the fair value of plan assets for the plan years 2002 and 2001 (dollars in thousands):

	2002	2001
Fair value of other postretirement benefit plan assets at beginning of year	$ 237,810	$ 249,154
Actual loss on plan assets	(27,802)	(12,550)
Employer contributions	23,600	11,400
Benefit payments	(10,134)	(10,194)
Fair value of other postretirement benefit plan assets at end of year	$ 223,474	$ 237,810

The following are weighted-average assumptions as of December 31, 2002 and 2001:

	2002	2001
Discount rate	6.75%	7.50%
Expected long-term rate of return on assets – pretax	9.00%	10.00%
Expected long-term rate of return on assets – after tax	7.84%	8.71%
Initial health care cost trend rate – under age 65	8.00%	7.00%
Initial health care cost trend rate – age 65 and over	8.00%	7.00%
Ultimate health care cost trend rate	5.00%	5.00%
Year ultimate health care trend rate is reached	2007	2006

The following table shows the effect of a 1% increase or decrease in the initial and ultimate health care expense and cost trend rate (dollars in millions):

	1% increase	1% decrease
Effect of the 2002 other postretirement benefit expense, after consideration of amounts capitalized or billed to electric plant participants	$ 5	$ (4)
Effect on the 2002 service and interest cost components of net periodic other postretirement benefit costs	7	(6)
Effect on the accumulated other postretirement benefit obligation at December 31, 2002	54	(43)

Severance Charges

In July 2002, we implemented a voluntary workforce reduction as part of our cost reduction program. We recorded $34 million before taxes in voluntary severance costs in 2002. No further charges are expected.

8. Leases

In 1986, we sold about 42% of our share of Palo Verde Unit 2 and certain common facilities in three separate sale-leaseback transactions. We account for these leases as operating leases. The gain resulting from the transaction of approximately $140 million was deferred and is being amortized to operations and maintenance expense over 29.5 years, the original term of the leases. There are options to renew the leases for two additional years and to purchase the property for fair market value at the end of the lease terms. Consistent with the ratemaking treatment, a regulatory asset is recognized for the difference between lease payments and rent expense calculated on a straight-line basis. See Note 18 for a discussion of VIEs, including the SPEs involved in the Palo Verde sale-leaseback transactions.

In addition, we lease certain land, buildings, equipment, vehicles and miscellaneous other items through operating rental agreements with varying terms, provisions and expiration dates.

Total lease expense recognized in the Statements of Income was $52 million in 2002, $52 million in 2001 and $53 million in 2000.

The amounts to be paid for the Palo Verde Unit 2 leases are approximately $49 million per year for the years 2003 to 2015.

In accordance with the 1999 Settlement Agreement and previous settlement agreements, we are continuing to accelerate amortization of the regulatory asset for leases over an eight-year period that will end June 30, 2004 (see Note 1). All regulatory asset amortization is included in depreciation and amortization expense in the Statements of Income. The balance of this regulatory asset at December 31, 2002 was $14 million.

Estimated future minimum lease payments for our operating leases are approximately $59 million for each of the years 2003 to 2007 and $456 million thereafter.

9. Jointly-Owned Facilities

We share ownership of some of our generating and transmission facilities with other companies. The following table shows our interest in those jointly-owned facilities recorded on the Balance Sheets at December 31, 2002. Our share of operating and maintaining these facilities is included in the Statements of Income in operations and maintenance expense.

	Percent Owned by APS	Plant in Service	Accumulated Depreciation	Construction Work in Progress
		(dollars in thousands)		
Generating facilities:				
Palo Verde Nuclear Generating Station Units 1 and 3	29.1%	$1,829,225	$(905,278)	$17,428
Palo Verde Nuclear Generating Station Unit 2 (see Note 8)	17.0%	574,745	(289,049)	68,475
Four Corners Steam Generating Station Units 4 and 5	15.0%	153,559	(82,434)	500
Navajo Steam Generating Station Units 1, 2 and 3	14.0%	235,743	(110,923)	3,010
Cholla Steam Generating Station Common Facilities (a)	62.8%(b)	76,322	(42,608)	1,733
Transmission facilities:				
ANPP 500KV System	35.8%(b)	68,314	(25,655)	31
Navajo Southern System	31.4%(b)	27,129	(17,405)	664
Palo Verde-Yuma 500KV System	23.9%(b)	9,591	(4,168)	383
Four Corners Switchyards	27.5%(b)	3,071	(1,979)	--
Phoenix-Mead System	17.1%(b)	36,418	(2,906)	--
Palo Verde – Estrella 500KV System	50.0%(b)	--	--	50,450

(a) PacifiCorp owns Cholla Unit 4 and we operate the unit for PacifiCorp. The common facilities at the Cholla Plant are jointly-owned.
(b) Weighted average of interests.

10. Commitments and Contingencies

Enron

We recorded charges totaling $13 million before income taxes for exposure to Enron and its affiliates in the fourth quarter of 2001. These charges take into consideration our rights of set-off with respect to the Enron related contractual obligations. The basis of the set-offs included, but was not limited to, provisions in the various contractual arrangements with Enron and its affiliates, including an International Swaps and Derivative Agreement (ISDA) between us and Enron North America. The write-off is also net of the expected recovery based on secondary market quotes from the bond market. The amounts were written-off from the balances of the related assets and liabilities from risk management and trading activities on the Balance Sheets.

Palo Verde Nuclear Generating Station

Nuclear power plant operators are required to enter into spent fuel disposal contracts with the DOE, and the DOE is required to accept and dispose of all spent nuclear fuel and other high-level radioactive wastes generated by domestic power reactors. Although the Nuclear Waste Act required the DOE to develop a permanent repository for the storage and disposal of spent nuclear fuel by 1998, the DOE has announced that the repository cannot be completed before 2010 and that it does not intend to begin accepting spent nuclear fuel prior to that date. In November 1997, the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit) issued a decision preventing the DOE from excusing its own delay, but refused to order the DOE to begin accepting spent nuclear fuel. Based on this decision and the DOE's delay, a number of utilities filed damages actions against the DOE in the Court of Federal Claims.

In February 2002, the Secretary of Energy recommended to President Bush that the Yucca Mountain, Nevada site be developed as a permanent repository for spent nuclear fuel. The President transmitted this recommendation to Congress and the State of Nevada vetoed the President's recommendation. Congress approved the Yucca Mountain site, overriding the Nevada veto. It is now expected that the DOE will submit a license application to the NRC in late 2004.

We have existing fuel storage pools at Palo Verde and are in the process of completing construction of a new facility for on-site dry storage of spent nuclear fuel. With the existing storage pools and the addition of the new facility, we believe that spent nuclear fuel storage or disposal methods will be available for use by Palo Verde to allow its continued operation through the term of the operating license for each Palo Verde unit.

Although some low-level waste has been stored on-site in a low-level waste facility, we are currently shipping low-level waste to off-site facilities. We currently believe that interim low-level waste storage methods are or will be available for use by Palo Verde to allow its continued operation and to safely store low-level waste until a permanent disposal facility is available.

We currently estimate that we will incur $115 million (in 2002 dollars) over the life of Palo Verde for our share of the costs related to the on-site interim storage of spent nuclear fuel. As of December 31, 2002, we had spent $2 million and had recorded accumulated spent nuclear fuel amortization of $44 million and a regulatory asset of $46 million for on-site interim spent nuclear fuel storage costs related to nuclear fuel burned to date.

The Palo Verde participants have insurance for public liability resulting from nuclear energy hazards to the full limit of liability under federal law. This potential liability is covered by primary liability insurance provided by commercial insurance carriers in the amount of $200 million ($300 million effective January 1, 2003) and the balance by an industry-wide retrospective assessment program. If losses at any nuclear power plant covered by the programs exceed the accumulated funds, we could be assessed retrospective premium adjustments. The maximum assessment per reactor under the program for each nuclear incident is approximately $88 million, subject to an annual limit of $10 million per incident. Based on our interest in the three Palo Verde units, our maximum potential assessment per incident for all three units is approximately $77 million, with an annual payment limitation of approximately $9 million.

The Palo Verde participants maintain "all risk" (including nuclear hazards) insurance for property damage to, and decontamination of, property at Palo Verde in the aggregate amount of $2.75 billion, a substantial portion of which must first be applied to stabilization and decontamination. We have also secured insurance against portions of any increased cost of generation or purchased power and business interruption resulting from a sudden and unforeseen outage of any of the three units. The insurance coverage discussed in this and the previous paragraph is subject to certain policy conditions and exclusions.

Purchased Power and Fuel Commitments

We are party to various purchased power and fuel contracts with terms expiring from 2003 through 2025 that include required purchase provisions. We estimate the contract requirements to be approximately $135 million in 2003; $82 million in 2004; $28 million in 2005; $31 million in 2006; $17 million in 2007 and $162 million thereafter. However, these amounts may vary significantly pursuant to certain provisions in such contracts that permit us to decrease required purchases under certain circumstances.

Of the various purchased power and fuel contracts mentioned above some of those contracts have take-or-pay provisions. The contracts we have for the supply of our coal and nuclear fuel supply have take-or-pay provisions. The current take-or-pay nuclear fuel contracts expire in 2003, and had not been renewed as of December 31, 2002. The current take-or-pay coal contracts have terms that expire in 2007.

The following table summarizes the estimated take-or-pay commitments for the existing terms (dollars in millions):

	Estimated Years Ending December 31,				
	2003	2004	2005	2006	2007
Coal	$ 43	$ 44	$ 9	$ 9	$ 9
Nuclear Fuel	22	--	--	--	--
Total take-or-pay commitments (a)	$ 65	$ 44	$ 9	$ 9	$ 9

(a) Total take-or-pay commitments are approximately $136 million. The total net present value of these commitments is approximately $119 million.

Coal Mine Reclamation Obligations

We must reimburse certain coal providers for amounts incurred for coal mine reclamation. Our coal mine reclamation obligation is about $59 million at December 31, 2002 and is included in deferred credits-other in the Balance Sheets.

A regulatory asset has been established for amounts not yet recovered from ratepayers related to the coal obligations. In accordance with the 1999 Settlement Agreement with the ACC, we are continuing to accelerate the amortization of the regulatory asset for coal mine reclamation over an eight-year period that will end June 30, 2004. Amortization is included in depreciation and amortization expense on the Statements of Income.

California Energy Market Issues and Refunds in the Pacific Northwest

In July 2001, the FERC ordered an expedited fact-finding hearing to calculate refunds for spot market transactions in California during a specified time frame. This order calls for a hearing, with findings of fact due to the FERC after the ISO and PX provide necessary historical data. The FERC directed an ALJ to make findings of fact with respect to: (1) the mitigated price in each hour of the refund period; (2) the amount of refunds owed by each supplier according to the methodology established in the order; and (3) the amount currently owed to each supplier (with separate quantities due from each entity) by the CAISO, the California Power Exchange, the investor-owned utilities, and the State of California.

We were a seller and a purchaser in the California markets at issue, and to the extent that refunds are ordered, we should be a recipient as well as a payor of such amounts. On December 12, 2002, an ALJ issued Proposed Findings of Fact with respect to the refunds. On March 26, 2003, the FERC adopted the great majority of the proposed findings, revising only the calculation of natural gas prices for the final determination of mitigated prices in the California markets. Sellers who may actually have paid more for natural gas than the proxy prices adopted by the FERC have 40 days in which to submit necessary data to the FERC, after which a technical conference will be held. Finalization of refund amounts is expected in mid-2003. We do not anticipate material changes in our exposure and still believes, subject to the finalization of the revised proxy prices, that we will be entitled to a net refund.

On November 20, 2002, the FERC reopened discovery in these proceedings pursuant to instructions of the United States Court of Appeals for the Ninth Circuit, that the FERC permit parties to offer additional evidence of potential market manipulation for the period January 1, 2000 through June 20, 2001. Parties have submitted additional evidence and proposed findings, which the FERC continues to consider.

The FERC also ordered an evidentiary proceeding to discuss and evaluate possible refunds for the Pacific Northwest. The FERC required that the record establish the volume of the transactions, the identification of the net sellers and net buyers, the price and terms and conditions of the sales contracts, and the extent of potential refunds. On September 24, 2001, an ALJ concluded that prices in the Pacific Northwest during the period December 25, 2000 through June 20, 2001 were the result of a number of factors in addition to price signals from the California markets, including the shortage of supply, excess demand, drought, and increased natural gas prices. Under these circumstances, the ALJ ultimately concluded that the prices in the Pacific Northwest were not unreasonable or unjust and refunds should not be ordered in this proceeding. The FERC is currently reviewing the ALJ's report and recommendations.

On December 19, 2002, the FERC opened a new discovery period to permit the parties to offer additional evidence for the period January 1, 2000 through June 20, 2001. Additional evidence has been submitted and a FERC decision on the newly submitted evidence is expected soon. Based on public comments from the FERC, it is anticipated that this case will be sent back to the ALJ for further proceedings on spot market and balance of month transactions.

Although the FERC has not yet made a final ruling in the Pacific Northwest matter nor calculated the specific refund amounts due in California, we do not expect that the resolution of these issues, as to the amounts alleged in the proceedings, will have a material adverse impact on our financial position, results of operations or liquidity.

On March 26, 2003, FERC made public a Final Report on Price Manipulation in Western Markets, prepared by its Staff and covering spot markets in the West in 2000 and 2001. The report stated that a significant number of entities who participated in the California markets during 2000-2001 time period, including APS, may potentially have been involved in arbitrage transactions that allegedly violated certain provisions of the ISO tariff. The report also recommended that the FERC issue an order to show cause why these transactions did not violate the ISO tariff with potential disgorgement of any unjust profits. Although APS has not yet had an opportunity to review the transactions at issue, it believes that it was not engaged in any such improper transactions. Based on the information available, it also appears that such transactions would not have a material adverse impact on our financial position, results of operation or liquidity.

SCE and PG&E have publicly disclosed that their liquidity has been materially and adversely affected because of, among other things, their inability to pass on to ratepayers the prices each has paid for energy and ancillary services procured through the PX and the ISO. PG&E filed for bankruptcy protection in 2001.

California Energy Market Litigation. On March 19, 2002, the State of California filed a complaint with the FERC alleging that wholesale sellers of power and energy, including the Company, failed to properly file rate information at the FERC in connection with sales to California from 2000 to the present. State of California v. British Columbia Power Exchange et. al., Docket No. EL02-71-000. The complaint requests the FERC to require the wholesale sellers to refund any rates that are "found to exceed just and reasonable levels." This complaint has been dismissed by the FERC and the State of California is now appealing the matter to the Ninth Circuit Court of Appeals. In addition, the State of California and others have filed various claims, which have now been consolidated, against several power suppliers to California alleging antitrust violations. Wholesale Electricity Antitrust Cases I and II, Superior Court in and for the County of San Diego, Proceedings Nos. 4204-00005 and 4204-00006. Two of the suppliers who were named as defendants in those matters, Reliant Energy Services, Inc. (and other Reliant entities) and Duke Energy and Trading, LLP (and other Duke entities), filed cross-claims against various other participants in the PX and ISO markets, including us, attempting to expand those matters to such other participants. We have not yet filed a responsive pleading in the matter, but we believe the claims by Reliant and Duke as they relate to us are without merit.

We were also named in a lawsuit regarding wholesale contracts in California. James Millar, et al. v. Allegheny Energy Supply, et al., United States District Court in and for the District of

Northern California, Case No. C02-2855 EMC. The complaint alleges basically that the contracts entered into were the result of an unfair and unreasonable market. The PX has filed a lawsuit against the State of California regarding the seizure of forward contracts and the State has filed a cross complaint against us and numerous other PX participants. Cal PX v. The State of California Superior Court in and for the County of Sacramento, JCCP No. 4203. Various preliminary motions are being filed and we cannot currently predict the outcome of this matter. The "United States Justice Foundation" is suing numerous wholesale energy contract suppliers to California, including Pinnacle West, as well as the California Department of Water Resources, based upon an alleged conflict of interest arising from the activities of a consultant for Edison International who also negotiated long-term contracts for the California Department of Water Resources. McClintock, et al. v. Yudhraja, Superior Court in and for the County of Los Angeles, Case No. GC 029447. The California Attorney General has indicated that an investigation by his office did not find evidence of improper conduct by the consultant. We believe the claims against Pinnacle West and us in the lawsuits mentioned in this paragraph are without merit and will have no material adverse impact on our financial position, results of operations or liquidity.

Power Service Agreement

By letter dated March 7, 2001, Citizens, which owns a utility in Arizona, advised us that it believes we overcharged Citizens by over $50 million under a power service agreement. We believe that our charges under the agreement were fully in accordance with the terms of the agreement. In addition, in testimony filed with the ACC on March 13, 2002, Citizens acknowledged that, based on its review, "if Citizens filed a complaint with FERC, it probably would lose the central issue in the contract interpretation dispute." We and Citizens terminated the power service agreement effective July 15, 2001. In replacement of the power service agreement, Pinnacle West and Citizens entered into a power sale agreement under which Pinnacle West will supply Citizens with future specified amounts of electricity and ancillary services through May 31, 2008. This new agreement does not address issues previously raised by Citizens with respect to charges under the original power service agreement through June 1, 2001.

Letters of Credit

We have entered into various agreements that require letters of credit for financial assurance purposes. At December 31, 2002 approximately $258 million of letters of credit were outstanding to support existing pollution control bonds of approximately $253 million. The letters of credit are available to fund the payment of principal and interest on such debt obligations. These letters of credit have expiration dates in 2003. We have also entered into approximately $115 million of letters of credit to support certain equity lessors in the Palo Verde sale-leaseback transactions (see Note 9 for further details on the Palo Verde sale-leaseback transactions). These letters of credit expire in 2005. Additionally, we have approximately $5 million of letters of credit related to counterparty collateral requirements and approximately $5 million of letters of credit related to workers' compensation expiring in 2003. We intend to provide from either existing or new facilities for the extension, renewal or substitution of the letters of credit to the extent required.

Indemnifications

In conjunction with our financing agreements, including our sale-leaseback transactions, we generally provide indemnifications relating to liabilities arising from or related to the agreements, except with certain limited exceptions depending on the particular agreement. We have also provided indemnifications to the equity participants and other parties in the Palo Verde sale-leaseback transactions with respect to certain tax matters. Generally, a maximum obligation is not explicitly stated in the indemnification and therefore, the overall maximum amount of the obligation under such indemnifications cannot be reasonably estimated. Based on historical experience and evaluation of the specific indemnities, we do not believe that any material loss related to such indemnifications is likely and therefore no related liability has been recorded.

Construction Program

Total capital expenditures in 2003 are estimated at $401 million.

Litigation

We are party to various claims, legal actions and complaints arising in the ordinary course of business, including but not limited to environmental matters related to the Clean Air Act, Navajo Nation issues and ADEQ issues. In our opinion, the ultimate resolution of these matters will not have a material adverse effect on our financial statements, results of operations or liquidity.

11. Nuclear Decommissioning Costs

We recorded $11 million for nuclear decommissioning expense in each of the years 2002, 2001 and 2000. We estimate it will cost approximately $1.8 billion ($528 million in 2002 dollars) to decommission our share of the three Palo Verde units. The majority of decommissioning costs are expected to be incurred over a 14-year period beginning in 2024. We charge decommissioning costs to expense over each unit's operating license term and we include them in the accumulated depreciation balance until each unit is retired. Nuclear decommissioning costs are recovered in rates.

Our current estimates are based on a 2001 site-specific study for Palo Verde that assumes the prompt removal/dismantlement method of decommissioning. An independent consultant prepared this study. We are required by the ACC to update the study every three years.

To fund the costs we expect to incur to decommission the plant, we established external decommissioning trusts in accordance with NRC regulations and ACC orders. We invest the trust funds primarily in fixed income securities and domestic stock and classify them as available for sale. Realized and unrealized gains and losses are reflected in accumulated depreciation in accordance with industry practice. The following table shows the cost and fair value of our nuclear decommissioning trust fund assets, which were reported in investments and other assets on the Balance Sheets at December 31, 2002 and 2001 (dollars in millions):

ARIZONA PUBLIC SERVICE COMPANY
NOTES TO FINANCIAL STATEMENTS

	2002	2001
Trust fund assets – at cost:		
Fixed income securities	$ 113	$ 103
Domestic stock	68	61
Total	$ 181	$ 164
Trust fund assets – fair value:		
Fixed income securities	$ 117	$ 106
Domestic stock	77	96
Total	$ 194	$ 202

See Note 2 for information on a new accounting standard on accounting for certain liabilities related to closure or removal of long-lived assets.

12. Selected Quarterly Financial Data (Unaudited)

Quarterly financial information for 2002 and 2001 is as follows:

	(dollars in thousands) 2002			
QUARTER ENDED	March 31	June 30	September 30	December 31
Electric operating revenues (a)				
Regulated electricity segment	$ 383,741	$ 507,711	$ 744,463	$ 423,424
Marketing and trading segment	10,693	2,369	9,126	11,866
Operating income	$ 61,221	$ 97,555	$ 120,452	$ 49,772
Net income	$ 31,763	$ 64,439	$ 86,570	$ 16,571

	(dollars in thousands) 2001			
QUARTER ENDED	March 31	June 30	September 30	December 31
Electric operating revenues (a)				
Regulated electricity segment	$ 412,807	$ 739,317	$ 973,398	$ 436,566
Marketing and trading segment	247,022	230,894	65,129	6,195
Operating income	$ 97,034	$ 95,238	$ 135,139	$ 71,567
Income before accounting change	$ 64,606	$ 69,639	$ 107,556	$ 38,887
Cumulative effect of change in accounting – net of income tax	(2,755)	--	(12,446)	--
Net income	$ 61,851	$ 69,639	$ 95,110	$ 38,887

(a) Our utility business is seasonal in nature, with the peak sales periods generally occurring during the summer months. Comparisons among quarters of a year may not represent overall trends and changes in operations. We have reclassified certain operating revenues to conform to the current presentation of netting energy trading contracts (see Note 16).

13. Fair Value of Financial Instruments

We believe that the carrying amounts of our cash equivalents and commercial paper are reasonable estimates of their fair values at December 31, 2002 and 2001 due to their short maturities.

We hold investments in debt and equity securities for purposes other than trading. The December 31, 2002 and 2001 fair values of such investments, which we determine by using quoted market prices, approximate their carrying amount.

On December 31, 2002, the carrying value of our long-term debt (excluding capitalized lease obligations) was $2.21 billion, with an estimated fair value of $2.30 billion. The carrying value of our long-term debt (excluding capitalized lease obligations) was $2.08 billion on December 31, 2001, with an estimated fair value of $2.10 billion. The fair value estimates are based on quoted market prices of the same or similar issues.

14. Stock-Based Compensation

Pinnacle West offers stock-based compensation plans for officers and key employees of our company.

In May 2002, Pinnacle West's shareholders approved the 2002 Long-term Incentive Plan (2002 plan), which allows Pinnacle West to grant performance shares, stock ownership incentive awards and non-qualified and performance-accelerated stock options to key employees. Pinnacle West has reserved 6 million shares of common stock for issuance under the 2002 plan. No more than

1.8 million shares may be issued in relation to performance share awards and stock ownership incentive awards. The plan also provides for the granting of new non-qualified stock options at a price per option not less than the fair market value of the common stock at the time of grant. The stock options vest over three years, unless certain performance criteria are met which can accelerate the vesting period. The term of the option cannot be longer than 10 years and the option cannot be repriced during its term.

The 1994 plan provides for the granting of new options (which may be non-qualified stock options or incentive stock options) of up to 3.5 million shares at a price per option not less than the fair market value on the date the option is granted. The 1985 plan includes outstanding options but no new options will be granted from the plan. Options vest one-third of the grant per year beginning one year after the date the option is granted and expire ten years from the date of the grant. The 1994 plan also provides for the granting of any combination of shares of restricted stock, stock appreciation rights or dividend equivalents.

In the third quarter of 2002, we began applying the fair value method of accounting for stock-based compensation, as provided for in SFAS No. 123. The fair value method of accounting is the preferred method. In accordance with the transition requirements of SFAS No. 123, we applied the fair value method prospectively, beginning with 2002 stock grants. In prior years, we recognized stock compensation expense based on the intrinsic value method allowed in APB No. 25. We recorded approximately $333,000 in stock option expense before income taxes in our Statements of Income in 2002. This amount may not be reflective of the stock option expense we will record in future years because stock options typically vest over several years and additional grants are generally made each year.

In December 2002, the FASB issued SFAS No. 148, "Accounting for Stock-Based Compensation – Transition and Disclosure." The standard amends SFAS No. 123 to provide alternative methods of transition for a voluntary change to the fair value method of accounting for stock-based compensation. The standard also amends the disclosure requirements of SFAS No. 123. SFAS No. 148 is effective for fiscal years ending after December 15, 2002. We adopted the disclosure requirements in 2002. See Note 1 for our pro forma disclosures on stock-based compensation and our weighted-average assumptions used to calculate the fair value of our stock options.

Total stock-based compensation expense, including stock option expense, was $3 million in 2002, $2 million in 2001 and $2 million in 2000.

15. Business Segments

We have two principal business segments (determined by services and the regulatory environment):

- our regulated electricity segment, which consists of regulated traditional retail and wholesale electricity businesses and related activities, and includes electricity transmission, distribution and generation; and

- our marketing and trading segment, which consists of our competitive energy business activities, including wholesale marketing and trading. See Note 1 for information about the transfers of the marketing and trading division. See Note 1 for more information regarding our marketing and trading activities.

Financial data for the years ended December 31, 2002, 2001 and 2000 by business segments is provided as follows (dollars in millions):

	Business Segments for Year Ended December 31, 2002		
	Regulated Electricity	Marketing and Trading	Total
Operating revenues	$ 2,059	$ 34	$ 2,093
Purchased power and fuel costs	595	33	628
Other operating expenses	604	--	604
Operating margin	860	1	861
Depreciation and amortization	400	--	400
Interest and other expenses	136	--	136
Pretax margin	324	1	325
Income taxes	126	--	126
Net income	$ 198	$ 1	$ 199
Total assets	$ 6,522	$ --	$ 6,522
Capital expenditures	$ 501	$ --	$ 501

	Business Segments for Year Ended December 31, 2001		
	Regulated Electricity	Marketing and Trading	Total
Operating revenues	$ 2,562	$ 549	$ 3,111
Purchased power and fuel costs	1,227	314	1,541
Other operating expenses	567	--	567
Operating margin	768	235	1,003
Depreciation and amortization	421	--	421
Interest and other expenses	119	--	119
Pretax margin	228	235	463
Income taxes	90	93	183
Income before accounting change	138	142	280
Cumulative effect of change in accounting for derivatives – net of income taxes of $10	(15)	--	(15)
Net income	$ 123	$ 142	$ 265
Total assets	$ 6,052	$ 174	$ 6,226
Capital expenditures	$ 471	$ --	$ 471

	Business Segments for Year Ended December 31, 2000		
	Regulated Electricity	Marketing and Trading	Total
Operating revenues	$ 2,539	$ 395	$ 2,934
Purchased power and fuel costs	1,065	267	1,332
Other operating expenses	531	--	531
Operating margin	943	128	1,071
Depreciation and amortization	425	--	425
Interest and other expenses	144	--	144
Pretax margin	374	128	502
Income taxes	146	49	195
Net income	$ 228	$ 79	$ 307
Total assets	$ 5,958	$ 392	$ 6,350
Capital expenditures	$ 472	$ --	$ 472

16. Derivative and Trading Accounting

We are exposed to the impact of market fluctuations in the price and transportation costs of electricity, natural gas, coal and emissions allowances. We manage risks associated with these market fluctuations by utilizing various commodity derivatives, including exchange-traded futures and options and over-the-counter forwards, options and swaps. As part of our overall risk management program, we enter into derivative transactions to hedge purchases and sales of electricity, fuels, and emissions allowances and credits. The changes in market value of such contracts have a high correlation to price changes in the hedged commodities. In addition, subject to specified risk parameters monitored by the ERMC, we engage in marketing and trading activities intended to profit from market price movements.

Effective January 1, 2001, we adopted SFAS No. 133. SFAS No. 133 requires that entities recognize all derivatives as either assets or liabilities on the balance sheet and measure those instruments at fair value. Changes in the fair value of derivative instruments are either recognized periodically in income or, if hedge criteria is met, in common stock equity (as a component of other comprehensive income). We use cash flow hedges to limit our exposure to cash flow variability on forecasted transactions. Hedge effectiveness is related to the degree to which the derivative contract and the hedged item are correlated. It is measured based on the relative changes in fair value between the derivative contract and the hedged item over time. We exclude the time value of certain options from our assessment of hedge effectiveness. Any change in the fair value resulting from ineffectiveness, or the amount by which the derivative contract and the hedged commodity are not directly correlated, is recognized immediately in net income. See Note 1 for further discussion on our derivative instrument accounting policy.

In 2001, we recorded a $15 million after-tax charge in net income and a $72 million after-tax credit in common stock equity (as a component of other comprehensive income), both as cumulative effects of a change in accounting for derivatives. The charge primarily resulted from electricity option contracts. The credit resulted from unrealized gains on cash flow hedges.

In December 2001, the FASB issued revised guidance on the accounting for electricity contracts with option characteristics and the accounting for contracts that combine a forward contract and a purchased option contract. The effective date for the revised guidance was April 1, 2002. The impact of this guidance was immaterial to our financial statements.

During 2002, the EITF discussed EITF 02-3 and reached a consensus on certain issues. EITF 02-3 rescinded EITF 98-10 and was effective October 25, 2002 for any new contracts and on January 1, 2003 for existing contracts, with early adoption permitted. As a result, our energy trading contracts that are derivatives continue to be accounted for at fair value under SFAS No. 133. Contracts that were previously marked-to-market as trading activities under EITF 98-10 that do not meet the definition of a derivative are now accounted for on an accrual basis with the associated revenues and costs recorded at the time the contracted commodities are delivered or received. Additionally, all gains and losses (realized and unrealized) on energy trading contracts that qualify as derivatives are included in marketing and trading segment revenues on the Statements of Income on a net basis. The rescission of EITF 98-10 has no effect on the accounting for derivative instruments used for non-trading activities, which continue to be accounted for in accordance with SFAS No. 133. We adopted the EITF 02-3 guidance for all contracts in the fourth quarter of 2002. The impact of this guidance was immaterial to our financial statements.

Both non-trading and trading derivatives are classified as assets and liabilities from risk management and trading activities in the Balance Sheets. For non-trading derivative instruments that qualify for cash flow hedge accounting treatment, changes in the fair value of the effective portion are recognized in common stock equity (as a component of accumulated other comprehensive income (loss)). Non-trading derivatives, or any portion thereof, that are not effective hedges are adjusted to fair value through income. Gains and losses related to non-trading derivatives that qualify as cash flow hedges of expected transactions are recognized in revenue or purchased power and fuel expense as an offset to the related item being hedged when the underlying hedged physical transaction impacts earnings. If it becomes probable that a forecasted transaction will not occur, we discontinue the use of hedge accounting and recognize in income the unrealized gains and losses that were previously recorded in other comprehensive income (loss). In the event a non-trading derivative is terminated or settled, the unrealized gains and losses remain in other comprehensive income (loss), and are recognized in income when the underlying transaction impacts earnings.

Derivatives associated with trading activities are adjusted to fair value through income. Derivative commodity contracts for the physical delivery of purchase and sale quantities transacted in the normal course of business are exempt from the requirements of SFAS No. 133 under the normal purchase and sales exception and are not reflected on the balance sheet at fair value. Most of our electricity purchase and sales agreements qualify as normal purchases and sales and are exempted from recognition in the financial statements until the electricity is delivered.

EITF 02-3 requires that derivatives held for trading purposes, whether settled financially or physically, be reported in the income statement on a net basis. Conversely, all non-trading contracts and derivatives are to be reported gross on the income statement. Previous guidance under EITF 98-10 permitted non-financially settled energy trading contracts to be reported either gross or net in the income statement. Beginning in the third quarter of 2002, we netted all of our energy trading activities on the Statements of Income and restated prior year amounts for all periods presented. Reclassification of such trading activity to a net basis of reporting resulted in reductions in both revenues and purchased power and fuel costs, but did not have any impact on our financial condition, results of operations or cash flows.

The changes in derivative fair value included in the Statements of Income for the years ended December 31, 2002 and 2001 are comprised of the following (dollars in thousands):

	2002	2001
Gains/(losses) on the ineffective portion of derivatives qualifying for hedge accounting (a)	$ 8,482	$ (6,056)
Losses from the discontinuance of cash flow hedges	(9,206)	(4,683)
Losses from non-hedge derivatives	(12,645)	(7,157)
Prior period mark-to-market losses realized upon delivery of commodities	10,413	25,948
Total pretax gain/(loss)	$ (2,956)	$ 8,052

(a) Time value component of options excluded from assessment of hedge effectiveness.

As of December 31, 2002, the maximum length of time over which we are hedging our exposure to the variability in future cash flows for forecasted transactions is approximately two years. During the twelve months ending December 31, 2003, we estimate that a net loss of $26 million before income taxes will be reclassified from accumulated other comprehensive loss as an offset to the effect on earnings of market price changes for the related hedged transactions.

Credit Risk

We are exposed to losses in the event of nonperformance or nonpayment by counterparties. We use a risk management process to assess and monitor the financial exposure of counterparties. Despite the fact that the great majority of trading counterparties are rated as investment grade by the credit rating agencies, there is still a possibility that one or more of these companies could default, resulting in a material impact on earnings for a given period. Counterparties in the portfolio consist principally of major energy companies, municipalities and local distribution companies. We maintain credit policies that we believe minimize overall credit risk to within acceptable limits. Determination of the credit quality of our counterparties is based upon a number of factors, including credit ratings and our evaluation of their financial condition. In many contracts, we employ collateral requirements and standardized agreements that allow for the netting of positive and negative exposures associated with a single counterparty. Credit valuation adjustments are established representing our estimated credit losses on our overall exposure to counterparties. See "Mark-to-Market Accounting" in Note 1 for a discussion of our credit valuation adjustment policy.

17. Other Income and Other Expense

The following table provides detail of other income and other expense for the years ended December 31, 2002, 2001 and 2000 (dollars in thousands):

	Year Ended December 31		
	2002	2001	2000
Other income:			
Environmental insurance recovery	$ --	$ 12,349	$ --
Equity earnings – net	--	--	1,624
Interest income	3,455	5,004	4,924
Miscellaneous	1,694	2,854	3,142
Total other income	$ 5,149	$ 20,207	$ 9,690
Other expense:			
Equity losses – net	$ (1,131)	$ (3,355)	$ --
Non-operating costs (a)	(16,424)	(14,637)	(14,853)
Miscellaneous	(1,783)	(2,798)	(5,694)
Total other expense	$ (19,338)	$ (20,790)	$ (20,547)

(a) As defined by FERC, includes below-the-line non-operating utility costs (primarily community relations and environmental compliance).

18. Variable Interest Entities

In January 2003, the FASB issued FIN No. 46, "Consolidation of Variable Interest Entities." FIN No. 46 requires that we consolidate a VIE if we have a majority of the risk of loss from the VIE's activities or we are entitled to receive a majority of the VIE's residual returns or both. A VIE is a corporation, partnership, trust or any other legal structure that either does not have equity investors with voting rights or has equity investors that do not provide sufficient financial resources for the entity to support its activities. FIN No. 46 is effective immediately for any VIE created after January 31, 2003 and is effective July 1, 2003 for VIEs created before February 1, 2003.

In 1986, we entered into agreements with three separate SPE lessors in order to sell and lease back interests in Palo Verde Unit 2. The leases are accounted for as operating leases in accordance with GAAP. See Note 8 for further information about the sale-leaseback transactions. Based on our preliminary assessment of FIN No. 46, we do not believe we will be required to consolidate the Palo Verde SPEs. However, we will continue to evaluate the requirements of the new guidance to determine what impact, if any, it will have on our financial statements.

We are exposed to losses under the Palo Verde sale-leaseback agreements upon the occurrence of certain events that we do not consider to be reasonably likely to occur. Under certain circumstances (for example, the NRC issuing specified violation orders with respect to Palo Verde or the occurrence of specified nuclear events), we would be required to assume the debt associated with the transactions, make specified payments to the equity participants, and take title to the leased Unit 2 interests, which if appropriate, may be required to be written down in value. If such an event had occurred as of December 31, 2002, we would have been required to assume approximately $285 million of debt and pay the equity participants approximately $200 million.

19. Intangible Assets

On January 1, 2002, we adopted SFAS No. 142, "Goodwill and Other Intangible Assets." This statement addresses financial accounting and reporting for acquired goodwill and other intangible assets and supersedes APB Opinion No. 17, "Intangible Assets." We have no goodwill recorded and have separately disclosed other intangible assets on our Balance Sheets. The intangible assets continue to be amortized over their finite useful lives. Thus, there was no impact on our financial position as a result of the adoption of SFAS No. 142. The Company's gross intangible assets (which are primarily software) were $193 million at December 31, 2002 and $170 million at December 31, 2001. The related accumulated amortization was $100 million at December 31, 2002 and $87 million at December 31, 2001. Amortization expense was $19 million in 2002, $21 million in 2001 and $20 million in 2000. Estimated amortization expense on existing intangible assets over the next five years is $21 million in 2003, $20 million in 2004, $19 million in 2005, $17 million in 2006 and $14 million in 2007.

20. Subsequent Events

See “ACC Applications” in Note 3 for information regarding the ACC’s approval on March 27, 2003 of a $500 million financing arrangement between us and Pinnacle West Energy and “Track B Order” in Note 3 for information regarding the ACC order issued on March 14, 2003, mandating a process by which we must competitively procure energy.

See “California Energy Issues and Refunds in the Pacific Northwest” in Note 10 for information regarding the FERC’s adoption on March 26, 2003 of an ALJ’s proposed findings, and issuance on March 26, 2003 of a Final Report on Price Manipulation in Western Markets.

ARIZONA PUBLIC SERVICE COMPANY
SCHEDULE II – RESERVE FOR UNCOLLECTIBLES
(dollars in thousands)

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at beginning of period	Charged to cost and expenses	Charged to other accounts	Deductions	Balance at end of Period
Reserve for uncollectibles					
Year ended December 31, 2002	$ 3,349	$ 2,680	$ --	$ 4,688	$ 1,341
Year ended December 31, 2001	$ 2,380	$ 7,609	$ --	$ 6,640	$ 3,349
Year ended December 31, 2000	$ 1,538	$ 5,438	$ --	$ 4,596	$ 2,380

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

Not applicable.

ITEM 11. EXECUTIVE COMPENSATION

Not applicable.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Not applicable.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

Not applicable.

ITEM 14. CONTROLS AND PROCEDURES

As of a date within 90 days of the date of this report (the "Evaluation Date"), we carried out an evaluation, under the supervision and with the participation of our management, including our Chief Executive Officer and our Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures, as defined in Rules 13a-14 and 15d-14 under the Securities Exchange Act of 1934, as amended (the "Exchange Act"). Based upon this evaluation, our Chief Executive Officer and our Chief Financial Officer, concluded that, as of the Evaluation Date, our disclosure controls and procedures were adequate to ensure that information required to be disclosed by us in the reports filed or submitted by us under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms.

There were no significant changes in our internal controls or in other factors that could significantly affect these controls subsequent to the date of the evaluation, including any corrective actions with regard to significant deficiencies and internal weaknesses.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES, AND REPORTS ON FORM 8-K

Financial Statements and Financial Statement Schedules

See the Index to Financial Statements in Part II, Item 8.

Exhibits Filed

Exhibit No.		*Description*
12.1	—	Computation of Ratio of Earnings to Fixed Charges
23.1	—	Consent of Deloitte & Touche LLP
99.1	—	Certification of Jack E. Davis, the Company's principal executive officer, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
99.2	—	Certification of Donald E. Brandt, the Company's principal financial officer, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
99.3	—	Risk Factors

In addition to those Exhibits shown above, the Company hereby incorporates the following Exhibits pursuant to Exchange Act Rule 12b-32 and Regulation §229.10(d) by reference to the filings set forth below:

Exhibit No.	*Description*	*Originally Filed as Exhibit:*	*File No.*[b]	*Date Effective*
3.1	Bylaws, amended as of September 18, 2002	3.2 to Pinnacle West September 2002 Form 10-Q Report	1-8962	11-14-02
3.2	Resolution of Board of Directors temporarily suspending Bylaws in part	3.2 to 1994 Form 10-K Report	1-4473	3-30-95
3.3	Articles of Incorporation, restated as of May 25, 1988	4.2 to Form S-3 Registration Nos. 33-33910 and 33-55248 by means of September 24, 1993 Form 8-K Report	1-4473	9-29-93

Exhibit No.	Description	Originally Filed as Exhibit:	File No.[b]	Date Effective
4.1	Mortgage and Deed of Trust Relating to the Company's First Mortgage Bonds, together with forty-eight indentures supplemental thereto	4.1 to September 1992 Form 10-Q Report	1-4473	11-9-92
4.2	Forty-ninth Supplemental Indenture	4.1 to 1992 Form 10-K Report	1-4473	3-30-93
4.3	Fiftieth Supplemental Indenture	4.2 to 1993 Form 10-K Report	1-4473	3-30-94
4.4	Fifty-first Supplemental Indenture	4.1 to August 1, 1993 Form 8-K Report	1-4473	9-27-93
4.5	Fifty-second Supplemental Indenture	4.1 to September 30, 1993 Form 10-Q Report	1-4473	11-15-93
4.6	Fifty-third Supplemental Indenture	4.5 to Registration Statement No. 33-61228 by means of February 23, 1994 Form 8-K Report	1-4473	3-1-94
4.7	Fifty-fourth Supplemental Indenture	4.1 to Registration Statements Nos. 33-61228, 33-55473, 33-64455 and 333-15379 by means of November 19, 1996 Form 8-K Report	1-4473	11-22-96
4.8	Fifty-fifth Supplemental Indenture	4.8 to Registration Statement Nos. 33-55473, 33-64455 and 333-15379 by means of April 7, 1997 Form 8-K Report	1-4473	4-9-97
4.9	Fifty-sixth Supplemental Indenture	4.1 to Pinnacle West 2002 Form 10-K Report	1-8962	3-31-03
4.10	Fifty-seventh Supplemental Indenture	4.2 to Pinnacle West 2002 Form 10-K Report	1-8962	3-31-03

Exhibit No.	Description	Originally Filed as Exhibit:	File No.[b]	Date Effective
4.11	Agreement, dated March 21, 1994, relating to the filing of instruments defining the rights of holders of long-term debt not in excess of 10% of the Company's total assets	4.1 to 1993 Form 10-K Report	1-4473	3-30-94
4.12	Indenture dated as of January 1, 1995 among the Company and The Bank of New York, as Trustee	4.6 to Registration Statement Nos. 33-61228 and 33-55473 by means of January 1, 1995 Form 8-K Report	1-4473	1-11-95
4.13	First Supplemental Indenture dated as of January 1, 1995	4.4 to Registration Statement Nos. 33-61228 and 33-55473 by means of January 1, 1995 Form 8-K Report	1-4473	1-11-95
4.14	Indenture dated as of November 15, 1996 among the Company and The Bank of New York, as Trustee	4.5 to Registration Statements Nos. 33-61228, 33-55473, 33-64455 and 333-15379 by means of November 19, 1996 Form 8-K Report	1-4473	11-22-96
4.15	First Supplemental Indenture	4.6 to Registration Statements Nos. 33-61228, 33-55473, 33-64455 and 333-15379 by means of November 19, 1996 Form 8-K Report	1-4473	11-22-96
4.16	Second Supplemental Indenture dated as of April 1, 1997	4.10 to Registration Statement Nos. 33-55473, 33-64455 and 333-15379 by means of April 7, 1997 Form 8-K Report	1-4473	4-9-97
4.17	Indenture dated as of January 15, 1998 among the Company and The Chase Manhattan Bank, as Trustee	4.10 to Registration Statement Nos. 333-15379 and 333-27551 by means of January 13, 1998 Form 8-K Report	1-4473	1-16-98

Exhibit No.	*Description*	*Originally Filed as Exhibit:*	*File No.*[b]	*Date Effective*
4.18	First Supplemental Indenture dated as of January 15, 1998	4.3 to Registration Statement Nos. 333-15379 and 333-27551 by means of January 13, 1998 Form 8-K Report	1-4473	1-16-98
4.19	Second Supplemental Indenture dated as of February 15, 1999	4.3 to Registration Statement Nos. 333-27551 and 333-58445 by means of February 18, 1999 Form 8-K Report	1-4473	2-22-99
4.20	Third Supplemental Indenture dated as of November 1, 1999	4.5 to Registration Statement No. 333-58445 by means of November 2, 1999 Form 8-K Report	1-4473	11-5-99
4.21	Fourth Supplemental Indenture dated as of August 1, 2000	4.1 to Registration Statement Nos. 333-58445 and 333-94277 by means of August 2, 2000 Form 8-K Report	1-4473	8-4-00
4.22	Fifth Supplemental Indenture dated as of October 1, 2001	4.1 to September 2001 Form 10-Q	1-4473	11-6-01
4.23	Sixth Supplemental Indenture dated as of March 1, 2002	4.1 to Registration Statement Nos. 333-63994 and 333-83398 by means of February 26, 2002 Form 8-K Report	1-4473	2-28-02
10.1	Two separate Decommissioning Trust Agreements (relating to PVNGS Units 1 and 3, respectively), each dated July 1, 1991, between the Company and Mellon Bank, N.A., as Decommissioning Trustee	10.2 to September 1991 Form 10-Q	1-4473	11-14-91

Exhibit No.	Description	Originally Filed as Exhibit:	File No.[b]	Date Effective
10.2	Amendment No. 1 to Decommissioning Trust Agreement (PVNGS Unit 1) dated as of December 1, 1994	10.1 to 1994 Form 10-K Report	1-4473	3-30-95
10.3	Amendment No. 2 to Decommissioning Trust Agreement (PVNGS Unit 1) dated as of July 1, 1991	10.4 to 1996 Form 10-K Report	1-4473	3-28-97
10.4	Amendment No. 1 to Decommissioning Trust Agreement (PVNGS Unit 3) dated as of December 1, 1994	10.2 to 1994 Form 10-K Report	1-4473	3-30-95
10.5	Amendment No. 2 to Decommissioning Trust Agreement (PVNGS Unit 3) dated as of July 1, 1991	10.6 to 1996 Form 10-K Report	1-4473	3-28-97
10.6	Amended and Restated Decommissioning Trust Agreement (PVNGS Unit 2) dated as of January 31, 1992, among the Company, Mellon Bank, N.A., as Decommissioning Trustee, and State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee under two separate Trust Agreements, each with a separate Equity Participant, and as Lessor under two separate Facility Leases, each relating to an undivided interest in PVNGS Unit 2	10.1 to Pinnacle West 1991 Form 10-K Report	1-8962	3-26-92

Exhibit No.	*Description*	*Originally Filed as Exhibit:*	*File No.*[b]	*Date Effective*
10.7	First Amendment to Amended and Restated Decommissioning Trust Agreement (PVNGS Unit 2), dated as of November 1, 1992	10.2 to 1992 Form 10-K Report	1-4473	3-30-93
10.8	Amendment No. 2 to Amended and Restated Decommissioning Trust Agreement (PVNGS Unit 2) dated as of November 1, 1994	10.3 to 1994 Form 10-K Report	1-4473	3-30-95
10.9	Amendment No. 3 to Amended and Restated Decommissioning Trust Agreement (PVNGS Unit 2) dated as of January 31, 1992	10.1 to June 1996 Form 10-Q Report	1-4473	8-9-96
10.10	Amendment No. 4 to Amended and Restated Decommissioning Trust Agreement (PVNGS Unit 2) dated as of January 31, 1992	10.5 to 1996 Form 10-K Report	1-4473	3-28-97
10.11	Amendment No. 5 to the Amended and Restated Decommissioning Trust Agreement (PVNGS Unit 2), dated as of June 30, 2000	10.1 to Pinnacle West's March 2002 Form 10-Q Report	1-8962	5-15-02
10.12	Amendment No. 3 to the Decommissioning Trust Agreement (PVNGS Unit 1), dated as of March 18, 2002	10.2 to Pinnacle West's March 2002 Form 10-Q Report	1-8962	5-15-02

Exhibit No.	*Description*	*Originally Filed as Exhibit:*	*File No.*[b]	*Date Effective*
10.13	Amendment No. 6 to the Amended and Restated Decommissioning Trust Agreement (PVNGS Unit 2), dated as of March 18, 2002	10.3 to Pinnacle West's March 2002 Form 10-Q Report	1-8962	5-15-02
10.14	Amendment No. 3 to the Decommissioning Trust Agreement (PVNGS Unit 3), dated as of March 18, 2002	10.4 to Pinnacle West's March 2002 Form 10-Q Report	1-8962	5-15-02
10.15	Asset Purchase and Power Exchange Agreement dated September 21, 1990 between the Company and PacifiCorp, as amended as of October 11, 1990 and as of July 18, 1991	10.1 to June 1991 Form 10-Q Report	1-4473	8-8-91
10.16	Long-Term Power Transactions Agreement dated September 21, 1990 between the Company and PacifiCorp, as amended as of October 11, 1990 and as of July 8, 1991	10.2 to June 1991 Form 10-Q Report	1-4473	8-8-91
10.17	Contract, dated July 21, 1984, with DOE providing for the disposal of nuclear fuel and/or high-level radioactive waste, ANPP	10.31 to Pinnacle West's Form S-14 Registration Statement	2-96386	3-13-85
10.18	Amendment No. 1 dated April 5, 1995 to the Long-Term Power Transactions Agreement and Asset Purchase and Power Exchange Agreement between PacifiCorp and the Company	10.3 to 1995 Form 10-K Report	1-4473	3-29-96

Exhibit No.	Description	Originally Filed as Exhibit:	File No.[b]	Date Effective
10.19	Restated Transmission Agreement between PacifiCorp and the Company dated April 5, 1995	10.4 to 1995 Form 10-K Report	1-4473	3-29-96
10.20	Contract among PacifiCorp, the Company and United States Department of Energy Western Area Power Administration, Salt Lake Area Integrated Projects for Firm Transmission Service dated May 5, 1995	10.5 to 1995 Form 10-K Report	1-4473	3-29-96
10.21	Reciprocal Transmission Service Agreement between the Company and PacifiCorp dated as of March 2, 1994	10.6 to 1995 Form 10-K Report	1-4473	3-29-96
10.22	Indenture of Lease with Navajo Tribe of Indians, Four Corners Plant	5.01 to Form S-7 Registration Statement	2-59644	9-1-77
10.23	Supplemental and Additional Indenture of Lease, including amendments and supplements to original lease with Navajo Tribe of Indians, Four Corners Plant	5.02 to Form S-7 Registration Statement	2-59644	9-1-77
10.24	Amendment and Supplement No. 1 to Supplemental and Additional Indenture of Lease, Four Corners, dated April 25,1985	10.36 to Registration Statement on Form 8-B of Pinnacle West	1-8962	7-25-85
10.25	Application and Grant of multi-party rights-of-way and easements, Four Corners Plant Site	5.04 to Form S-7 Registration Statement	2-59644	9-1-77

Exhibit No.	Description	Originally Filed as Exhibit:	File No.[b]	Date Effective
10.26	Application and Amendment No. 1 to Grant of multi-party rights-of-way and easements, Four Corners Power Plant Site, dated April 25, 1985	10.37 to Registration Statement on Form 8-B of Pinnacle West	1-8962	7-25-85
10.27	Four Corners Project Co-Tenancy Agreement Amendment No. 6	10.7 to Pinnacle West 2000 Form 10-K Report	1-8962	3-14-01
10.28	Application and Grant of Arizona Public Service Company rights-of-way and easements, Four Corners Plant Site	5.05 to Form S-7 Registration Statement	2-59644	9-1-77
10.29	Application and Amendment No. 1 to Grant of Arizona Public Service Company rights-of-way and easements, Four Corners Power Plant Site, dated April 25, 1985	10.38 to Registration Statement on Form 8-B of Pinnacle West	1-8962	7-25-85
10.30	Indenture of Lease, Navajo Units 1, 2, and 3	5(g) to Form S-7 Registration Statement	2-36505	3-23-70
10.31	Application and Grant of rights-of-way and ease-ments, Navajo Plant	5(h) to Form S-7 Registration Statement	2-36505	3-23-70
10.32	Water Service Contract Assignment with the United States Department of Interior, Bureau of Reclamation, Navajo Plant	5(l) to Form S-7 Registration Statement	2-39442	3-16-71

Exhibit No.	Description	Originally Filed as Exhibit:	File No.[b]	Date Effective
10.33	Arizona Nuclear Power Project Participation Agreement, dated August 23, 1973, among the Company, Salt River Project Agricultural Improvement and Power District, Southern California Edison Company, Public Service Company of New Mexico, El Paso Electric Company, Southern California Public Power Authority, and Department of Water and Power of the City of Los Angeles, and amendments 1-12 thereto	10.1 to 1988 Form 10-K Report	1-4473	3-8-89
10.34	Amendment No. 13 dated as of April 22, 1991, to Arizona Nuclear Power Project Participation Agreement, dated August 23, 1973, among the Company, Salt River Project Agricultural Improvement and Power District, Southern California Edison Company, Public Service Company of New Mexico, El Paso Electric Company, Southern California Public Power Authority, and Department of Water and Power of the City of Los Angeles	10.1 to March 1991 Form 10-Q Report	1-4473	5-15-91

Exhibit No.	Description	Originally Filed as Exhibit:	File No.[b]	Date Effective
10.35	Amendment No. 14, to Arizona Nuclear Power Project Participation Agreement, dated August 23, 1973, among the Company, Salt River Project Agricultural Improvement and Power District, Southern California Edison Company, Public Service Company of New Mexico, El Paso Electric Company, Southern California Public Power Authority, and Department of Water and Power of the City of Los Angeles	10.4 to the Pinnacle West June 30, 2000 Form 10-Q Report	1-8962	8-14-00
10.36[c]	Facility Lease, dated as of August 1, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its capacity as Owner Trustee, as Lessor, and the Company, as Lessee	4.3 to Form S-3 Registration Statement	33-9480	10-24-86
10.37[c]	Amendment No. 1, dated as of November 1, 1986, to Facility Lease, dated as of August 1, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its capacity as Owner Trustee, as Lessor, and the Company, as Lessee	10.5 to September 1986 Form 10-Q Report by means of Amendment No. 1 on December 3, 1986 Form 8	1-4473	12-4-86

Exhibit No.	Description	Originally Filed as Exhibit:	File No.[b]	Date Effective
10.38[c]	Amendment No. 2 dated as of June 1, 1987 to Facility Lease dated as of August 1, 1986 between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Lessor, and APS, as Lessee	10.3 to 1988 Form 10-K Report	1-4473	3-8-89
10.39[c]	Amendment No. 3, dated as of March 17, 1993, to Facility Lease, dated as of August 1, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Lessor, and the Company, as Lessee	10.3 to 1992 Form 10-K Report	1-4473	3-30-93
10.40	Facility Lease, dated as of December 15, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its capacity as Owner Trustee, as Lessor, and the Company, as Lessee	10.1 to November 18, 1986 Form 8-K Report	1-4473	1-20-87
10.41	Amendment No. 1, dated as of August 1, 1987, to Facility Lease, dated as of December 15, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Lessor, and the Company, as Lessee	4.13 to Form S-3 Registration Statement No. 33-9480 by means of August 1, 1987 Form 8-K Report	1-4473	8-24-87

Exhibit No.	*Description*	*Originally Filed as Exhibit:*	*File No.*[b]	*Date Effective*
10.42	Amendment No. 2, dated as of March 17, 1993, to Facility Lease, dated as of December 15, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Lessor, and the Company, as Lessee	10.4 to 1992 Form 10-K Report	1-4473	3-30-93
10.43[a]	Directors' Deferred Compensation Plan, as restated, effective January 1, 1986	10.1 to June 1986 Form 10-Q Report	1-4473	8-13-86
10.44[a]	Second Amendment to the Arizona Public Service Company Directors' Deferred Compensation Plan, effective as of January 1, 1993	10.2 to 1993 Form 10-K Report	1-4473	3-30-94
10.45[a]	Third Amendment to the Arizona Public Service Company Directors' Deferred Compensation Plan effective as of May 1, 1993	10.1 to September 1994 Form 10-Q	1-4473	11-10-94
10.46[a]	Fourth Amendment dated December 28, 1999 to the Arizona Public Service Company Directors Deferred Compensation Plan	10.8 to Pinnacle West's 1999 Form 10-K	1-8962	3-30-00

Exhibit No.	*Description*	*Originally Filed as Exhibit:*	*File No.*[b]	*Date Effective*
10.47[a]	Arizona Public Service Company Deferred Compensation Plan, as restated, effective January 1, 1984, and the second and third amendments thereto, dated December 22, 1986, and December 23, 1987, respectively	10.4 to 1988 Form 10-K Report	1-4473	3-8-89
10.48[a]	Third Amendment to the Arizona Public Service Company Deferred Compensation Plan, effective as of January 1, 1993	10.3 to 1993 Form 10-K Report	1-4473	3-30-94
10.49[a]	Fourth Amendment to the Arizona Public Service Company Deferred Compensation Plan effective as of May 1, 1993	10.2 to September 1994 Form 10-Q Report	1-4473	11-10-94
10.50[a]	Fifth Amendment to the Arizona Public Service Company Deferred Compensation Plan	10.3 to 1997 Form 10-K Report	1-4473	3-28-97

Exhibit No.	Description	Originally Filed as Exhibit:	File No.[b]	Date Effective
10.51[a]	Sixth Amendment to Arizona Public Service Company Deferred Compensation Plan	10.8 to Pinnacle West 2000 Form 10-K Report	1-8962	3-14-01
10.52[a]	Schedules of William J. Post and Jack E. Davis to Arizona Public Service Company Deferred Compensation Plan, as amended	10.2 to Pinnacle West Form 10-K Report	1-8962	3-31-03
10.53[a]	Pinnacle West Capital Corporation, Arizona Public Service Company, SunCor Development Company and El Dorado Investment Company Deferred Compensation Plan as amended and restated effective January 1, 1996	10.10 to 1995 Form 10-K Report	1-4473	3-29-96
10.54[a]	First Amendment effective as of January 1, 1999, to the Pinnacle West Capital Corporation, Arizona Public Service Company, SunCor Development Company and El Dorado Investment Company Deferred Compensation Plan	10.6 to Pinnacle West's 1999 Form 10-K Report	1-8962	3-30-00
10.55[a]	Second Amendment effective as of January 1, 2000, to the Pinnacle West Capital Corporation, Arizona Public Service Company, SunCor Development Company and El Dorado Investment Company Deferred Compensation Plan	10.10 to Pinnacle West's 1999 Form 10-K Report	1-8962	3-30-00

Exhibit No.	*Description*	*Originally Filed as Exhibit:*	*File No.*[b]	*Date Effective*
10.56[a]	Pinnacle West Capital Corporation Supplemental Excess Benefit Retirement Plan, as amended and restated, dated December 7, 1999	10.13 to Pinnacle West's 1999 Form 10-K Report	1-8962	3-30-00
10.57[a]	First Amendment to the Pinnacle West Capital Corporation Supplemental Excess Benefit Retirement Plan	10.7 to Pinnacle West's 2001 Form 10-K Report	1-8962	3-27-02
10.58[a]	Second Amendment to the Pinnacle West Capital Corporation Supplemental Excess Benefit Retirement Plan	10.8 to Pinnacle West's 2001 Form 10-K Report	1-8962	3-27-02
10.59[a]	Pinnacle West Capital Corporation and Arizona Public Service Company Directors' Retirement Plan effective as of January 1, 1995	10.7 to 1994 Form 10-K Report	1-4473	3-30-95
10.60[a]	Pinnacle West Capital Corporation and Arizona Public Service Company Directors' Retirement Plan, as amended and restated on June 21, 2000	99.2 to Pinnacle West's Registration Statement on Form S-8 No. 333-40796	1-8962	7-3-00
10.61[a]	Arizona Public Service Company Director Equity Plan	10.1 to September 1997 Form 10-K Report	1-4473	11-12-97
10.62[a]	Letter Agreement dated December 21, 1993, between the Company and William L. Stewart	10.6 to 1994 Form 10-K Report	1-4473	3-30-95

Exhibit No.	Description	Originally Filed as Exhibit:	File No.[b]	Date Effective
10.63[a]	Letter Agreement dated August 16, 1996 between the Company and William L. Stewart	10.8 to 1996 Form 10-K Report	1-4473	3-28-97
10.64[a]	Letter Agreement between the Company and William L. Stewart	10.2 to September 1997 Form 10-Q Report	1-4473	11-12-97
10.65[a]	Letter Agreement dated December 13, 1999 between the Company and William L. Stewart	10.9 to Pinnacle West's 1999 Form 10-K Report	1-8962	3-30-00
10.66[a]	Amendment to Letter Agreement, effective as of January 1, 2002, between APS and William L. Stewart	10.1 to Pinnacle West's June 2002 Form 10-Q Report	1-8962	8-13-02
10.67[a]	Letter Agreement dated as of January 1, 1996 between the Company and Robert G. Matlock & Associates, Inc. for consulting services	10.8 to 1995 Form 10-K Report	1-4473	3-29-96
10.68[a]	Letter Agreement dated October 3, 1997 between the Company and James M. Levine	10.17 to Pinnacle West's 1999 Form 10-K Report	1-8962	3-30-00
10.69[a]	Summary of James M. Levine Retirement Benefits	10.2 to Pinnacle West's March 2002 Form 10-Q Report	1-8962	5-15-02
10.70[a]	Employment Agreement, effective as of October 1, 2002, between APS and James M. Levine	10.1 to Pinnacle West's November 2002 Form 10-Q	1-8962	11-14-02
10.71[a]	Letter Agreement dated June 28, 2001 between Pinnacle West Capital Corporation and Steve Wheeler	10.4 to Pinnacle West's 2002 Form 10-K Report	1-8962	3-31-03

Exhibit No.	*Description*	*Originally Filed as Exhibit:*	*File No.*[b]	*Date Effective*
10.72[ad]	Key Executive Employment and Severance Agreement between Pinnacle West and certain executive officers of Pinnacle West and its subsidiaries	10.1 to Pinnacle West's June 1999 Form 10-Q Report	1-8962	8-16-99
10.73[a]	Pinnacle West Capital Corporation Stock Option and Incentive Plan	10.1 to 1992 Form 10-K Report	1-4473	3-30-93
10.74[a]	First Amendment dated December 7, 1999 to the Pinnacle West Capital Corporation Stock Option and Incentive Plan	10.11 to Pinnacle West's 1999 Form 10-K Report	1-8962	3-30-00
10.75[a]	Pinnacle West Capital Corporation 1994 Long-Term Incentive Plan effective as of March 23, 1994	A to the Proxy Statement for the Plan Report Pinnacle West 1994 Annual Meeting of Shareholders	1-8962	4-16-94
10.76[a]	First Amendment dated December 7, 1999, to the Pinnacle West Capital Corporation 1994 Long-Term Incentive Plan	10.12 to Pinnacle West's 1999 Form 10-K Report	1-8962	3-30-00
10.77[a]	Pinnacle West Capital Corporation 2002 Long-Term Incentive Plan	10.5 to Pinnacle West's 2002 Form 10-K Report	1-8962	3-31-03
10.78[a]	Trust for the Pinnacle West Capital Corporation, Arizona Public Service Company and SunCor Development Company Deferred Compensation Plans dated August 1, 1996	10.14 to Pinnacle West's 1999 Form 10-K Report	1-8962	3-30-00

Exhibit No.	Description	Originally Filed as Exhibit:	File No.[b]	Date Effective
10.79[a]	First Amendment dated December 7, 1999, to the Trust for the Pinnacle West Capital Corporation, Arizona Public Service Company and SunCor Development Company Deferred Compensation Plans	10.15 to Pinnacle West's 1999 Form 10-K Report	1-8962	3-30-00
10.80[a]	2003 Management Officer Incentive Plan	10.1 to Pinnacle West's 2002 Form 10-K Report	1-8962	3-31-03
10.81[a]	2003 CEO Variable Incentive Plan	10.2 to Pinnacle West's 2002 Form 10-K Report	1-8962	3-31-03
10.82	Agreement No. 13904 (Option and Purchase of Effluent) with Cities of Phoenix, Glendale, Mesa, Scottsdale, Tempe, Town of Youngtown, and Salt River Project Agricultural Improvement and Power District, dated April 23, 1973	10.3 to 1991 Form 10-K Report	1-4473	3-19-92
10.83	Agreement for the Sale and Purchase of Wastewater Effluent with City of Tolleson and Salt River Agricultural Improvement and Power District, dated June 12, 1981,including Amendment No. 1 dated as of November 12, 1981 and Amendment No. 2 dated as of June 4, 1986	10.4 to 1991 Form 10-K Report	1-4473	3-19-92
10.84	Territorial Agreement between the Company and Salt River Project	10.1 to March 1998 Form 10-Q Report	1-4473	5-15-98
10.85	Power Coordination Agreement between the Company and Salt River Project	10.2 to March 1998 Form 10-Q Report	1-4473	5-15-98

Exhibit No.	*Description*	*Originally Filed as Exhibit:*	*File No.*[b]	*Date Effective*
10.86	Memorandum of Agreement between the Company and Salt River Project	10.3 to March 1998 Form 10-Q Report	1-4473	5-15-98
10.87	Addendum to Memorandum of Agreement between the Company and Salt River Project dated as of May 19, 1998	10.2 to May 19, 1998 Form 8-K Report	1-4473	6-26-98
99.1	Collateral Trust Indenture among PVNGS II Funding Corp., Inc., the Company and Chemical Bank, as Trustee	4.2 to 1992 Form 10-K Report	1-4473	3-30-93
99.2	Supplemental Indenture to Collateral Trust Indenture among PVNGS II Funding Corp., Inc., the Company and Chemical Bank, as Trustee	4.3 to 1992 Form 10-K Report	1-4473	3-30-93
99.3[c]	Participation Agreement, dated as of August 1, 1986, among PVNGS Funding Corp., Inc., Bank of America National Trust and Savings Association, State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its individual capacity and as Owner Trustee, Chemical Bank, in its individual capacity and as Indenture Trustee, the Company, and the Equity Participant named therein	28.1 to September 1992 Form 10-Q Report	1-4473	11-9-92

Exhibit No.	Description	Originally Filed as Exhibit:	File No.[b]	Date Effective
99.4[c]	Amendment No. 1 dated as of November 1, 1986, to Participation Agreement, dated as of August 1,1986, among PVNGS Funding Corp., Inc., Bank of America National Trust and Savings Association, State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its individual capacity and as Owner Trustee, Chemical Bank, in its individual capacity and as Indenture Trustee, the Company, and the Equity Participant named therein	10.8 to September 1986 Form 10-Q Report by means of Amendment No. 1, on December 3, 1986 Form 8	1-4473	12-4-86
99.5[c]	Amendment No. 2, dated as of March 17, 1993, to Participation Agreement, dated as of August 1, 1986, among PVNGS Funding Corp., Inc., PVNGS II Funding Corp., Inc., State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its individual capacity and as Owner Trustee, Chemical Bank, in its individual capacity and as Indenture Trustee, the Company, and the Equity Participant named therein	28.4 to 1992 Form 10-K Report	1-4473	3-30-93

Exhibit No.	Description	Originally Filed as Exhibit:	File No.[b]	Date Effective
99.6[c]	Trust Indenture, Mortgage, Security Agreement and Assignment of Facility Lease, dated as of August 1, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee, and Chemical Bank, as Indenture Trustee	4.5 to Form S-3 Registration Statement	33-9480	10-24-86
99.7[c]	Supplemental Indenture No. 1, dated as of November 1, 1986 to Trust Indenture, Mortgage, Security Agreement and Assignment of Facility Lease, dated as of August 1, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee, and Chemical Bank, as Indenture Trustee	10.6 to September 1986 Form 10-Q Report by means of Amendment No. 1 on December 3, 1986 Form 8	1-4473	12-4-86
99.8[c]	Supplemental Indenture No. 2 to Trust Indenture, Mortgage, Security Agreement and Assignment of Facility Lease, dated as of August 1, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee, and Chemical Bank, as Indenture Trustee	4.4 to 1992 Form 10-K Report	1-4473	3-30-93
99.9[c]	Assignment, Assumption and Further Agreement, dated as of August 1, 1986, between the Company and State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee	28.3 to Form S-3 Registration Statement	33-9480	10-24-86

Exhibit No.	*Description*	*Originally Filed as Exhibit:*	*File No.*[b]	*Date Effective*
99.10[c]	Amendment No. 1, dated as of November 1, 1986, to Assignment, Assumption and Further Agreement, dated as of August 1, 1986, between the Company and State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee	10.10 to September 1986 Form 10-Q Report by means of Amendment No. 1 on December 3, 1986 Form 8	1-4473	12-4-86
99.11[c]	Amendment No. 2, dated as of March 17, 1993, to Assignment, Assumption and Further Agreement, dated as of August 1, 1986, between the Company and State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee	28.6 to 1992 Form 10-K Report	1-4473	3-30-93
99.12	Participation Agreement, dated as of December 15, 1986, among PVNGS Funding Corp., Inc., State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its individual capacity and as Owner Trustee, Chemical Bank, in its individual capacity and as Indenture Trustee under a Trust Indenture, the Company, and the Owner Participant named therein	28.2 to September 1992 Form 10-Q Report	1-4473	11-9-92

Exhibit No.	*Description*	*Originally Filed as Exhibit:*	*File No.*[b]	*Date Effective*
99.13	Amendment No. 1, dated as of August 1, 1987, to Participation Agreement, dated as of December 15, 1986, among PVNGS Funding Corp., Inc. as Funding Corporation, State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee, Chemical Bank, as Indenture Trustee, the Company, and the Owner Participant named therein	28.20 to Form S-3 Registration Statement No. 33-9480 by means of a November 6, 1986 Form 8-K Report	1-4473	8-10-87
99.14	Amendment No. 2, dated as of March 17, 1993, to Participation Agreement, dated as of December 15, 1986, among PVNGS Funding Corp., Inc., PVNGS II Funding Corp., Inc., State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its individual capacity and as Owner Trustee, Chemical Bank, in its individual capacity and as Indenture Trustee, the Company, and the Owner Participant named therein	28.5 to 1992 Form 10-K Report	1-4473	3-30-93
99.15	Trust Indenture, Mortgage, Security Agreement and Assignment of Facility Lease, dated as of December 15, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee, and Chemical Bank, as Indenture Trustee	10.2 to November 18, 1986 Form 8-K Report	1-4473	1-20-87

Exhibit No.	Description	Originally Filed as Exhibit:	File No.[b]	Date Effective
99.16	Supplemental Indenture No. 1, dated as of August 1, 1987, to Trust Indenture, Mortgage, Security Agreement and Assignment of Facility Lease, dated as of December 15, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee, and Chemical Bank, as Indenture Trustee	4.13 to Form S-3 Registration Statement No. 33-9480 by means of August 1, 1987 Form 8-K Report	1-4473	8-24-87
99.17	Supplemental Indenture No. 2 to Trust Indenture, Mortgage, Security Agreement and Assignment of Facility Lease, dated as of December 15, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee, and Chemical Bank, as Indenture Trustee	4.5 to 1992 Form 10-K Report	1-4473	3-30-93
99.18	Assignment, Assumption and Further Agreement, dated as of December 15, 1986, between the Company and State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee	10.5 to November 18, 1986 Form 8-K Report	1-4473	1-20-87

Exhibit No.	Description	Originally Filed as Exhibit:	File No.[b]	Date Effective
99.19	Amendment No. 1, dated as of March 17, 1993, to Assignment, Assumption and Further Agreement, dated as of December 15, 1986, between the Company and State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee	28.7 to 1992 Form 10-K Report	1-4473	3-30-93
99.20[c]	Indemnity Agreement dated as of March 17, 1993 by the Company	28.3 to 1992 Form 10-K Report	1-4473	3-30-93
99.21	Extension Letter, dated as of August 13, 1987, from the signatories of the Participation Agreement to Chemical Bank	28.20 to Form S-3 Registration Statement No. 33-9480 by means of a November 6, 1986 Form 8-K Report	1-4473	8-10-87
99.22	Rate Reduction Agreement dated December 4, 1995 between the Company and the ACC Staff	10.1 to December 4, 1995 Form 8-K Report	1-4473	12-14-95
99.23	Arizona Corporation Commission Order dated April 24, 1996	10.1 to March 1996 Form 10-Q Report	1-4473	5-14-96
99.24	Arizona Corporation Commission Order, Decision No. 59943, dated December 26, 1996, including the Rules regarding the introduction of retail competition in Arizona	99.1 to 1996 Form 10-K Report	1-4473	3-28-97
99.25	Retail Electric Competition Rules	10.1 to June 1998 Form 10-Q Report	1-4473	8-14-98
99.26	Arizona Corporation Commission Order, Decision No. 61973, dated October 6, 1999, approving our Settlement Agreement	10.1 to September 1999 10-Q Report	1-4473	11-15-99

Exhibit No.	Description	Originally Filed as Exhibit:	File No.[b]	Date Effective
99.27	Arizona Corporation Commission Order, Decision No. 61969, dated September 29, 1999, including the Retail Electric Competition Rules	10.2 to September 1999 10-Q Report	1-4473	11-15-99
99.28	Addendum to Settlement Agreement	10.1 to Pinnacle West September 2000 10-Q	1-8962	11-14-00
99.29	ACC Opinion and Order dated September 10, 2002, Decision No. 65154 (Track A Order)	99.1 to Pinnacle West's September 10, 2002 Form 8-K Report	1-8962	9-17-02
99.30	Arizona Public Service Company Application filed with the Arizona Corporation Commission on September 16, 2002	99.2 to Pinnacle West's September 10, 2002 Form 8-K Report	1-8962	9-17-02
99.31	Track "A" Appeals Issues - Principles for Resolution	99.1 to Pinnacle West's November 15, 2002 Form 8-K Report	1-8962	12-16-02

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[a]Management contract or compensatory plan or arrangement to be filed as an exhibit pursuant to Item 14(c) of Form 10-K.

[b]Reports filed under File No. 1-4473 were filed in the office of the Securities and Exchange Commission located in Washington, D.C.

[c]An additional document, substantially identical in all material respects to this Exhibit, has been entered into, relating to an additional Equity Participant. Although such additional document may differ in other respects (such as dollar amounts, percentages, tax indemnity matters, and dates of execution), there are no material details in which such document differs from this Exhibit.

[d]Additional agreements, substantially identical in all material respects to this Exhibit have been entered into with additional officers and key employees of the Company. Although such additional documents may differ in other respects (such as dollar amounts and dates of execution), there are no material details in which such agreements differ from this Exhibit.

Reports on Form 8-K

During the quarter ended December 31, 2002 and the period ended March 31, 2003, the Company filed the following Reports on Form 8-K:

Report dated October 17, 2002 regarding Pinnacle West's earnings outlook.

Report dated November 14, 2002 regarding an ACC staff recommendation that the Interim Financing Application be approved.

Report dated November 15, 2002 regarding: (i) appeals of the Track A Order and an agreement between APS and the ACC staff; (ii) ACC staff testimony on the Financing Application; and (iii) EITF 02-3.

Report dated November 22, 2002 regarding ACC approval of the Interim Financing Application and Pinnacle West Energy's decision to cancel Redhawk Units 3 and 4.

Report dated January 15, 2003 regarding NAC losses and Pinnacle West's earnings outlook.

Report dated January 30, 2003 regarding an ACC staff report on Track B.

Report dated February 24, 2003 regarding reclassifications of revenue from electricity trading activities to a net basis of reporting.

Report dated February 27, 2003 regarding the ACC Track B decision.

Report dated March 11, 2003 regarding an ACC ALJ recommendation on the Financing Application.

Report dated March 27, 2003 regarding ACC approval of a financing arrangement.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

ARIZONA PUBLIC SERVICE COMPANY
(Registrant)

Date: March 31, 2003

/s/ Jack E. Davis
(Jack E. Davis, President and Chief Executive Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ William J. Post (William J. Post, Chairman of the Board of Directors)	Director	March 31, 2003
/s/ Jack E. Davis (Jack E. Davis, President and Chief Executive Officer)	Principal Executive Officer and Director	March 31, 2003
/s/ Donald E. Brandt (Donald E. Brandt, Senior Vice President, and Chief Financial Officer)	Principal Financial Officer	March 31, 2003
/s/ Chris N. Froggatt (Chris N. Froggatt, Vice President and Controller)	Principal Accounting Officer	March 31, 2003
/s/ Edward N. Basha, Jr. (Edward N. Basha, Jr.)	Director	March 31, 2003

/s/ Michael L. Gallagher (Michael L. Gallagher)	Director	March 31, 2003
/s/ Pamela Grant (Pamela Grant)	Director	March 31, 2003
/s/ Roy A. Herberger, Jr. (Roy A. Herberger, Jr.)	Director	March 31, 2003
/s/ Martha O. Hesse (Martha O. Hesse)	Director	March 31, 2003
/s/ William S. Jamieson, Jr. (William S. Jamieson, Jr.)	Director	March 31, 2003
/s/ Humberto S. Lopez (Humberto S. Lopez)	Director	March 31, 2003
/s/ Robert G. Matlock (Robert G. Matlock)	Director	March 31, 2003
/s/ Kathryn L. Munro (Kathryn L. Munro)	Director	March 31, 2003
/s/ Bruce J. Nordstrom (Bruce J. Nordstrom)	Director	March 31, 2003

CERTIFICATIONS

I, Jack E. Davis, certify that:

1. I have reviewed this annual report on Form 10-K of Arizona Public Service Company;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and we have:

a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and

c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officer and I have indicated in this annual report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: March 31, 2003.

/s/ Jack E. Davis
Jack E. Davis
President and Chief Executive Officer

I, Donald E. Brandt, certify that:

1. I have reviewed this annual report on Form 10-K of Arizona Public Service Company;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and we have:

a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and

c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officer and I have indicated in this annual report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: March 31, 2003.

/s/ Donald E. Brandt
Donald E. Brandt
Senior Vice President and Chief
Financial Officer

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Schedule F-1
Page 1 of 1

ARIZONA PUBLIC SERVICE COMPANY
Projected Income Statements
Present and Proposed Rates
(Dollars in Thousands Except per Share Amounts)

Line No.	Description	Actual Test Year Ended 12/31/2002 (a)	Projected Year Present Rates Year Ending 12/31/2003 (b)	Projected Year Present Rates Year Ending 12/31/2004 (b)	Projected Year Proposed Rates Year Ending 12/31/2004 (b)	Projected Year Present Rates Year Ending 12/31/2005 (b)	Projected Year Proposed Rates Year Ending 12/31/2005 (b)	Line No.
1.	Electric Operating Revenues	$ 2,093,393	$ 1,969,996	$ 2,148,301	$ 2,263,598	$ 2,205,210	$ 2,405,450	1.
2.	Fuel and Purchased power	628,030	567,774	657,096	644,350	667,792	666,142	2.
3.	Operating Revenues Less Fuel and Purchased Power	1,465,363	1,402,222	1,491,205	1,619,248	1,537,418	1,739,308	3.
	Other Operating Expenses:							
4.	Oper & Maint excluding fuel expenses	495,845	490,333	518,388	518,388	552,953	552,953	4.
5.	Deprec & Amort	399,640	385,736	370,585	370,585	408,045	408,045	5.
6.	Income Taxes	132,953	110,584	131,695	183,207	108,805	192,268	6.
7.	Other Taxes	107,925	113,500	120,650	120,650	134,989	134,989	7.
8.	Operating Income	329,000	302,069	349,887	426,418	332,626	451,053	8.
	Other Income (Deductions):							
9.	Income Taxes	6,148	(627)	1,089	1,089	5,491	5,491	9.
10.	Other Income	5,149	12,095	9,698	9,698	321	321	10.
11.	Other Expenses	(19,338)	(10,508)	(12,454)	(12,454)	(14,223)	(14,223)	11.
12.	Total	(8,041)	960	(1,667)	(1,667)	(8,411)	(8,411)	12.
13.	Income Before Interest Deductions	320,959	303,029	348,220	424,751	324,215	442,642	13.
	Interest Deductions							
14.	Interest on long-term debt	128,462	145,805	157,513	155,148	172,808	163,399	14.
15.	Interest on short-term borrowings	5,416	1,900	3,300	3,300	5,300	5,300	15.
16.	Debt discount, premium and expense	2,888	3,000	3,000	3,000	3,000	3,000	16.
17.	Capitalized interest	(15,150)	(18,016)	(15,638)	(15,638)	(15,137)	(15,137)	17.
18.	Total	121,616	132,689	148,175	145,810	165,971	156,562	18.
19.	Net Income	$ 199,343	$ 170,340	$ 200,045	$ 278,941	$ 158,244	$ 286,080	19.
	Earnings per share of average Common Stock Outstanding*	$ 2.80	N/A	N/A	N/A	N/A	N/A	
	% Return on Average Common Equity	9.2%	7.9%	8.4%	11.5%	6.0%	10.4%	
	% Adjusted Return on Average Common Equity	7.9%	6.7%	7.8%	11.0%	6.0%	10.4%	

Supporting Schedules:
(a) E-2

Recap Schedules:
(b) A-2

* Optional for projected years.

F-2

ARIZONA PUBLIC SERVICE COMPANY
Projected Changes in Financial Position
Present and Proposed Rates
(Thousands of Dollars)

Line No.	Description	Actual Test Year 12/31/2002	Projected Year Present Rates Year Ending 12/31/2003	Projected Year Present Rates Year Ending 12/31/2004	Projected Year Proposed Rates Year Ending 12/31/2004	Projected Year Present Rates Year Ending 12/31/2005	Projected Year Proposed Rates Year Ending 12/31/2005	Line No.
		(a)	(b)	(b)	(b)	(b)	(b)	
	Cash Flows from Operations:							
1.	Net Income	$ 199,343	$ 170,340	$ 200,045	$ 278,941	$ 158,244	$ 286,080	1.
	Items not requiring cash:							
2.	Depreciation and amortization	399,640	385,736	370,585	370,585	408,045	408,045	2.
3.	Nuclear fuel amortization	31,185	37,618	38,481	38,481	38,974	38,974	3.
4.	Deferred income taxes	206,767	(41,006)	(12,344)	(12,344)	(48,593)	(48,593)	4.
5.	Mark-to-market gains	2,957	-	-	-	-	-	5.
6.	Other	(135,380)	88,575	(92,691)	(92,081)	(51,462)	(50,126)	6.
7.	Net cash provided	704,512	641,263	504,076	583,582	505,208	634,380	7.
	Cash Flows from Financing:							
8.	Long-term debt	459,926	500,000	458,506	379,000	587,086	457,914	8.
9.	Short-term borrowings - net	(171,162)	59,428	7,575	7,575	32,997	32,997	9.
10.	Dividends paid on common stock	(170,000)	(170,000)	(170,000)	(170,000)	(170,000)	(170,000)	10.
11.	Repayment and requisition of long-term debt	(337,160)	(89,332)	(386,192)	(386,192)	(400,000)	(400,000)	11.
12.	Net cash used	(218,396)	300,096	(90,111)	(169,617)	50,083	(79,089)	12.
	Cash Flows from Investing:							
13.	Capital expenditures (before AFUDC debt) (c)	(490,156)	(411,899)	(386,883)	(386,883)	(528,710)	(528,710)	13.
14.	Allowance for borrowed funds used during construction (c	(15,150)	(18,016)	(15,638)	(15,638)	(15,137)	(15,137)	14.
15.	Loans to associated companies	-	(500,000)	-	-	-	-	15.
16.	Other	44,918	(11,444)	(11,444)	(11,444)	(11,444)	(11,444)	16.
17.	Net cash used	(460,388)	(941,359)	(413,965)	(413,965)	(555,291)	(555,291)	17.
18.	Net increase (decrease) in cash and cash equivalents	25,728	-	-	-	-	-	18.
19.	Cash and cash equivalents at beginning of period	16,821	42,549	42,549	42,549	42,549	42,549	19.
20.	Cash and cash equivalents at end of period	$ 42,549	$ 42,549	$ 42,549	$ 42,549	$ 42,549	$ 42,549	20.

Supporting Schedules:
(a) E-3
(c) F-3

Recap Schedules:
(b) A-5

F-3

ARIZONA PUBLIC SERVICE COMPANY
Projected Construction Requirements
Test Year and Three Projected Years
(Thousands of Dollars)

Line No.	Description	Actual Test Year Ended 12/31/2002	Projected Year: Year Ended 12/31/2003	Projected Year: Year Ended 12/31/2004	Projected Year: Year Ended 12/31/2005	Line No.
	Electric:					
1.	Production Plant (Excluding Nuclear Fuel)	$ 108,428	$ 89,416	$ 69,202	$ 152,029	1.
2.	Nuclear Fuel	30,862	29,458	28,693	28,474	2.
3.	Total Production	139,290	118,874	97,895	180,503	3.
4.	Transmission	106,452	56,720	54,946	79,921	4.
5.	Distribution	208,481	197,265	202,855	218,022	5.
6.	General and Intangibles	44,062	34,783	27,202	44,879	6.
7.	Total Construction Expenditures (a)	498,285	407,642	382,898	523,325	7.
8.	Property Taxes Capitalized (a)	2,958	4,257	3,985	5,385	8.
9.	Allowance for Equity Funds Used During Construction	-	-	-	-	9.
10.	Allowance for Borrowed Funds Used During Construction	13,507	18,016	15,638	15,137	10.
11.	Total Capital Expenditures	$ 514,750	$ 429,915	$ 402,521	$ 543,847	11.

Supporting Schedules:
N/A

Recap Schedules:
(a) F-2 & A-4

F-4

ARIZONA PUBLIC SERVICE COMPANY
Assumptions Used in Developing Projections

Line No.	Item		Line No.
	A.	**Customer Growth**	
1.		Retail customer growth for the period 1/1/03 through 12/31/05 is forecasted to grow at an annual average rate of 3.4%.	1.
	B.	**Growth in Retail Energy and Retail Peak Demand**	
2.		Retail energy sales for the period 1/1/03 through 12/31/05 are forecasted to grow at an annual average rate of 4.8%. Retail	2.
3.		summer and winter peak demands for the same period are forecasted to grow at annual average rates of 4.3% and 2.9%,	3.
4.		respectively.	4.
	C.	**Wholesale and Economy Interchange Sales**	
5.		Firm wholesale sales and peak demand for obligation-to-serve customers are forecasted per existing contracts. The	5.
6.		Company sells energy on an economy interchange basis on a short-term basis from time to time. Such sales are made	6.
7.		at prices above the Company's variable costs to generate energy.	7.
	D.	**Fuel**	
8.		Fuel costs are based on projected sales, estimated fuel prices and projected operating availability factors of power	8.
9.		plants.	9.
	E.	**Operations & Maintenance Expenses**	
10.		The level of expenses reflect increases that are related to inflation and increased benefits costs, the current trend	10.
11.		of increased customers and additional plant requirements.	11.
	F.	**Construction Expenditures**	
12.		The level of expenditures is primarily driven by customer, sales, and load growth, maintaining reliability, and legal	12.
13.		and regulatory requirements.	13.
	G.	**Capital Structure Changes**	
14.		Capital Structure and Financing are shown on Schedules A-3, D-1, D-2, D-3 and F-2.	14.
	H.	**Financing Assumptions**	
15.		Forecasted Interest Rates:	15.
16.		Variable Rate Pollution Control Bonds - 1.31% in 2003, 2.05% in 2004, 3.35% in 2005	16.
17.		Commercial Paper - 1.9% in 2003, 3.3% in 2004, 5.3% in 2005	17.
18.		New Sr. Unsecured Debt - 7.0% in 2004, 7.5% in 2005	18.

G-1

ARIZONA PUBLIC SERVICE COMPANY
Cost of Service Summary - *Present Rates*
Rates of Return by Customer Classification
Adjusted Test Year Ending December 31, 2002
($000)

		Total Company	Total ACC Jurisdiction	All Other	Total ACC Jurisdiction				
					Residential	General Service	Irrigation	Street Lighting	Dusk to Dawn
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
1.a.	Revenues from Rates	1,827,189	1,791,584 (a)	35,605	889,898 (a)	883,595 (a)	2,099 (a)	10,794 (a)	5,198 (a)
1.b.	Other Revenues	150,987	148,562	2,425	71,187	74,249	215	2,582	329
2.	Expenses	1,626,563	1,590,132 (b)	36,432	839,733 (b)	730,686 (b)	2,360 (b)	12,439 (b)	4,914 (b)
3.	Operating Income Before Income Taxes	351,613	350,014	1,598	121,352	227,158	(46)	937	613
4.	Income Taxes	86,608	86,144	463	18,616	67,806	-75	-195	-7
5.	Net Operating Income	265,005	263,870	1,135	102,736	159,352	29	1,132	620
6.	Rate Base	4,221,019	4,207,476 (c)	13,543	2,367,112 (c)	1,769,998 (c)	4,571 (c)	45,676 (c)	20,118 (c)
7.	Rate of Return	6.28%	6.27%	8.38%	4.34%	9.00%	0.63%	2.48%	3.08%

Supporting Schedules:
(a) H-1
(b) G-4
(c) G-3

G-2

ARIZONA PUBLIC SERVICE COMPANY
Cost of Service Summary - *Proposed Rates*
Rates of Return by Customer Classification
Adjusted Test Year Ending December 31, 2002
($000)

		Total Company	Total ACC Jurisdiction	All Other	Total ACC Jurisdiction				
					Residential	General Service	Irrigation	Street Lighting	Dusk to Dawn
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
1.a.	Revenues from Rates	1,993,996	1,958,391 (a)	35,605	972,747 (a)	965,868 (a)	2,295 (a)	11,799 (a)	5,682 (a)
1.b.	Other Revenues	150,987	148,562	2,425	71,187	74,249	215	2,582	329
2.	Expenses	1,626,563	1,590,132 (b)	36,432	839,733 (b)	730,686 (b)	2,360 (b)	12,439 (b)	4,914 (b)
3.	Operating Income Before Income Taxes	518,420	516,821	1,598	204,201	309,431	150	1,942	1,097
4.	Income Taxes	152,496	152,033	463	51,968	99,684	1	197	183
5.	Net Operating Income	365,924	364,788	1,135	152,233	209,747	149	1,745	914
6.	Rate Base	4,221,019	4,207,476 (c)	13,543	2,367,112 (c)	1,769,998 (c)	4,571 (c)	45,676 (c)	20,118 (c)
7.	Rate of Return	8.67%	8.67%	8.38%	6.43%	11.85%	3.26%	3.82%	4.54%

Supporting Schedules:
(a) H-1
(b) G-4
(c) G-3

G-3

ARIZONA PUBLIC SERVICE COMPANY
Rate Base Allocation to Classes of Service
Total Rate Base
Adjusted Test Year Ending December 31, 2002
($000)

Line No.	Class of Service	Production - Demand (A)	Transmission Substation (B)	Transmission Lines (C)	Distribution Substation (D)	Distribution OH Primary (E)	Distribution OH Secondary (F)	Distribution UG Lines (G)	Distribution Line TXFs (H)	Total Demand (I)	Total Demand % (J)	Total Energy (K)	Total Energy % (L)
1.	Residential	1,062,376	0	0	87,562	147,786	67,667	438,874	198,240	2,002,505	55.13%	43,910	45.23%
2.	General Service	985,723	0	0	73,149	117,803	14,607	318,641	102,044	1,611,969	44.38%	52,429	54.01%
3.	Irrigation	3,327	0	0	946	1,596	0	0	361	6,230	0.17%	132	0.14%
4.	Street Lighting	0	0	0	875	1,477	593	4,321	1,083	8,349	0.23%	441	0.45%
5.	Dusk to Dawn	0	0	0	325	548	220	1,604	402	3,099	0.09%	164	0.17%
6.	Total	2,051,426 (b)	0	0	162,857 (b)	269,211 (b)	83,087 (b)	763,440 (b)	302,131 (b)	3,632,152	100.00%	97,076	100.00%

Line No.	Class of Service	Cust. Advances & Deposits (A)	Distribution OH Services (B)	Distribution UG Services (C)	Distribution Meters (D)	Customer Accounts (E)	Dusk to Dawn (F)	Street Lighting (G)	Customer Service & Info (H)	Sales (I)	Total Customer (J)	Total Customer % (K)
7.	Residential	(48,220)	23,377	112,951	83,928	49,075	0	0	1,396	9,720	232,226	77.08%
8.	General Service	(33,879)	2,511	11,113	30,600	5,994	0	0	170	1,187	17,696	5.87%
9.	Irrigation	(2,425)	37	0	295	22	0	0	1	4	(2,066)	-0.69%
10.	Street Lighting	(728)	0	0	0	45	0	37,339	1	9	36,666	12.17%
11.	Dusk to Dawn	(125)	0	0	0	475	16,317	0	14	94	16,774	5.57%
12.	Total	(85,378) (b)	25,925 (b)	124,064 (b)	114,824 (b)	55,610 (b)	16,317 (b)	37,339 (b)	1,582 (b)	11,014 (b)	301,296	100.00%

Line No.	Class of Service	Total Reg. Assets (A)	Total Reg. Assets % (B)	Total System Benefits (C)	Total System Benefits % (D)	TOTAL ACC JURIS. (a) (E)	TOTAL ACC JURIS. % (F)
13.	Residential	87,306	50.07%	1,165	45.23%	2,367,112	56.26%
14.	General Service	86,514	49.61%	1,391	54.01%	1,769,998	42.07%
15.	Irrigation	271	0.16%	4	0.14%	4,571	0.11%
16.	Street Lighting	208	0.12%	12	0.45%	45,676	1.09%
17.	Dusk to Dawn	77	0.04%	4	0.17%	20,118	0.48%
18.		174,376 (b)	100.00%	2,576 (b)	100.00%	4,207,476	100.00%

Supporting Schedules:
(b) G-5
(c) G-7

Recap Schedules:
(a) G-1 & G-2

G-4

ARIZONA PUBLIC SERVICE COMPANY
Expense Allocation to Classes of Service
Operating Expenses Excluding Income Taxes
Adjusted Test Year Ending December 31, 2002
($000)

Line No.	Class of Service	Production - Demand	Transmission Substation	Transmission Lines	Distribution Substation	Distribution OH Primary	Distribution OH Secondary	Distribution UG Lines	Distribution Line TXFs	Total Demand	Total Demand %	Total Energy	Total Energy %
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
1.	Residential	245,691	0	46,610	15,020	20,171	9,314	41,724	20,572	399,102	53.28%	278,597	45.23%
2.	General Service	228,814	0	46,031	12,548	16,079	2,011	30,294	10,589	346,365	46.24%	332,650	54.01%
3.	Irrigation	763	0	117	162	218	0	0	37	1,297	0.17%	838	0.14%
4.	Street Lighting	140	0	565	150	202	82	411	112	1,661	0.22%	2,800	0.45%
5.	Dusk to Dawn	65	0	264	56	75	30	152	42	684	0.09%	1,038	0.17%
6.	Total	475,472 (a)	0 (a)	93,587 (a)	27,936 (a)	36,745 (a)	11,436 (a)	72,580 (a)	31,352 (a)	749,109	100.00%	615,923	100.00%

Line No.	Class of Service	Distribution OH Services	Distribution UG Services	Distribution Meters	Customer Accounts	Dusk to Dawn	Street Lighting	Customer Service & Info	Sales	Total Customer	Total Customer %
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
7.	Residential	3,228	10,781	27,826	69,973	0	0	3,828	19,705	135,341	79.90%
8.	General Service	347	1,061	10,145	8,547	0	0	468	2,407	22,973	13.56%
9.	Irrigation	5	0	98	31	0	0	2	9	145	0.09%
10.	Street Lighting	0	0	0	64	0	7,714	3	18	7,799	4.60%
11.	Dusk to Dawn	0	0	0	677	2,218	0	37	191	3,123	1.84%
12.	Total	3,580 (a)	11,841 (a)	38,069 (a)	79,292 (a)	2,218 (a)	7,714 (a)	4,338 (a)	22,329 (a)	169,381	100.00%

Line No.	Class of Service	Total Reg. Assets	Total Reg. Assets %	Total System Benefits	Total System Benefits %	TOTAL ACC JURIS. (c)	TOTAL ACC JURIS. %
		(A)	(B)	(C)	(D)	(E)	(F)
13.	Residential	9,743	51.77%	16,951	45.94%	839,733	52.81%
14.	General Service	9,046	48.07%	19,651	53.26%	730,686	45.95%
15.	Irrigation	31	0.16%	49	0.13%	2,360	0.15%
16.	Street Lighting	0	0.00%	178	0.48%	12,439	0.78%
17.	Dusk to Dawn	0	0.00%	70	0.19%	4,914	0.31%
18.	Total	18,820 (a)	100.00% (a)	36,899 (a)	100.00%	1,590,132	100.00%

Supporting Schedules:
(a) G-6
(b) G-7

Recap Schedules:
(c) G-1 & G-2

G-5

ARIZONA PUBLIC SERVICE COMPANY
Distribution of Rate Base by Function
Total Rate Base
Adjusted Test Year Ending December 31, 2002
($000)

Line No.	Plant Classification	Production - Demand	Transmission Substation	Transmission Lines	Distribution Substation	Distribution OH Primary	Distribution OH Secondary	Distribution UG Lines	Distribution Line TXFs	Total Demand	Total Demand %
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
1.	Production - Demand	2,051,426	0	0	0	0	0	0	0	2,051,426	56.48%
2.	Transmission Substation	0	0	0	0	0	0	0	0	0	0.00%
3.	Transmission Lines	0	0	0	0	0	0	0	0	0	0.00%
4.	Distribution Substation	0	0	0	162,857	0	0	0	0	162,857	4.48%
5.	Distribution OH Primary	0	0	0	0	269,211	0	0	0	269,211	7.41%
6.	Distribution OH Secondary	0	0	0	0	0	83,087	0	0	83,087	2.29%
7.	Distribution UG Lines	0	0	0	0	0	0	763,440	0	763,440	21.02%
8.	Distribution Line TXFs	0	0	0	0	0	0	0	302,131	302,131	8.32%
9.	Total	2,051,426	0	0	162,857	269,211	83,087	763,440	302,131	3,632,152	100.00%

Line No.	Plant Classification	Cust. Advances & Deposits	Distribution OH Services	Distribution UG Services	Distribution Meters	Customer Accounts	Dusk to Dawn	Street Lighting	Customer Service & Info	Sales	Total Customer	Total Customer %
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
10.	Cust. Advances & Deposit	(85,378)	0	0	0	0	0	0	0	0	(85,378)	-28.34%
11.	Distribution OH Services	0	25,925	0	0	0	0	0	0	0	25,925	8.60%
12.	Distribution UG Services	0	0	124,064	0	0	0	0	0	0	124,064	41.18%
13.	Distribution Meters	0	0	0	114,824	0	0	0	0	0	114,824	38.11%
14.	Customer Accounts	0	0	0	0	55,610	0	0	0	0	55,610	18.46%
15.	Dusk to Dawn	0	0	0	0	0	16,317	0	0	0	16,317	5.42%
16.	Street Lighting	0	0	0	0	0	0	37,339	0	0	37,339	12.39%
17.	Customer Service & Info	0	0	0	0	0	0	0	1,582	0	1,582	0.52%
18.	Sales	0	0	0	0	0	0	0	0	11,014	11,014	3.66%
19.	Total	(85,378)	25,925	124,064	114,824	55,610	16,317	37,339	1,582	11,014	301,296	100.00%

Line No.	Plant Classification	Total Energy	Total Energy %	Total Reg. Assets	Total Reg. Assets %	Total System Benefits	Total System Benefits %	TOTAL ACC JURIS. (a)
		(A)	(B)	(C)	(D)	(E)	(F)	(G)
20.	Production - Energy	97,076	100.00%					
21.	Regulatory Assets			174,376	100.00%			
22.	System Benefits					2,576	100.00%	
23.	TOTAL ACC							4,207,476

Supporting Schedules:

Recap Schedules:
(a) G-3

G-6

ARIZONA PUBLIC SERVICE COMPANY
Distribution of Expenses by Function
Operating Expenses Excluding Income Taxes
Adjusted Test Year Ending December 31, 2002
($000)

Line No.	Plant Classification	Production - Demand	Transmission Substation	Transmission Lines	Distribution Substation	Distribution OH Primary	Distribution OH Secondary	Distribution UG Lines	Distribution Line TXFs	Total Demand	Total Demand %
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
1.	Production - Demand	475,472	0	0	0	0	0	0	0	475,472	63.47%
2.	Transmission Substation	0	0	0	0	0	0	0	0	0	0.00%
3.	Transmission Lines	0	0	93,587	0	0	0	0	0	93,587	12.49%
4.	Distribution Substation	0	0	0	27,936	0	0	0	0	27,936	3.73%
5.	Distribution OH Primary	0	0	0	0	36,745	0	0	0	36,745	4.91%
6.	Distribution OH Secondary	0	0	0	0	0	11,436	0	0	11,436	1.53%
7.	Distribution UG Lines	0	0	0	0	0	0	72,580	0	72,580	9.69%
8.	Distribution Line TXFs	0	0	0	0	0	0	0	31,352	31,352	4.19%
9.	Total	475,472	0	93,587	27,936	36,745	11,436	72,580	31,352	749,109	100.00%

Line No.	Plant Classification	Distribution OH Services	Distribution UG Services	Distribution Meters	Customer Accounts	Dusk to Dawn	Street Lighting	Customer Service & Info	Sales	Total Customer	Total Customer %
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
10.	Distribution OH Services	3,580	0	0	0	0	0	0	0	3,580	2.11%
11.	Distribution UG Services	0	11,841	0	0	0	0	0	0	11,841	6.99%
12.	Distribution Meters	0	0	38,069	0	0	0	0	0	38,069	22.48%
13.	Customer Accounts	0	0	0	79,292	0	0	0	0	79,292	46.81%
14.	Dusk to Dawn	0	0	0	0	2,218	0	0	0	2,218	1.31%
15.	Street Lighting	0	0	0	0	0	7,714	0	0	7,714	4.55%
16.	Customer Service & Info	0	0	0	0	0	0	4,338	0	4,338	2.56%
17.	Sales	0	0	0	0	0	0	0	22,329	22,329	13.18%
18.	Total	3,580	11,841	38,069	79,292	2,218	7,714	4,338	22,329	169,381	100.00%

Line No.	Plant Classification	Total Production - Energy	Total Energy %	Total Reg. Assets	Total Reg. Assets %	Total System Benefits	Total System Benefits %	TOTAL ACC JURIS. (a)
		(A)	(B)	(C)	(D)	(E)	(F)	(G)
19.	Production - Energy	615,923	100.00%					
20.	Regulatory Assets			18,820	100.00%			
21.	System Benefits					36,899	100.00%	
22.	TOTAL ACC							1,590,132

Supporting Schedules:

Recap Schedules:
(a) G-4

G-7

ARIZONA PUBLIC SERVICE COMPANY
Cost of Service Study
Development of Allocation Factors
Adjusted Test Year Ending December 31, 2002

Factor	Definition and Application of Allocation Factor	Total Company	Total ACC Jurisdiction	All Other	Total Retail	Residential	General Service	Irrigation	Street Lighting	Dusk to Dawn
1. DEMPROD1	4-CP Demand @ Generation (KW)	5,111,775	5,102,910	8,865	5,102,910	2,642,653	2,451,981	8,276	0	0
	Production Demand	100.00%	99.83%	0.17%	99.83%	51.70%	47.97%	0.16%	0.00%	0.00%
2. DEMPROD2	4-CP Demand @ Generation (KW)	5,111,775	5,102,910	8,865	5,102,910	2,642,653	2,451,981	8,276	0	0
	Production - Ancillary Service - Regulation	100.00%	99.83%	0.17%	99.83%	51.70%	47.97%	0.16%	0.00%	0.00%
3. DEMPROD3	4-CP Demand @ Generation (KW)	5,111,775	5,102,910	8,865	5,102,910	2,642,653	2,451,981	8,276	0	0
	Production - Ancillary Service - Spinning Reserve	100.00%	99.83%	0.17%	99.83%	51.70%	47.97%	0.16%	0.00%	0.00%
4. DEMPROD4	4-CP Demand @ Generation (KW)	5,111,775	5,102,910	8,865	5,102,910	2,642,653	2,451,981	8,276	0	0
	Production - Ancillary Service - Ready Reserve	100.00%	99.83%	0.17%	99.83%	51.70%	47.97%	0.16%	0.00%	0.00%
5. DEMPROD6	4-CP Demand @ Generation (KW)	5,111,775	5,102,910	8,865	5,102,910	2,642,653	2,451,981	8,276	0	0
	Production - Ancillary Service - Scheduling & Dispatch	100.00%	99.83%	0.17%	99.83%	51.70%	47.97%	0.16%	0.00%	0.00%
6. DEMPROD7	4-CP Demand @ Generation (KW)	5,111,775	5,102,910	8,865	5,102,910	2,642,653	2,451,981	8,276	0	0
	Production - Ancillary Service - Must Run	100.00%	99.83%	0.17%	99.83%	51.70%	47.97%	0.16%	0.00%	0.00%
7. DEMTRAN1	4-CP Demand @ Generation including Wheeling (KW)	6,445,773	5,102,910	1,342,863	5,102,910	2,642,653	2,451,981	8,276	0	0
	Transmission Substation	100.00%	79.17%	20.83%	79.17%	41.00%	38.04%	0.13%	0.00%	0.00%
8. DEMTRAN2	4-CP Demand @ Generation including Wheeling (KW)	6,445,773	5,102,910	1,342,863	5,102,910	2,642,653	2,451,981	8,276	0	0
	Transmission Lines	100.00%	79.17%	20.83%	79.17%	41.00%	38.04%	0.13%	0.00%	0.00%
9. DEMTRAN4	Transmission - SCE 500 KV Line	100	0	100	0	0	0	0	0	0
	SCE Specific	100.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
10. DEMDIST1	NCP Demand @ Substation Level w/losses (KW)	6,181,490	6,181,490	0	6,181,490	3,323,537	2,776,499	35,899	33,222	12,333
	Distribution Substation	100.00%	100.00%	0.00%	100.00%	53.77%	44.92%	0.58%	0.54%	0.20%
11. DEMDIST2	NCP Demand @ Primary Line Level w/losses (KW)	5,934,767	5,934,767	0	5,934,767	3,257,955	2,596,964	35,191	32,567	12,090
	Distribution OH Primary Lines	100.00%	100.00%	0.00%	100.00%	54.90%	43.76%	0.59%	0.55%	0.20%
12. DEMDIST3	Individual Maximum Demand @ Secondary Line Level w/losses (KW)	4,331,559	4,331,559	0	4,331,559	3,527,660	761,528	0	30,900	11,471
	Distribution OH Secondary Lines	100.00%	100.00%	0.00%	100.00%	81.44%	17.58%	0.00%	0.71%	0.26%
13. DEMDIST4	NCP Demand @ Primary Line Level w/losses (KW)	5,899,576	5,899,576	0	5,899,576	3,257,955	2,596,964	0	32,567	12,090
	Distribution UG Primary Lines	100.00%	100.00%	0.00%	100.00%	55.22%	44.02%	0.00%	0.55%	0.20%
14. DEMDIST5	Individual Maximum Demand @ Secondary Line Level w/losses (KW)	4,331,559	4,331,559	0	4,331,559	3,527,660	761,528	0	30,900	11,471
	Distribution UG Secondary Lines	100.00%	100.00%	0.00%	100.00%	81.44%	17.58%	0.00%	0.71%	0.26%
15. DEMDIST6	Individual Maximum Demand @ Secondary TXF Level w/losses (KW)	9,084,660	9,084,660	0	9,084,660	5,938,353	3,056,769	45,047	32,446	12,045
	Distribution OH Line Transformers	100.00%	100.00%	0.00%	100.00%	65.37%	33.65%	0.50%	0.36%	0.13%

Recap Schedules: G-4, G-3

ARIZONA PUBLIC SERVICE COMPANY
Cost of Service Study
Development of Allocation Factors
Adjusted Test Year Ending December 31, 2002

Factor	Definition and Application of Allocation Factor	Total Company	Total ACC Jurisdiction	All Other	Total Retail	Residential	General Service	Irrigation	Street Lighting	Dusk to Dawn
16. DEMDIST7	Individual Maximum Demand @ Secondary TXF Level w/losses (KW)	9,039,623	9,039,623	0	9,039,623	5,938,353	3,056,779	0	32,446	12,045
	Distribution UG Line Transformers	100.00%	100.00%	0.00%	100.00%	65.69%	33.82%	0.00%	0.36%	0.13%
17. CUSTOH1	Weighted Customer Costs for Distribution Services ($)	448,413	448,413	0	448,413	404,336	43,430	647	0	0
	Distribution OH Services	100.00%	100.00%	0.00%	100.00%	90.17%	9.69%	0.14%	0.00%	0.00%
18. CUSTUG1	Weighted Customer Costs for Distribution Services ($)	456,363	456,363	0	456,363	415,485	40,878	0	0	0
	Distribution UG Services	100.00%	100.00%	0.00%	100.00%	91.04%	8.96%	0.00%	0.00%	0.00%
19. DEMDIST10	NCP Demand @ Primary Line Level w/losses (KW)	5,934,767	5,934,767	0	5,934,767	3,257,955	2,596,964	35,191	32,567	12,090
	Distribution Rents	100.00%	100.00%	0.00%	100.00%	54.90%	43.76%	0.59%	0.55%	0.20%
20. ENERGY1	Customer Class Energy @ Generation (MWH)	25,161,766	24,795,184	366,582	24,795,184	11,215,488	13,391,465	33,737	112,701	41,793
	Production - Energy	100.00%	98.54%	1.46%	98.54%	44.57%	53.22%	0.13%	0.45%	0.17%
21. ENERGY2	Customer Class Energy @ Generation (MWH)	25,161,766	24,795,184	366,582	24,795,184	11,215,488	13,391,465	33,737	112,701	41,793
	Production - Energy (Fuel and Purchase Power)	100.00%	98.54%	1.46%	98.54%	44.57%	53.22%	0.13%	0.45%	0.17%
22. ENERGY4	Customer Class Energy @ Generation (MWH)	25,161,766	24,795,184	366,582	24,795,184	11,215,488	13,391,465	33,737	112,701	41,793
	Production - Energy - Ancillary Service - Must Run	100.00%	98.54%	1.46%	98.54%	44.57%	53.22%	0.13%	0.45%	0.17%
23. CUST370	Weighted Costs for Distribution Meters ($)	1,132,676	1,121,607	11,069	1,121,607	819,821	298,900	2,886	0	0
	Distribution Meters	100.00%	99.02%	0.98%	99.02%	72.38%	26.39%	0.25%	0.00%	0.00%
24. CUST371	Dusk to Dawn Customer Class Specific	1	1	0	1	0	0	0	0	1
	Dusk to Dawn	100.00%	100.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	100.00%
25. CUST373	Street Lighting Customer Class Specific	1	1	0	1	0	0	0	1	0
	Street Lighting	100.00%	100.00%	0.00%	100.00%	0.00%	0.00%	0.00%	100.00%	0.00%
26. CUSTNUM	Number of Customer Accounts	930,373	929,002	1,371	929,002	819,821	100,134	364	749	7,934
	Customer Accounts	100.00%	99.85%	0.15%	99.85%	88.12%	10.76%	0.04%	0.08%	0.85%
27. CUST910	Number of Customer Accounts	929,002	929,002	0	929,002	819,821	100,134	364	749	7,934
	Customer Service and Information	100.00%	100.00%	0.00%	100.00%	88.25%	10.78%	0.04%	0.08%	0.85%
28. CUST916	Number of Customer Accounts	930,373	929,002	1,371	929,002	819,821	100,134	364	749	7,934
	Sales Expense	100.00%	99.85%	0.15%	99.85%	88.12%	10.76%	0.04%	0.08%	0.85%
29. DEMREGAST	4-CP Demand @ Generation (KW)	5,111,775	5,102,910	8,865	5,102,910	2,642,653	2,451,981	8,276	0	0
	Regulatory Asset - Demand Related	100.00%	99.83%	0.17%	99.83%	51.70%	47.97%	0.16%	0.00%	0.00%
30. ERGREGAST	Customer Class Energy @ Generation (MWH)	25,161,766	24,795,184	366,582	24,795,184	11,215,488	13,391,465	33,737	112,701	41,793
	Regulatory Asset - Energy Related	100.00%	98.54%	1.46%	98.54%	44.57%	53.22%	0.13%	0.45%	0.17%
31. ERGSYSBEN	Customer Class Energy @ Generation (MWH)	25,161,766	24,795,184	366,582	24,795,184	11,215,488	13,391,465	33,737	112,701	41,793
	System Benefits - Energy Related	100.00%	98.54%	1.46%	98.54%	44.57%	53.22%	0.13%	0.45%	0.17%

Recap Schedules: G-4, G-3

ARIZONA PUBLIC SERVICE COMPANY
Cost of Service Study
Development of Allocation Factors
Adjusted Test Year Ending December 31, 2002

Factor	Definition and Application of Allocation Factor	General Service	Small General Service	Medium General Service	Large General Service	Extra-Large General Service	Residential	Residential E-10	Residential E-12	Residential EC-1	Residential ET-1	Residential ECT-1
1. DEMPROD1	4-CP Demand @ Generation (KW)	2,451,981	828,460	994,764	285,615	343,142	2,642,653	232,966	766,305	141,521	1,240,307	261,554
	Production Demand	47.97%	16.21%	19.46%	5.59%	6.71%	51.70%	4.56%	14.99%	2.77%	24.26%	5.12%
2. DEMPROD2	4-CP Demand @ Generation (KW)	2,451,981	828,460	994,764	285,615	343,142	2,642,653	232,966	766,305	141,521	1,240,307	261,554
	Production - Ancillary Service - Regulation	47.97%	16.21%	19.46%	5.59%	6.71%	51.70%	4.56%	14.99%	2.77%	24.26%	5.12%
3. DEMPROD3	4-CP Demand @ Generation (KW)	2,451,981	828,460	994,764	285,615	343,142	2,642,653	232,966	766,305	141,521	1,240,307	261,554
	Production - Ancillary Service - Spinning Reserve	47.97%	16.21%	19.46%	5.59%	6.71%	51.70%	4.56%	14.99%	2.77%	24.26%	5.12%
4. DEMPROD4	4-CP Demand @ Generation (KW)	2,451,981	828,460	994,764	285,615	343,142	2,642,653	232,966	766,305	141,521	1,240,307	261,554
	Production - Ancillary Service - Ready Reserve	47.97%	16.21%	19.46%	5.59%	6.71%	51.70%	4.56%	14.99%	2.77%	24.26%	5.12%
5. DEMPROD6	4-CP Demand @ Generation (KW)	2,451,981	828,460	994,764	285,615	343,142	2,642,653	232,966	766,305	141,521	1,240,307	261,554
	Production - Ancillary Service - Scheduling & Dispatch	47.97%	16.21%	19.46%	5.59%	6.71%	51.70%	4.56%	14.99%	2.77%	24.26%	5.12%
6. DEMPROD7	4-CP Demand @ Generation (KW)	2,451,981	828,460	994,764	285,615	343,142	2,642,653	232,966	766,305	141,521	1,240,307	261,554
	Production - Ancillary Service - Must Run	47.97%	16.21%	19.46%	5.59%	6.71%	51.70%	4.56%	14.99%	2.77%	24.26%	5.12%
7. DEMTRAN1	4-CP Demand @ Generation including Wheeling (KW)	2,451,981	828,460	994,764	285,615	343,142	2,642,653	232,966	766,305	141,521	1,240,307	261,554
	Transmission Substation	38.04%	12.85%	15.43%	4.43%	5.32%	41.00%	3.61%	11.89%	2.20%	19.24%	4.06%
8. DEMTRAN2	4-CP Demand @ Generation including Wheeling (KW)	2,451,981	828,460	994,764	285,615	343,142	2,642,653	232,966	766,305	141,521	1,240,307	261,554
	Transmission Lines	38.04%	12.85%	15.43%	4.43%	5.32%	41.00%	3.61%	11.89%	2.20%	19.24%	4.06%
9. DEMTRAN4	Transmission - SCE 500 KV Line	0	0	0	0	0	0	0	0	0	0	0
	SCE Specific	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
10. DEMDIST1	NCP Demand @ Substation Level w/losses (KW)	2,776,499	970,264	1,184,158	283,088	338,989	3,323,537	306,035	965,170	155,972	1,550,013	346,347
	Distribution Substation	44.92%	15.70%	19.16%	4.58%	5.48%	53.77%	4.95%	15.61%	2.52%	25.08%	5.60%
11. DEMDIST2	NCP Demand @ Primary Line Level w/losses (KW)	2,596,964	950,468	1,157,321	270,617	218,558	3,257,955	299,996	946,125	152,894	1,519,427	339,513
	Distribution OH Primary Lines	43.76%	16.02%	19.50%	4.56%	3.68%	54.90%	5.05%	15.94%	2.58%	25.60%	5.72%
12. DEMDIST3	Individual Maximum Demand @ Secondary Line Level w/losses (KW)	761,528	761,528	0	0	0	3,527,660	328,650	1,249,580	137,693	1,519,087	292,650
	Distribution OH Secondary Lines	17.58%	17.58%	0.00%	0.00%	0.00%	81.44%	7.59%	28.85%	3.18%	35.07%	6.76%
13. DEMDIST4	NCP Demand @ Primary Line Level w/losses (KW)	2,596,964	950,468	1,157,321	270,617	218,558	3,257,955	299,996	946,125	152,894	1,519,427	339,513
	Distribution UG Primary Lines	44.02%	16.11%	19.62%	4.59%	3.70%	55.22%	5.09%	16.04%	2.59%	25.75%	5.75%
14. DEMDIST5	Individual Maximum Demand @ Secondary Line Level w/losses (KW)	761,528	761,528	0	0	0	3,527,660	328,650	1,249,580	137,693	1,519,087	292,650
	Distribution UG Secondary Lines	17.58%	17.58%	0.00%	0.00%	0.00%	81.44%	7.59%	28.85%	3.18%	35.07%	6.76%
15. DEMDIST6	Individual Maximum Demand @ Secondary TXF Level w/losses (KW)	3,056,769	1,300,052	1,363,985	257,322	135,410	5,938,353	553,239	2,103,504	231,787	2,557,185	492,638
	Distribution OH Line Transformers	33.65%	14.31%	15.01%	2.83%	1.49%	65.37%	6.09%	23.15%	2.55%	28.15%	5.42%

ARIZONA PUBLIC SERVICE COMPANY
Cost of Service Study
Development of Allocation Factors
Adjusted Test Year Ending December 31, 2002

Factor	Definition and Application of Allocation Factor	General Service	Small General Service	Medium General Service	Large General Service	Extra-Large General Service	Residential	Residential E-10	Residential E-12	Residential EC-1	Residential ET-1	Residential ECT-1
16. DEMDIST7	Individual Maximum Demand @ Secondary TXF Level w/losses (KW)	3,056,779	1,300,052	1,363,985	257,332	135,410	5,938,353	553,239	2,103,504	231,787	2,557,185	492,638
	Distribution UG Line Transformers	33.82%	14.38%	15.09%	2.85%	1.50%	65.69%	6.12%	23.27%	2.56%	28.29%	5.45%
17. CUSTOH1	Weighted Customer Costs for Distribution Services ($)	43,430	39,828	3,602	0	0	819,821	93,834	381,583	24,806	276,670	42,928
	Distribution OH Services	9.69%	8.88%	0.80%	0.00%	0.00%	182.83%	20.93%	85.10%	5.53%	61.70%	9.57%
18. CUSTUG1	Weighted Customer Costs for Distribution Services ($)	40,878	33,450	4,064	2,828	536	819,821	93,834	381,583	24,806	276,670	42,928
	Distribution UG Services	8.96%	7.33%	0.89%	0.62%	0.12%	179.64%	20.56%	83.61%	5.44%	60.62%	9.41%
19. DEMDIST10	NCP Demand @ Primary Line Level w/losses (KW)	2,596,964	950,468	1,157,321	270,617	218,558	3,257,955	299,996	946,125	152,894	1,519,427	339,513
	Distribution Rents	43.76%	16.02%	19.50%	4.56%	3.68%	54.90%	5.05%	15.94%	2.58%	25.60%	5.72%
20. ENERGY1	Customer Class Energy @ Generation (MWH)	13,391,465	3,766,696	5,288,514	1,754,953	2,581,302	11,215,488	1,020,291	3,356,182	635,131	4,917,386	1,286,498
	Production - Energy	53.22%	14.97%	21.02%	6.97%	10.26%	44.57%	4.05%	13.34%	2.52%	19.54%	5.11%
21. ENERGY2	Customer Class Energy @ Generation (MWH)	13,391,465	3,766,696	5,288,514	1,754,953	2,581,302	11,215,488	1,020,291	3,356,182	635,131	4,917,386	1,286,498
	Production - Energy (Fuel and Purchase Power)	53.22%	14.97%	21.02%	6.97%	10.26%	44.57%	4.05%	13.34%	2.52%	19.54%	5.11%
22. ENERGY4	Customer Class Energy @ Generation (MWH)	13,391,465	3,766,696	5,288,514	1,754,953	2,581,302	11,215,488	1,020,291	3,356,182	635,131	4,917,386	1,286,498
	Production - Energy - Ancillary Service - Must Run	53.22%	14.97%	21.02%	6.97%	10.26%	44.57%	4.05%	13.34%	2.52%	19.54%	5.11%
23. CUST370	Weighted Costs for Distribution Meters ($)	298,900	259,684	32,608	3,818	2,790	560,930	42,736	173,790	24,806	276,670	42,928
	Distribution Meters	26.39%	22.93%	2.88%	0.34%	0.25%	49.52%	3.77%	15.34%	2.19%	24.43%	3.79%
24. CUST371	Dusk to Dawn Customer Class Specific	0	0	0	0	0	0	0	0	0	0	0
	Dusk to Dawn	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
25. CUST373	Street Lighting Customer Class Specific	0	0	0	0	0	0	0	0	0	0	0
	Street Lighting	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
26. CUSTNUM	Number of Customer Accounts	100,134	95,717	4,112	244	61	819,821	93,834	381,583	24,806	276,670	42,928
	Customer Accounts	10.76%	10.29%	0.44%	0.03%	0.01%	88.12%	10.09%	41.01%	2.67%	29.74%	4.61%
27. CUST910	Number of Customer Accounts	100,134	95,717	4,112	244	61	819,821	93,834	381,583	24,806	276,670	42,928
	Customer Service and Information	10.78%	10.30%	0.44%	0.03%	0.01%	88.25%	10.10%	41.07%	2.67%	29.78%	4.62%
28. CUST916	Number of Customer Accounts	100,134	95,717	4,112	244	61	819,821	93,834	381,583	24,806	276,670	42,928
	Sales Expense	10.76%	10.29%	0.44%	0.03%	0.01%	88.12%	10.09%	41.01%	2.67%	29.74%	4.61%
29. DEMREGAST	4-CP Demand @ Generation (KW)	2,451,981	828,460	994,764	285,615	343,142	2,642,653	232,966	766,305	141,521	1,240,307	261,554
	Regulatory Asset - Demand Related	47.97%	16.21%	19.46%	5.59%	6.71%	51.70%	4.56%	14.99%	2.77%	24.26%	5.12%
30. ERGREGAST	Customer Class Energy @ Generation (MWH)	13,391,465	3,766,696	5,288,514	1,754,953	2,581,302	11,215,488	1,020,291	3,356,182	635,131	4,917,386	1,286,498
	Regulatory Asset - Energy Related	53.22%	14.97%	21.02%	6.97%	10.26%	44.57%	4.05%	13.34%	2.52%	19.54%	5.11%
31. ERGSYSBEN	Customer Class Energy @ Generation (MWH)	13,391,465	3,766,696	5,288,514	1,754,953	2,581,302	11,215,488	1,020,291	3,356,182	635,131	4,917,386	1,286,498
	System Benefits - Energy Related	53.22%	14.97%	21.02%	6.97%	10.26%	44.57%	4.05%	13.34%	2.52%	19.54%	5.11%

Recap Schedules: G-4, G-3

H-1

ARIZONA PUBLIC SERVICE COMPANY
SUMMARY OF BASE REVENUES BY CUSTOMER CLASSIFICATION
PRESENT AND PROPOSED RATES
TEST YEAR ENDING DECEMBER 31, 2002, ADJUSTED

		Base Revenues in the Test Year (a)		Proposed Increase (b)				
		(A)	(B)	(C)	(D)	(E)	(F)	
Line No.	Customer Classification	Present Rates [1] ($000)	Proposed Rates [3][4] ($000)	Amount ($000) (B) - (A)	% (C) / (A)	Proposed CRCC [2] ($000)	Proposed Increase with CRCC % [(E) + (C)] / (A)	Line No.
1	Residential	889,898	972,747	82,849	9.31%	3,737	9.73%	1
2	General Service	883,595	965,868	82,273	9.31%	4,485	9.82%	2
3	Irrigation	2,099	2,295	196	9.34%	11	9.86%	3
4	Outdoor Lighting	10,794	11,799	1,005	9.31%	36	9.64%	4
5	Dusk to Dawn Lighting Service	5,198	5,682	484	9.31%	14	9.58%	5
6	Total Sales to Ultimate Retail Customers	1,791,584	1,958,391	166,807	9.31%	8,283	9.77%	6

(a) Supporting Schedules: H-2

(b) Recap Schedules: A-1

NOTES TO SCHEDULE:

1) Base Revenues under Present Rates reflect adjusted test year revenues including applicable proforma adjustments such as rate decreases and removal of franchise fees from base rates.
2) The CRCC is the Competition Rules Compliance Charge as proposed in ACC Docket No. E-01345A-02-0403. The proposed CRCC will be in place for five years.
3) Please note that the Proposed Increase shown on this schedule does not directly match the Proposed Increase on Schedule H-2 for the General Service and Irrigation classes. Schedule H-2 assumes customer migration from Irrigation to General Service due to more favorable rates. The total proposed revenue for both Irrigation and General Service classes on these two schedules match.
4) The total proposed revenue for both Outdoor Lighting and Dusk to Dawn classes on this schedule matches the total proposed revenue for both classes on Schedule H-2.

H-2

ARIZONA PUBLIC SERVICE COMPANY
ANALYSIS OF BASE REVENUES BY DETAILED CLASS
TEST YEAR ENDING DECEMBER 31, 2002, ADJUSTED

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	
						Proposed Rates (a)			Proposed Increase		
Line No.	Customer Classification and Current Rate Designation	Average Number of Customers	MWh Sales	Average Annual kWh Usage per Customer	Base Revenues under Present Rates ($000)	Proposed Rate Designation	Base Revenues ($000)	CRCC ($000)	Amount ($000)	%	Line No.
				[(C) x 1000] / (B)				(C) x 0.000353	[(G) + (H)] - (E)	(I) / (E)	
1	Residential										1
2	E-10	94,544	904,512	9,567	78,922	E-10 Step 1	88,530	319	9,927	12.58%	2
3						E-12	1,586		1,586	1.79%	3
4	E-12	375,020	3,186,522	8,497	301,433	E-12	320,161	1,125	19,853	6.59%	4
5	EC-1	24,951	568,530	22,786	42,753	ECT-1R	49,160	201	6,608	15.46%	5
6	ET-1	277,112	4,721,930	17,040	381,113	ET-1	422,085	1,667	42,639	11.19%	6
7	ECT-1R	43,117	1,205,109	27,950	85,677	ECT-1R	91,225	425	5,973	6.97%	7
8	DA-R1	-	-	-	-	DA-R1	Rate Cancelled				8
9	Total Residential	814,744	10,586,603	12,994	889,898		972,747	3,737	86,586	9.73%	9
10	General Service										10
11	E-20	339	36,907	108,870	3,009	E-20	3,430	13	434	14.42%	11
12	E-21	20	1,099	54,950	83	E-32TOU	101	-	18	21.69%	12
13	E-21	9	641	71,222	54	E-32	67	-	13	24.07%	13
14	E-22	5	4,899	979,800	362	E-32TOU	352	2	(8)	-2.21%	14
15	E-22	9	2,307	256,333	202	E-32	295	1	94	46.53%	15
16	E-23	97	31,308	322,763	2,245	E-32TOU	2,319	11	85	3.79%	16
17	E-23	51	14,655	287,353	1,045	E-32	1,046	5	6	0.57%	17
18	E-24	29	118,278	4,078,552	6,747	E-32TOU	7,777	42	1,072	15.89%	18
19	E-24	19	59,661	3,140,053	3,448	E-32	3,667	21	240	6.96%	19
20	E-30	4,023	6,721	1,671	973	E-30	1,065	2	94	9.66%	20
21	E-32, E-32R, E-53, E-54	94,180	9,551,113	101,413	716,195	E-32, E-32R, E-53, E-54	782,311	3,372	69,488	9.70%	21
22	E-34	41	1,232,771	30,067,585	66,458	E-34	72,904	435	6,881	10.35%	22
23	E-35	19	1,217,184	64,062,316	57,357	E-35	62,926	430	5,999	10.46%	23
24	E-38, E-38-8T, E-38TOW	88	7,320	83,182	471	E-221, E-221-8T, E-221TOW	541	3	73	15.50%	24
25	E-40	2	1	500	2	E-40	2	-		9.33%	25
26	E-51	4	18,135	4,533,750	1,158	E-51	1,282	6	130	11.23%	26
27	E-221, E-221-8T, E-221TOW	1,272	302,679	237,955	20,423	E-221, E-221-8T, E-221TOW	22,322	107	2,006	9.82%	27
28	Contracts	3	100,373	33,457,667	3,363	Contracts	3,485	35	157	4.67%	28
29	DA-GS1,10,11,12,13	-	-	-	-	DA-GS1,10,11,12,13		- - - Rates Cancelled - - -			29
30	Total General Service	100,210	12,706,052	126,794	883,595		965,892	4,485	86,782	9.82%	30

Supporting Schedules:

Recap Schedules: (a) H-1

ARIZONA PUBLIC SERVICE COMPANY
ANALYSIS OF BASE REVENUES BY DETAILED CLASS
TEST YEAR ENDING DECEMBER 31, 2002, ADJUSTED

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	
						Proposed Rates (a)			Proposed Increase		
Line No.	Customer Classification and Current Rate Designation	Average Number of Customers	MWh Sales	Average Annual kWh Usage per Customer	Base Revenues under Present Rates ($000)	Proposed Rate Designation	Base Revenues ($000)	CRCC ($000)	Amount ($000)	%	Line No.
				[(C) x 1000] / (B)				(C) x 0.000353	[(G) + (H)] - (E)	(I) / (E)	
31	Irrigation										31
32	E-32	135	11,308	83,763	822	E-221	805	4	(13)	-1.58%	32
33	E-38, E-38-8T, E-38TOW	69	7,786	112,841	476	E-221, E-221-8T, E-221TOW	569	3	96	20.17%	33
34	E-221, E-221-8T, E-221TOW	128	11,747	91,773	801	E-221, E-221-8T, E-221TOW	897	4	100	12.48%	34
35	Total Irrigation	332	30,841	92,895	2,099		2,271	11	183	8.72%	35
36	Outdoor Lighting										36
37	E-32	4	59	14,750	6	E-32	6	-	0	5.66%	37
38	E-58	517	21,744	42,058	4,552	E-58	4,976	8	432	9.49%	38
39	E-59	177	64,993	367,192	5,509	E-59	6,022	23	536	9.73%	39
40	E-67	231	4,579	19,823	156	E-67	186	2	32	20.51%	40
41	Contracts	24	9,366	390,250	571	Contracts	624	3	56	9.81%	41
42	Total Outdoor Lighting	953	100,741	105,709	10,794		11,814	36	1,056	9.79%	42
43	Dusk to Dawn Lighting Service	See Note 4)	38,475	See Note 4)	5,198		5,667	14	483	9.29%	43
44	Total Sales to Ultimate Retail Customers	916,239	23,462,712	25,608	1,791,584		1,958,391	8,283	175,090	9.77%	44

Supporting Schedules:

Recap Schedules: (a) H-1

NOTES TO SCHEDULE:
1) Base Revenues under Present Rates reflect adjusted test year revenues including applicable proforma adjustments such as rate decreases and removal of franchise fees from base rates.
2) The CRCC is the Competition Rules Compliance Charge as proposed in ACC Docket No. E-01345A-02-0403. The proposed CRCC will be in place for five years.
3) The following rate schedules will not change: Solar Rate Schedules, EPR Rate Schedules, Share the Light Rate Schedules, Rate Schedules E-36, E-52, and E-55, and Rate Schedules E-3 and E-4.
4) Dusk to Dawn Lighting customers are included in residential and general service counts as this service is included on each customer's primary billing.
5) Reclassification of revenue in Irrigation and General Service classes results in class revenue shifts. The total proposed revenue for both Irrigation and General Service classes on this schedule matches the total proposed revenue for both classes on Schedule H-1.
6) The total proposed revenue for both Outdoor Lighting and Dusk to Dawn classes on this schedule matches the total proposed revenue for both classes on Schedule H-1.

H-3

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

TEST YEAR ENDING DECEMBER 31, 2002

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
				Present Rates			Proposed Rates			Proposed Rates with				
Line No.	Rate Schedule	Description	Season	Block	Rates		Block	Rates		Franchise Fees (H) x 0.0144		Change (J) - (E)		Line No.
1	E-3	Residential Energy		NO CHANGE			NO CHANGE							1
2		Support Program												2
3	E-4	Residential Energy		NO CHANGE			NO CHANGE							3
4		Support Program												4
5	E-10	Residential Service	Summer	Basic Service Charge	$ 7.50	/mo						N/A		5
6	STEP 1						Basic Service Charge	$ 0.271	/day	$ 0.275	/day	N/A		6
7				First 400 kWh	0.06682	/kWh	First 400 kWh	0.07332	/kWh	0.07438	/kWh	0.00756	/kWh	7
8				Next 400 kWh	0.09189	/kWh	Next 400 kWh	0.10083	/kWh	0.10228	/kWh	0.01039	/kWh	8
9				All additional kWh	0.09440	/kWh	All additional kWh	0.10358	/kWh	0.10507	/kWh	0.01067	/kWh	9
10			Winter	Basic Service Charge	$ 7.50	/mo						N/A		10
11							Basic Service Charge	$ 0.271	/day	$ 0.275	/day	N/A		11
12				All kWh	0.07609	/kWh	All kWh	0.08349	/kWh	0.08469	/kWh	0.00860	/kWh	12
13			Sum & Win	Minimum	$ 7.50	/mo						N/A		13
14	E-10	Residential Service					Basic Service Charge	$ 0.411	/day	$ 0.417	/day	N/A		14
15	STEP 2						First 400 kWh	0.08640	/kWh	0.08764	/kWh	N/A		15
16	(Move to						Next 400 kWh	0.08640	/kWh	0.08764	/kWh	N/A		16
17	E-12)						All additional kWh	0.11006	/kWh	0.11164	/kWh	N/A		17
18							Basic Service Charge	$ 0.411	/day	$ 0.417	/day	N/A		18
19							All kWh	0.07004	/kWh	0.07105	/kWh	N/A		19
20	E-12	Residential Service	Summer	Basic Service Charge	$ 7.50	/mo						N/A		20
21							Basic Service Charge	$ 0.411	/day	$ 0.417	/day	N/A		21
22				First 400 kWh	0.07376	/kWh	First 400 kWh	0.08640	/kWh	0.08764	/kWh	0.01388	/kWh	22
23				Next 400 kWh	0.10281	/kWh	Next 400 kWh	0.08640	/kWh	0.08764	/kWh	(0.01517)	/kWh	23
24				All additional kWh	0.11991	/kWh	All additional kWh	0.11006	/kWh	0.11164	/kWh	(0.00827)	/kWh	24
25			Winter	Basic Service Charge	$ 7.50	/mo						N/A		25
26							Basic Service Charge	$ 0.411	/day	$ 0.417	/day	N/A		26
27				All kWh	0.07394	/kWh	All kWh	0.07004	/kWh	0.07105	/kWh	(0.00289)	/kWh	27
28			Sum & Win	Minimum	$ 7.50	/mo						N/A		28

Supporting Schedules:

NOTES TO SCHEDULE:
1) Franchise fees are shown as an average percentage of total revenue requirement (Present Rates include franchise fee).
2) Proposed rates are shown on a bundled basis. See tariff sheets for unbundled components.
3) Present rates are those rates effective 7/01/2003.

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

TEST YEAR ENDING DECEMBER 31, 2002

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
				Present Rates			Proposed Rates			Proposed Rates with				
Line No.	Rate Schedule	Description	Season	Block	Rates		Block	Rates		Franchise Fees (H) x 0.0144		Change (J) - (E)		Line No.
29	EC-1	Residential Service	Summer	Basic Service Charge	$ 10.00	/mo						N/A		29
30	(Move to	With Demand Charge					Basic Service Charge	$ 0.493	/day	$ 0.500	/day	N/A		30
31	ECT-1R)			All kW	9.84	/kW	All On-Peak kW	11.00	/kW	11.16	/kW	1.32	/kW	31
32				All kWh (demand cap)	0.07872	/kWh						N/A		32
33				All kWh	0.03827	/kWh						N/A		33
34							All On-Peak kWh	0.05204	/kWh	0.05279	/kWh	N/A		34
35							All Off-Peak kWh	0.03202	/kWh	0.03248	/kWh	N/A		35
36			Winter	Basic Service Charge	$ 10.00	/mo						N/A		36
37							Basic Service Charge	$ 0.493	/day	$ 0.500	/day	N/A		37
38				All kW	7.06	/kW	All kW	8.00	/kW	8.12	/kW	1.06	/kW	38
39				All kWh (demand cap)	0.05648	/kWh						N/A		39
40				All kWh	0.03176	/kWh						N/A		40
41							All kWh	0.03025	/kWh	0.03069	/kWh	N/A		41
42			Sum & Win	Minimum	$ 10.00	/mo						N/A		42
43	ET-1	Residential Service	Summer	Basic Service Charge	$ 15.00	/mo						N/A		43
44		Time of Use					Basic Service Charge	$ 0.485	/day	$ 0.492	/day	N/A		44
45				All On-Peak kWh	0.12815	/kWh	All On-Peak kWh	0.12151	/kWh	0.12326	/kWh	(0.00489)	/kWh	45
46				All Off-Peak kWh	0.04129	/kWh	All Off-Peak kWh	0.06121	/kWh	0.06209	/kWh	0.02080	/kWh	46
47			Winter	Basic Service Charge	$ 15.00	/mo						N/A		47
48							Basic Service Charge	$ 0.485	/day	$ 0.492	/day	N/A		48
49				All On-Peak kWh	0.10656	/kWh						N/A		49
50				All Off-Peak kWh	0.04129	/kWh						N/A		50
51							All kWh	0.06784	/kWh	0.06882	/kWh	N/A		51
52			Sum & Win	Minimum	$ 15.00	/mo						N/A		52
53	ECT-1R	Residential Service	Summer	Basic Service Charge	$ 15.00	/mo						N/A		53
54		Time of Use with					Basic Service Charge	$ 0.493	/day	$ 0.500	/day	N/A		54
55		Demand Charge		All On-Peak kW	11.33	/kW	All On-Peak kW	11.00	/kW	11.16	/kW	(0.17)	/kW	55
56				All kWh (demand cap)	0.08912	/kWh						N/A		56
57				All On-Peak kWh	0.04572	/kWh	All On-Peak kWh	0.05204	/kWh	0.05279	/kWh	0.00707	/kWh	57
58				All Off-Peak kWh	0.02543	/kWh	All Off-Peak kWh	0.03202	/kWh	0.03248	/kWh	0.00705	/kWh	58

Supporting Schedules:

NOTES TO SCHEDULE:
1) Franchise fees are shown as an average percentage of total revenue requirement (Present Rates include franchise fee).
2) Proposed rates are shown on a bundled basis. See tariff sheets for unbundled components.
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ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

TEST YEAR ENDING DECEMBER 31, 2002

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
				Present Rates			Proposed Rates			Proposed Rates with Franchise Fees				
Line No.	Rate Schedule	Description	Season	Block	Rates		Block	Rates		(H) x 0.0144		Change (J) - (E)		Line No.
59	ECT-1R		Winter	Basic Service Charge	$ 15.00	/mo						N/A		59
60	(cont)						Basic Service Charge	$ 0.493	/day	$ 0.500	/day	N/A		60
61				All On-Peak kW	8.11	/kW	All kW	8.00	/kW	8.12	/kW	0.01	/kW	61
62				All kWh (demand cap)	0.06488	/kWh						N/A		62
63				All On-Peak kWh	0.03618	/kWh						N/A		63
64				All Off-Peak kWh	0.02543	/kWh						N/A		64
65							All kWh	0.03025	/kWh	0.03069	/kWh	N/A		65
66			Sum & Win	Minimum	$ 15.00	/mo						N/A		66
67	E-20	General Service	Summer	Basic Service Charge	$ 27.00	/mo						N/A		67
68		Time of Use for					BSC: Self-Contained Meters	$ 0.600	/day	$ 0.609	/day	N/A		68
69		Religious Houses of					BSC: Instrument-rated Meters	$ 1.134	/day	$ 1.150	/day	N/A		69
70		Worship		All On-Peak kW	1.93	/kW	All On-Peak kW	2.00	/kW	2.03	/kW	0.10	/kW	70
71				Excess Off-Peak kW	0.97	/kW	Excess Off-Peak kW	1.00	/kW	1.01	/kW	0.04	/kW	71
72				All On-Peak kWh	0.11605	/kWh	All On-Peak kWh	0.10122	/kWh	0.10268	/kWh	(0.01337)	/kWh	72
73				All Off-Peak kWh	0.05605	/kWh	All Off-Peak kWh	0.06873	/kWh	0.06972	/kWh	0.01367	/kWh	73
74			Winter	Basic Service Charge	$ 27.00	/mo						N/A		74
75							BSC: Self-Contained Meters	$ 0.600	/day	$ 0.609	/day	N/A		75
76							BSC: Instrument-rated Meters	$ 1.134	/day	$ 1.150	/day	N/A		76
77				All On-Peak kW	1.74	/kW	All On-Peak kW	2.00	/kW	2.03	/kW	0.29	/kW	77
78				Excess Off-Peak kW	0.87	/kW	Excess Off-Peak kW	1.00	/kW	1.01	/kW	0.14	/kW	78
79				All On-Peak kWh	0.10205	/kWh						N/A		79
80				All Off-Peak kWh	0.05024	/kWh						N/A		80
81							All kWh	0.07638	/kWh	0.07748	/kWh	N/A		81
82			Sum & Win	Minimum - Basic Service Charge	$ 20.00	/mo						N/A		82
83							Minimum: Self-Contained Meters	$ 0.600	/day	$ 0.609	/day	N/A		83
84							Minimum: Instrument-rated Meters	$ 1.134	/day	$ 1.150	/day	N/A		84
85							Minimum: Primary Meters	$ 2.926	/day	$ 2.968	/day	N/A		85
86							Minimum: Transmission Meters	$ 22.422	/day	$ 22.745	/day	N/A		86
87				Minimum - Demand Charge	1.60	/kW	Minimum - Demand Charge	1.75	/kW	1.78	/kW	0.18	/kW	87

Supporting Schedules:

NOTES TO SCHEDULE:
1) Franchise fees are shown as an average percentage of total revenue requirement (Present Rates include franchise fee).
2) Proposed rates are shown on a bundled basis. See tariff sheets for unbundled components.
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ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

TEST YEAR ENDING DECEMBER 31, 2002

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
				Present Rates			Proposed Rates			Proposed Rates with Franchise Fees				
Line No.	Rate Schedule	Description	Season	Block	Rates		Block	Rates		(H) x 0.0144		Change (J) - (E)		Line No.
88	Experimental General Service		Summer				E-32TOU: 20 kW or less							88
89	Time-of-Use Rate Schedules						BSC: Self-Contained Meters	$ 0.600	/day	$ 0.609	/day	N/A		89
90	E-21, E-22, E-23, E-24						BSC: Instrument-rated Meters	1.134	/day	1.150	/day	N/A		90
91	are cancelled and are replaced by						BSC: Primary Meters	2.926	/day	2.968	/day	N/A		91
92	General Service Time-of-Use						All On-Peak kWh: Secondary	0.11375	/kWh	0.11539	/kWh	N/A		92
93	Rate Schedule E-32TOU						All Off-Peak kWh: Secondary	0.09375	/kWh	0.09510	/kWh	N/A		93
94							All On-Peak kWh: Primary	0.10653	/kWh	0.10806	/kWh			94
95							All Off-Peak kWh: Primary	0.08653	/kWh	0.08778	/kWh			95
96			Winter				BSC: Self-Contained Meters	$ 0.600	/day	$ 0.609	/day	N/A		96
97							BSC: Instrument-rated Meters	1.134	/day	1.134	/day	N/A		97
98							BSC: Primary Meters	2.926	/day	2.926	/day	N/A		98
99							All kWh: Secondary	0.09095	/kWh	0.09226	/kWh	N/A		99
100							All kWh: Primary	0.08373	/kWh	0.08494	/kWh			100
101			Summer				E-32TOU: Over 20 kW							101
102							BSC: Self-Contained Meters	$ 0.600	/day	$ 0.609	/day	N/A		102
103							BSC: Instrument-rated Meters	1.134	/day	1.134	/day	N/A		103
104							BSC: Primary Meters	2.926	/day	2.926	/day	N/A		104
105							BSC: Transmission Meters	22.422	/day	22.745	/day	N/A		105
106							First 500 On-Peak kW: Secondary	15.046	/kW	15.263	/kW	N/A		106
107							All additional On-Peak kW: Secondary	13.316	/kW	13.508	/kW	N/A		107
108							Residual Off-Peak kW: Secondary	6.783	/kW	6.881	/kW	N/A		108
109							First 500 On-Peak kW: Primary	13.456	/kW	13.650	/kW	N/A		109
110							All additional On-Peak kW: Primary	11.726	/kW	11.895	/kW	N/A		110
111							Residual Off-Peak kW: Primary	5.193	/kW	5.268	/kW	N/A		111
112							First 500 On-Peak kW: Trans.	10.446	/kW	10.596	/kW	N/A		112
113							All additional On-Peak kW: Trans.	8.716	/kW	8.842	/kW	N/A		113
114							Residual Off-Peak kW: Trans.	2.183	/kW	2.214	/kW	N/A		114
115							All On-Peak kWh	0.04855	/kWh	0.04925	/kWh	N/A		115
116							All Off-Peak kWh	0.03855	/kWh	0.03911	/kWh	N/A		116

Supporting Schedules:

NOTES TO SCHEDULE:
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ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

TEST YEAR ENDING DECEMBER 31, 2002

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
				Present Rates			Proposed Rates			Proposed Rates with Franchise Fees				
Line No.	Rate Schedule	Description	Season	Block	Rates		Block	Rates		(H) x 0.0144		Change (J) - (E)		Line No.
117	Experimental General Service		Winter				BSC: Self-Contained Meters	$ 0.600	/day	$ 0.609	/day	N/A		117
118	Time-of-Use Rate Schedules						BSC: Instrument-rated Meters	1.134	/day	1.150	/day	N/A		118
119	E-21, E-22, E-23, E-24						BSC: Primary Meters	2.926	/day	2.968	/day	N/A		119
120	are cancelled and are replaced by						BSC: Transmission Meters	22.422	/day	22.745	/day	N/A		120
121	General Service Time-of-Use						First 500 On-Peak kW: Secondary	15.046	/kW	15.263	/kW	N/A		121
122	Rate Schedule E-32TOU						All additional On-Peak kW: Secondary	13.316	/kW	13.508	/kW	N/A		122
123	(cont)						Residual Off-Peak kW: Secondary	6.783	/kW	6.881	/kW	N/A		123
124							First 500 On-Peak kW: Primary	13.456	/kW	13.650	/kW	N/A		124
125							All additional On-Peak kW: Primary	11.726	/kW	11.895	/kW	N/A		125
126							Residual Off-Peak kW: Primary	5.193	/kW	5.268	/kW	N/A		126
127							First 500 On-Peak kW: Trans.	10.446	/kW	10.596	/kW	N/A		127
128							All additional On-Peak kW: Trans.	8.716	/kW	8.842	/kW	N/A		128
129							Residual Off-Peak kW: Trans.	2.183	/kW	2.214	/kW	N/A		129
130							All kWh	0.03290	/kWh	0.03337	/kWh	N/A		130
131			Sum & Win				Minimum: Self-Contained Meters	$ 0.600	/day	$ 0.609	/day	N/A		131
132							Minimum: Instrument-rated Meters	1.134	/day	1.150	/day	N/A		132
133							Minimum: Primary Meters	2.926	/day	2.968	/day	N/A		133
134							Minimum: Transmission Meters	22.422	/day	22.745	/day	N/A		134
135							Minimum - Demand Charge	1.75	/kW	1.78	/kW	N/A		135
136	E-30	Extra Small General	Summer	Basic Service Charge	$ 6.25	/mo						N/A		136
137		Service Unmetered					Basic Service Charge	$ 0.286	/day	$ 0.290	/day	N/A		137
138				All kWh	0.10179	/kWh	All kWh	0.10091	/kWh	0.10236	/kWh	0.00057	/kWh	138
139			Winter	Basic Service Charge	$ 6.25	/mo						N/A		139
140							Basic Service Charge	$ 0.286	/day	$ 0.290	/day	N/A		140
141				All kWh	0.09168	/kWh	All kWh	0.09091	/kWh	0.09222	/kWh	0.00054	/kWh	141
142			Sum & Win	Minimum	$ 6.25	/mo						N/A		142

Supporting Schedules:

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ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

TEST YEAR ENDING DECEMBER 31, 2002

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
				Present Rates			Proposed Rates			Proposed Rates with Franchise Fees			
Line No.	Rate Schedule	Description	Season	Block	Rates		Block	Rates		(H) x 0.0144		Change (J) - (E)	Line No.
143							E-32: 20 kW or less						143
144	E-32	General Service	Summer	Basic Service Charge	$ 12.50	/mo						N/A	144
145							BSC: Self-Contained Meters	$ 0.575	/day	$ 0.583	/day	N/A	145
146							BSC: Instrument-rated Meters	1.134	/day	1.150	/day	N/A	146
147							BSC: Primary Meters	2.926	/day	2.968	/day	N/A	147
148				All kW over 5	1.70	/kW						N/A	148
149				First 2,500 kWh:	0.10201	/kWh						N/A	149
150				Next 100 kWh per kW over 5:	0.10201	/kWh						N/A	150
151				Next 42,000 kWh	0.06989	/kWh						N/A	151
152				All additional kWh	0.04403	/kWh						N/A	152
153							All kWh: Secondary	0.10095	/kWh	0.10240	/kWh	N/A	153
154							All kWh: Primary	0.09373	/kWh	0.09508	/kWh	N/A	154
155			Winter	Basic Service Charge	$ 12.50	/mo						N/A	155
156							BSC: Self-Contained Meters	$ 0.575	/day	$ 0.583	/day	N/A	156
157							BSC: Instrument-rated Meters	1.134	/day	1.150	/day	N/A	157
158							BSC: Primary Meters	2.926	/day	2.968	/day	N/A	158
159				All kW over 5	1.55	/kW						N/A	159
160				First 2,500 kWh:	0.09188	/kWh						N/A	160
161				Next 100 kWh per kW over 5:	0.09188	/kWh						N/A	161
162				Next 42,000 kWh	0.06276	/kWh						N/A	162
163				All additional kWh	0.03937	/kWh						N/A	163
164							All kWh: Secondary	0.09095	/kWh	0.09226	/kWh	N/A	164
165							All kWh: Primary	0.08373	/kWh	0.08494	/kWh	N/A	165
166			Sum & Win	Minimum - Basic Service Charge	$ 12.50	/mo						N/A	166
167				Minimum - Demand Charge	1.60	/kW						N/A	167

Supporting Schedules:

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ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

TEST YEAR ENDING DECEMBER 31, 2002

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
				Present Rates			Proposed Rates			Proposed Rates with				
Line No.	Rate Schedule	Description	Season	Block	Rates		Block	Rates		Franchise Fees (H) x 0.0144		Change (J) - (E)		Line No.
168							E-32: Over 20 kW							168
169	E-32	General Service	Summer	Basic Service Charge	$ 12.50	/mo						N/A		169
170	(cont)						BSC: Self-Contained Meters	$ 0.575	/day	$ 0.583	/day	N/A		170
171							BSC: Instrument-rated Meters	1.134	/day	1.150	/day	N/A		171
172							BSC: Primary Meters	2.926	/day	2.968	/day	N/A		172
173							BSC: Transmission Meters	22.422	/day	22.745	/day	N/A		173
174				All kW over 5	1.70	/kW						N/A		174
175							First 500 kW: Secondary	6.348	/kW	6.439	/kW	N/A		175
176							All additional kW: Secondary	4.618	/kW	4.684	/kW	N/A		176
177							First 500 kW: Primary	4.758	/kW	4.827	/kW	N/A		177
178							All additional kW: Primary	3.028	/kW	3.072	/kW	N/A		178
179							First 500 kW: Trans.	1.748	/kW	1.773	/kW	N/A		179
180							All additional kW: Trans.	0.018	/kW	0.018	/kW	N/A		180
181				First 2,500 kWh:	0.10201	/kWh						N/A		181
182				Next 100 kWh per kW over 5:	0.10201	/kWh						N/A		182
183				Next 42,000 kWh	0.06989	/kWh						N/A		183
184				All additional kWh	0.04403	/kWh						N/A		184
185							First 200 kWh per kW:	0.08518	/kWh	0.08641	/kWh	N/A		185
186							All additional kWh:	0.04290	/kWh	0.04352	/kWh	N/A		186
187			Winter	Basic Service Charge	$ 12.50	/mo						N/A		187
188							BSC: Self-Contained Meters	$ 0.575	/day	$ 0.583	/day	N/A		188
189							BSC: Instrument-rated Meters	1.134	/day	1.150	/day	N/A		189
190							BSC: Primary Meters	2.926	/day	2.968	/day	N/A		190
191							BSC: Transmission Meters	22.422	/day	22.745	/day	N/A		191
192				All kW over 5	1.55	/kW						N/A		192
193							First 500 kW: Secondary	6.348	/kW	6.439	/kW	N/A		193
194							All additional kW: Secondary	4.618	/kW	4.684	/kW	N/A		194
195							First 500 kW: Primary	4.758	/kW	4.827	/kW	N/A		195
196							All additional kW: Primary	3.028	/kW	3.072	/kW	N/A		196
197							First 500 kW: Trans.	1.748	/kW	1.773	/kW	N/A		197
198							All additional kW: Trans.	0.018	/kW	0.018	/kW	N/A		198
199				First 2,500 kWh:	0.09188	/kWh						N/A		199
200				Next 100 kWh per kW over 5:	0.09188	/kWh						N/A		200
201				Next 42,000 kWh	0.06276	/kWh						N/A		201
202				All additional kWh	0.03937	/kWh						N/A		202
203							First 200 kWh per kW:	0.07518	/kWh	0.07626	/kWh	N/A		203
204							All additional kWh:	0.03290	/kWh	0.03337	/kWh	N/A		204

Supporting Schedules:

NOTES TO SCHEDULE:
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ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

TEST YEAR ENDING DECEMBER 31, 2002

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
				Present Rates			Proposed Rates			Proposed Rates with				
Line No.	Rate Schedule	Description	Season	Block	Rates		Block	Rates		Franchise Fees (H) x 0.0144		Change (J) - (E)		Line No.
205	E-32		Sum & Win	Minimum - Basic Service Charge	$ 12.50	/mo						N/A		205
206	(cont)						Minimum: Self-Contained Meters	$ 0.575	/day	$ 0.583	/day	N/A		206
207							Minimum: Instrument-rated Meters	1.134	/day	1.150	/day	N/A		207
208							Minimum: Primary Meters	2.926	/day	2.968	/day	N/A		208
209							Minimum: Transmission Meters	22.422	/day	22.745	/day	N/A		209
210				Minimum - Demand Charge	1.60	/kW	Minimum - Demand Charge	1.75	/kW	1.78	/kW	0.18	/mo	210
211	E-32R	Partial Requirements		NO CHANGE			NO CHANGE							211
212		General Service												212
213	E-34	Extra Large General	Sum & Win	Basic Service Charge	$ 2,430.00	/mo						N/A		213
214		Service					BSC: Self-Contained Meters	$ 0.575	/day	$ 0.583	/day	N/A		214
215							BSC: Instrument-rated Meters	1.134	/day	1.150	/day	N/A		215
216							BSC: Primary Meters	2.926	/day	2.968	/day	N/A		216
217							BSC: Transmission Meters	22.422	/day	22.745	/day	N/A		217
218				All kW	10.61	/kW	All kW: Secondary	13.062	/kW	13.250	/kW	2.640	/kW	218
219							All kW: Primary	12.372	/kW	12.550	/kW	N/A		219
220							All kW: Trans.	8.882	/kW	9.010	/kW	N/A		220
221				All kWh	0.03126	/kWh	All kWh	0.03284	/kWh	0.03331	/kWh	0.00205	/kWh	221
222			Sum & Win	Minimum - Basic Service Charge	$ 2,430.00	/mo						N/A		222
223				Minimum - Demand Charge	10.61	/kW						N/A		223
224	E-35	Extra Large General	Sum & Win	Basic Service Charge	$ 2,450.00	/mo						N/A		224
225		Service Time of Use					BSC: Self-Contained Meters	$ 0.600	/day	$ 0.609	/day	N/A		225
226							BSC: Instrument-rated Meters	1.134	/day	1.150	/day	N/A		226
227							BSC: Primary Meters	2.926	/day	2.968	/day	N/A		227
228							BSC: Transmission Meters	22.422	/day	22.745	/day	N/A		228
229				All On-Peak kW	13.05	/kW	All On-Peak kW: Secondary	13.598	/kW	13.794	/kW	0.744	/kW	229
230				Excess Off-Peak Billing Demand	6.53	/kW	Excess Off-Peak kW: Secondary	6.717	/kW	6.814	/kW	0.284	/kW	230
231							All On-Peak kW: Primary	12.908	/kW	13.094	/kW	N/A		231
232							Excess Off-Peak kW: Primary	6.027	/kW	6.114	/kW	N/A		232
233							All On-Peak kW: Trans.	9.418	/kW	9.554	/kW	N/A		233
234							Excess Off-Peak kW: Trans.	2.537	/kW	2.574	/kW	N/A		234
235				All On-Peak kWh	0.03605	/kWh	All On-Peak kWh	0.03618	/kWh	0.03670	/kWh	0.00065	/kWh	235
236				All Off-Peak kWh	0.02105	/kWh	All Off-Peak kWh	0.02868	/kWh	0.02909	/kWh	0.00804	/kWh	236
237			Sum & Win	Minimum - Basic Service Charge	$ 2,450.00	/mo						N/A		237
238				Minimum - Demand Charge	13.05	/kW						N/A		238

Supporting Schedules:

NOTES TO SCHEDULE:
1) Franchise fees are shown as an average percentage of total revenue requirement (Present Rates include franchise fee).
2) Proposed rates are shown on a bundled basis. See tariff sheets for unbundled components.
3) Present rates are those rates effective 7/01/2003.

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

TEST YEAR ENDING DECEMBER 31, 2002

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
				Present Rates			Proposed Rates			Proposed Rates with Franchise Fees		Change		
Line No.	Rate Schedule	Description	Season	Block	Rates		Block	Rates		(H) x 0.0144		(J) - (E)		Line No.
239	E-36	Station Use Service		NO CHANGE			NO CHANGE							239
240	E-38	Agricultural		Rate Schedules E-38 and E-38-8T										240
241		Irrigation Service		are being cancelled. Customers will be moved to										241
242				E-221 and E-221-8T.										242
243	E-40	Agricultural Wind	Sum & Win	Service Charge $/HP/yr	$ 12.23	/mo	Service Charge $/HP/yr	$ 13.37	/mo	$ 13.56	/mo	$ 1.33	/mo	243
244		Machine Service		All kWh	0.06256	/kWh	All kWh	0.06838	/kWh	0.06936	/kWh	0.00680	/kWh	244
245	E-47	Dusk to Dawn Lighting		Rate Schedule E-47 is completely redesigned; therefore										245
246		Service		one-on-one comparisons are not meaningful. Please see										246
247				the actual rate schedule itself for rates.										247
248	E-51	Optional Electric	Sum & Win	Basic Service Charge	$ 8.00	/mo						N/A		248
249		Service for Qualified		Generator Meter Charge	24.00	/mo						N/A		249
250		Cogeneration and Small					Basic Service Charge	$ 0.263	/day	$ 0.267	/day	N/A		250
251		Power Production					Generator Meter Charge	$ 0.789	/day	$ 0.800	/day	N/A		251
252			Sum & Win	Reservation Charge per kW	$ 1.99	/kW	Reservation Charge per kW	$ 1.98	/kW	2.01	/kW	0.020	/kW	252
253		Facilities over 100 KW		Initial Reservation Charge	19.79	/kW	Initial Reservation Charge	19.79	/kW	20.07	/kW	0.280	/kW	253
254			Summer	Standby - All On-Peak kWh	0.04383	/kWh	Standby - All On-Peak kWh	0.04383	/kWh	0.04446	/kWh	0.00063	/kWh	254
255				Standby - All Off-Peak kWh	0.02040	/kWh	Standby - All Off-Peak kWh	0.02040	/kWh	0.02069	/kWh	0.00029	/kWh	255
256			Winter	Standby - All On-Peak kWh	0.03115	/kWh						N/A		256
257				Standby - All Off-Peak kWh	0.02040	/kWh						N/A		257
258							Standby - All kWh	0.02234	/kWh	0.02266	/kWh	N/A		258
259			Sum & Win	Maintenance - All kWh	$ 0.02040	/kWh	Maintenance - All kWh	$ 0.02040	/kWh	0.02069	/kWh	0.00029	/kWh	259
260	E-52	Electric Service for		NO CHANGE			NO CHANGE							260
261		Partial Requirements												261
262		Service of less than												262
263		3000 kW												263
264	E-53	Electric Service for		NO CHANGE			NO CHANGE							264
265		Athletic Stadiums												265
266		and Sports Fields												266

Supporting Schedules:

NOTES TO SCHEDULE:
1) Franchise fees are shown as an average percentage of total revenue requirement (Present Rates include franchise fee).
2) Proposed rates are shown on a bundled basis. See tariff sheets for unbundled components.
3) Present rates are those rates effective 7/01/2003.

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

TEST YEAR ENDING DECEMBER 31, 2002

	(A)	(B)	(C)	(D)	(E) (F)	(G)	(H) (I)	(J) (K)	(L) (M)	
				Present Rates		Proposed Rates		Proposed Rates with		
Line No.	Rate Schedule	Description	Season	Block	Rates	Block	Rates	Franchise Fees (H) x 0.0144	Change (J) - (E)	Line No.
267	E-54	Seasonal Service		NO CHANGE		NO CHANGE				267
268 269 270 271	E-55	Electric Service for Partial Requirements Service of 3000 kW or greater		NO CHANGE		NO CHANGE				268 269 270 271
272 273 274	E-58	Street Lighting Service		Rate Schedule E-58 is completely redesigned; therefore one-on-one comparisons are not meaningful. Please see the actual rate schedule itself for rates.						272 273 274
275 276	E-59	Energy Services for Govt Owned ST. Lighting Systems	Sum & Win	Service Charge Energy Charge	$ 1.79 /mo 0.05870 /kWh	Service Charge Energy Charge	$ 2.45 /mo 0.04635 /kWh	$ 2.49 /mo 0.04702 /kWh	$ 0.70 /mo (0.01168) /kWh	275 276
277	E-66	Share the Light		NO CHANGE		NO CHANGE				277
278 279	E-67	Municipal Lighting Service -- City of Phoenix	Sum & Win	All kWh	$ 0.03480 /kWh	All kWh	$ 0.04128 /kWh	0.04187 /kWh	$ 0.00707 /kWh	278 279
280	E-114	Share the Light		NO CHANGE		NO CHANGE				280
281	E-116	Share the Light		NO CHANGE		NO CHANGE				281
282	E-145	Share the Light		NO CHANGE		NO CHANGE				282

Supporting Schedules:

NOTES TO SCHEDULE:
1) Franchise fees are shown as an average percentage of total revenue requirement (Present Rates include franchise fee).
2) Proposed rates are shown on a bundled basis. See tariff sheets for unbundled components.
3) Present rates are those rates effective 7/01/2003.

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

TEST YEAR ENDING DECEMBER 31, 2002

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
Line No.	Rate Schedule	Description	Season	Present Rates Block	Present Rates Rates		Proposed Rates Block	Proposed Rates Rates		Proposed Rates with Franchise Fees (H) x 0.0144		Change (J) - (E)		Line No.
283	E-221	Water Pumping Service	Sum & Win	Basic Service Charge	$ 15.00	/mo						N/A		283
284							Basic Service Charge	$ 0.575	/day	$ 0.583	/day	N/A		284
285				All kW	1.62	/kW	All kW	1.80	/kW	1.83	/kW	0.21	/kW	285
286				First 240 kWh	0.09475	/kWh						N/A		286
287				Next 275 kWh per kW	0.06441	/kWh	First 275 kWh per kW	0.06911	/kWh	0.07011	/kWh	0.00570	/kWh	287
288				All additional kWh	0.05289	/kWh	All additional kWh	0.05562	/kWh	0.05642	/kWh	0.00353	/kWh	288
289			Sum & Win	Based on Measured kWh in Control Period:			Based on Measured kWh in Control Period:							289
290				2 kWh per kW or less	$ (0.00690)	/kWh	2 kWh per kW or less	$(0.00739)	/kWh	(0.00750)	/kWh	$ (0.00060)	/kWh	290
291				Greater than 8 kWh/kW	0.00345	/kWh	Greater than 8 kWh/kW	0.00370	/kWh	0.00375	/kWh	0.00030	/kWh	291
292			Sum & Win	Minimum Basic Service Charge	$ 15.00	/mo						N/A		292
293							Minimum Basic Service Charge	$ 0.575	/day	$ 0.583	/day	N/A		293
294				Minimum Demand Charge	1.62	/kW	Minimum Demand Charge	1.80	/kW	1.83	/kW	0.21	/kW	294
295				Minimum Annual kW Charge	19.66	/kW	Minimum Annual kW Charge	21.60	/kW	21.91	/kW	2.25	/kW	295
296	E-221-8T	Water Pumping Service Time Of Use	Sum & Win	Basic Service Charge	$ 25.87	/mo						N/A		296
297							Basic Service Charge	$ 0.851	/day	$ 0.863	/day	N/A		297
298				All On-Peak kW	3.85	/kW	All On-Peak kW	4.21	/kW	4.27	/kW	0.42	/kW	298
299				All Off-Peak kW	2.30	/kW	All Off-Peak kW	2.51	/kW	2.55	/kW	0.25	/kW	299
300				All On-Peak kWh	0.07769	/kWh	All On-Peak kWh	0.08492	/kWh	0.08614	/kWh	0.00845	/kWh	300
301				All Off-Peak kWh	0.04178	/kWh	All Off-Peak kWh	0.04567	/kWh	0.04633	/kWh	0.00455	/kWh	301
302			Sum & Win	Minimum Basic Service Charge	$ 25.87	/mo						N/A		302
303							Minimum Basic Service Charge	$ 0.851	/day	$ 0.863	/day	N/A		303
304				Minimum Demand Charge	2.30	/kW	Minimum Demand Charge	2.51	/kW	2.55	/kW	0.25	/kW	304
305				Minimum Annual kW Charge	27.79	/kW	Minimum Annual kW Charge	30.12	/kW	30.55	/kW	2.76	/kW	305
306	E-249	Share the Light		NO CHANGE			NO CHANGE							306
307	EPR-2	Purchase Rates		NO CHANGE			NO CHANGE							307
308	EPR-3	Purchase Rates		NO CHANGE			NO CHANGE							308
309	EPR-4	Purchase Rates		NO CHANGE			NO CHANGE							309

<u>Supporting Schedules:</u>

NOTES TO SCHEDULE:
1) Franchise fees are shown as an average percentage of total revenue requirement (Present Rates include franchise fee).
2) Proposed rates are shown on a bundled basis. See tariff sheets for unbundled components.
3) Present rates are those rates effective 7/01/2003.

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

TEST YEAR ENDING DECEMBER 31, 2002

	(A)	(B)	(C)	(D)	(E)	(G)	(H)	(J)	(L)	
				Present Rates		Proposed Rates		Proposed Rates with		
Line No.	Rate Schedule	Description	Season	Block	Rates	Block	Rates	Franchise Fees (H) x 0.0144	Change (J) - (E)	Line No.
310	EQF-M	Scheduled Maintenance Electric Service		NO CHANGE		NO CHANGE				310
311		for Qualified CoGenerators and								311
312		Small Power Production Facilities								312
313	EQF-S	Standby Electric Service for Qualified		NO CHANGE		NO CHANGE				313
314		CoGenerators and Small Power								314
315		Production Facilities								315
316	Solar-1	Photovoltaic Service		NO CHANGE		NO CHANGE				316
317		Pilot Program								317
318	Solar-2	Individual Solar		NO CHANGE		NO CHANGE				318
319		Electric Service								319
320	SP-1	Solar Partners		NO CHANGE		NO CHANGE				320

Column letters (F), (I), (K), (M) are printed in the header without separate column content.

Supporting Schedules:

NOTES TO SCHEDULE:
1) Franchise fees are shown as an average percentage of total revenue requirement (Present Rates include franchise fee).
2) Proposed rates are shown on a bundled basis. See tariff sheets for unbundled components.
3) Present rates are those rates effective 7/01/2003.

H-4

Arizona Public Service Company

Typical Residential Bill Analysis
E-10 Winter (November-April)

Customer Bills at Varying Consumption Levels
at Present and STEP 1 Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
	Monthly Bill	Components of Proposed Bill - Step 1			Monthly Bill	Change	
Monthly kWh	under Present Rates	Base	CRCC	Franchise	under Proposed Rates	Amount ($)	%
			(A) x $0.000353	[(C) + (D)] x 0.0144	(C) + (D) + (E)	(F) - (B)	(G) / (B)
200	22.72	24.83	0.07	0.36	25.26	2.54	11.2%
250	26.52	29.00	0.09	0.42	29.51	2.99	11.3%
300	30.33	33.18	0.11	0.48	33.77	3.44	11.3%
350	34.13	37.35	0.12	0.54	38.01	3.88	11.4%
400	37.94	41.53	0.14	0.60	42.27	4.33	11.4%
450	41.74	45.70	0.16	0.66	46.52	4.78	11.5%
500	45.55	49.88	0.18	0.72	50.78	5.23	11.5%
550	49.35	54.05	0.19	0.78	55.02	5.67	11.5%
600	53.15	58.22	0.21	0.84	59.27	6.12	11.5%
650	56.96	62.40	0.23	0.90	63.53	6.57	11.5%
700	60.76	66.57	0.25	0.96	67.78	7.02	11.6%
750	64.57	70.75	0.26	1.02	72.03	7.46	11.6%
800	68.37	74.92	0.28	1.08	76.28	7.91	11.6%
850	72.18	79.10	0.30	1.14	80.54	8.36	11.6%
900	75.98	83.27	0.32	1.20	84.79	8.81	11.6%
950	79.79	87.45	0.34	1.26	89.05	9.26	11.6%
1,000	83.59	91.62	0.35	1.32	93.29	9.70	11.6%
1,100	91.20	99.97	0.39	1.45	101.81	10.61	11.6%
1,200	98.81	108.32	0.42	1.57	110.31	11.50	11.6%
1,300	106.42	116.67	0.46	1.69	118.82	12.40	11.7%
1,400	114.03	125.02	0.49	1.81	127.32	13.29	11.7%
1,500	121.64	133.37	0.53	1.93	135.83	14.19	11.7%
1,600	129.24	141.71	0.56	2.05	144.32	15.08	11.7%
1,700	136.85	150.06	0.60	2.17	152.83	15.98	11.7%
1,800	144.46	158.41	0.64	2.29	161.34	16.88	11.7%
1,900	152.07	166.76	0.67	2.41	169.84	17.77	11.7%
2,000	159.68	175.11	0.71	2.53	178.35	18.67	11.7%
2,200	174.90	191.81	0.78	2.77	195.36	20.46	11.7%
2,400	190.12	208.51	0.85	3.01	212.37	22.25	11.7%
2,600	205.33	225.20	0.92	3.26	229.38	24.05	11.7%
2,800	220.55	241.90	0.99	3.50	246.39	25.84	11.7%
3,000	235.77	258.60	1.06	3.74	263.40	27.63	11.7%

Supporting Schedules:

NOTES TO SCHEDULE:
1) Bills do not include EPS, Regulatory Assessment, or Tax charges.
2) Franchise dollars are shown as an average percentage of total revenue requirement.
3) Proposed CRCC is calculated in accordance with the proposed Plan for Administration as filed in ACC Docket No. E-01345A-02-0403.
4) Present Rates are rates effective 7/1/2003.

Arizona Public Service Company

Typical Residential Bill Analysis
E-10 Summer (May - October)

Customer Bills at Varying Consumption Levels
at Present and Proposed STEP 1 Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
	Monthly Bill	Components of Proposed Bill - Step 1			Monthly Bill	Change	
Monthly	under				under		
kWh	Present Rates	Base	CRCC	Franchise	Proposed Rates	Amount ($)	%
			(A) x $0.000353	[(C) + (D)] x 0.0144	(C) + (D) + (E)	(F) - (B)	(G) / (B)
200	20.86	22.79	0.07	0.33	23.19	2.33	11.2%
250	24.21	26.46	0.09	0.38	26.93	2.72	11.2%
300	27.55	30.13	0.11	0.44	30.68	3.13	11.4%
350	30.89	33.79	0.12	0.49	34.40	3.51	11.4%
400	34.23	37.46	0.14	0.54	38.14	3.91	11.4%
450	38.82	42.50	0.16	0.61	43.27	4.45	11.5%
500	43.42	47.54	0.18	0.69	48.41	4.99	11.5%
550	48.01	52.58	0.19	0.76	53.53	5.52	11.5%
600	52.61	57.62	0.21	0.83	58.66	6.05	11.5%
650	57.20	62.67	0.23	0.91	63.81	6.61	11.6%
700	61.80	67.71	0.25	0.98	68.94	7.14	11.6%
750	66.39	72.75	0.26	1.05	74.06	7.67	11.6%
800	70.98	77.79	0.28	1.12	79.19	8.21	11.6%
850	75.70	82.97	0.30	1.20	84.47	8.77	11.6%
900	80.42	88.15	0.32	1.27	89.74	9.32	11.6%
950	85.14	93.33	0.34	1.35	95.02	9.88	11.6%
1,000	89.86	98.51	0.35	1.42	100.28	10.42	11.6%
1,100	99.30	108.86	0.39	1.57	110.82	11.52	11.6%
1,200	108.74	119.22	0.42	1.72	121.36	12.62	11.6%
1,300	118.18	129.58	0.46	1.87	131.91	13.73	11.6%
1,400	127.62	139.94	0.49	2.02	142.45	14.83	11.6%
1,500	137.06	150.30	0.53	2.17	153.00	15.94	11.6%
1,600	146.50	160.65	0.56	2.32	163.53	17.03	11.6%
1,700	155.94	171.01	0.60	2.47	174.08	18.14	11.6%
1,800	165.38	181.37	0.64	2.62	184.63	19.25	11.6%
1,900	174.82	191.73	0.67	2.77	195.17	20.35	11.6%
2,000	184.26	202.09	0.71	2.92	205.72	21.46	11.6%
2,200	203.14	222.80	0.78	3.22	226.80	23.66	11.6%
2,400	222.02	243.52	0.85	3.52	247.89	25.87	11.7%
2,600	240.90	264.23	0.92	3.82	268.97	28.07	11.7%
2,800	259.78	284.95	0.99	4.12	290.06	30.28	11.7%
3,000	278.66	305.67	1.06	4.42	311.15	32.49	11.7%

Supporting Schedules:

NOTES TO SCHEDULE:
1) Bills do not include EPS, Regulatory Assessment, or Tax charges.
2) Franchise dollars are shown as an average percentage of total revenue requirement.
3) Proposed CRCC is calculated in accordance with the proposed Plan for Administration as filed in ACC Docket No. E-01345A-02-0403.
4) Present Rates are rates effective 7/1/2003.

Arizona Public Service Company

Typical Residential Bill Analysis
E-10 Winter (November-April)

Customer Bills at Varying Consumption Levels
at Proposed STEP 1 and Proposed E-12 Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
		Components of Proposed Bill - E-12				Change	
Monthly kWh	Monthly Bill under Proposed Step 1 Rates	Base	CRCC	Franchise	Monthly Bill under Proposed E-12	Amount ($)	%
			(A) x $0.000353	[(C) + (D)] x 0.0144	(C) + (D) + (E)	(F) - (B)	(G) / (B)
200	24.83	26.34	0.07	0.38	26.79	1.96	7.9%
250	29.00	29.84	0.09	0.43	30.36	1.36	4.7%
300	33.18	33.34	0.11	0.48	33.93	0.75	2.3%
350	37.35	36.84	0.12	0.53	37.49	0.14	0.4%
400	41.53	40.35	0.14	0.58	41.07	(0.46)	-1.1%
450	45.70	43.85	0.16	0.63	44.64	(1.06)	-2.3%
500	49.88	47.35	0.18	0.68	48.21	(1.67)	-3.3%
550	54.05	50.85	0.19	0.73	51.77	(2.28)	-4.2%
600	58.22	54.35	0.21	0.79	55.35	(2.87)	-4.9%
650	62.40	57.86	0.23	0.84	58.93	(3.47)	-5.6%
700	66.57	61.36	0.25	0.89	62.50	(4.07)	-6.1%
750	70.75	64.86	0.26	0.94	66.06	(4.69)	-6.6%
800	74.92	68.36	0.28	0.99	69.63	(5.29)	-7.1%
850	79.10	71.86	0.30	1.04	73.20	(5.90)	-7.5%
900	83.27	75.37	0.32	1.09	76.78	(6.49)	-7.8%
950	87.45	78.87	0.34	1.14	80.35	(7.10)	-8.1%
1,000	91.62	82.37	0.35	1.19	83.91	(7.71)	-8.4%
1,100	99.97	89.37	0.39	1.29	91.05	(8.92)	-8.9%
1,200	108.32	96.38	0.42	1.39	98.19	(10.13)	-9.4%
1,300	116.67	103.38	0.46	1.50	105.34	(11.33)	-9.7%
1,400	125.02	110.39	0.49	1.60	112.48	(12.54)	-10.0%
1,500	133.37	117.39	0.53	1.70	119.62	(13.75)	-10.3%
1,600	141.71	124.39	0.56	1.80	126.75	(14.96)	-10.6%
1,700	150.06	131.40	0.60	1.90	133.90	(16.16)	-10.8%
1,800	158.41	138.40	0.64	2.00	141.04	(17.37)	-11.0%
1,900	166.76	145.41	0.67	2.10	148.18	(18.58)	-11.1%
2,000	175.11	152.41	0.71	2.20	155.32	(19.79)	-11.3%
2,200	191.81	166.42	0.78	2.41	169.61	(22.20)	-11.6%
2,400	208.51	180.43	0.85	2.61	183.89	(24.62)	-11.8%
2,600	225.20	194.43	0.92	2.81	198.16	(27.04)	-12.0%
2,800	241.90	208.44	0.99	3.02	212.45	(29.45)	-12.2%
3,000	258.60	222.45	1.06	3.22	226.73	(31.87)	-12.3%

Supporting Schedules:

NOTES TO SCHEDULE:
1) Bills do not include EPS, Regulatory Assessment, or Tax charges.
2) *Franchise dollars are shown as an average percentage of total revenue requirement.*
3) Proposed CRCC is calculated in accordance with the proposed Plan for Administration as filed in ACC Docket No. E-01345A-02-0403.
4) Present Rates are rates effective 7/1/2003.

Arizona Public Service Company

Typical Residential Bill Analysis
E-10 Summer (May - October)

Customer Bills at Varying Consumption Levels
at Proposed STEP 1 and Proposed E-12 Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
		Components of Proposed Bill - E-12				Change	
Monthly kWh	Monthly Bill under Proposed Step 1 Rates	Base	CRCC	Franchise	Monthly Bill under Proposed E-12	Amount ($)	%
			(A) x $0.000353	[(C) + (D)] x 0.0144	(C) + (D) + (E)	(F) - (B)	(G) / (B)
200	22.79	29.61	0.07	0.43	30.11	7.32	32.1%
250	26.46	33.93	0.09	0.49	34.51	8.05	30.4%
300	30.13	38.25	0.11	0.55	38.91	8.78	29.1%
350	33.79	42.57	0.12	0.61	43.30	9.51	28.1%
400	37.46	46.89	0.14	0.68	47.71	10.25	27.4%
450	42.50	51.21	0.16	0.74	52.11	9.61	22.6%
500	47.54	55.53	0.18	0.80	56.51	8.97	18.9%
550	52.58	59.85	0.19	0.86	60.90	8.32	15.8%
600	57.62	64.17	0.21	0.93	65.31	7.69	13.3%
650	62.67	68.49	0.23	0.99	69.71	7.04	11.2%
700	67.71	72.81	0.25	1.05	74.11	6.40	9.5%
750	72.75	77.13	0.26	1.11	78.50	5.75	7.9%
800	77.79	81.45	0.28	1.18	82.91	5.12	6.6%
850	82.97	86.95	0.30	1.26	88.51	5.54	6.7%
900	88.15	92.46	0.32	1.34	94.12	5.97	6.8%
950	93.33	97.96	0.34	1.42	99.72	6.39	6.8%
1,000	98.51	103.46	0.35	1.49	105.30	6.79	6.9%
1,100	108.86	114.47	0.39	1.65	116.51	7.65	7.0%
1,200	119.22	125.47	0.42	1.81	127.70	8.48	7.1%
1,300	129.58	136.48	0.46	1.97	138.91	9.33	7.2%
1,400	139.94	147.49	0.49	2.13	150.11	10.17	7.3%
1,500	150.30	158.49	0.53	2.29	161.31	11.01	7.3%
1,600	160.65	169.50	0.56	2.45	172.51	11.86	7.4%
1,700	171.01	180.50	0.60	2.61	183.71	12.70	7.4%
1,800	181.37	191.51	0.64	2.77	194.92	13.55	7.5%
1,900	191.73	202.52	0.67	2.93	206.12	14.39	7.5%
2,000	202.09	213.52	0.71	3.08	217.31	15.22	7.5%
2,200	222.80	235.53	0.78	3.40	239.71	16.91	7.6%
2,400	243.52	257.55	0.85	3.72	262.12	18.60	7.6%
2,600	264.23	279.56	0.92	4.04	284.52	20.29	7.7%
2,800	284.95	301.57	0.99	4.36	306.92	21.97	7.7%
3,000	305.67	323.58	1.06	4.67	329.31	23.64	7.7%

Supporting Schedules:

NOTES TO SCHEDULE:
1) Bills do not include EPS, Regulatory Assessment, or Tax charges.
2) Franchise dollars are shown as an average percentage of total revenue requirement.
3) Proposed CRCC is calculated in accordance with the proposed Plan for Administration as filed in ACC Docket No. E-01345A-02-0403.
4) Present Rates are rates effective 7/1/2003.

Arizona Public Service Company

Typical Residential Bill Analysis
E-12 Winter (November-April)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
	Monthly Bill	Components of Proposed Bill			Monthly Bill	Change	
Monthly kWh	under Present Rates	Base	CRCC	Franchise	under Proposed Rates	Amount ($)	%
			(A) x $0.000353	[(C) + (D)] x 0.0144	(C) + (D) + (E)	(F) - (B)	(G) / (B)
200	22.29	26.34	0.07	0.38	26.79	4.50	20.2%
250	25.99	29.84	0.09	0.43	30.36	4.37	16.8%
300	29.68	33.34	0.11	0.48	33.93	4.25	14.3%
350	33.38	36.84	0.12	0.53	37.49	4.11	12.3%
400	37.08	40.35	0.14	0.58	41.07	3.99	10.8%
450	40.77	43.85	0.16	0.63	44.64	3.87	9.5%
500	44.47	47.35	0.18	0.68	48.21	3.74	8.4%
550	48.17	50.85	0.19	0.73	51.77	3.60	7.5%
600	51.86	54.35	0.21	0.79	55.35	3.49	6.7%
650	55.56	57.86	0.23	0.84	58.93	3.37	6.1%
700	59.26	61.36	0.25	0.89	62.50	3.24	5.5%
750	62.96	64.86	0.26	0.94	66.06	3.10	4.9%
800	66.65	68.36	0.28	0.99	69.63	2.98	4.5%
850	70.35	71.86	0.30	1.04	73.20	2.85	4.1%
900	74.05	75.37	0.32	1.09	76.78	2.73	3.7%
950	77.74	78.87	0.34	1.14	80.35	2.61	3.4%
1,000	81.44	82.37	0.35	1.19	83.91	2.47	3.0%
1,100	88.83	89.37	0.39	1.29	91.05	2.22	2.5%
1,200	96.23	96.38	0.42	1.39	98.19	1.96	2.0%
1,300	103.62	103.38	0.46	1.50	105.34	1.72	1.7%
1,400	111.02	110.39	0.49	1.60	112.48	1.46	1.3%
1,500	118.41	117.39	0.53	1.70	119.62	1.21	1.0%
1,600	125.80	124.39	0.56	1.80	126.75	0.95	0.8%
1,700	133.20	131.40	0.60	1.90	133.90	0.70	0.5%
1,800	140.59	138.40	0.64	2.00	141.04	0.45	0.3%
1,900	147.99	145.41	0.67	2.10	148.18	0.19	0.1%
2,000	155.38	152.41	0.71	2.20	155.32	(0.06)	0.0%
2,200	170.17	166.42	0.78	2.41	169.61	(0.56)	-0.3%
2,400	184.96	180.43	0.85	2.61	183.89	(1.07)	-0.6%
2,600	199.74	194.43	0.92	2.81	198.16	(1.58)	-0.8%
2,800	214.53	208.44	0.99	3.02	212.45	(2.08)	-1.0%
3,000	229.32	222.45	1.06	3.22	226.73	(2.59)	-1.1%

Supporting Schedules:

NOTES TO SCHEDULE:
1) Bills do not include EPS, Regulatory Assessment, or Tax charges.
2) Franchise dollars are shown as an average percentage of total revenue requirement.
3) Proposed CRCC is calculated in accordance with the proposed Plan for Administration as filed in ACC Docket No. E-01345A-02-0403.
4) Present Rates are rates effective 7/1/2003.

Arizona Public Service Company

Typical Residential Bill Analysis
E-12 Summer (May - October)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
		Components of Proposed Bill				Change	
Monthly kWh	Monthly Bill under Present Rates	Base	CRCC	Franchise	Monthly Bill under Proposed Rates	Amount ($)	%
			(A) x $0.000353	[(C) + (D)] x 0.0144	(C) + (D) + (E)	(F) - (B)	(G) / (B)
200	22.25	29.61	0.07	0.43	30.11	7.86	35.3%
250	25.94	33.93	0.09	0.49	34.51	8.57	33.0%
300	29.63	38.25	0.11	0.55	38.91	9.28	31.3%
350	33.32	42.57	0.12	0.61	43.30	9.98	30.0%
400	37.00	46.89	0.14	0.68	47.71	10.71	28.9%
450	42.14	51.21	0.16	0.74	52.11	9.97	23.7%
500	47.29	55.53	0.18	0.80	56.51	9.22	19.5%
550	52.43	59.85	0.19	0.86	60.90	8.47	16.2%
600	57.57	64.17	0.21	0.93	65.31	7.74	13.4%
650	62.71	68.49	0.23	0.99	69.71	7.00	11.2%
700	67.85	72.81	0.25	1.05	74.11	6.26	9.2%
750	72.99	77.13	0.26	1.11	78.50	5.51	7.5%
800	78.13	81.45	0.28	1.18	82.91	4.78	6.1%
850	84.12	86.95	0.30	1.26	88.51	4.39	5.2%
900	90.12	92.46	0.32	1.34	94.12	4.00	4.4%
950	96.11	97.96	0.34	1.42	99.72	3.61	3.8%
1,000	102.11	103.46	0.35	1.49	105.30	3.19	3.1%
1,100	114.10	114.47	0.39	1.65	116.51	2.41	2.1%
1,200	126.09	125.47	0.42	1.81	127.70	1.61	1.3%
1,300	138.08	136.48	0.46	1.97	138.91	0.83	0.6%
1,400	150.07	147.49	0.49	2.13	150.11	0.04	0.0%
1,500	162.07	158.49	0.53	2.29	161.31	(0.76)	-0.5%
1,600	174.06	169.50	0.56	2.45	172.51	(1.55)	-0.9%
1,700	186.05	180.50	0.60	2.61	183.71	(2.34)	-1.3%
1,800	198.04	191.51	0.64	2.77	194.92	(3.12)	-1.6%
1,900	210.03	202.52	0.67	2.93	206.12	(3.91)	-1.9%
2,000	222.02	213.52	0.71	3.08	217.31	(4.71)	-2.1%
2,200	246.00	235.53	0.78	3.40	239.71	(6.29)	-2.6%
2,400	269.98	257.55	0.85	3.72	262.12	(7.86)	-2.9%
2,600	293.97	279.56	0.92	4.04	284.52	(9.45)	-3.2%
2,800	317.95	301.57	0.99	4.36	306.92	(11.03)	-3.5%
3,000	341.93	323.58	1.06	4.67	329.31	(12.62)	-3.7%

Supporting Schedules:

NOTES TO SCHEDULE:
1) Bills do not include EPS, Regulatory Assessment, or Tax charges.
2) *Franchise dollars are shown as an average percentage of total revenue requirement.*
3) Proposed CRCC is calculated in accordance with the proposed Plan for Administration as filed in ACC Docket No. E-01345A-02-0403.
4) Present Rates are rates effective 7/1/2003.

Arizona Public Service Company

Typical Residential Bill Analysis
EC-1 Winter (November-April)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
			Monthly Bill	Components of Proposed Bill			Monthly Bill	Change	
	Load	Monthly	under				under		
kW	Factor	kWh	Present Rates	Base	CRCC	Franchise	Proposed Rates	Amount ($)	%
					(C) x $0.000353	[(E) + (F)] x 0.0144	(E) + (F) + (G)	(H) - (D)	(I) / (D)
3	20%	438	45.09	52.04	0.15	0.75	52.94	7.85	17.4%
3	30%	657	52.05	58.66	0.23	0.85	59.74	7.69	14.8%
3	40%	876	59.00	65.29	0.31	0.94	66.54	7.54	12.8%
3	50%	1,095	65.96	71.91	0.39	1.04	73.34	7.38	11.2%
3	75%	1,643	83.36	88.49	0.58	1.28	90.35	6.99	8.4%
5	20%	730	68.48	76.87	0.26	1.11	78.24	9.76	14.3%
5	30%	1,095	80.08	87.91	0.39	1.27	89.57	9.49	11.9%
5	40%	1,460	91.67	98.96	0.52	1.43	100.91	9.24	10.1%
5	50%	1,825	103.26	110.00	0.64	1.59	112.23	8.97	8.7%
5	75%	2,738	132.26	137.61	0.97	2.00	140.58	8.32	6.3%
8	20%	1,168	103.58	114.12	0.41	1.65	116.18	12.60	12.2%
8	30%	1,752	122.12	131.79	0.62	1.91	134.32	12.20	10.0%
8	40%	2,336	140.67	149.45	0.82	2.16	152.43	11.76	8.4%
8	50%	2,920	159.22	167.12	1.03	2.42	170.57	11.35	7.1%
8	75%	4,380	205.59	211.29	1.55	3.06	215.90	10.31	5.0%
10	20%	1,460	126.97	138.96	0.52	2.01	141.49	14.52	11.4%
10	30%	2,190	150.15	161.04	0.77	2.33	164.14	13.99	9.3%
10	40%	2,920	173.34	183.12	1.03	2.65	186.80	13.46	7.8%
10	50%	3,650	196.52	205.20	1.29	2.97	209.46	12.94	6.6%
10	75%	5,475	254.49	260.41	1.93	3.78	266.12	11.63	4.6%
12	20%	1,752	150.36	163.79	0.62	2.37	166.78	16.42	10.9%
12	30%	2,628	178.19	190.29	0.93	2.75	193.97	15.78	8.9%
12	40%	3,504	206.01	216.79	1.24	3.14	221.17	15.16	7.4%
12	50%	4,380	233.83	243.29	1.55	3.53	248.37	14.54	6.2%
12	75%	6,570	303.38	309.53	2.32	4.49	316.34	12.96	4.3%
15	20%	2,190	185.45	201.04	0.77	2.91	204.72	19.27	10.4%
15	30%	3,285	220.23	234.16	1.16	3.39	238.71	18.48	8.4%
15	40%	4,380	255.01	267.29	1.55	3.87	272.71	17.70	6.9%
15	50%	5,475	289.79	300.41	1.93	4.35	306.69	16.90	5.8%
15	75%	8,213	376.74	383.23	2.90	5.56	391.69	14.95	4.0%

Supporting Schedules:

NOTES TO SCHEDULE:
1) Bills do not include EPS, Regulatory Assessment, or Tax charges.
2) Franchise dollars are shown as an average percentage of total revenue requirement.
3) Proposed CRCC is calculated in accordance with the proposed Plan for Administration as filed in ACC Docket No. E-01345A-02-0403.
4) Present Rates are rates effective 7/1/2003.

Arizona Public Service Company

Typical Residential Bill Analysis
EC-1 Summer (May-October)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
				Components of Proposed Bill				Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Base	CRCC	Franchise	Monthly Bill under Proposed Rates	Amount ($)	%
					(C) x $0.000353	[(E) + (F)] x 0.0144	(E) + (F) + (G)	(H) - (D)	(I) / (D)
3	20%	438	56.28	65.45	0.15	0.94	66.54	10.26	18.2%
3	30%	657	64.66	74.29	0.23	1.07	75.59	10.93	16.9%
3	40%	876	73.04	83.12	0.31	1.20	84.63	11.59	15.9%
3	50%	1,095	81.43	91.95	0.39	1.33	93.67	12.24	15.0%
3	75%	1,643	102.40	114.05	0.58	1.65	116.28	13.88	13.6%
5	20%	730	87.14	99.23	0.26	1.43	100.92	13.78	15.8%
5	30%	1,095	101.11	113.95	0.39	1.65	115.99	14.88	14.7%
5	40%	1,460	115.07	128.67	0.52	1.86	131.05	15.98	13.9%
5	50%	1,825	129.04	143.39	0.64	2.07	146.10	17.06	13.2%
5	75%	2,738	163.98	180.21	0.97	2.61	183.79	19.81	12.1%
8	20%	1,168	133.42	149.89	0.41	2.16	152.46	19.04	14.3%
8	30%	1,752	155.77	173.45	0.62	2.51	176.58	20.81	13.4%
8	40%	2,336	178.12	197.00	0.82	2.85	200.67	22.55	12.7%
8	50%	2,920	200.47	220.55	1.03	3.19	224.77	24.30	12.1%
8	75%	4,380	256.34	279.43	1.55	4.05	285.03	28.69	11.2%
10	20%	1,460	164.27	183.67	0.52	2.65	186.84	22.57	13.7%
10	30%	2,190	192.21	213.11	0.77	3.08	216.96	24.75	12.9%
10	40%	2,920	220.15	242.55	1.03	3.51	247.09	26.94	12.2%
10	50%	3,650	248.09	271.99	1.29	3.94	277.22	29.13	11.7%
10	75%	5,475	317.93	345.59	1.93	5.00	352.52	34.59	10.9%
12	20%	1,752	195.13	217.45	0.62	3.14	221.21	26.08	13.4%
12	30%	2,628	228.65	252.77	0.93	3.65	257.35	28.70	12.6%
12	40%	3,504	262.18	288.10	1.24	4.17	293.51	31.33	11.9%
12	50%	4,380	295.70	323.43	1.55	4.68	329.66	33.96	11.5%
12	75%	6,570	379.51	411.75	2.32	5.96	420.03	40.52	10.7%
15	20%	2,190	241.41	268.11	0.77	3.87	272.75	31.34	13.0%
15	30%	3,285	283.32	312.27	1.16	4.51	317.94	34.62	12.2%
15	40%	4,380	325.22	356.43	1.55	5.15	363.13	37.91	11.7%
15	50%	5,475	367.13	400.59	1.93	5.80	408.32	41.19	11.2%
15	75%	8,213	471.91	511.01	2.90	7.40	521.31	49.40	10.5%

EC-1 Summer Average Energy On-Peak: 42%

Supporting Schedules:

NOTES TO SCHEDULE:
1) Bills do not include EPS, Regulatory Assessment, or Tax charges.
2) Franchise dollars are shown as an average percentage of total revenue requirement.
3) Proposed CRCC is calculated in accordance with the proposed Plan for Administration as filed in ACC Docket No. E-01345A-02-0403.
4) Present Rates are rates effective 7/1/2003.

Arizona Public Service Company

Typical Residential Bill Analysis
ET-1 Winter (November-April)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
	Monthly Bill	Components of Proposed Bill			Monthly Bill	Change	
Monthly kWh	under Present Rates	Base	CRCC	Franchise	under Proposed Rates	Amount ($)	%
			(A) x $0.000353	[(C) + (D)] x 0.0144	(C) + (D) + (E)	(F) - (B)	(G) / (B)
200	27.17	28.12	0.07	0.41	28.60	1.43	5.3%
250	30.22	31.51	0.09	0.46	32.06	1.84	6.1%
300	33.26	34.90	0.11	0.50	35.51	2.25	6.8%
350	36.30	38.29	0.12	0.55	38.96	2.66	7.3%
400	39.35	41.69	0.14	0.60	42.43	3.08	7.8%
450	42.39	45.08	0.16	0.65	45.89	3.50	8.3%
500	45.44	48.47	0.18	0.70	49.35	3.91	8.6%
550	48.48	51.86	0.19	0.75	52.80	4.32	8.9%
600	51.52	55.25	0.21	0.80	56.26	4.74	9.2%
650	54.57	58.65	0.23	0.85	59.73	5.16	9.5%
700	57.61	62.04	0.25	0.90	63.19	5.58	9.7%
750	60.65	65.43	0.26	0.95	66.64	5.99	9.9%
800	63.70	68.82	0.28	1.00	70.10	6.40	10.0%
850	66.74	72.21	0.30	1.04	73.55	6.81	10.2%
900	69.78	75.61	0.32	1.09	77.02	7.24	10.4%
950	72.83	79.00	0.34	1.14	80.48	7.65	10.5%
1,000	75.87	82.39	0.35	1.19	83.93	8.06	10.6%
1,100	81.96	89.17	0.39	1.29	90.85	8.89	10.8%
1,200	88.05	95.96	0.42	1.39	97.77	9.72	11.0%
1,300	94.13	102.74	0.46	1.49	104.69	10.56	11.2%
1,400	100.22	109.53	0.49	1.58	111.60	11.38	11.4%
1,500	106.31	116.31	0.53	1.68	118.52	12.21	11.5%
1,600	112.39	123.09	0.56	1.78	125.43	13.04	11.6%
1,700	118.48	129.88	0.60	1.88	132.36	13.88	11.7%
1,800	124.57	136.66	0.64	1.98	139.28	14.71	11.8%
1,900	130.65	143.45	0.67	2.08	146.20	15.55	11.9%
2,000	136.74	150.23	0.71	2.17	153.11	16.37	12.0%
2,200	148.92	163.80	0.78	2.37	166.95	18.03	12.1%
2,400	161.09	177.37	0.85	2.57	180.79	19.70	12.2%
2,600	173.26	190.93	0.92	2.76	194.61	21.35	12.3%
2,800	185.44	204.50	0.99	2.96	208.45	23.01	12.4%
3,000	197.61	218.07	1.06	3.16	222.29	24.68	12.5%

ET-1 Winter Average Energy On-Peak: 30%

Supporting Schedules:

NOTES TO SCHEDULE:
1) Bills do not include EPS, Regulatory Assessment, or Tax charges.
2) Franchise dollars are shown as an average percentage of total revenue requirement.
3) Proposed CRCC is calculated in accordance with the proposed Plan for Administration as filed in ACC Docket No. E-01345A-02-0403.
4) Present Rates are rates effective 7/1/2003.

Arizona Public Service Company

Typical Residential Bill Analysis
ET-1 Summer (May - October)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
	Monthly Bill	Components of Proposed Bill			Monthly Bill	Change	
Monthly kWh	under Present Rates	Base	CRCC	Franchise	under Proposed Rates	Amount ($)	%
			(A) x $0.000353	*[(C) + (D)] x 0.0144*	*(C) + (D) + (E)*	*(F) - (B)*	*(G) / (B)*
200	30.21	31.62	0.07	0.46	32.15	1.94	6.4%
250	34.01	35.88	0.09	0.52	36.49	2.48	7.3%
300	37.81	40.15	0.11	0.58	40.84	3.03	8.0%
350	41.61	44.42	0.12	0.64	45.18	3.57	8.6%
400	45.41	48.68	0.14	0.70	49.52	4.11	9.1%
450	49.22	52.95	0.16	0.76	53.87	4.65	9.4%
500	53.02	57.22	0.18	0.83	58.23	5.21	9.8%
550	56.82	61.48	0.19	0.89	62.56	5.74	10.1%
600	60.62	65.75	0.21	0.95	66.91	6.29	10.4%
650	64.42	70.01	0.23	1.01	71.25	6.83	10.6%
700	68.22	74.28	0.25	1.07	75.60	7.38	10.8%
750	72.03	78.55	0.26	1.13	79.94	7.91	11.0%
800	75.83	82.81	0.28	1.20	84.29	8.46	11.2%
850	79.63	87.08	0.30	1.26	88.64	9.01	11.3%
900	83.43	91.35	0.32	1.32	92.99	9.56	11.5%
950	87.23	95.61	0.34	1.38	97.33	10.10	11.6%
1,000	91.03	99.88	0.35	1.44	101.67	10.64	11.7%
1,100	98.64	108.41	0.39	1.57	110.37	11.73	11.9%
1,200	106.24	116.95	0.42	1.69	119.06	12.82	12.1%
1,300	113.84	125.48	0.46	1.81	127.75	13.91	12.2%
1,400	121.45	134.01	0.49	1.94	136.44	14.99	12.3%
1,500	129.05	142.55	0.53	2.06	145.14	16.09	12.5%
1,600	136.65	151.08	0.56	2.18	153.82	17.17	12.6%
1,700	144.26	159.61	0.60	2.31	162.52	18.26	12.7%
1,800	151.86	168.14	0.64	2.43	171.21	19.35	12.7%
1,900	159.46	176.68	0.67	2.55	179.90	20.44	12.8%
2,000	167.07	185.21	0.71	2.68	188.60	21.53	12.9%
2,200	182.27	202.28	0.78	2.92	205.98	23.71	13.0%
2,400	197.48	219.34	0.85	3.17	223.36	25.88	13.1%
2,600	212.69	236.41	0.92	3.42	240.75	28.06	13.2%
2,800	227.90	253.47	0.99	3.66	258.12	30.22	13.3%
3,000	243.10	270.54	1.06	3.91	275.51	32.41	13.3%

ET-1 Summer Average Energy On-Peak: 40%

Supporting Schedules:

NOTES TO SCHEDULE:
1) Bills do not include EPS, Regulatory Assessment, or Tax charges.
2) Franchise dollars are shown as an average percentage of total revenue requirement.
3) Proposed CRCC is calculated in accordance with the proposed Plan for Administration as filed in ACC Docket No. E-01345A-02-0403.
4) *Present Rates are rates effective 7/1/2003.*

Arizona Public Service Company

Typical Residential Bill Analysis
ECT-1R Winter (November-April)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
				Components of Proposed Bill				Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Base	CRCC	Franchise	Monthly Bill under Proposed Rates	Amount ($)	%
					(C) x $0.000353	[(E) + (F)] x 0.0144	(E) + (F) + (G)	(H) - (D)	(I) / (D)
3	20%	438	51.93	52.04	0.15	0.75	52.94	1.01	1.9%
3	30%	657	58.23	58.66	0.23	0.85	59.74	1.51	2.6%
3	40%	876	64.53	65.29	0.31	0.94	66.54	2.01	3.1%
3	50%	1,095	70.82	71.91	0.39	1.04	73.34	2.52	3.6%
3	75%	1,643	86.59	88.49	0.58	1.28	90.35	3.76	4.3%
5	20%	730	76.55	76.87	0.26	1.11	78.24	1.69	2.2%
5	30%	1,095	87.04	87.91	0.39	1.27	89.57	2.53	2.9%
5	40%	1,460	97.54	98.96	0.52	1.43	100.91	3.37	3.5%
5	50%	1,825	108.04	110.00	0.64	1.59	112.23	4.19	3.9%
5	75%	2,738	134.30	137.61	0.97	2.00	140.58	6.28	4.7%
8	20%	1,168	113.47	114.12	0.41	1.65	116.18	2.71	2.4%
8	30%	1,752	130.27	131.79	0.62	1.91	134.32	4.05	3.1%
8	40%	2,336	147.07	149.45	0.82	2.16	152.43	5.36	3.6%
8	50%	2,920	163.87	167.12	1.03	2.42	170.57	6.70	4.1%
8	75%	4,380	205.86	211.29	1.55	3.06	215.90	10.04	4.9%
10	20%	1,460	138.09	138.96	0.52	2.01	141.49	3.40	2.5%
10	30%	2,190	159.09	161.04	0.77	2.33	164.14	5.05	3.2%
10	40%	2,920	180.09	183.12	1.03	2.65	186.80	6.71	3.7%
10	50%	3,650	201.08	205.20	1.29	2.97	209.46	8.38	4.2%
10	75%	5,475	253.57	260.41	1.93	3.78	266.12	12.55	4.9%
12	20%	1,752	162.71	163.79	0.62	2.37	166.78	4.07	2.5%
12	30%	2,628	187.91	190.29	0.93	2.75	193.97	6.06	3.2%
12	40%	3,504	213.10	216.79	1.24	3.14	221.17	8.07	3.8%
12	50%	4,380	238.30	243.29	1.55	3.53	248.37	10.07	4.2%
12	75%	6,570	301.29	309.53	2.32	4.49	316.34	15.05	5.0%
15	20%	2,190	199.64	201.04	0.77	2.91	204.72	5.08	2.5%
15	30%	3,285	231.13	234.16	1.16	3.39	238.71	7.58	3.3%
15	40%	4,380	262.63	267.29	1.55	3.87	272.71	10.08	3.8%
15	50%	5,475	294.12	300.41	1.93	4.35	306.69	12.57	4.3%
15	75%	8,213	372.88	383.23	2.90	5.56	391.69	18.81	5.0%

ECT-1R Winter Average Energy On-Peak: 31%

Supporting Schedules:

NOTES TO SCHEDULE:
1) Bills do not include EPS, Regulatory Assessment, or Tax charges.
2) Franchise dollars are shown as an average percentage of total revenue requirement.
3) Proposed CRCC is calculated in accordance with the proposed Plan for Administration as filed in ACC Docket No. E-01345A-02-0403.
4) Present Rates are rates effective 7/1/2003.

Arizona Public Service Company

Typical Residential Bill Analysis
ECT-1R Summer (May-October)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
			Monthly Bill	Components of Proposed Bill			Monthly Bill	Change	
kW	Load Factor	Monthly kWh	under Present Rates	Base	CRCC	Franchise	under Proposed Rates	Amount ($)	%
					(C) x $0.000353	[(E) + (F)] x 0.0144	(E) + (F) + (G)	(H) - (D)	(I) / (D)
3	20%	438	63.51	65.15	0.15	0.94	66.24	2.73	4.3%
3	30%	657	70.76	73.83	0.23	1.07	75.13	4.37	6.2%
3	40%	876	78.02	82.50	0.31	1.19	84.00	5.98	7.7%
3	50%	1,095	85.28	91.18	0.39	1.32	92.89	7.61	8.9%
3	75%	1,643	103.44	112.90	0.58	1.63	115.11	11.67	11.3%
5	20%	730	95.84	98.72	0.26	1.43	100.41	4.57	4.8%
5	30%	1,095	107.94	113.18	0.39	1.64	115.21	7.27	6.7%
5	40%	1,460	120.03	127.65	0.52	1.85	130.02	9.99	8.3%
5	50%	1,825	132.13	142.11	0.64	2.06	144.81	12.68	9.6%
5	75%	2,738	162.39	178.29	0.97	2.58	181.84	19.45	12.0%
8	20%	1,168	144.35	149.08	0.41	2.15	151.64	7.29	5.1%
8	30%	1,752	163.70	172.22	0.62	2.49	175.33	11.63	7.1%
8	40%	2,336	183.06	195.36	0.82	2.82	199.00	15.94	8.7%
8	50%	2,920	202.41	218.50	1.03	3.16	222.69	20.28	10.0%
8	75%	4,380	250.79	276.36	1.55	4.00	281.91	31.12	12.4%
10	20%	1,460	176.68	182.65	0.52	2.64	185.81	9.13	5.2%
10	30%	2,190	200.88	211.57	0.77	3.06	215.40	14.52	7.2%
10	40%	2,920	225.07	240.50	1.03	3.48	245.01	19.94	8.9%
10	50%	3,650	249.26	269.43	1.29	3.90	274.62	25.36	10.2%
10	75%	5,475	309.74	341.75	1.93	4.95	348.63	38.89	12.6%
12	20%	1,752	209.02	216.22	0.62	3.12	219.96	10.94	5.2%
12	30%	2,628	238.05	250.93	0.93	3.63	255.49	17.44	7.3%
12	40%	3,504	267.08	285.65	1.24	4.13	291.02	23.94	9.0%
12	50%	4,380	296.11	320.36	1.55	4.64	326.55	30.44	10.3%
12	75%	6,570	368.69	407.14	2.32	5.90	415.36	46.67	12.7%
15	20%	2,190	257.53	266.57	0.77	3.85	271.19	13.66	5.3%
15	30%	3,285	293.82	309.97	1.16	4.48	315.61	21.79	7.4%
15	40%	4,380	330.10	353.36	1.55	5.11	360.02	29.92	9.1%
15	50%	5,475	366.39	396.75	1.93	5.74	404.42	38.03	10.4%
15	75%	8,213	457.13	505.25	2.90	7.32	515.47	58.34	12.8%

ECT-1R Summer Average Energy On-Peak: 38%

Supporting Schedules:

NOTES TO SCHEDULE:
1) Bills do not include EPS, Regulatory Assessment, or Tax charges.
2) Franchise dollars are shown as an average percentage of total revenue requirement.
3) Proposed CRCC is calculated in accordance with the proposed Plan for Administration as filed in ACC Docket No. E-01345A-02-0403.
4) Present Rates are rates effective 7/1/2003.

Arizona Public Service Company

Typical General Service Bill Analysis
E-30 Summer (May - October)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
		Components of Proposed Bill				Change	
Monthly kWh	Monthly Bill under Present Rates	Base	CRCC	Franchise	Monthly Bill under Proposed Rates	Amount ($)	%
			(A) x $0.000353	[(C) + (D)] x 0.0144	(C) + (D) + (E)	(F) - (B)	(G) / (B)
30	9.00	11.31	0.01	0.16	11.48	2.48	27.6%
40	9.92	12.22	0.01	0.18	12.41	2.49	25.1%
50	10.83	13.13	0.02	0.19	13.34	2.51	23.2%
60	11.75	14.03	0.02	0.20	14.25	2.50	21.3%
70	12.67	14.94	0.02	0.22	15.18	2.51	19.8%
80	13.58	15.85	0.03	0.23	16.11	2.53	18.6%
90	14.50	16.76	0.03	0.24	17.03	2.53	17.4%
100	15.42	17.67	0.04	0.26	17.97	2.55	16.5%
125	17.71	19.94	0.04	0.29	20.27	2.56	14.5%
150	20.00	22.22	0.05	0.32	22.59	2.59	13.0%
175	22.29	24.49	0.06	0.35	24.90	2.61	11.7%
200	24.59	26.76	0.07	0.39	27.22	2.63	10.7%
225	26.88	29.03	0.08	0.42	29.53	2.65	9.9%
250	29.17	31.31	0.09	0.45	31.85	2.68	9.2%
275	31.46	33.58	0.10	0.48	34.16	2.70	8.6%
300	33.75	35.85	0.11	0.52	36.48	2.73	8.1%
325	36.05	38.13	0.11	0.55	38.79	2.74	7.6%
350	38.34	40.40	0.12	0.58	41.10	2.76	7.2%
375	40.63	42.67	0.13	0.62	43.42	2.79	6.9%
400	42.92	44.94	0.14	0.65	45.73	2.81	6.5%
425	45.21	47.22	0.15	0.68	48.05	2.84	6.3%
450	47.51	49.49	0.16	0.71	50.36	2.85	6.0%
475	49.80	51.76	0.17	0.75	52.68	2.88	5.8%
500	52.09	54.04	0.18	0.78	55.00	2.91	5.6%
600	61.26	63.13	0.21	0.91	64.25	2.99	4.9%
700	70.43	72.22	0.25	1.04	73.51	3.08	4.4%
800	79.59	81.31	0.28	1.17	82.76	3.17	4.0%
900	88.76	90.40	0.32	1.31	92.03	3.27	3.7%
1,000	97.93	99.49	0.35	1.44	101.28	3.35	3.4%
1,500	143.77	144.95	0.53	2.09	147.57	3.80	2.6%
2,000	189.61	190.40	0.71	2.75	193.86	4.25	2.2%
2,500	235.45	235.86	0.88	3.41	240.15	4.70	2.0%

Supporting Schedules:

NOTES TO SCHEDULE:
1) Bills do not include EPS, Regulatory Assessment, or Tax charges.
2) Franchise dollars are shown as an average percentage of total revenue requirement.
3) Proposed CRCC is calculated in accordance with the proposed Plan for Administration as filed in ACC Docket No. E-01345A-02-0403.
4) Present Rates are rates effective 7/1/2003.

Arizona Public Service Company

Typical General Service Bill Analysis
E-30 Winter (November-April)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
		Components of Proposed Bill				Change	
Monthly kWh	Monthly Bill under Present Rates	Base	CRCC	Franchise	Monthly Bill under Proposed Rates	Amount ($)	%
			(A) x $0.000353	[(C) + (D)] x 0.0144	(C) + (D) + (E)	(F) - (B)	(G) / (B)
30	9.30	11.61	0.01	0.17	11.79	2.49	26.8%
40	10.32	12.62	0.01	0.18	12.81	2.49	24.1%
50	11.34	13.63	0.02	0.20	13.85	2.51	22.1%
60	12.36	14.63	0.02	0.21	14.86	2.50	20.2%
70	13.38	15.64	0.02	0.23	15.89	2.51	18.8%
80	14.39	16.65	0.03	0.24	16.92	2.53	17.6%
90	15.41	17.66	0.03	0.25	17.94	2.53	16.4%
100	16.43	18.67	0.04	0.27	18.98	2.55	15.5%
125	18.97	21.19	0.04	0.31	21.54	2.57	13.5%
150	21.52	23.72	0.05	0.34	24.11	2.59	12.0%
175	24.06	26.24	0.06	0.38	26.68	2.62	10.9%
200	26.61	28.76	0.07	0.42	29.25	2.64	9.9%
225	29.15	31.28	0.08	0.45	31.81	2.66	9.1%
250	31.70	33.81	0.09	0.49	34.39	2.69	8.5%
275	34.24	36.33	0.10	0.52	36.95	2.71	7.9%
300	36.79	38.85	0.11	0.56	39.52	2.73	7.4%
325	39.33	41.38	0.11	0.60	42.09	2.76	7.0%
350	41.88	43.90	0.12	0.63	44.65	2.77	6.6%
375	44.42	46.42	0.13	0.67	47.22	2.80	6.3%
400	46.97	48.94	0.14	0.71	49.79	2.82	6.0%
425	49.51	51.47	0.15	0.74	52.36	2.85	5.8%
450	52.06	53.99	0.16	0.78	54.93	2.87	5.5%
475	54.60	56.51	0.17	0.82	57.50	2.90	5.3%
500	57.15	59.04	0.18	0.85	60.07	2.92	5.1%
600	67.32	69.13	0.21	1.00	70.34	3.02	4.5%
700	77.50	79.22	0.25	1.14	80.61	3.11	4.0%
800	87.68	89.31	0.28	1.29	90.88	3.20	3.6%
900	97.86	99.40	0.32	1.44	101.16	3.30	3.4%
1,000	108.04	109.49	0.35	1.58	111.42	3.38	3.1%
1,500	158.94	159.95	0.53	2.31	162.79	3.85	2.4%
2,000	209.83	210.40	0.71	3.04	214.15	4.32	2.1%
2,500	260.73	260.86	0.88	3.77	265.51	4.78	1.8%

Supporting Schedules:

NOTES TO SCHEDULE:
1) Bills do not include EPS, Regulatory Assessment, or Tax charges.
2) Franchise dollars are shown as an average percentage of total revenue requirement.
3) Proposed CRCC is calculated in accordance with the proposed Plan for Administration as filed in ACC Docket No. E-01345A-02-0403.
4) Present Rates are rates effective 7/1/2003.

Arizona Public Service Company

Typical General Service Bill Analysis
E-32 Winter (November-April)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
				Components of Proposed Bill				Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Base	CRCC	Franchise	Monthly Bill under Proposed Rates	Amount ($)	%
					(C) x $0.000353	[(E) + (F)] x 0.0144	(E) + (F) + (G)	(H) - (D)	(I) / (D)
10	15%	1,095	120.86	116.84	0.39	1.69	118.92	(1.94)	-1.6%
10	30%	2,190	221.47	216.43	0.77	3.13	220.33	(1.14)	-0.5%
10	45%	3,285	313.78	316.02	1.16	4.57	321.75	7.97	2.5%
10	60%	4,380	382.50	415.61	1.55	6.01	423.17	40.67	10.6%
10	75%	5,475	451.22	515.20	1.93	7.45	524.58	73.36	16.3%
100	15%	10,950	1,165.84	1,492.04	3.87	21.54	1,517.45	351.61	30.2%
100	30%	21,900	1,883.63	2,234.93	7.73	32.29	2,274.95	391.32	20.8%
100	45%	32,850	2,570.86	2,595.19	11.60	37.54	2,644.33	73.47	2.9%
100	60%	43,800	3,258.08	2,955.44	15.46	42.78	3,013.68	(244.40)	-7.5%
100	75%	54,750	3,927.76	3,315.70	19.33	48.02	3,383.05	(544.71)	-13.9%
200	15%	21,900	2,326.92	2,950.06	7.73	42.59	3,000.38	673.46	28.9%
200	30%	43,800	3,704.28	4,435.84	15.46	64.10	4,515.40	811.12	21.9%
200	45%	65,700	5,038.96	5,156.35	23.19	74.59	5,254.13	215.17	4.3%
200	60%	87,600	5,901.16	5,876.86	30.92	85.07	5,992.85	91.69	1.6%
200	75%	109,500	6,763.37	6,597.37	38.65	95.56	6,731.58	(31.79)	-0.5%
500	15%	54,750	5,730.10	7,324.13	19.33	105.75	7,449.21	1,719.11	30.0%
500	30%	109,500	8,803.67	11,038.57	38.65	159.51	11,236.73	2,433.06	27.6%
500	45%	164,250	10,959.17	12,839.85	57.98	185.73	13,083.56	2,124.39	19.4%
500	60%	219,000	13,114.68	14,641.12	77.31	211.95	14,930.38	1,815.70	13.8%
500	75%	273,750	15,270.19	16,442.40	96.63	238.16	16,777.19	1,507.00	9.9%
1,500	15%	164,250	17,064.32	17,843.10	57.98	257.78	18,158.86	1,094.54	6.4%
1,500	30%	328,500	24,226.70	28,986.43	115.96	419.07	29,521.46	5,294.76	21.9%
1,500	45%	492,750	30,693.22	34,390.26	173.94	497.72	35,061.92	4,368.70	14.2%
1,500	60%	657,000	37,159.74	39,794.08	231.92	576.37	40,602.37	3,442.63	9.3%
1,500	75%	821,250	43,626.26	45,197.91	289.90	655.02	46,142.83	2,516.57	5.8%
3,000	15%	328,500	34,065.65	34,733.41	115.96	501.83	35,351.20	1,285.55	3.8%
3,000	30%	657,000	47,361.24	57,020.08	231.92	824.43	58,076.43	10,715.19	22.6%
3,000	45%	985,500	60,294.29	67,827.73	347.88	981.73	69,157.34	8,863.05	14.7%
3,000	60%	1,314,000	73,227.33	78,635.38	463.84	1,139.03	80,238.25	7,010.92	9.6%
3,000	75%	1,642,500	86,160.38	89,443.03	579.80	1,296.33	91,319.16	5,158.78	6.0%

Supporting Schedules:

NOTES TO SCHEDULE:
1) Bills do not include EPS, Regulatory Assessment, or Tax charges.
2) Franchise dollars are shown as an average percentage of total revenue requirement.
3) Proposed CRCC is calculated in accordance with the proposed Plan for Administration as filed in ACC Docket No. E-01345A-02-0403.
4) Present Rates are rates effective 7/1/2003.
5) For purposes of calculating the monthly bill, E-32 customers are categorized in this manner:
   - 0 - 99 kW = self contained
   - 100 - 999 kW = Instrument-rated
   - 1000 and above = primary

Arizona Public Service Company

Typical General Service Bill Analysis
E-32 Summer (May-October)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
			Monthly Bill	Components of Proposed Bill			Monthly Bill	Change	
kW	Load Factor	Monthly kWh	under Present Rates	Base	CRCC	Franchise	under Proposed Rates	Amount ($)	%
					(C) x $0.000353	[(E) + (F)] x 0.0144	(E) + (F) + (G)	(H) - (D)	(I) / (D)
10	15%	1,095	132.70	127.79	0.39	1.85	130.03	(2.67)	-2.0%
10	30%	2,190	244.40	238.33	0.77	3.44	242.54	(1.86)	-0.8%
10	45%	3,285	346.95	348.87	1.16	5.04	355.07	8.12	2.3%
10	60%	4,380	423.48	459.41	1.55	6.64	467.60	44.12	10.4%
10	75%	5,475	500.01	569.95	1.93	8.24	580.12	80.11	16.0%
100	15%	10,950	1,291.01	1,601.54	3.87	23.12	1,628.53	337.52	26.1%
100	30%	21,900	2,090.03	2,453.93	7.73	35.45	2,497.11	407.08	19.5%
100	45%	32,850	2,855.33	2,923.69	11.60	42.27	2,977.56	122.23	4.3%
100	60%	43,800	3,620.62	3,393.44	15.46	49.09	3,457.99	(162.63)	-4.5%
100	75%	54,750	4,366.52	3,863.20	19.33	55.91	3,938.44	(428.08)	-9.8%
200	15%	21,900	2,578.02	3,169.06	7.73	45.75	3,222.54	644.52	25.0%
200	30%	43,800	4,111.82	4,873.84	15.46	70.41	4,959.71	847.89	20.6%
200	45%	65,700	5,598.45	5,813.35	23.19	84.05	5,920.59	322.14	5.8%
200	60%	87,600	6,562.71	6,752.86	30.92	97.69	6,881.47	318.76	4.9%
200	75%	109,500	7,526.97	7,692.37	38.65	111.33	7,842.35	315.38	4.2%
500	15%	54,750	6,350.72	7,871.63	19.33	113.63	8,004.59	1,653.87	26.0%
500	30%	109,500	9,776.37	12,133.57	38.65	175.28	12,347.50	2,571.13	26.3%
500	45%	164,250	12,187.01	14,482.35	57.98	209.38	14,749.71	2,562.70	21.0%
500	60%	219,000	14,597.65	16,831.12	77.31	243.48	17,151.91	2,554.26	17.5%
500	75%	273,750	17,008.29	19,179.90	96.63	277.58	19,554.11	2,545.82	15.0%
1,500	15%	164,250	18,915.67	19,485.60	57.98	281.43	19,825.01	909.34	4.8%
1,500	30%	328,500	26,916.94	32,271.43	115.96	466.38	32,853.77	5,936.83	22.1%
1,500	45%	492,750	34,148.86	39,317.76	173.94	568.68	40,060.38	5,911.52	17.3%
1,500	60%	657,000	41,380.79	46,364.08	231.92	670.98	47,266.98	5,886.19	14.2%
1,500	75%	821,250	48,612.72	53,410.41	289.90	773.28	54,473.59	5,860.87	12.1%
3,000	15%	328,500	37,763.11	38,018.41	115.96	549.13	38,683.50	920.39	2.4%
3,000	30%	657,000	52,627.79	63,590.08	231.92	919.04	64,741.04	12,113.25	23.0%
3,000	45%	985,500	67,091.65	77,682.73	347.88	1,123.64	79,154.25	12,062.60	18.0%
3,000	60%	1,314,000	81,555.50	91,775.38	463.84	1,328.24	93,567.46	12,011.96	14.7%
3,000	75%	1,642,500	96,019.36	105,868.03	579.80	1,532.85	107,980.68	11,961.32	12.5%

Supporting Schedules:

NOTES TO SCHEDULE:
1) Bills do not include EPS, Regulatory Assessment, or Tax charges.
2) Franchise dollars are shown as an average percentage of total revenue requirement.
3) Proposed CRCC is calculated in accordance with the proposed Plan for Administration as filed in ACC Docket No. E-01345A-02-0403.
4) Present Rates are rates effective 7/1/2003.
5) For purposes of calculating the monthly bill, E-32 customers are categorized in this manner:
   0 - 99 kW = self contained
   100 - 999 kW = Instrument-rated

Arizona Public Service Company

Typical General Service Bill Analysis
E-34

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
				Components of Proposed Bill				Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Base	CRCC	Franchise	Monthly Bill under Proposed Rates	Amount ($)	%
					(C) x $0.000353	[(E) + (F)] x 0.0144	(E) + (F) + (G)	(H) - (D)	(I) / (D)
3,000	20%	438,000	47,951.88	51,587.70	154.61	745.09	52,487.40	4,535.52	9.5%
3,000	30%	657,000	54,797.82	58,779.66	231.92	849.77	59,861.35	5,063.53	9.2%
3,000	40%	876,000	61,643.76	65,971.62	309.23	954.44	67,235.29	5,591.53	9.1%
3,000	50%	1,095,000	68,489.70	73,163.58	386.54	1,059.12	74,609.24	6,119.54	8.9%
3,000	75%	1,642,500	85,604.55	91,143.48	579.80	1,320.82	93,044.10	7,439.55	8.7%
3,500	20%	511,000	55,538.86	60,171.02	180.38	869.06	61,220.46	5,681.60	10.2%
3,500	30%	766,500	63,525.79	68,561.64	270.57	991.18	69,823.39	6,297.60	9.9%
3,500	40%	1,022,000	71,512.72	76,952.26	360.77	1,113.31	78,426.34	6,913.62	9.7%
3,500	50%	1,277,500	79,499.65	85,342.88	450.96	1,235.43	87,029.27	7,529.62	9.5%
3,500	75%	1,916,250	99,466.98	106,319.43	676.44	1,540.74	108,536.61	9,069.63	9.1%
4,000	20%	584,000	63,125.84	68,754.34	206.15	993.03	69,953.52	6,827.68	10.8%
4,000	30%	876,000	72,253.76	78,343.62	309.23	1,132.60	79,785.45	7,531.69	10.4%
4,000	40%	1,168,000	81,381.68	87,932.90	412.30	1,272.17	89,617.37	8,235.69	10.1%
4,000	50%	1,460,000	90,509.60	97,522.18	515.38	1,411.74	99,449.30	8,939.70	9.9%
4,000	75%	2,190,000	113,329.40	121,495.38	773.07	1,760.67	124,029.12	10,699.72	9.4%
4,500	20%	657,000	70,712.82	77,337.66	231.92	1,117.00	78,686.58	7,973.76	11.3%
4,500	30%	985,500	80,981.73	88,125.60	347.88	1,274.02	89,747.50	8,765.77	10.8%
4,500	40%	1,314,000	91,250.64	98,913.54	463.84	1,431.03	100,808.41	9,557.77	10.5%
4,500	50%	1,642,500	101,519.55	109,701.48	579.80	1,588.05	111,869.33	10,349.78	10.2%
4,500	75%	2,463,750	127,191.83	136,671.33	869.70	1,980.59	139,521.62	12,329.79	9.7%
5,000	20%	730,000	78,299.80	85,920.98	257.69	1,240.97	87,419.64	9,119.84	11.6%
5,000	30%	1,095,000	89,709.70	97,907.58	386.54	1,415.44	99,709.56	9,999.86	11.1%
5,000	40%	1,460,000	101,119.60	109,894.18	515.38	1,589.90	111,999.46	10,879.86	10.8%
5,000	50%	1,825,000	112,529.50	121,880.78	644.23	1,764.36	124,289.37	11,759.87	10.5%
5,000	75%	2,737,500	141,054.25	151,847.28	966.34	2,200.52	155,014.14	13,959.89	9.9%
6,000	20%	876,000	93,473.76	103,087.62	309.23	1,488.91	104,885.76	11,412.00	12.2%
6,000	30%	1,314,000	107,165.64	117,471.54	463.84	1,698.27	119,633.65	12,468.01	11.6%
6,000	40%	1,752,000	120,857.52	131,855.46	618.46	1,907.62	134,381.54	13,524.02	11.2%
6,000	50%	2,190,000	134,549.40	146,239.38	773.07	2,116.98	149,129.43	14,580.03	10.8%
6,000	75%	3,285,000	168,779.10	182,199.18	1,159.61	2,640.37	185,999.16	17,220.06	10.2%
7,000	20%	1,022,000	108,647.72	120,254.26	360.77	1,736.86	122,351.89	13,704.17	12.6%
7,000	30%	1,533,000	124,621.58	137,035.50	541.15	1,981.10	139,557.75	14,936.17	12.0%
7,000	40%	2,044,000	140,595.44	153,816.74	721.53	2,225.35	156,763.62	16,168.18	11.5%
7,000	50%	2,555,000	156,569.30	170,597.98	901.92	2,469.60	173,969.50	17,400.20	11.1%
7,000	75%	3,832,500	196,503.95	212,551.08	1,352.87	3,080.22	216,984.17	20,480.22	10.4%

Supporting Schedules:

NOTES TO SCHEDULE:
1) Bills do not include EPS, Regulatory Assessment, or Tax charges.
2) Franchise dollars are shown as an average percentage of total revenue requirement.
3) Proposed CRCC is calculated in accordance with the proposed Plan for Administration as filed in ACC Docket No. E-01345A-02-0403.
4) Present Rates are rates effective 7/1/2003.
5) For purposes of calculating the monthly bill, E-34 customers are categorized as primary customers.

Arizona Public Service Company

Typical General Service Bill Analysis
E-35

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
			Monthly Bill	Components of Proposed Bill			Monthly Bill	Change	
kW	Load Factor	Monthly kWh	under Present Rates	Base	CRCC	Franchise	under Proposed Rates	Amount ($)	%
					(C) x $0.000353	[(E) + (F)] x 0.0144	(E) + (F) + (G)	(H) - (D)	(I) / (D)
3,000	20%	438,000	53,053.70	52,490.52	154.61	758.09	53,403.22	349.52	0.7%
3,000	30%	657,000	58,780.55	59,329.89	231.92	857.69	60,419.50	1,638.95	2.8%
3,000	40%	876,000	64,507.40	66,169.26	309.23	957.29	67,435.78	2,928.38	4.5%
3,000	50%	1,095,000	70,234.25	73,008.63	386.54	1,056.89	74,452.06	4,217.81	6.0%
3,000	75%	1,642,500	84,551.38	90,107.06	579.80	1,305.89	91,992.75	7,441.37	8.8%
3,500	20%	511,000	61,487.65	61,224.31	180.38	884.23	62,288.92	801.27	1.3%
3,500	30%	766,500	68,168.98	69,203.58	270.57	1,000.43	70,474.58	2,305.60	3.4%
3,500	40%	1,022,000	74,850.30	77,182.84	360.77	1,116.63	78,660.24	3,809.94	5.1%
3,500	50%	1,277,500	81,531.63	85,162.11	450.96	1,232.83	86,845.90	5,314.27	6.5%
3,500	75%	1,916,250	98,234.94	105,110.27	676.44	1,523.33	107,310.04	9,075.10	9.2%
4,000	20%	584,000	69,921.60	69,958.10	206.15	1,010.37	71,174.62	1,253.02	1.8%
4,000	30%	876,000	77,557.40	79,077.26	309.23	1,143.17	80,529.66	2,972.26	3.8%
4,000	40%	1,168,000	85,193.20	88,196.42	412.30	1,275.97	89,884.69	4,691.49	5.5%
4,000	50%	1,460,000	92,829.00	97,315.58	515.38	1,408.77	99,239.73	6,410.73	6.9%
4,000	75%	2,190,000	111,918.50	120,113.48	773.07	1,740.77	122,627.32	10,708.82	9.6%
4,500	20%	657,000	78,355.55	78,691.89	231.92	1,136.50	80,060.31	1,704.76	2.2%
4,500	30%	985,500	86,945.83	88,950.95	347.88	1,285.90	90,584.73	3,638.90	4.2%
4,500	40%	1,314,000	95,536.10	99,210.00	463.84	1,435.30	101,109.14	5,573.04	5.8%
4,500	50%	1,642,500	104,126.38	109,469.06	579.80	1,584.70	111,633.56	7,507.18	7.2%
4,500	75%	2,463,750	125,602.06	135,116.69	869.70	1,958.20	137,944.59	12,342.53	9.8%
5,000	20%	730,000	86,789.50	87,425.68	257.69	1,262.64	88,946.01	2,156.51	2.5%
5,000	30%	1,095,000	96,334.25	98,824.63	386.54	1,428.64	100,639.81	4,305.56	4.5%
5,000	40%	1,460,000	105,879.00	110,223.58	515.38	1,594.64	112,333.60	6,454.60	6.1%
5,000	50%	1,825,000	115,423.75	121,622.53	644.23	1,760.64	124,027.40	8,603.65	7.5%
5,000	75%	2,737,500	139,285.63	150,119.91	966.34	2,175.64	153,261.89	13,976.26	10.0%
6,000	20%	876,000	103,657.40	104,893.26	309.23	1,514.92	106,717.41	3,060.01	3.0%
6,000	30%	1,314,000	115,111.10	118,572.00	463.84	1,714.12	120,749.96	5,638.86	4.9%
6,000	40%	1,752,000	126,564.80	132,250.74	618.46	1,913.32	134,782.52	8,217.72	6.5%
6,000	50%	2,190,000	138,018.50	145,929.48	773.07	2,112.52	148,815.07	10,796.57	7.8%
6,000	75%	3,285,000	166,652.75	180,126.33	1,159.61	2,610.52	183,896.46	17,243.71	10.3%
7,000	20%	1,022,000	120,525.30	122,360.84	360.77	1,767.19	124,488.80	3,963.50	3.3%
7,000	30%	1,533,000	133,887.95	138,319.37	541.15	1,999.59	140,860.11	6,972.16	5.2%
7,000	40%	2,044,000	147,250.60	154,277.90	721.53	2,231.99	157,231.42	9,980.82	6.8%
7,000	50%	2,555,000	160,613.25	170,236.43	901.92	2,464.39	173,602.74	12,989.49	8.1%
7,000	75%	3,832,500	194,019.88	210,132.76	1,352.87	3,045.39	214,531.02	20,511.14	10.6%

E-35 Average Energy On-Peak: 34%

Supporting Schedules:

NOTES TO SCHEDULE:
1) Bills do not include EPS, Regulatory Assessment, or Tax charges.
2) Franchise dollars are shown as an average percentage of total revenue requirement.
3) Proposed CRCC is calculated in accordance with the proposed Plan for Administration as filed in ACC Docket No. E-01345A-02-0403.
4) Present Rates are rates effective 7/1/2003.
5) For purposes of calculating the monthly bill, E-34 customers are categorized as primary customers.

Arizona Public Service Company

Typical General Service Bill Analysis
E-221 Water Pumping Power

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
				Components of Proposed Bill				Change	
kW	Load Factor	kWh	Monthly Bill under Present Rates	Base	CRCC	Franchise	Monthly Bill Under Proposed Rates	Amount $	%
					(C) x $0.000353	[(E) + (F)] x 0.0144	(E) + (F) + (G)	(H) - (D)	(I) / (D)
10	20%	1,460	132.52	136.15	0.52	1.97	138.63	6.11	4.6%
10	35%	2,555	203.05	211.83	0.90	3.06	215.79	12.74	6.3%
10	50%	3,650	265.97	275.36	1.29	3.98	280.63	14.66	5.5%
10	65%	4,745	323.89	336.26	1.67	4.87	342.81	18.92	5.8%
10	80%	5,840	381.80	397.17	2.06	5.75	404.98	23.17	6.1%
30	20%	4,380	353.00	373.95	1.55	5.41	380.91	27.91	7.9%
30	35%	7,665	564.58	600.98	2.71	8.69	612.38	47.79	8.5%
30	50%	10,950	747.83	791.58	3.87	11.45	806.90	59.07	7.9%
30	65%	14,235	921.58	974.29	5.02	14.10	993.42	71.84	7.8%
30	80%	17,520	1,095.32	1,157.00	6.18	16.75	1,179.94	84.62	7.7%
75	20%	10,950	849.07	909.00	3.87	13.15	926.02	76.94	9.1%
75	35%	19,163	1,378.07	1,476.60	6.76	21.36	1,504.73	126.66	9.2%
75	50%	27,375	1,832.01	1,953.08	9.66	28.26	1,991.01	159.00	8.7%
75	65%	35,588	2,266.40	2,409.89	12.56	34.88	2,457.33	190.94	8.4%
75	80%	43,800	2,700.73	2,866.64	15.46	41.50	2,923.60	222.87	8.3%
100	20%	14,600	1,124.67	1,206.26	5.15	17.44	1,228.85	104.19	9.3%
100	35%	25,550	1,829.96	1,963.01	9.02	28.40	2,000.43	170.47	9.3%
100	50%	36,500	2,434.33	2,598.36	12.88	37.60	2,648.84	214.51	8.8%
100	65%	47,450	3,013.48	3,207.39	16.75	46.43	3,270.57	257.09	8.5%
100	80%	58,400	3,592.62	3,816.43	20.62	55.25	3,892.30	299.68	8.3%
150	20%	21,900	1,675.86	1,800.76	7.73	26.04	1,834.53	158.67	9.5%
150	35%	38,325	2,733.79	2,935.89	13.53	42.47	2,991.89	258.10	9.4%
150	50%	54,750	3,638.97	3,888.91	19.33	56.28	3,964.51	325.54	8.9%
150	65%	71,175	4,507.69	4,802.47	25.12	69.52	4,897.11	389.42	8.6%
150	80%	87,600	5,376.41	5,716.02	30.92	82.76	5,829.70	453.29	8.4%
200	20%	29,200	2,227.05	2,395.26	10.31	34.64	2,440.21	213.16	9.6%
200	35%	51,100	3,637.63	3,908.77	18.04	56.55	3,983.36	345.72	9.5%
200	50%	73,000	4,843.62	5,179.46	25.77	74.96	5,280.18	436.57	9.0%
200	65%	94,900	6,001.91	6,397.54	33.50	92.61	6,523.64	521.74	8.7%
200	80%	116,800	7,160.20	7,615.62	41.23	110.26	7,767.10	606.91	8.5%
300	20%	43,800	3,329.44	3,584.27	15.46	51.84	3,651.57	322.13	9.7%
300	35%	76,650	5,445.31	5,854.53	27.06	84.69	5,966.28	520.98	9.6%
300	50%	109,500	7,252.90	7,760.57	38.65	112.31	7,911.53	658.63	9.1%
300	65%	142,350	8,990.34	9,587.68	50.25	138.79	9,776.72	786.38	8.7%
300	80%	175,200	10,727.77	11,414.80	61.85	165.26	11,641.91	914.13	8.5%

<u>Supporting Schedules:</u>

NOTES TO SCHEDULE:
1) Bills do not include EPS, Regulatory Assessment, or Tax charges.
2) Franchise dollars are shown as an average percentage of total revenue requirement.
3) Proposed CRCC is calculated in accordance with the proposed Plan for Administration as filed in ACC Docket No. E-01345A-02-0403.
4) Present Rates are rates effective 7/1/2003.

H-5

ARIZONA PUBLIC SERVICE COMPANY
BILL COUNT

BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE
TEST YEAR ENDED DECEMBER 31, 2002 UNADJUSTED

RATE SCHEDULE: E-10
DESCRIPTION: Residential Electric Rate Applicable in All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				BILLS		CONSUMPTION				BILLS		CONSUMPTION		
Line No.	BLOCK (kWh)	Number of BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	Number of BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	Line No.
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
1	0	10,969	-	10,969	1.86%	-	0.00%	15,271	-	15,271	2.55%	-	0.00%	1
2	1-50	11,820	271,814	22,789	3.86%	271,814	0.05%	16,499	389,675	31,770	5.30%	389,675	0.10%	2
3	51-100	12,363	946,538	35,152	5.96%	1,218,352	0.23%	14,750	1,119,056	46,520	7.76%	1,508,731	0.37%	3
4	101-150	15,188	1,919,128	50,340	8.54%	3,137,480	0.58%	16,550	2,090,400	63,070	10.52%	3,599,131	0.88%	4
5	151-200	17,440	3,069,531	67,780	11.49%	6,207,011	1.15%	20,935	3,692,944	84,005	14.01%	7,292,075	1.79%	5
6	201-250	20,194	4,566,339	87,974	14.92%	10,773,350	2.00%	25,767	5,828,303	109,772	18.30%	13,120,378	3.22%	6
7	251-300	22,078	6,090,648	110,052	18.66%	16,863,998	3.13%	30,060	8,293,185	139,832	23.32%	21,413,563	5.25%	7
8	301-350	23,562	7,672,869	133,614	22.66%	24,536,867	4.55%	32,708	10,654,519	172,540	28.77%	32,068,082	7.86%	8
9	351-400	24,097	9,049,708	157,711	26.75%	33,586,575	6.23%	33,104	12,431,471	205,644	34.29%	44,499,553	10.91%	9
10	401-450	24,559	10,451,980	182,270	30.91%	44,038,555	8.17%	32,816	13,960,432	238,460	39.76%	58,459,985	14.34%	10
11	451-500	24,059	11,439,814	206,329	34.99%	55,478,369	10.29%	32,010	15,218,689	270,470	45.10%	73,678,674	18.07%	11
12	501-550	23,480	12,337,146	229,809	38.97%	67,815,515	12.58%	30,040	15,776,309	300,510	50.11%	89,454,983	21.94%	12
13	551-600	22,594	12,997,077	252,403	42.80%	80,812,592	14.99%	28,123	16,172,619	328,633	54.80%	105,627,602	25.90%	13
14	601-650	21,344	13,347,515	273,747	46.42%	94,160,107	17.46%	25,777	16,114,869	354,410	59.09%	121,742,471	29.85%	14
15	651-700	20,011	13,512,021	293,758	49.82%	107,672,129	19.97%	23,930	16,158,276	378,340	63.08%	137,900,747	33.82%	15
16	701-750	18,976	13,762,129	312,734	53.04%	121,434,258	22.52%	21,479	15,573,574	399,819	66.66%	153,474,321	37.63%	16
17	751-800	17,702	13,726,628	330,436	56.04%	135,160,886	25.07%	19,261	14,929,446	419,080	69.88%	168,403,767	41.30%	17
18	801-850	16,546	13,652,219	346,982	58.84%	148,813,105	27.60%	17,566	14,492,553	436,646	72.81%	182,896,320	44.85%	18
19	851-900	15,054	13,175,147	362,036	61.40%	161,988,252	30.04%	15,756	13,788,608	452,402	75.43%	196,684,928	48.23%	19
20	901-950	13,786	12,754,824	375,822	63.74%	174,743,076	32.41%	14,083	13,029,337	466,485	77.78%	209,714,265	51.43%	20
21	951-1,000	13,071	12,749,142	388,893	65.95%	187,492,218	34.78%	12,888	12,566,915	479,373	79.93%	222,281,180	54.51%	21
22	1,001-1,100	23,555	24,718,033	412,448	69.95%	212,210,251	39.36%	21,753	22,815,530	501,126	83.56%	245,096,710	60.10%	22
23	1,101-1,200	20,711	23,808,472	433,159	73.46%	236,018,723	43.78%	17,920	20,587,835	519,046	86.54%	265,684,545	65.15%	23
24	1,201-1,300	18,321	22,898,836	451,480	76.57%	258,917,559	48.02%	14,270	17,814,439	533,316	88.92%	283,498,984	69.52%	24
25	1,301-1,400	16,412	22,152,334	467,892	79.35%	281,069,893	52.13%	11,562	15,600,173	544,878	90.85%	299,099,157	73.35%	25
26	1,401-1,500	14,781	21,425,165	482,673	81.86%	302,495,058	56.11%	9,538	13,815,654	554,416	92.44%	312,914,811	76.73%	26
27	1,501-1,600	13,086	20,275,629	495,759	84.07%	322,770,687	59.87%	7,745	11,998,926	562,161	93.73%	324,913,737	79.68%	27
28	1,601-1,700	11,734	19,361,956	507,493	86.06%	342,132,643	63.46%	6,355	10,478,978	568,516	94.79%	335,392,715	82.25%	28
29	1,701-1,800	10,426	18,241,183	517,919	87.83%	360,373,826	66.84%	5,371	9,393,471	573,887	95.69%	344,786,186	84.55%	29
30	1,801-1,900	9,341	17,278,588	527,260	89.42%	377,652,414	70.05%	4,265	7,882,744	578,152	96.40%	352,668,930	86.48%	30
31	1,901-2,000	8,301	16,181,088	535,561	90.82%	393,833,502	73.05%	3,536	6,891,402	581,688	96.99%	359,560,332	88.17%	31
32	2,001-2,500	28,640	63,633,257	564,201	95.68%	457,466,758	84.85%	10,151	22,462,617	591,839	98.68%	382,022,949	93.68%	32
33	2,501-3,000	13,759	37,430,338	577,960	98.02%	494,897,096	91.79%	4,181	11,347,961	596,020	99.38%	393,370,910	96.46%	33
34	3,001-4,000	8,869	29,911,639	586,829	99.52%	524,808,736	97.34%	2,693	9,105,339	598,713	99.83%	402,476,249	98.70%	34
35	4,001-5,000	1,917	8,417,131	588,746	99.84%	533,225,867	98.90%	651	2,863,699	599,364	99.94%	405,339,948	99.40%	35
36	5,001-10,000	873	5,278,982	589,619	99.99%	538,504,848	99.88%	365	2,224,533	599,729	100.00%	407,564,481	99.94%	36
37	10,001-20,000	41	518,399	589,660	100.00%	539,023,247	99.98%	14	164,141	599,743	100.00%	407,728,622	99.98%	37
38	over 20,000	3	130,967	589,663	100.00%	539,154,214	100.00%	1	68,240	599,744	100.00%	407,796,862	100.00%	38

Summer:
Average Number of Customers: 98,277
Average Consumption: 914 kWh per bill
Median Consumption: 703 kWh per bill

Winter:
Average Number of Customers: 99,957
Average Consumption: 680 kWh per bill
Median Consumption: 549 kWh per bill

Supporting Schedules:

Recap Schedules:

ARIZONA PUBLIC SERVICE COMPANY
BILL COUNT
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE
TEST YEAR ENDED DECEMBER 31, 2002 UNADJUSTED

RATE SCHEDULE: E-12
DESCRIPTION: Residential Electric Rate Applicable in All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				BILLS		CONSUMPTION				BILLS		CONSUMPTION		
Line No.	BLOCK (kWh)	Number of BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	Number of BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	Line No.
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
1	0	73,255	-	73,255	3.16%	-	0.00%	56,841	-	56,841	2.42%	-	0.00%	1
2	1-50	79,014	1,750,788	152,269	6.58%	1,750,788	0.10%	84,368	1,991,797	141,209	6.01%	1,991,797	0.15%	2
3	51-100	68,922	5,241,353	221,191	9.55%	6,992,141	0.39%	80,417	6,112,355	221,626	9.43%	8,104,152	0.60%	3
4	101-150	74,784	9,409,201	295,975	12.78%	16,401,342	0.92%	91,457	11,543,646	313,083	13.31%	19,647,798	1.44%	4
5	151-200	79,883	14,039,337	375,858	16.23%	30,440,678	1.71%	108,114	19,055,579	421,197	17.91%	38,703,377	2.84%	5
6	201-250	85,385	19,279,079	461,243	19.92%	49,719,758	2.79%	126,480	28,598,333	547,677	23.29%	67,301,710	4.94%	6
7	251-300	90,404	24,918,937	551,647	23.82%	74,638,695	4.19%	138,420	38,174,381	686,097	29.18%	105,476,091	7.75%	7
8	301-350	94,469	30,766,628	646,116	27.90%	105,405,323	5.91%	144,305	46,984,216	830,402	35.31%	152,460,307	11.20%	8
9	351-400	97,239	36,519,296	743,355	32.10%	141,924,619	7.96%	144,493	54,240,356	974,895	41.46%	206,700,663	15.18%	9
10	401-450	98,295	41,819,955	841,650	36.35%	183,744,574	10.30%	138,976	59,111,317	1,113,871	47.37%	265,811,980	19.53%	10
11	451-500	96,590	45,919,063	938,240	40.52%	229,663,637	12.88%	130,874	62,189,105	1,244,745	52.94%	328,001,085	24.10%	11
12	501-550	94,573	49,687,061	1,032,813	44.61%	279,350,698	15.67%	121,661	63,898,051	1,366,406	58.11%	391,899,136	28.79%	12
13	551-600	90,980	52,341,905	1,123,793	48.53%	331,692,602	18.60%	110,323	63,444,017	1,476,729	62.80%	455,343,153	33.45%	13
14	601-650	86,409	54,032,192	1,210,202	52.27%	385,724,794	21.63%	100,649	62,913,980	1,577,378	67.08%	518,257,133	38.07%	14
15	651-700	82,005	55,373,048	1,292,207	55.81%	441,097,843	24.74%	89,351	60,320,476	1,666,729	70.88%	578,577,609	42.50%	15
16	701-750	77,061	55,886,951	1,369,268	59.14%	496,984,794	27.87%	79,821	57,872,752	1,746,550	74.28%	636,450,361	46.76%	16
17	751-800	72,384	56,113,330	1,441,652	62.26%	553,098,124	31.02%	70,389	54,555,609	1,816,939	77.27%	691,005,970	50.76%	17
18	801-850	67,376	55,603,404	1,509,028	65.17%	608,701,527	34.14%	62,461	51,524,982	1,879,400	79.93%	742,530,952	54.55%	18
19	851-900	62,081	54,328,374	1,571,109	67.85%	663,029,901	37.18%	54,890	48,030,183	1,934,290	82.26%	790,561,135	58.08%	19
20	901-950	57,874	53,545,371	1,628,983	70.35%	716,575,273	40.19%	47,678	44,103,327	1,981,968	84.29%	834,664,462	61.32%	20
21	951-1,000	54,357	53,008,068	1,683,340	72.70%	769,583,340	43.16%	42,480	41,413,573	2,024,448	86.09%	876,078,035	64.36%	21
22	1,001-1,100	96,393	101,139,761	1,779,733	76.86%	870,723,101	48.83%	69,998	73,373,236	2,094,446	89.07%	949,451,271	69.75%	22
23	1,101-1,200	82,575	94,895,161	1,862,308	80.43%	965,618,262	54.15%	53,677	61,642,109	2,148,123	91.35%	1,011,093,380	74.28%	23
24	1,201-1,300	70,924	88,592,265	1,933,232	83.49%	1,054,210,527	59.12%	41,485	51,784,646	2,189,608	93.12%	1,062,878,026	78.08%	24
25	1,301-1,400	60,670	81,850,704	1,993,902	86.11%	1,136,061,231	63.71%	32,199	43,424,711	2,221,807	94.49%	1,106,302,737	81.27%	25
26	1,401-1,500	51,004	73,910,912	2,044,906	88.32%	1,209,972,143	67.86%	25,160	36,436,848	2,246,967	95.56%	1,142,739,585	83.95%	26
27	1,501-1,600	43,276	67,037,640	2,088,182	90.18%	1,277,009,783	71.62%	19,577	30,309,086	2,266,544	96.39%	1,173,048,671	86.18%	27
28	1,601-1,700	36,690	60,505,916	2,124,872	91.77%	1,337,515,699	75.01%	15,475	25,509,621	2,282,019	97.05%	1,198,558,292	88.05%	28
29	1,701-1,800	30,743	53,767,959	2,155,615	93.10%	1,391,283,658	78.03%	12,336	21,575,341	2,294,355	97.57%	1,220,133,633	89.63%	29
30	1,801-1,900	25,969	48,016,286	2,181,584	94.22%	1,439,299,944	80.72%	9,861	18,229,373	2,304,216	97.99%	1,238,363,006	90.97%	30
31	1,901-2,000	21,529	41,953,193	2,203,113	95.15%	1,481,253,136	83.07%	8,055	15,693,907	2,312,271	98.33%	1,254,056,913	92.13%	31
32	2,001-2,500	64,190	142,121,632	2,267,303	97.92%	1,623,374,768	91.04%	21,902	48,424,413	2,334,173	99.27%	1,302,481,326	95.68%	32
33	2,501-3,000	25,915	70,282,940	2,293,218	99.04%	1,693,657,708	94.98%	8,848	24,026,027	2,343,021	99.64%	1,326,507,353	97.45%	33
34	3,001-4,000	15,737	53,120,484	2,308,955	99.72%	1,746,778,192	97.96%	5,779	19,496,998	2,348,800	99.89%	1,346,004,351	98.88%	34
35	4,001-5,000	3,786	16,634,949	2,312,741	99.88%	1,763,413,141	98.90%	1,481	6,538,043	2,350,281	99.95%	1,352,542,394	99.36%	35
36	5,001-10,000	2,451	15,443,309	2,315,192	99.99%	1,778,856,450	99.76%	1,030	6,460,052	2,351,311	100.00%	1,359,002,446	99.84%	36
37	10,001-20,000	246	3,139,151	2,315,438	100.00%	1,781,995,601	99.94%	96	1,187,240	2,351,407	100.00%	1,360,189,686	99.92%	37
38	over 20,000	20	1,103,723	2,315,458	100.00%	1,783,099,324	100.00%	20	1,042,692	2,351,427	100.00%	1,361,232,378	100.00%	38

	Summer		Winter	
Average Number of Customers:	385,910		391,905	
Average Consumption:	770	kWh per bill	579	kWh per bill
Median Consumption:	620	kWh per bill	474	kWh per bill

Supporting Schedules:

Recap Schedules:

ARIZONA PUBLIC SERVICE COMPANY
BILL COUNT
BILLING ACTIVITY BY BLOCK FOR EACH MAJOR RATE
TEST YEAR ENDED DECEMBER 31, 2002 UNADJUSTED

RATE SCHEDULE: ET-1
DESCRIPTION: Residential Electric Rate Applicable in All Territory Served by Company

		SUMMER (May through October)						WINTER (November through April)						
				CUMULATIVE						CUMULATIVE				
				BILLS		CONSUMPTION				BILLS		CONSUMPTION		
Line No.	BLOCK (kWh)	Number of BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	Number of BILLS BY BLOCK	CONSUMPTION kWh BY BLOCK	Number	% of Total	Amount (kWh)	% of Total	Line No.
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
1	0	7,585	-	7,585	0.46%	-	0.00%	6,809	-	6,809	0.42%	-	0.00%	1
2	1-50	7,637	178,525	15,222	0.92%	178,525	0.01%	9,586	232,695	16,395	1.00%	232,695	0.01%	2
3	51-100	6,530	496,872	21,752	1.31%	675,396	0.02%	10,102	773,257	26,497	1.62%	1,005,952	0.06%	3
4	101-150	7,273	914,168	29,025	1.75%	1,589,564	0.06%	11,590	1,464,008	38,087	2.33%	2,469,960	0.14%	4
5	151-200	7,677	1,347,547	36,702	2.22%	2,937,111	0.10%	14,925	2,638,932	53,012	3.25%	5,108,892	0.30%	5
6	201-250	8,573	1,938,217	45,275	2.73%	4,875,328	0.17%	21,742	4,938,596	74,754	4.58%	10,047,488	0.59%	6
7	251-300	9,621	2,656,523	54,896	3.31%	7,531,851	0.26%	30,365	8,403,076	105,119	6.44%	18,450,564	1.07%	7
8	301-350	11,580	3,777,063	66,476	4.01%	11,308,914	0.39%	39,221	12,806,793	144,340	8.85%	31,257,357	1.82%	8
9	351-400	13,484	5,072,267	79,960	4.83%	16,381,181	0.57%	47,483	17,858,413	191,823	11.76%	49,115,770	2.86%	9
10	401-450	15,605	6,649,451	95,565	5.77%	23,030,632	0.80%	53,497	22,787,979	245,320	15.03%	71,903,749	4.19%	10
11	451-500	18,059	8,600,082	113,624	6.86%	31,630,714	1.10%	57,333	27,276,914	302,653	18.55%	99,180,663	5.78%	11
12	501-550	20,447	10,753,822	134,071	8.09%	42,384,536	1.47%	60,313	31,702,420	362,966	22.24%	130,883,083	7.62%	12
13	551-600	22,808	13,135,174	156,879	9.47%	55,519,710	1.93%	62,320	35,874,982	425,286	26.06%	166,758,065	9.71%	13
14	601-650	24,831	15,536,782	181,710	10.97%	71,056,492	2.47%	62,561	39,134,244	487,847	29.90%	205,892,309	11.99%	14
15	651-700	26,390	17,834,100	208,100	12.56%	88,890,592	3.09%	63,388	42,816,076	551,235	33.78%	248,708,385	14.49%	15
16	701-750	28,290	20,532,086	236,390	14.27%	109,422,677	3.80%	62,654	45,452,135	613,889	37.62%	294,160,520	17.13%	16
17	751-800	29,705	23,043,368	266,095	16.06%	132,466,045	4.60%	61,596	47,762,998	675,485	41.39%	341,923,518	19.91%	17
18	801-850	31,347	25,883,627	297,442	17.96%	158,349,672	5.50%	59,829	49,384,474	735,314	45.06%	391,307,992	22.79%	18
19	851-900	33,007	28,907,105	330,449	19.95%	187,256,777	6.51%	58,504	51,215,473	793,818	48.65%	442,523,465	25.77%	19
20	901-950	33,903	31,382,276	364,352	22.00%	218,639,053	7.60%	56,767	52,526,255	850,585	52.12%	495,049,720	28.83%	20
21	951-1,000	34,914	34,063,038	399,266	24.10%	252,702,091	8.78%	54,757	53,409,876	905,342	55.48%	548,459,596	31.94%	21
22	1,001-1,100	71,598	75,234,924	470,864	28.43%	327,937,015	11.40%	102,311	107,386,373	1,007,653	61.75%	655,845,969	38.20%	22
23	1,101-1,200	74,220	85,404,894	545,084	32.91%	413,341,909	14.37%	91,647	105,343,791	1,099,300	67.37%	761,189,760	44.33%	23
24	1,201-1,300	75,517	94,442,128	620,601	37.47%	507,784,037	17.65%	81,432	101,747,026	1,180,732	72.36%	862,936,786	50.26%	24
25	1,301-1,400	75,492	101,939,961	696,093	42.02%	609,723,998	21.19%	70,020	94,467,817	1,250,752	76.65%	957,404,603	55.76%	25
26	1,401-1,500	74,815	108,518,372	770,908	46.54%	718,242,370	24.96%	60,837	88,168,811	1,311,589	80.38%	1,045,573,414	60.90%	26
27	1,501-1,600	73,567	114,045,355	844,475	50.98%	832,287,725	28.93%	52,001	80,557,523	1,363,590	83.56%	1,126,130,937	65.59%	27
28	1,601-1,700	70,881	116,967,797	915,356	55.26%	949,255,522	32.99%	43,919	72,438,414	1,407,509	86.25%	1,198,569,351	69.81%	28
29	1,701-1,800	67,851	118,757,552	983,207	59.36%	1,068,013,074	37.12%	36,741	64,267,700	1,444,250	88.51%	1,262,837,051	73.55%	29
30	1,801-1,900	64,357	119,047,122	1,047,564	63.24%	1,187,060,196	41.26%	31,136	57,571,994	1,475,386	90.41%	1,320,409,045	76.90%	30
31	1,901-2,000	59,820	116,644,620	1,107,384	66.85%	1,303,704,816	45.31%	25,989	50,653,402	1,501,375	92.01%	1,371,062,447	79.85%	31
32	2,001-2,500	237,157	529,392,783	1,344,541	81.17%	1,833,097,599	63.71%	76,636	169,580,354	1,578,011	96.70%	1,540,642,801	89.73%	32
33	2,501-3,000	144,889	395,145,141	1,489,430	89.92%	2,228,242,740	77.44%	29,752	80,678,618	1,607,763	98.53%	1,621,321,419	94.43%	33
34	3,001-4,000	119,935	406,972,350	1,609,365	97.16%	2,635,215,090	91.58%	17,400	58,642,270	1,625,163	99.59%	1,679,963,689	97.84%	34
35	4,001-5,000	31,466	138,185,012	1,640,831	99.06%	2,773,400,102	96.39%	4,023	17,691,875	1,629,186	99.84%	1,697,655,564	98.87%	35
36	5,001-10,000	14,691	89,262,056	1,655,522	99.94%	2,862,662,158	99.49%	2,401	15,023,128	1,631,587	99.99%	1,712,678,692	99.75%	36
37	10,001-20,000	794	10,052,066	1,656,316	99.99%	2,872,714,223	99.84%	183	2,392,108	1,631,770	100.00%	1,715,070,800	99.89%	37
38	over 20,000	142	4,637,271	1,656,458	100.00%	2,877,351,495	100.00%	50	1,930,644	1,631,820	100.00%	1,717,001,444	100.00%	38

	Summer		Winter	
Average Number of Customers:	276,076		271,970	
Average Consumption:	1,737	kWh per bill	1,052	kWh per bill
Median Consumption:	1,578	kWh per bill	920	kWh per bill

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ARIZONA PUBLIC SERVICE COMPANY

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Classification of Services

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CLASSIFICATION

OF

SERVICE

A. RESIDENTIAL SERVICE

1. Residence - Single
Residential service to a single residence covers electric service to a private residence or individually metered apartment unit, only.

Outbuildings on the same premises may be connected to the residential service meter, but only if such outbuildings form a part of the general living establishment.

2. Residence - Multiple
Residential service to two or more residences on the same premises or a residence or residences subdivided into two or more individual housekeeping apartments shall not be supplied through one meter on a Residential Service Rate Schedule.

Individual meters will be installed by the Company for each individual dwelling or housekeeping unit. If, for any reason, a separate meter is not installed for each individual dwelling or housekeeping unit, then the appropriate General Service Rate Schedule will be used for billing for the service supplied through the single meter.

3. Professional Offices or Commercial Activities in Dwellings
The supply of service under a Residential Rate Schedule to a dwelling involving some business or professional activity will be permitted only where such activity is of only occasional occurrence, or where the energy used in connection with such activity is small in amount and used only by equipment which would normally be in use if the space were used as living quarters.

Where the portion of a dwelling is used regularly for business, professional or other gainful purposes, and any considerable amount of electricity is used for other than domestic purposes, or electric equipment not normally used in living quarters is installed in connection with such activities referred to above, the entire premises shall be classified as non-residential and the appropriate General Service Rate Schedule shall be applied. Customer may at his option provide separate circuits so that the residential uses can be metered and billed separately under the appropriate Residential Service Rate Schedule, and the other uses under the appropriate General Service Rate Schedule.

4. Farm and Rural Residences
The Residential Service Rate Schedules are available for electric service through one meter to a farm residence, and the usual farm uses outside the dwelling unit, but not if the use extends to operations such as canning plants, packing plants, stone quarries, ice cream manufacturing plants, stores, restaurants, tea rooms, tourist and trailer camps, gasoline stations, automobile service stations, repair shops, blacksmith shops or any other commercial or non-farming operation.

In no case shall the use extend to the processing, preparing or distributing of products not raised on the same farm and in no cases shall the use extend to a hatchery, dairy, butchery, greenhouse, or any other specialized operation unless such operation is conducted solely by the farmer and is incidental to the usual farm residence uses.

Customer may at his option elect to take the entire service under the appropriate General Service Rate Schedule, or may provide separate circuits so that the residential uses, together with the usual farm uses outside the dwelling unit, can be metered and billed separately under the appropriate Residential Service Rate Schedule, and the other uses under the appropriate General Service Rate Schedule.

The Residential Service Rate Schedules are not available for any use outside the dwelling unit on a farm which is not operated by an individual owner or lessee, occupying the farm residence.

B. GENERAL SERVICE

This covers service to any establishment for any purpose not prohibited by the rate schedule or Agreement for Service.

The General Service Rate Schedules are available only when all electric service required on the premises is taken through one meter at one point of delivery, except that:

(a) General Service Rate Schedules are available for more than one point of delivery on any one premise, provided that in such event, service supplied at each point of delivery will be separately metered and separately billed.

(b) The General Service Rate Schedules will be available for service to that portion of the Customer's premises which cannot be served at the Residential Service Rate Schedule or a Classified Service Rate Schedule. Service to such portion of the premises shall be considered as service to a separate customer, and all electric service taken therein at the General Service Rate Schedule must be through one meter at one point of delivery.

C. CLASSIFIED SERVICE

Classified service covers service for which specific rate schedules are available, due to the nature and load characteristics of the particular business. For such service, the General Service Rate Schedule may be used, except as specifically prohibited in that Schedule, while Classified Rate Schedules are available only to those businesses complying with the specific requirements of the particular schedule.

Service supplied under a Classified Rate Schedule shall be used only for the purposes specified in such rate schedule. In the event the Company questions whether the service is being used in compliance with said rate schedule, the customer shall have the burden of establishing such compliance to the satisfaction of the Company. In the absence of such compliance, the Company may substitute an appropriate General Service Rate Schedule.

A customer conducting mixed operations, a part of which may be served at a Classified Rate Schedule may, at his option, elect to take the entire service under the General Service Rate Schedule or may provide separate circuits so that the classified service can be metered and billed separately at the available classified schedule, and the other uses metered and billed under the available General Service Rate Schedule.

The Classified Services for which specific rate schedules are available, excluding special street light service, are listed below.

Schedule No.	Classification
E-20*	Time of Use for Religious Houses of Worship
E-36	Station Use Service
E-40	Agricultural Wind Machine Service
E-47**	Dusk to Dawn Lighting Service
E-51*	Optional Electric Service for Qualified Cogeneration and Small Power Production Facilities over 100 kW
E-52	Electric Service for Partial Requirements Service of less than 3,000 kW
E-55	Electric Service for Partial Requirements Service 3,000 kW or greater
E-58**	Street Lighting Service
E-59	Government Owned Street Lighting Systems
E-221	Water Pumping Service
E-221-8T	Water Pumping Service Time of Use
EQF-M	Scheduled Maintenance Service for Qualified Facilities
EQF-S	Standby Electric Service for Qualified Facilities
Solar-1*	Photovoltaic Service Pilot Program
Solar-2	Individual Solar Electric Service
SP-1	Solar Partners
	Purchase Rates
EPR-2	Purchase Rates for Qualified Facilities under 100 kW for Partial Requirements
EPR-3*	Purchase Rates for Qualified Facilities 10 kW or Less for Partial Requirements
EPR-4	Purchase Rates for Renewable Qualified Facilities 10 kW or Less for Partial Requirements

* Frozen Rate
** Partially Frozen Rate

RESIDENTIAL

RATE SCHEDULE E-3
RESIDENTIAL SERVICE
ENERGY SUPPORT PROGRAM

AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

APPLICATION

This rate schedule is applicable to all Standard Offer and Direct Access electric service billed under Residential Rate Schedules, where the customer has qualified for this rate as specified in the Company's Plan for Administration of the Residential Energy Support Program pursuant to Arizona Corporation Commission Decision No. 55931 and 56680. All provisions of the applicable Residential Rate Schedule will apply except as modified herein.

RATES

The customer's bill shall be in accordance with the applicable specified schedule with the following exceptions:

For Bills with Usage of:		The Total Bill as calculated according to the applicable Residential Rate Schedule (before Taxes, Regulatory Assessments and Franchise Fees) Will be Discounted by:
0 – 400	kWh	30%
401 – 800	kWh	20%
801 – 1200	kWh	10%
1201	kWh and above	$10.00

APS

RATE SCHEDULE E-4
RESIDENTIAL SERVICE
MEDICAL CARE EQUIPMENT

AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

APPLICATION

This rate schedule is applicable to all Standard Offer and Direct Access electric service billed under Residential Rate Schedules, where the customer has qualified for this rate as specified in the Company's Plan for Administration of the Medical Care Equipment Program pursuant to Arizona Corporation Commission Decision No. 59222. All provisions of the applicable Residential Rate Schedule will apply except as modified herein.

RATES

The customer's bill shall be in accordance with the applicable specified schedule with the following exceptions:

For Bills with Usage of:	The Total Bill as calculated according to the applicable Residential Rate Schedule (before Taxes, Regulatory Assessment and Franchise Fees) Will be Discounted by:
0 – 800 kWh	30%
801 – 1400 kWh	20%
1401 – 2000 kWh	10%
2001 kWh and above	$20.00

RATE SCHEDULE E-10
RESIDENTIAL SERVICE
CLASSIC RATE

AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

APPLICATION

This rate schedule is applicable to all Standard Offer electric service, except as stated below, required for residential purposes in individual private dwellings and in individually metered apartments when such service is supplied at one site through one point of delivery and measured through one meter. For those dwellings and apartments where electric service has historically been measured through two meters, when one of the meters was installed pursuant to a water heating or space heating rate schedule no longer in effect, the electric service measured by such meters shall be combined for billing purposes. Direct Access customers are not eligible for service under this schedule.

Additionally, this rate schedule is applicable only to those customers being served on the Company's Rate Schedule E-10 prior to December 6, 1991. This rate schedule will terminate twelve (12) months after the effective date shown below. At that time, customers will be transferred to other applicable residential schedules.

This rate schedule is not applicable to breakdown, standby, supplementary or resale service.

TYPE OF SERVICE

The type of service provided under this schedule will be single phase, 60 Hertz, at a single standard voltage (120/240 or 120/208 as may be selected by customer subject to availability at the customer's site). Three phase service may be furnished under the Company's Schedule 3 (Conditions Governing Extensions of Electric Distribution Lines and Services), and is required for motors of an individual rated capacity of 7-1/2 HP or more.

RATES

The customer's bill shall be computed at the following rates plus any adjustments incorporated in this schedule:

Bundled Standard Offer Service

Basic Service Charge: $0.271 per day; plus

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
$0.07332 per kWh for the first 400 kWh, plus $0.10083 per kWh for the next 400 kWh, plus $0.10358 per kWh for all additional kWh	$0.08349 per kWh

RATES (cont)

ADJUSTMENTS

1. The Environmental Portfolio Surcharge shall be applied to every retail electric service as set forth in the Company's Rate Schedule EPS-1.

2. The bill is subject to the Power Supply Adjustment factor as set forth in the Company's Rate Schedule PSA-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

3. The bill is subject to the Transmission Adjustment factor as set forth in the Company's Rate Schedule TCA-1.

4. The bill is subject to the Competition Rules Compliance Charge as set forth in the Company's Rate Schedule CRCC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

5. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Assignment Charge as set forth in the Company's Rate Schedule RCDAC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

6. The bill is subject to the System Benefits Adjustment charge as set forth in the Company's Rate Schedule SBAC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

7. The bill is subject to the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of APS and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

CONTRACT PERIOD

Any applicable contract period will be set forth in APS' standard agreement for service.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

APPLICATION

This rate schedule is applicable to all Standard Offer and Direct Access electric service, except as stated below, required for residential purposes in individual private dwellings and in individually metered apartments when such service is supplied at one site through one point of delivery and measured through one meter. For those dwellings and apartments where electric service has historically been measured through two meters, when one of the meters was installed pursuant to a water heating or space heating rate schedule no longer in effect, the electric service measured by such meters shall be combined for billing purposes. Rate selection is subject to paragraphs 3.2 and 3.3 of the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services.

This schedule is not applicable to breakdown, standby, supplementary or resale service.

TYPE OF SERVICE

The type of service provided under this schedule will be single phase, 60 Hertz, at a single standard voltage (120/240 or 120/208 as may be selected by customer subject to availability at the customer's site). Three phase service may be furnished under the Company's Schedule 3 (Conditions Governing Extensions of Electric Distribution Lines and Services), and is required for motors of an individual rated capacity of 7-1/2 HP or more.

RATES

The customer's bill shall be computed at the following rates plus any adjustments incorporated in this schedule:

Bundled Standard Offer Service

Basic Service Charge: $0.411 per day; plus

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
$0.08640 per kWh for the first 800 kWh, plus $0.11006 per kWh for all additional kWh	$0.07004 per kWh

The Bundled Standard Offer Service rate consists of the following Unbundled Components:

Unbundled Components

Basic Service Charge: $0.215 per day

RATES (cont)

Unbundled Components (cont)

Revenue Cycle Service Charges:

Metering	$0.079	per day
Meter Reading	$0.055	per day
Billing	$0.062	per day

System Benefits Charge:	$0.00161	per kWh
Transmission Charge:	$0.00476	per kWh
Distribution Charge:	$0.02181	per kWh

Generation Charges:

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
$0.05822 per kWh for the first 800 kWh, plus $0.08188 per kWh for all additional kWh	$0.04186 per kWh

DIRECT ACCESS

The bill for Direct Access customers will consist of the Unbundled Components Basic Service Charge, the System Benefits Charge, and the Distribution Charge. Direct Access customers must acquire and pay for generation, transmission, and revenue cycle services from a competitive third party supplier. If any revenue cycle services are not available from a third party supplier and must be obtained from the Company, charges will be applied to the customer's bill in accordance with this rate schedule.

ADJUSTMENTS

1. The Environmental Portfolio Surcharge shall be applied to every retail electric service as set forth in the Company's Rate Schedule EPS-1.

2. The bill is subject to the Power Supply Adjustment factor as set forth in the Company's Rate Schedule PSA-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

3. The bill is subject to the Transmission Adjustment factor as set forth in the Company's Rate Schedule TCA-1.

4. The bill is subject to the Competition Rules Compliance Charge as set forth in the Company's Rate Schedule CRCC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

5. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Assignment Charge as set forth in the Company's Rate Schedule RCDAC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

RATES (cont)

ADJUSTMENTS (cont)

6. The bill is subject to the System Benefits Adjustment charge as set forth in the Company's Rate Schedule SBAC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

7. The bill is subject to the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of APS and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

CONTRACT PERIOD

Any applicable contract period will be set forth in APS' standard agreement for service.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

APPLICATION

This rate schedule is applicable to all Standard Offer and Direct Access electric service, except as stated below, required for residential purposes in individual private dwellings and in individually metered apartments when such service is supplied at one site through one point of delivery and measured through one meter.

Rate selection is subject to paragraphs 3.2 and 3.3 of the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services, and this rate schedule will become effective only after the Company has installed the required timed kilowatt/kilowatthour meter.

This schedule is not applicable to breakdown, standby, supplementary or resale service.

TYPE OF SERVICE

The type of service provided under this schedule will be single phase, 60 Hertz, at a single standard voltage (120/240 or 120/208 as may be selected by customer subject to availability at the customer's site). Three phase service may be furnished under the Company's Schedule 3 (Conditions Governing Extensions of Electric Distribution Lines and Services), and is required for motors of an individual rated capacity of 7-1/2 HP or more.

RATES

The customer's bill shall be computed at the following rates plus any adjustments incorporated in this schedule:

Bundled Standard Offer Service

Basic Service Charge: $0.493 per day; plus

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
$11.00 per kW during On-Peak hours, plus $ 0.05204 per kWh during On-Peak hours, plus $ 0.03202 per kWh during Off-Peak hours	$8.00 per kW, plus $0.03025 per kWh

The Bundled Standard Offer Service Rate consists of the following Unbundled Components:

Unbundled Components

Basic Service Charge: $0.211 per day

RATES (cont)

Unbundled Components (cont)

Revenue Cycle Service Charges:

Metering	$0.165	per day
Meter Reading	$0.055	per day
Billing	$0.062	per day

System Benefits Charge: $0.00161 per kWh

Transmission Charge: $0.00476 per kWh

Distribution Charges:

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
$2.84 per kW during On-Peak hours, plus $0.01095 per kWh	$2.22 per kW, plus $0.01128 per kWh

Generation Charges:

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
$8.16 per kW during On-Peak hours, plus $0.03472 per kWh during On-Peak hours, plus $0.01470 per kWh during Off-Peak hours	$5.78 per kW, plus $0.01259 per kWh

DIRECT ACCESS

The bill for Direct Access customers will consist of the Unbundled Components Basic Service Charge, the System Benefits Charge, and the Distribution Charge. Direct Access customers must acquire and pay for generation, transmission, and revenue cycle services from a competitive third party supplier. If any revenue cycle services are not available from a third party supplier and must be obtained from the Company, appropriate charges will be applied to the customer's bill.

TIME PERIODS

The standard Company On-Peak time period is 9 a.m. to 9 p.m. Monday through Friday. Mountain Standard Time shall be used in the application of this rate schedule.

OPTIONAL TIME PERIODS – TEST PROGRAM

The customer may choose one of the following On-Peak time periods in lieu of the Company's standard On-Peak time period:

7 a.m. – 7 p.m. Monday through Friday
8 a.m. – 8 p.m. Monday through Friday

RATES (cont)

TIME PERIODS (cont)

OPTIONAL TIME PERIODS – TEST PROGRAM (cont):

A maximum of 10,000 customers will be allowed to participate in this test program. The program will be applicable to both Rate Schedule ECT-1R and Rate Schedule ET-1. Customer participation will be subject to meter availability and work schedule constraints.

DETERMINATION OF KW

The kW charges billed in this schedule shall be based on the average kW supplied during the 60-minute period of maximum use during the customer's chosen On-Peak hours during summer months and any hour during winter months, as determined from readings of the Company's meter. In the event the meter is inaccessible to the Company, the kW used for billing shall be estimated using reasonable estimating methodology as determined by the Company. In any billing period in which the kW was estimated, the customer may request a reread and reset of the dial for a charge of $20.00 per trip as long as the request is made within three (3) days of notification from the Company that the kW dial was not read or reset.

ADJUSTMENTS

1. The Environmental Portfolio Surcharge shall be applied to every retail electric service as set forth in the Company's Rate Schedule EPS-1.
2. The bill is subject to the Power Supply Adjustment factor as set forth in the Company's Rate Schedule PSA-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.
3. The bill is subject to the Transmission Adjustment factor as set forth in the Company's Rate Schedule TCA-1.
4. The bill is subject to the Competition Rules Compliance Charge as set forth in the Company's Rate Schedule CRCC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.
5. Direct Access Customers returning to Standard Offer service may be subject to a Returning Customer Direct Assignment Charge as set forth in the Company's Rate Schedule RCDAC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.
6. The bill is subject to the System Benefits Adjustment charge as set forth in the Company's Rate Schedule SBAC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.
7. The bill is subject to the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of APS and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

CONTRACT PERIOD

Any applicable contract period will be set forth in APS' standard agreement for service.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

APS

RATE SCHEDULE ET-1
RESIDENTIAL SERVICE TIME-OF-USE
TIME ADVANTAGE PLAN

AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

APPLICATION

This rate schedule is applicable to all Standard Offer and Direct Access electric service, except as stated below, required for residential purposes in individual private dwellings and in individually metered apartments when such service is supplied at one site through one point of delivery and measured through one meter.

Rate selection is subject to paragraphs 3.2 and 3.3 of the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services, and this rate schedule will become effective only after the Company has installed the required timed kilowatthour meter.

This schedule is not applicable to breakdown, standby, supplementary or resale service.

TYPE OF SERVICE

The type of service provided under this schedule will be single phase, 60 Hertz, at a single standard voltage (120/240 or 120/208 as may be selected by customer subject to availability at the customer's site). Three phase service may be furnished under the Company's Schedule 3 (Conditions Governing Extensions of Electric Distribution Lines and Services), and is required for motors of an individual rated capacity of 7-1/2 HP or more.

RATES

The customer's bill shall be computed at the following rates plus any adjustments incorporated in this schedule:

Bundled Standard Offer Service

Basic Service Charge: $0.485 per day; plus

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
$0.12151 per kWh during On-Peak hours, plus $0.06121 per kWh during Off-Peak hours	$0.06784 per kWh

The Bundled Standard Offer Service Rate consists of the following Unbundled Components:

Unbundled Components

Basic Service Charge: $ 0.205 per day

RATES (cont)

Unbundled Components (cont)

Revenue Cycle Service Charges:		
Metering	$ 0.163	per day
Meter Reading	$ 0.055	per day
Billing	$ 0.062	per day
System Benefits Charge:	$ 0.00161	per kWh
Transmission Charge:	$ 0.00476	per kWh
Distribution Charge:	$ 0.02108	per kWh

Generation Charges:

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
$0.09406 per kWh during On-Peak hours, plus $0.03376 per kWh during Off-Peak hours	$0.04039 per kWh

DIRECT ACCESS

The bill for Direct Access customers will consist of the Unbundled Components Basic Service Charge, the System Benefits Charge, and the Distribution Charge. Direct Access customers must acquire and pay for generation, transmission, and revenue cycle services from a competitive third party supplier. If any revenue cycle services are not available from a third party supplier and must be obtained from the Company, appropriate charges will be applied to the customer's bill.

TIME PERIODS

Standard Company On-Peak time period is 9 a.m. to 9 p.m. Monday through Friday. Mountain Standard Time shall be used in the application of this rate schedule.

OPTIONAL TIME PERIODS – TEST PROGRAM

The customer may choose one of the following On-Peak time periods in lieu of Company's standard On-Peak time period:

7 a.m. – 7 p.m. Monday through Friday
8 a.m. – 8 p.m. Monday through Friday

A maximum of 10,000 customers will be allowed to participate in this test program. The program will be applicable to both Rate Schedule ECT-1R and Rate Schedule ET-1. Customer participation will be subject to meter availability and work schedule constraints.

RATES (cont)

ADJUSTMENTS

1. The Environmental Portfolio Surcharge shall be applied to every retail electric service as set forth in the Company's Rate Schedule EPS-1.

2. The bill is subject to the Power Supply Adjustment factor as set forth in the Company's Rate Schedule PSA-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

3. The bill is subject to the Transmission Adjustment factor as set forth in the Company's Rate Schedule TCA-1.

4. The bill is subject to a Competition Rules Compliance Charge as set forth in the Company's Rate Schedule CRCC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

5. Direct Access Customers returning to Standard Offer service may be subject to a Returning Customer Direct Assignment Charge as set forth in the Company's Rate Schedule RCDAC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

6. The bill is subject to the System Benefits Adjustment charge as set forth in the Company's Rate Schedule SBAC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

7. The bill is subject to the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of APS and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

CONTRACT PERIOD

Any applicable contract period will be set forth in APS' standard agreement for service.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

GENERAL SERVICE

RATE SCHEDULE E-30
GENERAL SERVICE
EXTRA SMALL UNMETERED

AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

APPLICATION

This rate schedule is applicable to all Standard Offer and Direct Access electric service where demand and energy requirements are constant, subject to the limitations set forth in the Special Provisions of this schedule. Billing quantities must be subject to accurate determination without the use of metering equipment, and service must be supplied at one point of delivery.

This rate schedule is not applicable to breakdown, standby, supplementary, residential, or resale service.

TYPE OF SERVICE

The type of service provided under this schedule will be single phase, 60 Hertz, at a single standard voltage (120/240 or 120/208 volts as may be selected by customer subject to availability at the customer's site). The cost of service extension shall include transformation equipment, if required.

RATES

The customer's bill shall be computed at the following rates plus any adjustments incorporated in this schedule:

Bundled Standard Offer Service

Basic Service Charge: $0.286 per day; plus

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
$0.10091 per kWh	$0.09091 per kWh

The Bundled Standard Offer Service rate consists of the following Unbundled Components:

Unbundled Components

Basic Service Charge:	$0.218	per day
Revenue Cycle Service Charges: Billing	$0.063	per day
System Benefits Charge:	$0.00177	per kWh

RATES (cont)

Unbundled Components (cont)

Transmission Charge:	$0.00476	per kWh
Distribution Charge:	$0.03560	per kWh

Generation Charges:

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
$0.05878 per kWh	$0.04878 per kWh

DIRECT ACCESS

The bill for Direct Access customers will consist of the Unbundled Components Basic Service Charge, the System Benefits Charge, and the Distribution Charge only. Direct Access customers must acquire and pay for generation, transmission, and revenue cycle services from a competitive third party supplier. If any revenue cycle services are not available from a third party supplier and must be obtained from the Company, appropriate charges will be applied to the customer's bill.

ADJUSTMENTS

1. The Environmental Portfolio Surcharge shall be applied to every retail electric service as set forth in the Company's Rate Schedule EPS-1.
2. The bill is subject to the Power Supply Adjustment factor as set forth in the Company's Rate Schedule PSA-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.
3. The bill is subject to the Transmission Adjustment factor as set forth in the Company's Rate Schedule TCA-1.
4. The bill is subject to the Competition Rules Compliance Charge as set forth in the Company's Rate Schedule CRCC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.
5. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Assignment Charge as set forth in the Company's Rate Schedule RCDAC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.
6. The bill is subject to the System Benefits Adjustment charge as set forth in the Company's Rate Schedule SBAC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.
7. The bill is subject to the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of APS and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RATES (cont)

SPECIAL PROVISIONS

1. This rate schedule is applicable only to loads where monthly demand (kW) and energy (kWh) requirements remain constant. Monthly demand and energy requirements may not exceed 1.5 kW or 1,095 kWh at 120 volts or 2.9 kW or 2,117 kWh at 240 volts, for each delivery point. Determination of fixed monthly energy usage will be based on an average 730 hour month.

2. Prior written approval by an authorized Company representative is required before service is implemented under this rate schedule.

3. Prior written approval by an authorized Company representative is required for any change in loads. An unauthorized load change will automatically disqualify that customer from service under this rate schedule.

4. The Company shall have the right to inspect the customer's load facilities at any time to ensure compliance with all provisions of this rate schedule.

CONTRACT PERIOD

Any applicable contract period will be set forth in the Company's standard agreement for service.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

RATE SCHEDULE E-32
GENERAL SERVICE

AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

APPLICATION

This rate schedule is applicable to all Standard Offer and Direct Access electric service required when such service is supplied at one point of delivery and measured through one meter. Rate selection is subject to paragraphs 3.2 and 3.3 of the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services.

This schedule is not applicable to breakdown, standby, supplementary, residential or resale service nor to service for which Rate Schedule E-34 is applicable.

TYPE OF SERVICE

The type of service provided under this schedule will be single or three phase, 60 Hertz, at one standard voltage as may be selected by customer subject to availability at the customer's site. Three phase service is furnished under the Company's Schedule 3 (Conditions Governing Extensions of Electric Distribution Lines and Services). Three phase service is not furnished for motors of an individual rated capacity of less than 7-1/2 HP, except for existing facilities or where total aggregate HP of all connected three phase motors exceeds 12 HP. Three phase service is required for motors of an individual rated capacity of more than 7-1/2 HP.

Service under this schedule is generally provided at secondary voltage, primary voltage when the customer owns the distribution transformer(s), or transmission voltage.

RATES

The bill shall be computed at the following rates or the minimum rates, whichever is greater, plus any adjustments incorporated in this schedule:

FOR MONTHLY MAXIMUM DEMANDS OF 20 kW OR LESS

Bundled Standard Offer Service

Basic Service Charge:

For service through Self-Contained Meters:	$ 0.575	per day
For service through Instrument-Rated Meters:	$ 1.134	per day
For service at Primary Voltage:	$ 2.926	per day, plus

RATES (cont)

FOR MONTHLY MAXIMUM DEMANDS OF 20 kW OR LESS (cont)

Bundled Standard Offer Service (cont)

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
Secondary Service $0.10095 per kWh	Secondary Service $0.09095 per kWh
Primary Service $0.09373 per kWh	Primary Service $0.08373 per kWh

The Bundled Standard Offer Service rate consists of the following Unbundled Components:

Unbundled Components

Basic Service Charge:	$0.108	per day
Revenue Cycle Service Charges:		
Metering:		
Self-Contained Meters:	$ 0.345	per day
Instrument-Rated Meters:	$0.904	per day
Primary:	$ 2.696	per day
Transmission:	$22.192	per day
Meter Reading:	$ 0.058	per day
Billing:	$ 0.064	per day
System Benefits Charge:	$ 0.00177	per kWh
Transmission Charge:	$ 0.00476	per kWh
Distribution Charge:		
Secondary Service	$ 0.03623	per kWh
Primary Service	$ 0.02901	per kWh

Generation Charges:

May - October Billing Cycles (Summer)	November - April Billing Cycles (Winter)
$0.05819 per kWh	$0.04819 per kWh

RATES (cont)

FOR MONTHLY MAXIMUM DEMANDS OF GREATER THAN 20 kW

Bundled Standard Offer Service

Basic Service Charge:

For service through Self-Contained Meters:	$0.575	per day
For service through Instrument-Rated Meters:	$1.134	per day
For service at Primary Voltage:	$2.926	per day
For service at Transmission Voltage:	$22.422	per day, plus

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
Secondary Service kW Charges $6.348 per kW for the first 500 kW $4.618 per kW for all additional kW	Secondary Service kW Charges $6.348 per kW for the first 500 kW $4.618 per kW for all additional kW
Primary Service kW Charges $4.758 per kW for all first 500 kW $3.028 per kW for all additional kW	Primary Service kW Charges $4.758 per kW for all first 500 kW $3.028 per kW for all additional kW
Transmission Service kW Charges $1.748 per kW for first 500 kW $0.018 per kW for all additional kW	Transmission Service kW Charges $1.748 per kW for first 500 kW $0.018 per kW for all additional kW
Plus Energy Charges $0.08518 per kWh for the first 200 kWh per kW, plus $0.04290 per kWh for all additional kWh	Plus Energy Charges $0.07518 per kWh for the first 200 kWh per kW, plus $0.03290 per kWh for all additional kWh

MINIMUM

The bill for service under this rate schedule will not be less than the applicable Basic Service Charge plus $1.75 for each kW of either the highest kW established during the 12 months ending with the current month or the minimum kW specified in the agreement for service, whichever is the greater.

RATES (cont)

FOR MONTHLY MAXIMUM DEMANDS OF GREATER THAN 20 kW (cont)

Unbundled Components:

Basic Service Charge:	$ 0.108	per day
Revenue Cycle Service Charges:		
Metering:		
Self-Contained Meters:	$ 0.345	per day
Instrument-Rated Meters:	$ 0.904	per day
Primary:	$ 2.696	per day
Transmission:	$22.192	per day
Meter Reading	$ 0.058	per day
Billing	$ 0.064	per day
System Benefits Charge:	$ 0.00172	per kWh
Transmission Charge:	$ 0.00476	per kWh

Distribution Charges:

Secondary Service kW Charges	$6.348 per kW for the first 500 kW, plus $4.618 per kW for all additional kW
Primary Service kW Charges	$ 4.758 per kW for the first 500 kW, plus $ 3.028 per kW for all additional kW
Transmission Service kW Charges	$ 1.748 per kW for the first 500 kW, plus $ 0.018 per kW for all additional kW
Plus Energy Charges	$ 0.00366 per kWh

Generation Charges:

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
$0.07504 per kWh for the first 200 kWh per kW, plus $0.03276 per kWh for all additional kWh	$0.06504 per kWh for the first 200 kWh per kW, plus $0.02276 per kWh for all additional kWh

DIRECT ACCESS

The bill for Direct Access customers will consist of the Unbundled Components Basic Service Charge, the System Benefits Charge, and the Distribution Charge only. Direct Access customers must acquire and pay for generation, transmission, and revenue cycle services from a competitive third party supplier. If any revenue cycle services are not available from a third party supplier and must be obtained from the Company, appropriate charges will be applied to the customer's bill.

RATES (cont)

DETERMINATION OF KW

The kW charges billed in this rate schedule shall be based on the average kW supplied during the 15-minute period of maximum use during the month, as determined from readings of the Company's meter.

ADJUSTMENTS

1. The Environmental Portfolio Surcharge shall be applied to every retail electric service as set forth in the Company's Rate Schedule EPS-1.

2. The bill is subject to the Power Supply Adjustment factor as set forth in the Company's Rate Schedule PSA-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

3. The bill is subject to the Transmission Adjustment factor as set forth in the Company's Rate Schedule TCA-1.

4. The bill is subject to the Competition Rules Compliance Charge as set forth in the Company's Rate Schedule CRCC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

5. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Assignment Charge as set forth in the Company's Rate Schedule RCDAC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

6. The bill is subject to the System Benefits Adjustment charge as set forth in the Company's Rate Schedule SBAC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

7. The bill is subject to the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of APS and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

CONTRACT PERIOD

For customers with monthly maximum demands less than 2,000 kW, any applicable contract period will be set forth in the Company's standard agreement for service. For customers with monthly maximum demands of 2,000 kW or greater, and at the Company's option, the contract period will be three (3) years or longer where additional distribution construction is required to serve the customer or, if no additional distribution construction is required, the contract period will be one (1) year or longer.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

APPLICATION

This rate schedule is applicable to all Standard Offer electric service billed under general service rate schedules to customers not taking all electric power requirements from the Company, but continue to desire a permanent electric connection with the Company as a standby or supplementary power source. All provisions of the otherwise applicable general service rate schedule will apply except those specifically modified herein. Direct Access customers are not eligible for service under this schedule.

This rate schedule is not applicable to breakdown, residential, or resale service nor to service for which Rate Schedules E-34 or E-35 is applicable, or when the customer's other sources of power supply are being held solely for emergency use.

RATE

Customers being served under this rate schedule will be billed monthly in accordance with the otherwise applicable general service rate with the following exceptions:

A. For electric service billed on standard general service rate schedules the kW charges billed shall be based on the greater of the following:

   1. The average kW supplied during the 15-minute period (or other period as specified by customer contract) of maximum use during the month, as determined from readings of the Company's meter.

   2. 80% of the average of the highest kW measured during each of the six (6) summer billing months (May-October) of the 12 months ending with the current month.

   3. The minimum kW specified in the agreement for service or individual customer contract.

B. For electric service billed on time-of-use general service rate schedules the kW charges billed shall be based on the greater of the following:

   1. The average kW supplied during the 15-minute period (or other period as specified by customer contract) of maximum use during the On-Peak hours of the month, as determined from readings of the Company's meter.

   2. 80% of the average of the highest kW measured during the on-peak hours of the six (6) summer billing months (May-October) of the 12 months ending with the current month.

   3. The minimum kW specified in the agreement for service or individual customer contract.

AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

APPLICATION

This rate schedule is applicable to all Standard Offer and Direct Access electric service required when such service is supplied at one point of delivery and measured through one meter. Rate Selection is subject to paragraphs 3.2 and 3.3 of the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services, and this rate schedule will become effective only after the Company has installed the required timed kilowatt meter.

This schedule is not applicable to breakdown, standby, supplementary, residential or resale service nor to service for which Rate Schedule E-35 is applicable.

TYPE OF SERVICE

The type of service provided under this schedule will be single or three phase, 60 Hertz, at one standard voltage as may be selected by customer subject to availability at the customer's site. Three phase service is furnished under the Company's Schedule 3 (Conditions Governing Extensions of Electric Distribution Lines and Services). Three phase service is not furnished for motors of an individual rated capacity of less than 7-1/2 HP, except for existing facilities or where total aggregate HP of all connected three phase motors exceeds 12 HP. Three phase service is required for motors of an individual rated capacity of more than 7-1/2 HP.

Service under this schedule is generally provided at secondary voltage, primary voltage when the customer owns the distribution transformer(s), or transmission voltage.

RATES

The bill shall be computed at the following rates or the minimum rates, whichever is greater, plus any adjustments incorporated in this schedule:

FOR MONTHLY MAXIMUM DEMANDS OF 20 kW OR LESS

Bundled Standard Offer Service

Basic Service Charge:

For service through Self-Contained Meters:	$0.600	per day
For service through Instrument-Rated Meters:	$1.134	per day
For service at Primary Voltage:	$2.926	per day

RATES (cont)

FOR MONTHLY MAXIMUM DEMANDS OF 20 kW OR LESS (cont)

Bundled Standard Offer Service (cont)

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
Secondary Service $0.11375 per kWh during On-Peak hours, plus $0.09375 per kWh during Off-Peak hours	Secondary Service $0.09095 per kWh
Primary Service $0.10653 per kWh during On-Peak hours, plus $0.08653 per kWh during Off-Peak hours	Primary Service $0.008373 per kWh

The Bundled Standard Offer Service rate consists of the following Unbundled Components:

Unbundled Components

Basic Service Charge:	$0.108	per day
Revenue Cycle Service Charges:		
Metering:		
Self-Contained Meters:	$ 0.370	per day
Instrument-Rated Meters:	$ 0.904	per day
Primary:	$ 2.696	per day
Meter Reading	$ 0.058	per day
Billing	$ 0.064	per day
System Benefits Charge:	$ 0.00177	per kWh
Transmission Charge:	$ 0.00476	per kWh
Distribution Charge:		
Secondary Service	$ 0.03623	per kWh
Primary Service	$ 0.02901	per KWh

Generation Charges:

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
$0.07099 per kWh during On-Peak hours, plus $0.05099 per kWh during Off-Peak hours	$0.04819 per kWh

RATES (cont)

FOR MONTHLY MAXIMUM DEMANDS OF GREATER THAN 20 kW:

Bundled Standard Offer Service

Basic Service Charge:

For service through Self-Contained Meters:	$0.600	per day
For service through Instrument-Rated Meters:	$1.134	per day
For service at Primary Voltage:	$2.926	per day
For service at Transmission Voltage:	$22.422	per day, plus

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
Secondary Service kW Charges $15.046 per kW for the first 500 kW $13.316 per kW for all additional kW	Secondary Service kW Charges $15.046 per kW for the first 500 kW $13.316 per kW for all additional kW
Primary Service kW Charges $13.456 per kW for all first 500 kW $11.726 per kW for all additional kW	Primary Service kW Charges $13.456 per kW for all first 500 kW $11.726 per kW for all additional kW
Transmission Service kW Charges $10.446 per kW for first 500 kW $ 8.716 per kW for all additional kW	Transmission Service kW Charges $10.446 per kW for first 500 kW $ 8.716 per kW for all additional kW
Plus Energy Charges $0.04855 per kWh during On-Peak hours, plus $0.03855 per during Off-Peak hours	Plus Energy Charges $0.03290 per kWh

In addition to the above charges, if applicable, a Residual Distribution Off-Peak kW charge of $6.783 per kW for secondary service, $5.193 per kW for primary service, or $2.183 per kW for transmission service will be applied to all measured Off-Peak kW that are higher than the measured On-Peak kW for the billing month.

MINIMUM

The bill for service under this rate schedule will not be less than the applicable Basic Service Charge plus $1.75 for each kW of either the highest kW established during the 12 months ending with the current month or the minimum kW specified in the agreement for service, whichever is the greater.

RATES (cont)

FOR MONTHLY MAXIMUM DEMANDS OF GREATER THAN 20 kW (cont)

Unbundled Components

Basic Service Charge:		$ 0.108	per day
Revenue Cycle Service Charges:			
Metering:	Self-Contained Meters:	$ 0.370	per day
	Instrument-Rated Meters:	$ 0.904	per day
	Primary:	$ 2.696	per day
	Transmission:	$22.192	per day
Meter Reading		$ 0.058	per day
Billing		$ 0.064	per day
System Benefits Charge:		$ 0.00172	per kWh
Transmission Charge:		$ 0.00476	per kWh

Distribution Charges

Secondary Service kW Charges	$6.348 per kW for the first 500 kW, plus $4.618 per kW for all additional kW
Primary Service kW Charges	$ 4.758 per kW for the first 500 kW, plus $ 3.028 per kW for all additional kW
Transmission Service kW Charges	$ 1.748 per kW for the first 500 kW, plus $ 0.018 per kW for all additional kW
Plus Energy Charges	$ 0.00366 per kWh

In addition to the above Distribution charges, if applicable, an Residual Off-Peak kW charge of $6.348 per kW for secondary service, $4.758 per kW for primary service, or $1.748 per kW for transmission service will be applied to all measured Off-Peak kW that are higher than the measured On-Peak kW for the billing month.

Generation Charges:

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
$8.698 per On-Peak kW, plus $0.03841 per kWh during On-Peak hours, plus $0.02841 per kWh during Off-Peak hours	$8.698 per On-Peak kW, plus $0.02276 per kWh

In addition to the above Generation charges, if applicable, a Residual Generation Off-Peak kW charge of $0.435 per kW will be applied to all measured Off-Peak kW that are higher than the measured On-Peak kW for the billing month.

RATES (cont)

DIRECT ACCESS

The bill for Direct Access customers will consist of the Unbundled Components Basic Service Charge, the System Benefits Charge, and the Distribution Charge only. Direct Access customers must acquire and pay for generation and revenue cycle services from a competitive third party supplier. If any revenue cycle services are not available from a third party supplier and must be obtained from the Company, appropriate charges will be applied to the customer's bill.

DETERMINATION OF KW

The kW charges billed in this schedule shall be based on the average kW supplied during the 15-minute period of maximum use during the On-Peak and Off-Peak periods of the month, as determined from readings of the Company's meter.

TIME PERIODS

Time periods applicable to usage under this rate schedule are as follows:

On-Peak hours:	9:00 am – 9:00 pm Monday through Friday
Off-Peak hours:	All remaining hours

Mountain Standard Time shall be used in the application of this rate schedule.

ADJUSTMENTS

1. The Environmental Portfolio Surcharge shall be applied to every retail electric service as set forth in the Company's Rate Schedule EPS-1.

2. The bill is subject to the Power Supply Adjustment factor as set forth in the Company's Rate Schedule PSA-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

3. The bill is subject to the Transmission Adjustment factor as set forth in the Company's Rate Schedule TCA-1.

4. The bill is subject to the Competition Rules Compliance Charge as set forth in the Company's Rate Schedule CRCC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

5. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Assignment Charge as set forth in the Company's Rate Schedule RCDAC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

RATES (cont)

ADJUSTMENTS (cont)

6. The bill is subject to the System Benefits Adjustment charge as set forth in the Company's Rate Schedule SBAC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

7. The bill is subject to the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of APS and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

CONTRACT PERIOD

For customers with monthly maximum demands less than 2,000 kW, any applicable contract period will be set forth in the Company's standard agreement for service. For customers with monthly maximum demands of 2,000 kW or greater, and at the Company's option, the contract period will be three (3) years or longer where additional distribution construction is required to serve the customer or, if no additional distribution construction is required, the contract period will be one (1) year or longer.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

RATE SCHEDULE E-34
EXTRA LARGE GENERAL SERVICE

AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the site served.

APPLICATION

This rate schedule is applicable to all Standard Offer and Direct Access customers whose monthly maximum demand registers 3,000 kW or more for three (3) consecutive months in any continuous twelve (12) month period ending with the current month. Service must be supplied at one point of delivery and measured through one meter unless otherwise specified by an individual customer contract.

This schedule is not applicable to breakdown, standby, supplementary or resale service.

TYPE OF SERVICE

The type of service provided under this schedule will be three phase, 60 Hertz, at the Company's standard voltages that are available within the vicinity of the customer's site.

Service under this schedule is generally provided at secondary voltage, primary voltage when the customer owns the distribution transformer(s), or transmission voltage.

RATES

The bill shall be computed at the following rates plus any adjustments incorporated in this schedule:

Bundled Standard Offer Service

Basic Service Charge:

For service through Self-Contained Meters:	$ 0.575	per day
For service through Instrument-Rated Meters:	$ 1.134	per day
For service at Primary Voltage:	$ 2.926	per day
For service at Transmission Voltage:	$22.422	per day, plus
Demand Charge:		
Secondary Service	$13.062	per kW
Primary Service	$12.372	per kW
Transmission Service	$ 8.882	per kW
Energy Charge:	$ 0.03284	per kWh

RATES (cont)

Unbundled Components

Basic Service Charge:		$ 0.108	per day
Revenue Cycle Service Charges:			
Metering:	Self-Contained Meters:	$ 0.345	per day
	Instrument-Rated Meters:	$ 0.904	per day
	Primary:	$ 2.696	per day
	Transmission:	$22.192	per day
Meter Reading		$ 0.058	per day
Billing		$ 0.064	per day
System Benefits Charge:		$ 0.00161	per kWh
Transmission Charge:		$ 0.00476	per kWh
Distribution Charge:			
Secondary Service		$ 4.782	per kW
Primary Service		$ 4.092	per kW
Transmission Service		$ 0.602	per kW, plus
Energy Charge		$ 0.00134	per kWh
Generation Charges:		$ 8.280	per kW, plus
		$ 0.02513	per kWh

DIRECT ACCESS

The bill for Direct Access customers will consist of the Unbundled Components Basic Service Charge, the System Benefits Charge, and the Distribution Charge only. Direct Access customers must acquire and pay for generation, transmission, and revenue cycle services from a competitive third party supplier. If any revenue cycle services are not available from a third party supplier and must be obtained from the Company, appropriate charges will be applied to the customer's bill.

DETERMINATION OF KW

The kW charges billed under this schedule shall be the greater of the following:

1. The average kW supplied during the 15-minute period (or other period as specified by an individual customer contract) of maximum use during the month, as determined from readings of the Company's meter.

2. 80% of the highest kW measured during the six (6) summer billing months (May-October) of the 12 months ending with the current month.

RATES (cont)

DETERMINATION OF KW (cont)

3. The minimum kW specified in the agreement for service or individual customer contract.

ADJUSTMENTS

1. The Environmental Portfolio Surcharge shall be applied to every retail electric service as set forth in the Company's Rate Schedule EPS-1.

2. The bill is subject to the Power Supply Adjustment factor as set forth in the Company's Rate Schedule PSA-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

3. The bill is subject to the Transmission Adjustment factor as set forth in the Company's Rate Schedule TCA-1.

4. The bill is subject to the Competition Rules Compliance Charge as set forth in the Company's Rate Schedule CRCC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

5. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Assignment Charge as set forth in the Company's Rate Schedule RCDAC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

6. The bill is subject to the System Benefits Adjustment charge as set forth in the Company's Rate Schedule SBAC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

7. The bill is subject to the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of APS and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

CONTRACT PERIOD

The contract period for customers served under this rate schedule will be three (3) years, at the Company's option. If the Company determines that the customer's service location is such that unusual or substantial distribution construction is required to serve the site, the Company may require a contract period of ten (10) years or longer with a standard seven (7) year termination provision.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

RATE SCHEDULE E-35
EXTRA LARGE GENERAL SERVICE
TIME OF USE

AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the site served.

APPLICATION

This rate schedule is applicable to all Standard Offer and Direct Access customers whose monthly maximum demand registers 3,000 kW or more for three (3) consecutive months in any continuous twelve (12) month period ending with the current month. Service must be supplied at one point of delivery and measured through one meter unless otherwise specified by an individual customer contract.

This schedule is not applicable to breakdown, standby, supplementary or resale service.

TYPE OF SERVICE

The type of service provided under this schedule will be three phase, 60 Hertz, at the Company's standard voltages that are available within the vicinity of the customer's site.

Service under this schedule is generally provided at secondary voltage, primary voltage when the customer owns the distribution transformer(s), or transmission voltage.

RATES

The bill shall be computed at the following rates plus any adjustments incorporated in this schedule:

Bundled Standard Offer Service

Basic Service Charge:		
For service through Self-Contained Meters:	$0.600	per day
For service through Instrument-Rated Meters:	$1.134	per day
For service at Primary Voltage:	$2.926	per day
For service at Transmission Voltage:	$22.422	per day, plus
Demand Charge:		
Secondary Service	$13.598	per On-Peak kW, plus
Primary Service	$12.908	per On-Peak kW
Transmission Service	$ 9.418	per On-Peak kW
Energy Charge:	$0.03618	per kWh during On-Peak hours, plus
	$0.02868	per kWh during Off-Peak hours

In addition to the above charges, if applicable, an Excess Off-Peak kW charge of $6.717 per kW for secondary service, $6.027 per kW for primary service, or $2.537 per kW for transmission service will be applied to all measured Off-Peak kW that are higher than twice the measured On-Peak kW for the billing month.

RATES (cont)

The Unbundled Standard Offer Service rate consists of the following Unbundled Components:

Unbundled Components

Basic Service Charge:		$ 0.108	per day
Revenue Cycle Service Charges:			
Metering:	Self-Contained Meters:	$ 0.370	per day
	Instrument-Rated Meters:	$ 0.904	per day
	Primary:	$ 2.696	per day
	Transmission:	$22.192	per day
Meter Reading		$ 0.058	per day
Billing		$ 0.064	per day
System Benefits Charge:		$ 0.00161	per kWh
Transmission Charge:		$ 0.00476	per kWh
Distribution Charge:			
Secondary Service		$ 4.423	per On-Peak kW, plus
Primary Service		$ 3.733	per On-Peak kW
Transmission Service		$ 0.243	per On-Peak kW
Energy Charge		$ 0.00067	per kWh

In addition to the above Distribution charges, if applicable, an Excess Distribution Off-Peak kW charge of $4.423 per kW for secondary service, $3.733 per kW for primary service, or $0.243 per kW for transmission service will be applied to all measured Off-Peak kW that are higher than twice the measured On-Peak kW for the billing month.

Generation Charges:	$ 9.175	per On-Peak kW, plus
	$ 0.02914	per kWh during On-Peak hours, plus
	$ 0.02164	per kWh during Off-Peak hours

In addition to the above Generation charges, if applicable, an Excess Generation Off-Peak kW charge of $2.294 per kW will be applied to all measured Off-Peak kW that are higher than twice the measured On-Peak kW for the billing month.

RATES (cont)

Unbundled Components (cont)

DIRECT ACCESS

The bill for Direct Access customers will consist of the Unbundled Components Basic Service Charge, the System Benefits Charge, and the Distribution Charge only. Direct Access customers must acquire and pay for generation, transmission, and revenue cycle services from a competitive third party supplier. If any revenue cycle services are not available from a third party supplier and must be obtained from the Company, appropriate charges will be applied to the customer's bill.

DETERMINATION OF KW

The On-Peak kW charges billed under this schedule shall be the greater of the following:

1. The average kW supplied during the 15-minute period (or other period as specified by individual customer contract) of maximum use during the On-Peak period of the month, as determined from readings of the Company's meter.

2. 80% of the highest kW measured during the six (6) summer billing months (May-October) of the 12 months ending with the current month.

The Off-Peak kW charges billed under this schedule shall be the average kW supplied during the 15-minute period (or other period as specified by individual customer contract) of maximum use during the Off-Peak period of the month as determined from readings of the Company's meter.

TIME PERIODS

Time periods applicable to usage under this rate schedule are as follows:

On-Peak hours:	9:00 am – 9:00 pm Monday through Friday
Off-Peak hours:	All remaining hours

Mountain Standard Time shall be used in the application of this rate schedule.

ADJUSTMENTS

1. The Environmental Portfolio Surcharge shall be applied to every retail electric service as set forth in the Company's Rate Schedule EPS-1.

2. The bill is subject to the Power Supply Adjustment factor as set forth in the Company's Rate Schedule PSA-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

3. The bill is subject to the Transmission Adjustment factor as set forth in the Company's Rate Schedule TCA-1.

RATES (cont)

ADJUSTMENTS (cont)

4. The bill is subject to the Competition Rules Compliance Charge as set forth in the Company's Rate Schedule CRCC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

5. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Assignment Charge as set forth in the Company's Rate Schedule RCDAC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

6. The bill is subject to the System Benefits Adjustment charge as set forth in the Company's Rate Schedule SBAC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

7. The bill is subject to the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of APS and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

CONTRACT PERIOD

The contract period for customers served under this rate schedule will be three (3) years, at the Company's option. If the Company determines that the customer's service location is such that unusual or substantial distribution construction is required to serve the site, the Company may require a contract period of ten (10) years or longer with a standard seven (7) year termination provision.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

APPLICATION

This rate schedule is applicable to Standard Offer electric service for outdoor athletic stadiums and sports fields operated by schools, churches or municipalities where such service is supplied at one point of delivery and measured through one meter. All provisions of the applicable general service rate schedule will apply except those specifically modified herein. Direct Access customers are not eligible for service under this schedule.

This rate schedule is not applicable to breakdown, standby, supplementary or resale service.

RATES

Customers being served under this rate schedule will be billed in accordance with the otherwise applicable general service rate with the following exceptions:

1. KW for a minimum bill will be based on the average kW measured during the 15-minute period of maximum use during the current billing month.

2. In those months in which service is not used, no bills will be rendered.

AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

APPLICATION

To Standard Offer or Direct Access electric service billed under general service rate schedules (except as limited below) where the customer's requirements are distinctly of a recurring seasonal nature, and where the customer enters into an agreement for service with the Company for a sufficient period of time and guarantees payments of a sufficient amount (in no event less than $583.08 in any 12 consecutive months) to justify the Company's expenses for installing service facilities and leaving them in place from season to season.

1. The application of this rate schedule is subject to the following limitations:
2. This schedule is applicable only to electric service billed on Rate Schedule E-32.
3. This schedule is not applicable to breakdown, standby, supplementary, residential or resale service.
4. Customers whose highest measured monthly kW occurs in the billing months of June, July or August are not eligible for this rate schedule.

RATES

Customers being served under this rate schedule will be billed in accordance with the otherwise applicable general service rate with the following exception:

The minimum bill shall be that minimum specified in the rate schedule, but not more than an amount sufficient to make the total charges for the 12 months ending with the current month equal to twelve times the minimum specified in the rate schedule as calculated on the highest kW established during the 12 months ending with the current month, or the minimum kW specified in an agreement for service, whichever is greater, but in no event less than $583.08.

CLASSIFIED

RATE SCHEDULE E-20
CLASSIFIED SERVICE
TIME OF USE FOR RELIGIOUS HOUSES OF WORSHIP

AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

APPLICATION

This rate schedule is applicable to Standard Offer electric service for non-taxable religious houses of worship whose main purpose is worship and who have an established and continuing membership. Only the meter that measures service to the building in which the sanctuary or principal place of worship is located is eligible for this schedule. Customers must apply to the Company in order to determine eligibility for service under this schedule, and the Company may request a copy of the Internal Revenue Service letter in which the customer's non-taxable status as a religious organization is determined. In addition, customers agree to provide the Company a copy of any Internal Revenue Service letter which changes or supersedes that tax status determination.

Rate selection is subject to paragraphs 3.2 and 3.3 of the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services, and this rate schedule will become effective only after the Company has installed the required timed kilowatt meter.

This schedule is not applicable to breakdown, standby, supplementary, residential or resale service nor to service for which Rate Schedule E-35 is applicable. Direct Access customers are not eligible for this rate schedule.

TYPE OF SERVICE

The type of service provided under this schedule will be single or three phase, 60 Hertz, at one standard voltage as may be selected by customer subject to availability at the customer's site. Three phase service is furnished under the Company's Schedule 3 (Conditions Governing Extensions of Electric Distribution Lines and Services). Three phase service is not furnished for motors of an individual rated capacity of less than 7-1/2 HP, except for existing facilities or where total aggregate HP of all connected three phase motors exceeds 12 HP. Three phase service is required for motors of an individual rated capacity of more than 7-1/2 HP.

RATES

The bill shall be computed at the following rates or the minimum rates, whichever is greater, plus any adjustments incorporated in this schedule:

RATE

Basic Service Charge:

For service through Self-Contained Meters:	$0.600 per day
For service through Instrument-Rated Meters:	$1.134 per day

RATES (cont)

RATE (cont)

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
$2.00 per On-Peak kW, plus $0.10122 per kWh during On-Peak hours, plus $0.06873 per kWh during Off-Peak hours	$2.00 per On-Peak kW, plus $0.07638 per kWh during all hours

In addition to the above charges, if applicable, an Excess Off-Peak kW charge of $1.00 per kW will be applied to all measured Off-Peak kW that are higher than twice the measured On-Peak kW for the billing month.

MINIMUM

The bill for service under this rate schedule will not be less than the applicable Basic Service Charge plus $1.75 for each kW of either the highest kW established during the 12 months ending with the current month or the minimum kW specified in the agreement for service, whichever is the greater.

DETERMINATION OF KW

The kW charges billed in this schedule shall be based on the average kW supplied during the 15-minute period of maximum use during the On-Peak and Off-Peak periods of the month, as determined from readings of the Company's meter.

TIME PERIODS

Time periods applicable to usage under this rate schedule are as follows:

On-Peak hours:	9:00 am – 9:00 pm Monday through Friday
Off-Peak hours:	All remaining hours

Mountain Standard Time shall be used in the application of this rate schedule.

ADJUSTMENTS

1. The Environmental Portfolio Surcharge shall be applied to every retail electric service as set forth in the Company's Rate Schedule EPS-1.

2. The bill is subject to the Power Supply Adjustment factor as set forth in the Company's Rate Schedule PSA-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

3. The bill is subject to the Transmission Adjustment factor as set forth in the Company's Rate Schedule TCA-1.

RATES (cont)

ADJUSTMENTS (cont)

4. The bill is subject to the Competition Rules Compliance Charge as set forth in the Company's Rate Schedule CRCC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

5. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Assignment Charge as set forth in the Company's Rate Schedule RCDAC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

6. The bill is subject to the System Benefits Adjustment charge as set forth in the Company's Rate Schedule SBAC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

7. The bill is subject to the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of APS and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

CONTRACT PERIOD

The contract period for all customers receiving service under this rate schedule will be one (1) year at the Company's option.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the premises served.

APPLICATION

This rate schedule is applicable to start-up and/or auxiliary load requirements for generation plants with a Power Supply capacity requirement of greater than 3 MW. Service must be supplied at one point of delivery and measured through one meter unless otherwise specified by individual customer contract. This rate schedule may be used in conjunction with other applicable Company rate schedules.

TYPE OF SERVICE

Three phase, 60 Hertz, at one standard voltage available within the vicinity of the customer's site.

RATES

The bill shall be the sum of the amounts included under A., B. and C. below, including any applicable adjustments:

A. Basic Service

$6,100.00 per month Basic Service Charge

B. Metering Service

1.29% of total metering cost specified in the Electric Supply Agreement between the Company and the customer. This percentage will be reduced to 0.35% when the customer provides all necessary metering equipment and is responsible for its replacement. The customer shall also be responsible for all applicable costs associated with communications facilities used to compile metered usage information.

C. Power Supply Service

The charge for Power Supply Service shall be the sum of 1. and 2. below:

1. T & D Capacity Rate	$4.58	per kW of Contract Power Supply Capacity for service provided at secondary distribution voltage levels (less than 12.5 kV)
	$4.42	per kW of Contract Power Supply Capacity for service provided at primary distribution.voltage levels (12.5 kV to below 69 kV)
	$1.43	per kW of Contract Power Supply Capacity for service provided at transmission voltage levels (69 kV or higher)
2. Power Supply/Energy/Ancillary Service Charge		Market price plus $0.0005 for each kWh used

CONTRACT PERIOD

Any applicable contract periods will be set forth in an Electric Supply Agreement between the customer and the Company.

CONNECTION COSTS

The customer will pay all applicable connection costs and system improvement costs not otherwise covered in this schedule as a non-refundable contribution in aid of construction, including any associated tax liability.

POWER SUPPLY CAPACITY

Power Supply Capacity kW shall be defined as the greater of:

(a) The amount of capacity (kW) reserved by the customer in the Electric Supply Agreement; or

(b) The highest 15 minute measured kW supplied by the Company, by voltage level, to accommodate the start-up of the customer's generation unit(s) plus any necessary auxiliary load (including generation auxiliary load and/or any other load requirements at the plant site that would otherwise be provided by the customer when the generation unit(s) are running).

If more than one generation unit is present at a single site, the Electric Supply Agreement may, at the Company's option, allow the customer to start one unit at a time. In this instance, Power Supply Capacity kW shall be defined as the greater of:

(a) The amount of capacity (kW) reserved by the customer in the Electric Supply Agreement; or

(b) The highest 15 minute measured kW supplied by the Company, by voltage level, to accommodate the start-up of one and only one customer generation unit at any given time plus any necessary auxiliary load (including any or all generation auxiliary load and/or any other load requirements at the entire plant site that would otherwise be provided by the customer when any or all generation unit(s) are running).

If, during any one billing period, the highest 15 minute measured kW supplied by the Company (by voltage level) exceeds the amount of Power Supply Capacity specified in the Electric Supply Agreement, the Power Supply Capacity reservation (by voltage level) shall be permanently increased to equal the higher measured kW. If the Company incurs additional connection costs to provide this added capacity, the customer is responsible for payment of these costs as specified herein.

DETERMINATION OF MARKET PRICE

Market price charges shall represent the Company's total cost, as expressed on a per kWh basis, for system incremental power (as determined by the Company or its Scheduling Coordinator) at the time Station Use power is supplied to the customer. The cost for both the generation and purchased power components of the Market Price shall be determined by real time operators on an hourly basis at the time of the operator's power supply source decision(s).

System Incremental Cost shall be computed as the weighted average price of the marginal dispatchable generation resources and/or third party purchases made by the Company's real time operators to serve the specific customer.

METERING

The Company will normally install a supply meter at the point of delivery to the customer and a generator meter(s) at the point(s) of output from each of the customer's generators. However, the customer can elect to supply this metering as long as it conforms to Company specifications. All meters will record integrated demand and energy on the same 15-minute interval basis as specified by the Company.

ADJUSTMENTS

1. The Environmental Portfolio Surcharge shall be applied to every retail electric service as set forth in the Company's Rate Schedule EPS-1.

2. The bill is subject to the Power Supply Adjustment factor as set forth in the Company's Rate Schedule PSA-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

3. The bill is subject to the Transmission Adjustment factor as set forth in the Company's Rate Schedule TCA-1.

4. The bill is subject to the Competition Rules Compliance Charge as set forth in the Company's Rate Schedule CRCC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

5. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Assignment Charge as set forth in the Company's Rate Schedule RCDAC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

6. The bill is subject to the System Benefits Adjustment charge as set forth in the Company's Rate Schedule SBAC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

7. The bill is subject to the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of APS and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

INTERCONNECTION REQUIREMENTS

The customer must meet all interconnection requirements as determined by the Company. The customer is responsible for all costs associated with interconnection of the customer's generation facility to the Company's system.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

RATE SCHEDULE E-40
CLASSIFIED SERVICE
AGRICULTURAL WIND MACHINE SERVICE

AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the premises served.

APPLICATION

This rate schedule is applicable to all Standard Offer electric service required for the operation of wind machine for frost control during the months of November thru March only when such service is supplied at one point of delivery and measured through one meter. Direct Access customers are not eligible for this rate schedule.

This schedule is not applicable to temporary, breakdown, standby, supplementary, or resale service.

TYPE OF SERVICE

The type of service provided under this schedule will be three phase, 60 Hertz, at one standard voltage (120/240, 120/480, or 7,200/12,000 volts as may be selected by customer subject to availability at the site).

RATES

Basic Service Charge:	$13.37	per HorsePower per year, plus
Energy Charge:	$ 0.06838	per kWh for all kWh

HorsePower will be equivalent to the wind machine name plate rating unless Company tests indicate the motor is overloaded by more than 15%.

ADJUSTMENTS

1. The Environmental Portfolio Surcharge shall be applied to every retail electric service as set forth in the Company's Rate Schedule EPS-1.

2. The bill is subject to the Power Supply Adjustment factor as set forth in the Company's Rate Schedule PSA-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

3. The bill is subject to the Transmission Adjustment factor as set forth in the Company's Rate Schedule TCA-1.

4. The bill is subject to the Competition Rules Compliance Charge as set forth in the Company's Rate Schedule CRCC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

5. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Assignment Charge as set forth in the Company's Rate Schedule RCDAC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

RATES (cont)

ADJUSTMENTS (cont)

6. The bill is subject to the System Benefits Adjustment charge as set forth in the Company's Rate Schedule SBAC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

7. The bill is subject to the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of APS and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

SPECIAL PROVISIONS

1. For billing under this rate schedule, the customer may choose between one of the following options:

   a) Monthly billing;
   b) Semiannual billing for three (3) months in advance and three (3) months actual use; or
   c) Annual billing for six (6) months in advance and six (6) months actual use.

   After initial selection of payment by the customer no change may be made during the term of the service agreement.

2. Thermostatically controlled wind machines with automatic reclosing switches must be equipped at the customer's expense with suitable time-delay devices to permit the required adjustment of the time of reclosure after interruption of service.

   A time-delay device is a relay or other type of equipment that can be preset to delay with various time intervals the reclosing of the automatic switches in order to stagger the reconnection of the load on the utility's system. This device must be constructed so as to effectively permit a variable overall time interval of not less than five minutes with adjustable time increments of not greater than ten seconds. The particular setting to be utilized for each separate installation is to be determined by the Company from time to time in accordance with its operating requirements.

CONTRACT PERIOD

The initial customer contract period shall be five (5) years. The contract period for any renewals shall be three (3) years.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

RATE SCHEDULE E-47
CLASSIFIED SERVICE
DUSK to DAWN LIGHTING SERVICE

AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

APPLICATION

This rate schedule is applicable to outdoor lighting which operates only from dusk to dawn and where service can be supplied from the existing secondary facilities of the Company. Dusk is defined as the time between sunset and full night when a photocontrol senses the lack of sufficient sunlight and turns on the lights. Dawn is defined as the time between full night and sunrise when a photocontrol senses sufficient sunlight to turn off lights.

RATES

The customer's bill shall be computed at the following rates for each type of standard facility and/or service utilized to provide outdoor lighting, plus any adjustments incorporated in this schedule:

FIXTURES (Includes Mounting Arm, if Applicable)

				RATES	
	Lumen	Watts	kWh	Company Owned	Customer Owned
A. Acorn	9,500 HPS	100	41	$20.27	$5.00
	16,000 HPS	150	69	22.45	6.71
B. Architectural	9,500 HPS	100	41	14.32	6.41
	16,000 HPS	150	69	16.65	8.59
	30,000 HPS	250	99	19.66	10.94
	50,000 HPS	400	153	24.13	15.16
	14,000 MH	175	72	19.07	10.22
	21,000 MH	250	101	21.58	12.53
	36,000 MH	400	159	26.87	17.07
	8,000 LPS	55	30	20.59	7.80
	13,500 LPS	90	50	24.20	9.16
	22,500 LPS	135	72	27.57	11.17
	33,000 LPS	180	90	31.77	12.99
C. Cobra/Roadway	5,800 HPS	70	29	8.34	5.47
	9,500 HPS	100	41	9.73	6.41
	16,000 HPS	150	69	12.07	8.59
	30,000 HPS	250	99	14.45	10.94
	50,000 HPS	400	153	19.42	15.16
	14,000 MH	175	72	11.39	7.97
	21,000 MH	250	101	13.25	9.78
	36,000 MH	400	159	17.31	13.32
	8,000 FL	100	38	13.03	3.58

RATES (cont)

FIXTURES (Includes Mounting Arm, if Applicable) (cont)

					RATES	
		Lumen	Watts	kWh	Company Owned	Customer Owned
D. Decorative Transit	Pedestrian (4")	9,500 HPS	100	41	$27.63	$5.00
	Pedestrian (6")	9,500 HPS	100	41	27.63	5.00
	Streetlight (6")	30,000 HPS	250	99	31.57	8.54
E. Flood		30,000 HPS	250	99	18.28	10.94
		50,000 HPS	400	153	22.56	15.16
		21,000 MH	250	101	16.55	9.78
		36,000 MH	400	159	20.09	13.32
F. Post Top	Colonial Gray	8,000 FL	100	38	14.01	3.58
		9,500 HPS	100	41	10.02	6.41
	Colonial Black	9,500 HPS	100	41	11.03	6.41
	Decorative Transit	9,500 HPS	100	41	24.24	5.00
G. FROZEN		4,000 INC	295	103	10.23	3.78
		7,000 MV	175	73	10.33	4.97
		20,000 MV	400	150	14.35	9.47

FROZEN

NOTES:

1. Company Owned fixtures are those fixtures that the Company installs, owns, operates, and maintains.
2. Customer Owned fixtures are those fixtures where the customer installs and maintains the lighting fixtures, and the Company approves the installation, operates the fixtures, and replaces Company standard lamps only.
3. Listed kWh's reflect the assigned monthly usage kWh's for each type of fixture and are used to determine any applicable transmission, distribution, energy and adjustment charges.
4. HPS = High Pressure Sodium
5. MH = Metal Halide
6. LPS = Low Pressure Sodium
7. FL = Fluorescent
8. INC = Incandescent. Incandescent lighting charges are applicable and available only to those customers being served and those installations in service on April 21, 1983.
9. MV = Mercury Vapor. Mercury Vapor lighting charges are applicable and available only to those customers being served and those installation in service on June 1, 1987 in accordance with A.R.S. §49-1104(A).

RATES (cont)

POLES

			Height	RATES Company Owned
A. Anchor Base Mounted (Flush)	Round Steel	1 Simplex Adapter	12 ft.	$ 8.68
			22 ft.	9.80
			25 ft	10.63
			30 ft	12.25
			32 ft	12.88
	Round Steel	2 Simplex Adapters	12 ft.	9.27
			22 ft.	10.69
			25 ft.	11.16
			30 ft.	13.01
			32 ft.	13.90
	Square Steel	5"	13 ft.	9.99
			15 ft.	8.90
			23 ft.	10.60
			25 ft.	11.68
			28 ft.	12.99
			32 ft.	13.47
	Concrete		12 ft.	30.26
	Fiberglass		12 ft.	25.59
	Decorative Transit Pedestrian	4"	16 ft.	24.94
	Decorative Transit	6"	30 ft.	25.48
B. Anchor Base Mounted (Pedestal)	Round Steel	1 Simplex Adapter	12 ft.	8.34
			22 ft.	9.46
			25 ft.	10.28
			30 ft.	11.91
			32 ft.	12.53
	Round Steel	2 Simplex Adapters	12 ft.	8.93
			22 ft.	10.00
			25 ft.	10.82
			30 ft.	12.67
			32 ft.	13.55
		3 Bolt Arm	32 ft.	15.61
	Square Steel	5"	13 ft.	9.65
			15 ft.	9.88
			23 ft.	10.26
			25 ft.	11.34
			28 ft.	12.64
			32 ft.	13.13

RATES (cont)

POLES (cont)

				RATES
			Height	Company Owned
C. Direct Bury	Round Steel		19 ft.	13.27
			30 ft.	12.54
			38 ft.	15.34
		Self Support	40 ft.	18.19
		Stepped	49 ft.	47.44
	Square Steel	4"	34 ft.	13.85
		5"	20 ft.	12.62
			30 ft.	13.71
			38 ft.	14.89
	Steel Distribution Pole		35 ft.	17.02
D. Post Top	Decorative Transit Anchor Base		16 ft.	25.48
	Gray Steel/Fiberglass		23 ft.	10.57
	Black Steel		23 ft.	11.20

E. FROZEN	Wood Poles	30 ft.	6.08
		35 ft.	7.66
		40 ft.	9.70

NOTES:

1. All distribution lines required to serve dusk to dawn facilities are owned by the Company.
2. Monthly rates for all new Company owned poles include up to 100 feet of overhead secondary wire, or up to 100 feet of underground secondary line if customer provides earthwork and conduit (excluding the overhead to underground transition). Any additional wire required (over and above the first 100 feet provided) to install fixtures is subject to the additional monthly wire charges specified in below.
3. When adding lighting fixtures to an existing Company owned pole, any and all additional distribution wire required is subject to the additional monthly wire charges specified below.
4. Any and all distribution wire required to serve lighting facilities placed on a customer owned pole, whether new or existing, is subject to the additional monthly wire charges specified below.

ANCHOR BASE

		Height	RATES Company Owned
A. Flush		4 ft.	$7.27
		6 ft.	8.67
B. Pedestal		8 ft.	9.94
	For 32' Round Steel Pole only	4 ft. 6"	6.89

RATES FOR OPTIONAL OR ADDITIONAL EQUIPMENT

	RATES Company Owned
1. Each 100 feet of overhead secondary wire, or each 100 feet of underground secondary wire if customer provides earthwork and conduit.	2.57
2. Additional maintenance charge for HPS lamp and luminaire that is not accessible by bucket truck.	2.05
3. Additional maintenance charge for MH lamp and luminaire that is not accessible by bucket truck.	4.43

ADJUSTMENTS

1. The Environmental Portfolio Surcharge shall be applied to every retail electric service as set forth in the Company's Rate Schedule EPS-1.

2. The bill is subject to the Power Supply Adjustment factor as set forth in the Company's Rate Schedule PSA-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

3. The bill is subject to the Transmission Adjustment factor as set forth in the Company's Rate Schedule TCA-1.

4. The bill is subject to the Competition Rules Compliance Charge as set forth in the Company's Rate Schedule CRCC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

5. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Assignment Charge as set forth in the Company's Rate Schedule RCDAC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

6. The bill is subject to the System Benefits Adjustment charge as set forth in the Company's Rate Schedule SBAC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

7. The bill is subject to the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of APS and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

SPECIAL PROVISIONS

1. The 4,000 and 7,000 lumen lamps use an open glass diffuser. All units are controlled by a photoelectric switch.

2. The customer is not authorized to make connections to the lighting circuits or to make attachments.

3. Should a customer request relocation of a dusk-to-dawn lighting installation, the costs of such relocation shall be paid by the customer.

4. The Company cannot guarantee that all dusk to dawn facilities will always operate as intended. Therefore, the customer will be responsible for notifying the Company when the dusk to dawn facilities are not operating as intended. The Company will use reasonable efforts to complete normal maintenance (replacement of lamps, photocontrols or fixtures) within ten (10) working days from notification by customer; however, if the maintenance requires cable replacement or repairs, the Company shall use reasonable efforts to complete said repairs within twenty (20) working days.

5. The customer's bills will not be reduced due to lamp, photocontrol or cable repair or replacement outages.

6. The customer may cancel a lighting service agreement by payment of the bill including the applicable tax adjustment, multiplied by the number of remaining months of the initial agreement, or the calculated installation and removal costs for the extension, whichever is lower.

NON-STANDARD FACILITIES – CUSTOMER OWNED

When the customer requests any non-standard dusk-to-dawn lighting facilities (non-standard being defined as any equipment not listed in the Company's Transmission and Distribution Construction Standards book), the customer will own, operate and maintain all components to the system excluding the distribution facilities installed by the Company to serve the lighting system. Bills rendered for non-standard facilities will be computed at the following rates, plus any adjustments incorporated in this schedule:

A.	Service Charge per installed lamp	$2.56, plus	
B.	Energy Charge	$0.04847	per kWh

If, at the Company's discretion, the customer chooses to have the Company maintain the entire non-standard facility, the Company may require the customer to enter into a separate maintenance agreement which may be subject to additional charges mutually agreed upon by the Company and the customer.

CONTRACT PERIOD

All Dusk-to-Dawn lighting installations will require a written agreement for service for a minimum of three (3) years, or longer at Company's option.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

RATE SCHEDULE E-51
CLASSIFIED SERVICE
OPTIONAL ELECTRIC SERVICE FOR QUALIFIED COGENERATION AND SMALL POWER PRODUCTION FACILITIES OVER 100 kW

AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

APPLICATION

This rate schedule is applicable only to qualified cogeneration and small power production facilities greater than 100 kW that meet qualifying status as defined under 18 CFR, Chapter 1, Part 292, Subpart B of the Federal Energy Regulatory Commission regulations and pursuant to the Arizona Corporation Commission's Decision No. 52345. The facility's generator(s) and load must be located at the same site.

Applicable only to those customers being served on the Company's Rate Schedule E-51 prior to July 1, 1996.

TYPE OF SERVICE

Single or three phase, 60 Hertz, at one standard voltage as may be selected by Customer subject to availability at Customer's premise.

RATES

The bill shall be the sum of the amounts computed under A., B., C., and D. below, including the applicable Adjustments:

A. Basic Service
   $ 0.263 per day Cogeneration Basic Service Charge, plus
   $ 0.789 per day per each generator meter

B. Supplemental Service
   In accordance with the rate levels contained in General Service Rate Schedule E-32 or E-34, whichever is applicable based upon Customer's maximum Supplemental demand.

C. Standby Service

   1. Monthly Reservation Charge of $1.98 per kW of Contract Standby Capacity, to be adjusted as specified on page 2, plus

   2. Standby Energy Charge:

May - October Billing Cycles (Summer)	$0.04383 per kWh On-Peak $0.02040 per kWh Off-Peak
November - April Billing Cycles (Winter)	.02234 per kWh

RATES(cont)

D. Maintenance Service

$0.02040 per kWh of maintenance energy

DETERMINATION OF MONTHLY RESERVATION CHARGE

For initial service, the Monthly Reservation Charge shall be: the product of [$19.79/kW multiplied by a Forced Outage Rate (FOR) of 10%] multiplied by the customer's applicable Contract Standby Capacity. At the end of the first 6 summer billing months, the initial FOR of 10% will be replaced by the actual FOR experienced by the cogeneration system during on-peak summer hours. Customer's summer on-peak FOR will then be reevaluated annually each November for the preceding 12-month period to be used in the calculation of Customer's Reservation Charge for the current and succeeding 11 months.

DETERMINATION OF SUPPLEMENTAL SERVICE

Supplemental service shall be defined as demand and energy contracted by Customer to augment the power and energy generated by Customer's generation facility.

Supplemental demand shall be equal to the maximum 15 minute integrated kW demand as calculated for every 15-minute interval as the demand of the Supply meter plus the demand of the Generator meter(s) less the Contract Standby Capacity of Customer's cogenerator(s).

Supplemental energy shall be equal to all energy supplied to Customer as determined from readings of the Supply meter, less any energy determined to be either Standby or Maintenance energy as defined in this Schedule.

DETERMINATION OF STANDBY ENERGY

Standby Energy shall be defined to be electric energy supplied by Company to replace power ordinarily generated by Customer's generation facility during unscheduled full and partial outages of said facility.

When the sum of the energy measured on both the Supply and Generator(s) Meters is greater than the maximum energy output of the generator(s) at Contract Standby Capacity, the Standby Energy shall be equal to the summation of the differences between the maximum energy output of the generator(s) at Contract Standby Capacity and the energy measured on the Generator Meter(s) for every 15-minute interval of the month, except when maintenance power is being utilized or those intervals where energy measured on the Supply Meter is zero. When the sum of the energy measured on both the Supply and Generator(s) Meters is less than the maximum energy output of the generator(s) at Contract Standby Capacity, then the Standby energy shall be that energy measured on the Supply Meter.

All Standby Energy exceeding 250 kWh/kW of Contract Standby Capacity in a billing period will be billed at the otherwise applicable rate for Supplemental Service.

RATES (cont)

DETERMINATION OF MAINTENANCE ENERGY

Maintenance energy shall be defined as energy supplied to Customer up to a maximum of the Contract Standby Capacity times the hours in the Scheduled Maintenance period for that energy used only during the Scheduled Maintenance period. Maintenance periods shall not exceed 30 days per cogeneration unit during any consecutive 12-month period and must be scheduled during the winter billing months. Customer shall supply Company with Maintenance Schedule for a 12-month period at least 60 days prior to the beginning of that period, which shall be subject to Company approval. Energy used in excess of a 30-day period or unauthorized maintenance energy shall be billed on either the Standby or Supplemental Rate as specified in this Schedule.

METERING

The Company will install a Supply Meter at its point of delivery to Customer and a Generator Meter(s) at the point(s) of output from each of Customer's generators. All meters will record integrated demand and energy on the same 15-minute interval basis as specified by Company.

DEFINITIONS

1. Contract Standby Capacity - the measured kW output of each cogeneration unit at time of start-up test, which will be re-evaluated annually each November and specified in Customer's Agreement for Service, however, not to exceed Customer's actual total load.

2. Forced Outage Rate - the ratio of the standby energy used during the Customer's summer on-peak hours to the product of the Contract Standby Capacity multiplied by the total customer's summer on-peak hours.

3. Generator Meter - the time-of-use meter used to measure in 15-minute intervals the total power and energy output of each of Customer's cogeneration units.

4. Supply Meter - the time-of-use meter used to measure in 15-minute intervals the total power and energy supplied by Company to Customer.

5. Time Periods - On-Peak Period: 9 a.m. - 9 p.m. Monday through Friday
Off-Peak Period: All Other Hours

Mountain Standard Time shall be used in the application of this rate schedule.

ADJUSTMENTS

1. The Environmental Portfolio Surcharge shall be applied to every retail electric service as set forth in the Company's Rate Schedule EPS-1.

2. The bill is subject to the Power Supply Adjustment factor as set forth in the Company's Rate Schedule PSA-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

RATES (cont)

ADJUSTMENTS (cont)

3. The bill is subject to the Transmission Adjustment factor as set forth in the Company's Rate Schedule TCA-1.

4. The bill is subject to the Competition Rules Compliance Charge as set forth in the Company's Rate Schedule CRCC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

5. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Assignment Charge as set forth in the Company's Rate Schedule RCDAC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

6. The bill is subject to the System Benefits Adjustment charge as set forth in the Company's Rate Schedule SBAC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

7. The bill is subject to the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of APS and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

TERMINATION PROVISION

Should Customer cease to operate his cogeneration unit(s) for 60 consecutive days during periods other than planned scheduled maintenance periods, Company reserves the option to terminate the Agreement for service under this rate schedule with Customer.

CONTRACT PERIOD

As provided in Company's Agreement for Service.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

AVAILABILITY

This rate schedule is available in all territory served by Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the premises served and when all applicable provisions described herein have been met.

APPLICATION

Applicable to any non-residential customer requiring Partial Requirements services, Supplemental Power, Standby Power or Maintenance Energy with an aggregate Partial Requirements service load of less than 3,000 kW. Customer may elect to take any of the Partial Requirements services offered hereunder, Supplemental Power, Standby Power and Maintenance Power independently of one another or in combination with one another as required.

Each customer shall be allowed to designate the specific periods and hours within a month for which utilization of Standby Service is required (see Designated Standby Service Hours).

TYPE OF SERVICE

Single or three phase, 60 Hertz, at one standard voltage as may be selected by Customer subject to availability at Customer's premise.

RATES

The bill shall be the sum of the amounts computed under A., B., C., and D. below, including the applicable Adjustments:

A. Basic Service
   $ 106.79 per month Basic Service Charge, plus
   $ 17.06 per month for each Generator Meter

B. Supplemental Service
   In accordance with the rate levels contained in General Service Rate Schedule E-32 excluding the monthly Basic Service Charge.

C. Standby Service
   The monthly charge for Standby Service shall be the sum of the amounts computed in accordance with sections 1 and 2 below:

RATES (cont)

C. Standby Service (cont)

1. Monthly Reservation Charge of either a, b or c:

   a) $5.01 per kW of Contract Standby Capacity for Standby Service customers with alternate supply resources demonstrating an aggregate Capacity Factor of 90% or greater during the billing month.

   b) $6.59 per kW of contract Standby Capacity for Standby Service customers with alternate supply resources demonstrating an aggregate Capacity Factor between 80% - 89.9% during the billing month.

   c) Standby Service customers whose alternate supply resource(s) achieved an aggregate capacity factor of less than 80% during a billing month shall be assessed the same charge as set forth in Section VIII of this rate schedule.

2. Standby Energy Charge:

June - October Billing Cycles (Summer)	$0.02961 per kWh on-peak $0.01574 per kWh off-peak
November - May Billing Cycles (Winter)	$0.02537 per kWh on-peak $0.01006 per kWh off-peak

The charges for Standby Service contained in Section C herein reflect the Company's costs to serve Standby Service loads. For applications where the charges for Standby Service stated herein are not competitive with customer installed standby resource alternatives, the Company may negotiate alternate Monthly Reservation Charges from those contained in this rate schedule; however, the maximum discount allowed shall not be greater than fifty percent (50%) of the Reservation Charges stated herein; however, such discount shall not result in a reservation charge lower than the Company's long run capacity costs associated with this service. No changes to the Standby Energy Charge rate component shall be allowed.

To be eligible for negotiated Monthly Reservation Charges different than those contained herein, the customer must demonstrate to the Company's satisfaction and provide conclusive documentation (e.g., engineering studies, analysis, etc.) that the customer's on-site self-generation resource(s) would be a lower cost option over the life of the equipment than had the customer subscribed to Standby Service from the Company. Notwithstanding the potential competitiveness of the customer's self generation standby facilities, the Company in its sole opinion, shall have the option of not offering any discounts to the otherwise applicable Reservation Charge.

RATES (cont)

D. Maintenance Service
$0.02537 per kWh on-peak
$0.01006 per kWh off-peak

E. Energy Rates
The energy rates in Sections C and D above are based on the Company's estimated marginal costs and will be updated annually to reflect changes in the Company's fuel costs.

DETERMINATION OF SUPPLEMENTAL SERVICE

Supplemental service shall be defined as demand and energy contracted by Customer to augment the power and energy generated by Customer's generation facility.

Supplemental demand shall be the highest 15-minute interval during the billing month which shall equal the (a) 15-minute integrated kW demand calculated for every 15-minute interval as recorded on the Supply Meter, plus (b) the simultaneous 15 minute integrated kW demand as recorded on the Generator Meter(s), less (c) the aggregate Contract Standby Capacity of all the customer's generating units; however, the result shall never be less than zero (0) for purposes of determining Supplemental Demand. If Company authorized scheduled maintenance was being performed on any of the customer's generators at the time of the highest 15 minute interval during the billing month, the amount of demand recorded on the Supply Meter shall be reduced by the applicable Maintenance Power Level (as determined in Section VII hereof) of the generator unit(s) undergoing authorized scheduled maintenance for purposes of calculating supplemental demand used for billing.

Customer's maximum Supplemental Service kW requirements shall not exceed that established in the Electric Supply Agreement.

Supplemental energy shall be equal to all energy supplied to Customer as determined from readings of the Supply Meter, less any energy determined to be either Standby or Maintenance energy as defined in this Schedule.

DETERMINATION OF STANDBY ENERGY

Standby Energy shall be defined to be electric energy supplied by Company to replace power ordinarily generated by Customer's generation facility during unscheduled full and partial outages of said facility.

When the sum of the energy measured on both the Supply and Generator(s) Meters during simultaneous periods is greater than the maximum energy output of the generator(s) at Contract Standby Capacity, the Standby Energy shall be equal to the summation of the differences between the maximum energy output of the generator(s) at Contract Standby Capacity and the energy measured on the Generator Meter(s) for every 15-minute interval of the month, except when maintenance power is being utilized or those intervals where energy measured on the Supply Meter is zero. When the sum of the energy measured on both the Supply and Generator(s) Meter is equal to or less than the maximum energy output of the generator(s) at Contract Standby Capacity, then the Standby energy shall be that energy measured on the Supply Meter.

DETERMINATION OF MAINTENANCE ENERGY

Maintenance energy shall be defined as energy supplied to Customer to replace energy normally supplied by the Customer's generator(s) during an authorized Scheduled Maintenance period.

Maintenance periods shall not exceed 30 days per cogeneration unit during any consecutive 12-month period and must be scheduled during the non-Summer billing months. Customer shall provide Company with its planned maintenance schedule 12 months in advance of any planned maintenance in order for the Company to coordinate customer's scheduled maintenance with that of the Company. Upon review, Company shall either approve customer's planned maintenance schedule or notify customer of alternate acceptable periods. Customer, in turn, shall notify the Company of an acceptable alternate maintenance period(s), and shall also confirm with the Company its intention to perform its planned maintenance 45 days prior to the actual commencement date of the planned maintenance period.

Any energy used in excess of a 30-day period or unauthorized maintenance energy shall be billed on either the Standby or Supplemental Rate as specified in this Schedule.

Maintenance energy, during a Company authorized period of scheduled maintenance to a customer's generation unit(s), shall be determined as follows:

Maintenance Power Level = (Contract Standby Capacity) X (Generating Unit(s) Capacity Factor for the most recent 12 months)

The maintenance power level as determined by the above formula shall not exceed any actual 15 minute interval of integrated kW demand as recorded on the supply meter.

If customer has less than 12 months of billing history on Standby Service, use the capacity factor demonstrated to date; however, not less than one full month.

Maintenance Energy = (Maintenance Power Level) X (hours of maintenance authorized by Company during billing month)

CAPACITY FACTOR STANDARDS

Customer's generating unit(s) must maintain a Capacity Factor of no less than 75% over a continuous rolling 18 month period to remain eligible to receive Standby Service under this rate schedule. The calculation of the Capacity Factor is designed so that the customer shall not be subject to this Capacity Factor Standard provision for any purpose other than substandard operational performance of the customer's generating unit(s) recognizing that the customer's load profile may not require the full output capability of such generation unit(s). If the Capacity Factor falls below 75%, in lieu of the otherwise applicable Reservation Charge for Standby Service, the customer shall be assessed a monthly Reservation Charge the greater of:

1. $18.79 per kW/month X 2/3 X Contract Standby Capacity; or

2. $18.79 per kW/month X Maximum Standby Capacity
   (If customer's system is directly interconnected with the Company's bulk transmission system, the applicable Reservation Charge shall be $14.39 per kW per month.)

CAPACITY FACTOR STANDARDS (cont)

Maximum Standby Capacity is intended to represent the maximum 15-minute interval of Standby Power provided the customer by the Company during the billing month. Maximum Standby Capacity shall equal the highest 15-minute interval during the billing month of the following calculation:

$$MSC = \Sigma CSC - Maint.$$

Where:

MSC = Maximum 15-minute interval during the billing month of Standby Power (kW) being supplied by Company.

ΣCSC = The aggregate Contract Standby Capacity of all the customer's self-generation units.

Maint = The simultaneous 15-minute interval of any Maintenance Power (kW) being supplied to customer by the Company.

METERING

The Company will install a Supply Meter at its point of delivery to Customer and a Generator Meter(s) at the point(s) of output from each of Customer's generators. All meters will record integrated demand and energy on the same 15-minute interval basis as specified by Company.

DEFINITIONS

1. Contract Standby Capacity - for each specific customer generating unit for which the Company is providing Standby Service, Contract Standby Capacity shall be the greater of: a) the measured kW output of each customer self-generation unit at time of start-up test, or b) the highest 15 minute measured kW output of each generating unit, however, not to exceed Customer's actual total load.

2. Generator Meter - the time-of-use meter used to measure in 15-minute intervals the total power and energy output of each cogeneration unit.

3. Designated Standby Service Hours - Customers requiring Standby Service for less than the total hours in a billing month shall be allowed to designate those periods and hours of a month when Standby Service is required. These Designated Standby Service Hours shall represent those hours within a billing month during which the customer is authorized to utilize Standby Service. Use during any period or hours other than Designated Standby Service Hours shall represent an Unauthorized Use of Standby Service subject to certain special provisions for determining the appropriate Capacity Factor value during billing periods when unauthorized Standby Service was utilized. Such hours shall be specified in whole hour intervals beginning on an hour for each designated day of the week. Designated Standby Service Hours shall never total less than 280 hours a billing month.

DEFINITIONS (cont)

4. Capacity Factor - for purposes of this rate schedule, capacity factor shall mean the capacity factor of the customer's generating unit(s) and shall not reflect any period of time during a billing month that Company authorized Maintenance Power was being utilized. The Capacity factor shall be calculated in accordance with the following formula:

$$\text{Capacity Factor} = \frac{\text{Actual customer generated kWh's during the billing month}}{A}$$

For purposes of use in this rate schedule, the value of the capacity factor calculation shall never exceed 100%.

Where:

A = The lesser of:
 a) [(Contract Standby Capacity) X (MH)]; or
 b) CTL

MH = The number of Designated Standby Service Hours in the billing month, exclusive of any hours during the billing month that customer's unit(s) were non-operational during Company authorized scheduled maintenance, for which the customer has contracted for Standby Service (but not less than 280 hours per billing month).

In the event the customer utilizes Standby Service in any period other than during Designated Standby Service Hours, MH shall be represented as the actual number of hours in the billing month (exclusive of any hours during which the customer was receiving Company authorized scheduled Maintenance Energy).

Furthermore, in the event there are more than two (2) instances in any 12 month rolling period of Unauthorized Use of Standby Service, MH shall be represented as the actual number of hours in the billing month (exclusive of any hours during which the customer was receiving Company authorized scheduled Maintenance Energy) for the month during which the third breach of service occurred, and for the next three months thereafter. At the end of any three month breach period, a new twelve (12) month rolling period shall commence for determining the number of instances of Unauthorized Use.

CTL = Customer's maximum total load during the billing month during the Designated Standby Service Hours for which the Customer has contracted for Standby Service (but not less than 280 hours per month).

CTL shall represent the customer's maximum total load during the hours in the billing month for which use of Standby Service has been authorized as set forth in the definition of Designated Standby Service Hours. CTL shall be calculated by first adding the maximum simultaneous 15-minute kW peak periods as recorded on the Supply Meter and Generator Meter(s) during authorized periods of Standby Service the sum of which is then multiplied by MH.

In the event the customer utilizes Standby Service during any period of a billing month other than those authorized, CTL shall represent the customer's maximum total (peak demand) load during the billing month calculated as the sum of the maximum simultaneous 15-minute kW peak period during the billing period recorded on the Supply Meter and the Generator Meter(s) during all hours of the billing month. CTL shall be similarly calculated for any other months during which the provision for breach of service explained in the definition of MH above is being assessed.

CTL shall only be used for calculating Capacity Factor in those months where the customer's maximum kW load is less than total Contract Standby Capacity.

5. Supply Meter - the time-of-use meter used to measure in 15-minute intervals the total power and energy supplied by Company to Customer.

6. Time Periods - On-Peak Period: 9 a.m. - 9 p.m. Monday through Friday
Off-Peak Period: All Other Hours

Mountain Standard Time shall be used in the application of this rate schedule. In addition, to prevent radical changes in the system loads the beginning and ending hours for individual customers may be varied by up to one hour (total hours in each time period to remain unchanged) and because of potential differences of the timing devices, there may be a variation of up to 15 minutes in timing for the pricing periods.

ADJUSTMENTS

1. The Environmental Portfolio Surcharge shall be applied to every retail electric service as set forth in the Company's Rate Schedule EPS-1.

2. The bill is subject to the Power Supply Adjustment factor as set forth in the Company's Rate Schedule PSA-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

3. The bill is subject to the Transmission Adjustment factor as set forth in the Company's Rate Schedule TCA-1.

4. The bill is subject to the Competition Rules Compliance Charge as set forth in the Company's Rate Schedule CRCC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

5. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Assignment Charge as set forth in the Company's Rate Schedule RCDAC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

6. The bill is subject to the System Benefits Adjustment charge as set forth in the Company's Rate Schedule SBAC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

ADJUSTMENT (cont)

7. The bill is subject to the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of APS and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

TERMINATION PROVISION

Should Customer cease to operate his cogeneration unit(s) for 60 consecutive days during periods other than planned scheduled maintenance periods, Company reserves the option to terminate the Agreement for service under this rate schedule with Customer.

CONTRACT PERIOD

As provided in the Electric Supply Agreement between Company and Customer.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

Customer must enter into an Agreement for the Interconnection and The Sale of Power with Company and an Electric Supply Agreement which shall establish all pertinent details related to interconnection and other required service standards. Customer will not have the option to sell power and energy to Company under this tariff. Should Customer desire to do so, Customer would be required to enter into a new Service Agreement which would set forth the applicable purchase rate in addition terms and conditions for interconnection and for the sale of power to the Company.

Customer will be required to contract for adequate standby power to cover the total output of all the customer's generators unless adequate facilities have been installed, to the satisfaction of APS, that isolate portions of the customer's load from APS' system so that APS will in no event be providing standby service in excess of Contracted Standby Capacity.

CHANGE IN DESIGNATED STANDBY SERVICE HOURS

Customers shall be allowed no more than one (1) change in their Designated Standby Service Hours during any eighteen (18) month time period. In no event shall the total of Designated Standby Service Hours during a month fall below 280 hours.

AVAILABILITY

In all territory served by Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the premises served and when all applicable provisions described herein have been met.

APPLICATION

Applicable to any customer requiring Partial Requirements services, Supplemental Power, Standby Power or Maintenance Energy with an aggregate Partial Requirements service load of no less than 3,000 kW. Customer may elect to take any of the Partial Requirements services offered hereunder (Supplemental Power, Standby Power and Maintenance Power) independently of one another or in combination with one another as required.

Customers having Standby Service requirements not exceeding 2,999 kW shall be allowed to designate specific periods and hours within a month for which utilization of Standby Service is required (see Designated Standby Service Hours).

TYPE OF SERVICE

Single or three phase, 60 Hertz, at one standard voltage as may be selected by Customer subject to availability at Customer's premise.

RATES

The bill shall be the sum of the amounts computed under A., B., C., and D. below, including the applicable Adjustments:

A. Basic Service

1. a) For applications no greater than 15,000 kW:

$ 1,671.39 per month Basic Service Charge; plus

b) For applications greater than 15,000 kW:

The monthly Basic Service Charge shall be $1,671.39 plus an applicable adder for recovery of non-standard metering costs and related O&M expenses; plus

2. $ 62.51 per month for each Generator Meter

B. Supplemental Service

In accordance with the rate levels contained in General Service Rate Schedule E-32, excluding the monthly Basic Service Charge (or E-34 if Supplemental Power requirements are 3,000 kW or more).

RATES(cont)

C. Standby Service

The monthly charge for Standby Service shall be the sum of the amounts computed in accordance with sections 1, 2 and 3 below:

1. For customers taking service at voltage levels of less than 69 kV, a Monthly Reservation Charge of either a, b, c or d:

   a) $ 4.21 per kW of Contract Standby Capacity for Standby Service customers with alternate supply resources demonstrating an aggregate Capacity Factor of 95% or greater during the billing month.

   b) $ 5.14 per kW of Contract Standby Capacity for Standby Service customers with alternate supply resources demonstrating an aggregate Capacity Factor between 90% - 94.9% during the billing month.

   c) $ 6.77 per kW of Contract Standby Capacity for Standby Service customers with alternate supply resources demonstrating an aggregate Capacity Factor between 80% - 89.9% during the billing month.

   d) Standby Service customers whose alternate supply resource(s) achieved an aggregate capacity factor of less than 80% during a billing month shall be assessed the same charge as set forth in Section VIII.A of this rate schedule.

2. For customers who take service at voltage levels of 69 kV or greater, a Monthly Reservation Charge of either a, b, c or d:

   a) $ 1.45 per kW of Contract Standby Capacity for Standby Service customers with alternate supply resources demonstrating an aggregate Capacity Factor of 95% or greater during the billing month.

   b) $ 2.30 per kW of Contract Standby Capacity for Standby Service customers with alternate supply resources demonstrating an aggregate Capacity Factor between 90% - 94.9% during the billing month.

   c) $ 4.11 per kW of Contract Standby Capacity for Standby Service customers with alternate supply resources demonstrating an aggregate Capacity Factor between 80% - 89.9% during the billing month.

   d) Standby Service customers whose alternate supply resource(s) achieved an aggregate capacity factor of less than 80% during a billing month shall be assessed the same charge as set forth in Section VIII.B of this rate schedule.

RATES (cont)

Standby Service (cont)

3. Standby Energy Charge:

June - October Billing Cycles (Summer)	$0.03040	per kWh On-peak
	$0.01616	per kWh Off-peak
November - May Billing Cycles (Winter)	$0.02605	per kWh on-peak
	$0.01033	per kWh off-peak

The charges for Standby Service contained in Section C herein reflect the Company's costs to serve Standby Service loads. For applications where the charges for Standby Service stated herein are not competitive with customer installed standby resource alternatives, the Company may negotiate alternate Monthly Reservation Charges from those contained in this rate schedule; however, the maximum discount allowed shall not be greater than fifty percent (50%) of the Reservation Charges stated herein; however, such discount shall not result in a reservation charge lower than the Company's long run capacity costs associated with this service. No changes to the Standby Energy Charge rate component shall be allowed.

To be eligible for negotiated Monthly Reservation Charges different than those contained herein, the customer must demonstrate to the Company's satisfaction and provide conclusive documentation (e.g., engineering studies, analysis, etc.) that the customer's on-site self-generation resource(s) would be a lower cost option over the life of the equipment than had the customer subscribed to Standby Service from the Company. Notwithstanding the potential competitiveness of the customer's self generation standby facilities, the Company in its sole opinion, shall have the option of not offering any discounts to the otherwise applicable Reservation Charge.

D. Maintenance Service

$0.02605	per kWh On-peak
$0.01033	per kWh Off-peak

E. Energy Rates

The energy rates in Sections C and D above are based on the Company's estimated marginal costs and will be updated annually to reflect changes in the Company's fuel costs.

DETERMINATION OF SUPPLEMENTAL SERVICE

Supplemental service shall be defined as demand and energy contracted by Customer to augment the power and energy generated by Customer's generation facility.

DETERMINATION OF SUPPLEMENTAL SERVICE (cont)

Supplemental demand shall be the highest 15-minute interval during the billing month which shall equal the (a) 15-minute integrated kW demand calculated for every 15-minute interval as recorded on the Supply Meter, plus (b) the simultaneous 15 minute integrated kW demand as recorded on the Generator Meter(s), less (c) the aggregate Contract Standby Capacity of all the customer's generating units; however, the result shall never be less than zero (0) for purposes of determining Supplemental Demand. If Company authorized scheduled maintenance was being performed on any of the customer's generators at the time of the highest 15 minute interval during the billing month, the amount of demand recorded on the Supply Meter shall be reduced by the applicable Maintenance Power Level (as determined in Section VII hereof) of the generator unit(s) undergoing authorized scheduled maintenance for purposes of calculating supplemental demand used for billing.

Customer's maximum Supplemental Service kW requirements shall not exceed that established in the Electric Supply Agreement.

Supplemental energy shall be equal to all energy supplied to Customer as determined from readings of the Supply Meter, less any energy determined to be either Standby or Maintenance energy as defined in this Schedule.

DETERMINATION OF STANDBY ENERGY

Standby Energy shall be defined to be electric energy supplied by Company to replace power ordinarily generated by Customer's generation facility during unscheduled full and partial outages of said facility.

When the sum of the energy measured on both the Supply and Generator(s) Meters during simultaneous periods is greater than the maximum energy output of the generator(s) at Contract Standby Capacity, the Standby Energy shall be equal to the summation of the differences between the maximum energy output of the generator(s) at Contract Standby Capacity and the energy measured on the Generator Meter(s) for every 15-minute interval of the month, except when maintenance power is being utilized or those intervals where energy measured on the Supply Meter is zero. When the sum of the energy measured on both the Supply and Generator(s) Meter is equal to or less than the maximum energy output of the generator(s) at Contract Standby Capacity, then the Standby energy shall be that energy measured on the Supply Meter.

DETERMINATION OF MAINTENANCE ENERGY

Maintenance energy shall be defined as energy supplied to Customer to replace energy normally supplied by the Customer's generator(s) during an authorized Scheduled Maintenance period.

Maintenance periods shall not exceed 30 days per cogeneration unit during any consecutive 12-month period and must be scheduled during the non-Summer billing months. Customer shall provide Company with its planned maintenance schedule 12 months in advance of any planned maintenance in order for the Company to coordinate customer's scheduled maintenance with that of the Company. Upon review, Company shall either approve customer's planned maintenance schedule or notify customer of alternate acceptable periods. Customer, in turn, shall notify the Company of an acceptable alternate maintenance period(s), and shall also confirm with the Company its intention to perform its planned maintenance 45 days prior to the actual commencement date of the planned maintenance period.

Any energy used in excess of a 30-day period or unauthorized maintenance energy shall be billed on either the Standby or Supplemental Rate as specified in this Schedule.

DETERMINATION OF MAINTENANCE ENERGY (cont)

Maintenance energy, during a Company authorized period of scheduled maintenance to a customer's generation unit(s), shall be determined as follows:

Maintenance Power Level = (Contract Standby Capacity) X (Generating Unit(s) Capacity Factor for the most recent 12 months)

The maintenance power level as determined by the above formula shall not exceed any actual 15 minute interval of integrated kW demand as recorded on the supply meter.

If customer has less than 12 months of billing history on Standby Service, use the capacity factor demonstrated to date; however, not less than one full month.

Maintenance Energy = (Maintenance Power Level) X (hours of maintenance authorized by Company during billing month)

CAPACITY FACTOR STANDARDS

Customer's generating unit(s) must maintain a Capacity Factor of no less than 75% over a continuous rolling 18 month period to remain eligible to receive Standby Service under this rate schedule. The calculation of the Capacity Factor is designed so that the customer shall not be subject to this Capacity Factor Standard provision for any purpose other than substandard operational performance of the customer's generating unit(s) recognizing that the customer's load profile may not require the full output capability of such generation unit(s). If the Capacity Factor falls below 75%, in lieu of the otherwise applicable Reservation Charge for Standby Service, the customer shall be assessed a monthly Reservation Charge the greater of:

A. For customers taking service at voltage levels of less than 69 kV:

1. $ 21.28 per kW/month X 2/3 X Contract Standby Capacity; or

2. $ 21.28 per kW/month X Maximum Standby Capacity (If customer's system is directly interconnected with the Company's bulk transmission system, the applicable Reservation Charge shall be $ 18.05 per kW per month.)

B. For customers who take service at voltage levels of 69 kV or greater:

1. $ 18.94 per kW/month X 2/3 X Contract Standby Capacity; or

2. $ 18.94 per kW/month X Maximum Standby Capacity (If customer's system is directly interconnected with the Company's bulk transmission system, the applicable Reservation Charge shall be $ 18.11 per kW per month.)

Maximum Standby Capacity is the maximum 15-minute interval of Standby Power provided the customer by the Company during the billing month. Maximum Standby Capacity shall equal the highest 15-minute interval during the billing month of the following calculation:

CAPACITY FACTOR STANDARDS (cont)

$$MSC = \Sigma CSC - Maint.$$

Where:

MSC = Maximum 15-minute interval during the billing month of Standby Power (kW) being supplied by Company.

ΣCSC = The aggregate Contract Standby Capacity of all the customer's self-generation units.

Maint = The simultaneous 15-minute interval of any Maintenance Power (kW) being supplied to customer by the Company.

METERING

The Company will install a Supply Meter at its point of delivery to Customer and a Generator Meter(s) at the point(s) of output from each of Customer's generators. All meters will record integrated demand and energy on the same 15-minute interval basis as specified by Company.

DEFINITIONS

1. Contract Standby Capacity - for each specific customer generating unit for which the Company is providing Standby Service, Contract Standby Capacity shall be the greater of a) the measured kW output of each customer self-generation unit at time of start-up test, or b) the highest 15 minute measured kW output of each generating unit, however, not to exceed Customer's actual total load.

2. Generator Meter - the time-of-use meter used to measure in 15-minute intervals the total power and energy output of each cogeneration unit.

3. Designated Standby Service Hours - Customers requiring Standby Service for less than the total hours in a billing month shall be allowed to designate those periods and hours of a month when Standby Service is required. These Designated Standby Service Hours shall represent those hours within a billing month during which the customer is authorized to utilize Standby Service. Use during any period or hours other than Designated Standby Service Hours shall represent an Unauthorized Use of Standby Service subject to certain special provisions for determining the appropriate Capacity Factor value during billing periods when unauthorized Standby Service was utilized. Such hours shall be specified in whole hour intervals beginning on an hour for each designated day of the week. Designated Standby Service Hours shall never total less than 365 hours a billing month. This provision is applicable only to those customers whose Standby Service requirements are less than 3,000 kW.

4. Capacity Factor - for purposes of this rate schedule, capacity factor shall mean the capacity factor of the customer's generating unit(s) and shall not reflect any period of time during a billing month that Company authorized Maintenance Power was being utilized. The Capacity factor shall be calculated in accordance with the following formula:

DEFINITIONS (cont)

Capacity Factor (cont)

$$\text{Capacity Factor} = \frac{\text{Actual customer generated kWh's during the billing month}}{A}$$

For purposes of use in this rate schedule, the value of the capacity factor calculation shall never exceed 100%.

Where:

A = The lesser of: a) [(Contract Standby Capacity) X (MH)]; or
b) CTL

Customers having Standby Service Requirements of 3,000 kW or greater:

MH = Hours in the billing month exclusive of any hours during the billing month that customer's unit(s) were non-operational during Company authorized scheduled maintenance.

CTL = Customer's maximum total load during the billing month as determined by the total of energy generated on customer's generating unit as recorded on the Generator Meter plus all energy provided by Company during the billing month (exclusive of maintenance energy) as recorded on the Supply Meter.

Customers having Standby Service Requirements of less than 3,000 kW:

MH = The number of Designated Standby Service Hours in the billing month, exclusive of any hours during the billing month that customer's unit(s) were non-operational during Company authorized scheduled maintenance, for which the customer has contracted for Standby Service (but not less than 365 hours per billing month).
In the event the customer utilizes Standby Service in any period other than during Designated Standby Service Hours, MH shall be represented as the actual number of hours in the billing month (exclusive of any hours during which the customer was receiving Company authorized scheduled Maintenance Energy).

Furthermore, in the event there are more than two (2) instances in any 12 month rolling period of Unauthorized Use of Standby Service, MH shall be represented as the actual number of hours in the billing month (exclusive of any hours during which the customer was receiving Company authorized scheduled Maintenance Energy) for the month during which the third breach of service occurred, and for the next three months thereafter. At the end of any three month period, a new twelve (12) month rolling period shall commence for determining the number of instances of Unauthorized Use.

CTL = Customer's maximum total load during the billing month during the Designated Standby Service Hours for which the Customer has contracted for Standby Service (but not less than 365 hours per month).as determined by the total of energy generated on customer's generating unit as recorded on the Generator Meter plus all energy provided by Company

DEFINITIONS (cont)

Capacity Factor (cont)

during the billing month (exclusive of maintenance energy) as recorded on the SupplyMeter.

CTL shall represent the customer's maximum total load during the hours in the billing month for which use of Standby Service has been authorized as set forth in the definition of Designated Standby Service Hours. CTL shall be calculated by first adding the maximum simultaneous 15-minute kW peak periods as recorded on the Supply Meter and Generator Meter(s) during authorized periods of Standby Service the sum of which is then multiplied by MH.

In the event the customer utilizes Standby Service during any period of a billing month other than those authorized, CTL shall represent the customer's maximum total load (peak demand) during the billing month calculated as the sum of the maximum simultaneous 15-minute kW peak period during the billing period recorded on the Supply Meter and the Generator Meter(s) during all hours of the billing month. CTL shall be similarly calculated for any other months during which the provision for breach of service explained in the definition of MH above is being assessed.

CTL shall only be used for calculating Capacity Factor in those months where the customer's maximum kW load is less than total Contract Standby Capacity.

5. Supply Meter the time-of-use meter used to measure in 15-minute intervals the total power and energy supplied by Company to Customer.

6. Time Periods - On-Peak Period: 9 a.m. - 9 p.m. Monday through Friday
Off-Peak Period: All Other Hours

Mountain Standard Time shall be used in the application of this rate schedule. In addition, to prevent radical changes in the system loads the beginning and ending hours for individual customers may be varied by up to one hour (total hours in each time period to remain unchanged) and because of potential differences of the timing devices, there may be a variation of up to 15 minutes in timing for the pricing periods.

7. Unauthorized Use - any period or hour of the month that the customer utilized Standby Service other than Designated Standby Service Hours.

ADJUSTMENTS

1. The Environmental Portfolio Surcharge shall be applied to every retail electric service as set forth in the Company's Rate Schedule EPS-1.

2. The bill is subject to the Power Supply Adjustment factor as set forth in the Company's Rate Schedule PSA-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

ADJUSTMENTS(cont)

3. The bill is subject to the Transmission Adjustment factor as set forth in the Company's Rate Schedule TCA-1.

4. The bill is subject to the Competition Rules Compliance Charge as set forth in the Company's Rate Schedule CRCC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

5. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Assignment Charge as set forth in the Company's Rate Schedule RCDAC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

6. The bill is subject to the System Benefits Adjustment charge as set forth in the Company's Rate Schedule SBAC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

7. The bill is subject to the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of APS and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

TERMINATION PROVISION

Should Customer cease to operate his cogeneration unit(s) for 60 consecutive days during periods other than planned scheduled maintenance periods, Company reserves the option to terminate the Agreement for service under this rate schedule with Customer.

CONTRACT PERIOD

As provided in the Electric Supply Agreement between Company and Customer.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

Customer must enter into an Agreement for the Interconnection and The Sale of Power with Company and an Electric Supply Agreement which shall establish all pertinent details related to interconnection and other required service standards. Customer will not have the option to sell power and energy to Company under this tariff. Should Customer desire to do so, Customer would be required to enter into a new Service Agreement which would set forth the applicable purchase rate in addition terms and conditions for interconnection and for the sale of power to the Company.

Customer will be required to contract for adequate standby power to cover the total output of all the customer's generators unless adequate facilities have been installed, to the satisfaction of APS, that isolate portions of the customer's load from APS' system so that APS will in no event be providing standby service in excess of Contracted Standby Capacity.

CHANGE IN DESIGNATED STANDBY SERVICE HOURS

Customers for which Designated Standby Service Hours is applicable shall be allowed no more than one (1) change in their Designated Standby Service Hours during any eighteen (18) month time period. In no event shall the total of Designated Standby Service Hours during a month fall below 365 hours.

AVAILABILITY

This rate schedule is available in those portions of cities, towns and unincorporated communities in which Company does a general retail electric business and where Company has installed a multiple or series street lighting system of adequate capacity for the service to be rendered.

APPLICATION

This rate schedule is applicable to service for lighting public streets, alleys, thoroughfares, public parks and playgrounds from dusk to dawn by use of Company's facilities where such service for the whole area is contracted for from the Company by the city, town, other governmental agencies, or a responsible individual for unincorporated communities. Dusk is defined as the time between sunset and full night when a photocontrol senses the lack of sufficient sunlight and turns on the lights. Dawn is defined as the time between full night and sunrise when a photocontrol senses sufficient sunlight to turn off lights.

RATES

The bill shall be computed at the following rates for each type of standard facility and/or service utilized to provide street lighting, plus any adjustments incorporated in this schedule:

FIXTURES (Includes Mounting Arm, if Applicable)

				RATES	
	Lumen	Watts	kWh	Investment by Company	Investment by Others
A. Acorn	9,500 HPS	100	41	$19.86	$6.76
	16,000 HPS	150	69	22.04	8.55
B. Architectural	9,500 HPS	100	41	11.75	5.60
	16,000 HPS	150	69	13.73	7.51
	30,000 HPS	250	99	16.29	9.63
	50,000 HPS	400	153	20.09	13.30
	14,000 MH	175	72	15.79	8.65
	21,000 MH	250	101	17.92	10.67
	36,000 MH	400	159	22.41	14.67
	8,000 LPS	55	30	17.09	7.20
	13,500 LPS	90	50	20.15	8.69
	22,500 LPS	135	72	23.02	10.60
	33,000 LPS	180	90	26.58	12.49
C. Cobra/Roadway	5,800 HPS	70	29	6.67	3.95
	9,500 HPS	100	41	7.86	4.83
	16,000 HPS	150	69	9.84	6.74
	30,000 HPS	250	99	11.87	8.76
	50,000 HPS	400	153	16.09	12.51

FIXTURES (Includes Mounting Arm, if Applicable) (cont):

					RATES	
		Lumen	Watts	kWh	Investment by Company	Investment By Others
C. Cobra/Roadway (cont.)		14,000 MH	175	72	$10.98	$7.49
		21,000 MH	250	101	12.84	9.31
		36,000 MH	400	159	16.90	12.94
		8,000 FL	100	38	12.62	3.70
D. Decorative Transit	Pedestrian (4")	9,500 HPS	100	41	27.22	8.15
	Pedestrian (6")	9,500 HPS	100	41	27.22	8.15
	Streetlight (6")	30,000 HPS	250	99	31.16	11.76
E. Flood		30,000 HPS	250	99	15.12	9.40
		50,000 HPS	400	153	18.75	13.04
		21,000 MH	250	101	16.14	9.93
		36,000 MH	400	159	19.68	13.47
F. Post Top	Colonial Gray	8,000 FL	100	38	13.60	3.84
		9,500 HPS	100	41	8.10	4.88
	Colonial Black	9,500 HPS	100	41	8.96	5.05
	Decorative Transit	9,500 HPS	100	41	23.83	7.51
G. FROZEN		4,000 INC	295	103	6.88	6.88
		7,000 MV	175	73	8.91	5.11
		11,000 MV	250	96	11.16	6.80
		20,000 MV	400	150	17.52	9.93

NOTES:

1. Investment by Company. These rates are applicable where the Company provides the initial investment to purchase and install all facilities necessary for street lighting service. The Company will own, operate, and maintain the street lighting system.
2. Investment by Others. These rates are applicable in those instances where the requesting entity or individual purchases and installs the street lighting facilities at their own expense and in accordance with Company specifications. These rates will also apply in the instance where the customer provides a non-refundable advance to the Company to cover the Company's cost of purchasing and installing the street lighting system. The Company retains ownership of the street lighting system and provides operation and maintenance for all facilities.
3. Listed kWh's reflect the assigned monthly usage kWh's for each type of fixture and are used to determine any applicable transmission, distribution, energy and adjustment charges.
4. HPS = High Pressure Sodium
5. MH = Metal Halide
6. LPS = Low Pressure Sodium
7. FL = Fluorescent
8. INC = Incandescent. Incandescent lighting charges are applicable and available only to those customers being served and those installations in service on November 1, 1986.
9. MV = Mercury Vapor. Mercury Vapor lighting charges are applicable and available only to those customers being served and those installation in service on November 1, 1986 in accordance with A.R.S. §49-1104(A).

POLES

				RATES	
			Height	Investment by Company	Investment By Others
A. Anchor Base Mounted (Flush)	Round Steel	1 Simplex Adapter	12 ft.	$8.93	$1.23
			22 ft.	10.05	1.38
			25 ft.	10.88	1.50
			30 ft.	12.50	1.72
			32 ft.	13.13	1.81
		2 Simplex Adapters	12 ft.	9.52	1.31
			22 ft.	10.94	1.51
			25 ft.	11.41	1.57
			30 ft.	13.26	1.83
			32 ft.	14.15	1.95
	Square Steel	5"	13 ft.	10.24	1.41
			15 ft.	9.15	1.26
			23 ft.	10.85	1.49
			25 ft.	11.93	1.64
			28 ft.	13.24	1.82
			32 ft.	13.72	1.89
	Concrete		12 ft.	30.51	4.20
	Fiberglass		12 ft.	25.84	3.56
	Decorative Transit Pedestrian	4"	16 ft.	25.19	3.47
	Decorative Transit	6"	30 ft.	25.73	3.54
B. Anchor Base Mounted (Pedestal)	Round Steel	1 Simplex Adapter	12 ft.	8.59	1.18
			22 ft.	9.71	1.34
			25 ft.	10.53	1.45
			30 ft.	12.16	1.68
			32 ft.	12.78	1.76
		2 Simplex Adapters	12 ft.	9.18	1.26
			22 ft.	10.25	1.41
			25 ft.	11.07	1.52
			30 ft.	12.92	1.78
			32 ft.	13.80	1.90
		3 Bolt Arm	32 ft.	15.86	2.18
	Square Steel	5"	13 ft.	9.90	1.36
			15 ft.	10.13	1.39
			23 ft.	10.51	1.45
			25 ft.	11.59	1.60
			28 ft.	12.89	1.78
			32 ft.	13.38	1.84

POLES (cont)

			Height	RATES Investment by Company	RATES Investment By Others
C. Direct Bury	Round Steel		19 ft.	13.52	1.86
			30 ft.	10.99	2.03
			38 ft.	13.42	2.08
		Self Support	40 ft.	15.86	2.62
		Stepped	49 ft.	47.69	6.57
	Square Steel	4"	34 ft.	12.14	2.11
		5"	20 ft.	11.06	1.83
			30 ft.	12.00	1.98
			38 ft.	13.03	2.26
	Steel Distribution Pole		35 ft.	17.27	2.38
D. Post Top	Decorative Transit Anchor Base		16 ft.	25.73	3.54
	Gray Steel/Fiberglass		23 ft.	9.30	1.53
	Black Steel		23 ft.	9.84	1.62
E. FROZEN	Wood Poles		30 ft.	6.83	1.14
			35 ft.	6.83	1.14

FROZEN

NOTE: The monthly rate for all new poles includes up to 300 feet of overhead secondary wire, or up to 300 feet of underground secondary wire if the customer provides earthwork and conduit (excluding the underground to overhead transition).

ANCHOR BASE

		Height	RATES Investment by Company	RATES Investment By Others
A. Flush		4 ft.	$7.27	$1.00
		6 ft.	8.67	1.50
B. Pedestal		8 ft.	9.94	1.73
	For 32' Round Steel Pole only	4 ft. 6"	6.89	1.20

CHARGES FOR OPTIONAL OR ADDITIONAL EQUIPMENT

	RATES Company Owned
Underground Circuit Charges:	
a. Per foot of cable, installed under paving	0.11910
b. Per foot of cable, not installed under paving	0.04236

FROZEN

ADJUSTMENTS

1. The Environmental Portfolio Surcharge shall be applied to every retail electric service as set forth in the Company's Rate Schedule EPS-1.

2. The bill is subject to the Power Supply Adjustment factor as set forth in the Company's Rate Schedule PSA-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

3. The bill is subject to the Transmission Adjustment factor as set forth in the Company's Rate Schedule TCA-1.

4. The bill is subject to the Competition Rules Compliance Charge as set forth in the Company's Rate Schedule CRCC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

5. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Assignment Charge as set forth in the Company's Rate Schedule RCDAC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

6. The bill is subject to the System Benefits Adjustment charge as set forth in the Company's Rate Schedule SBAC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

7. The bill is subject to the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of APS and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

SPECIAL PROVISIONS

1. Street lighting facilities installed under this rate schedule are of the type currently being furnished by Company as standard at the time service is initially requested. Standard facilities are those listed in the Company's Transmission and Distribution Construction Standards book.

2. The Company cannot guarantee that streetlighting facilities will always operate as intended. Therefore, the customer will be responsible for notifying the Company when the streetlighting facilities are not operating as intended. The Company will use reasonable efforts to complete normal maintenance (replacement of lamps, photocontrols or fixtures) within ten (10) working days from notification by customer; however, if the maintenance requires cable replacement or repairs, the Company shall use reasonable efforts to complete said repairs within twenty (20) working days.

3. The customer's monthly bills will not be reduced due to lamp, photocontrol or cable repair or replacement outages.

NON-STANDARD FACILITIES

Non-standard facilities (non-standard being defined as any facility not listed in the Company's Transmission and Distribution Construction Standards book) do not qualify for this rate schedule. At the Company's discretion, such facilities may be served under another of the Company's rate schedules.

EXTENSION OF STREET LIGHTING SYSTEM

The Company will extend its standard street lighting system up to a distance of 300 feet for each additional lighting installation without cost at the request of the customer. When the extension is underground the customer will provide earthwork as specified in Section 6.1.2 of the Company's Schedule 3, Conditions Governing Extensions of Electric Distribution Lines and Services; or, at the customer's request, the Company will provide such earthwork for a contribution in aid of construction equal to the cost of such earthwork. Any additional extension required (over and above the first 300 feet) will be provided by Company for a contribution in aid of construction equal to the cost of the additional extension.

Extensions to isolated areas requiring a substantial extension of the electric distribution system, as opposed to an extension of the street lighting system, will require a special study to determine the terms and conditions under which the Company will undertake such an extension.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

AVAILABILITY

This rate schedule is available in those portions of cities, towns and unincorporated communities in which the Company does a general retail electric business and where the customer has installed or purchased a multiple or series street lighting system and the Company has distribution facilities of adequate capacity for the service to be rendered.

APPLICATION

This rate schedule is applicable to Standard Offer electric service for lighting public streets, alleys, thoroughfares, public parks and playgrounds from dusk to dawn by use of the customer's facilities where such service for the whole area is contracted for from the Company pursuant to the terms set forth herein by the city, town, other governmental entities, or a responsible individual for unincorporated communities. Dusk is defined as the time between sunset and full night when a photocontrol senses the lack of sufficient sunlight and turns on the lights. Dawn is defined as the time between full night and sunrise when a photocontrol senses sufficient sunlight to turn off lights.

The customer will own, operate, and maintain the street lighting system including lamps and glass replacements but excluding distribution facilities installed by the Company to serve the lighting system.

RATES

The bill shall be computed at the following rates plus any adjustments incorporated in this schedule:

Service Charge:	$2.56	per installed lamp; plus
Energy Charge:	$0.04847	per kWh

ADJUSTMENTS

1. The Environmental Portfolio Surcharge shall be applied to every retail electric service as set forth in the Company's Rate Schedule EPS-1.

2. The bill is subject to the Power Supply Adjustment factor as set forth in the Company's Rate Schedule PSA-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

3. The bill is subject to the Transmission Adjustment factor as set forth in the Company's Rate Schedule TCA-1.

4. The bill is subject to the Competition Rules Compliance Charge as set forth in the Company's Rate Schedule CRCC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

5. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Assignment Charge as set forth in the Company's Rate Schedule RCDAC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

RATES (cont)

ADJUSTMENTS (cont)

6. The bill is subject to the System Benefits Adjustment charge as set forth in the Company's Rate Schedule SBAC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

7. The bill is subject to the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of APS and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

SPECIAL PROVISIONS

Billed energy is based upon the summation of the contracted energy rating of installed facilities specified in the streetlighting contract.

The customer's bills will not be reduced due to lamp, photocontrol or cable repair or replacement outages.

Presently installed units which do not conform to the types specified in Rate Schedule E-58 will be billed in accordance with the type which is most nearly like such units.

EXTENSION OF COMPANY DISTRIBUTION SYSTEM

The Company will extend its standard street lighting system up to a distance of 300 feet for each additional lighting installation without cost at the request of the customer. When the extension is underground the customer will provide earthwork as specified in Section 6.1.2 of the Company's Schedule 3, Conditions Governing Extensions of Electric Distribution Lines and Services; or, at the customer's request, the Company will provide such earthwork for a contribution in aid of construction equal to the cost of such earthwork. Any additional extension required (over and above the first 300 feet) will be provided by Company for a contribution in aid of construction equal to the cost of the additional extension.

Extensions to isolated areas requiring a substantial extension of the electric distribution system, as opposed to an extension of the street lighting system, will require a special study to determine the terms and conditions under which the Company will undertake such an extension.

CONTRACT PERIOD

The contract period for service under this rate schedule shall be a fixed period of not less than 1 year and not more than 20 years, as agreed to by the customer and as specified in the streetlighting contract.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

AVAILABILITY

In the Town of Litchfield Park.

APPLICATION

To electric service billed under the applicable Street Lighting Schedule E-58.

All provisions of the Street Lighting Schedule E-58 will apply except as specifically modified herein.

Service under this rate schedule is limited to those street lights installed prior to April 8, 1980. The Company is not obligated to install new light fixtures, poles or distribution circuits, but will continue to maintain and operate those installed prior to April 8, 1980 only while maintenance and replacement materials are available from Company stock or until this rate schedule is cancelled, whichever comes first, provided, however, under no circumstances shall poles be relocated. Interfering poles shall only be removed. The Company is authorized to collect from the sponsoring entity, any and all unpaid bills for street lighting service.

THE STREET LIGHTING SYSTEM

The Company has installed at its own expense, a street lighting system as prescribed by Litchfield Park Properties, a subsidiary of Goodyear Tire & Rubber Company.

The Company agrees to submit all requests for increases or decreases in number or size of lamps, change in location, or like matters, for each subdivision, to Litchfield Park Properties for approval before any action is taken by the Company.

RATES

Customers to be assessed for street lighting shall include all customers of Arizona Public Service Company located within the following subdivisions or geographic areas:

1. Geographic Area Number 1 described as:

   E 1/2 of the SE 1/4 of the NE 1/4, Section 21, T 2 N, R 1 W, the E 1/2 of the SE 1/4, Section 21, T 2 N, R 1 W; the SW 1/4, Section 22, T 2 N, R 1 W; the N 1/2 of the NW 1/4, Section 27, T 2 N, R 1 W and the N 1/2 of the NE 1/4, Section 28, T2 N, R 1 W, except area within Litchfield Park Subdivision #10, all in Township 2 north, Range 1 West.

2. Litchfield Park Subdivision #10.

3. Litchfield Park Subdivision #12.

   Each of the above subdivisions or geographic areas is, for rate purposes, to be considered as a separate Street Lighting Area.

The following method is to be used to compute the individual residential and commercial street lighting monthly charge, for each subdivision or geographic area.

The monthly charge for street lighting for each subdivision or geographic area with street lighting is to be divided by a figure equal to the total number of residential customers for the month, plus six times the total number of commercial and industrial customers. The assessment is to be adjusted to the nearest cent. Each subdivision or geographic area residential customer is to be assessed the amount of the individual assessment as determined by the above method. Each subdivision or geographic area commercial or industrial customer is to be assessed six times the amount of the individual assessment as determined by the above method. The above assessment will be added to the customer's monthly bill for service.

One meter in each business house is to be counted as a commercial or industrial customer and one meter in each residence as a residential customer, regardless of the number of meters installed on the customer's premises to serve any such commercial, industrial or residential customer.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

AVAILABILITY

This rate schedule is available within the City of Phoenix at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

APPLICATION

This rate schedule is applicable to Standard Offer electric service furnished for the lighting of alleys, buildings, and other public places owned or maintained by the City. Streetlighting service is not eligible for this schedule. Service to traffic signals is limited to those installations being served as of January 31, 1985, under the Agreement of April 4, 1930, as modified, between Central Arizona Light and Power Company and the City of Phoenix, and no new or reconnected traffic signal installations may be served after that time. Service must be supplied at one site through one point of delivery and measured through one meter. Direct Access service is not available under this rate schedule.

This schedule is not applicable to breakdown, standby, supplementary, or resale service.

TYPE OF SERVICE

The type of service provided under this schedule will be single or three phase, 60 Hertz, at one standard voltage (as may be selected by customer, subject to availability at the customer's site).

RATES

The bill shall be computed at the following rate plus any adjustments incorporated in this schedule:

RATE

$0.04128 per kWh for all kWh

ADJUSTMENTS

1. The Environmental Portfolio Surcharge shall be applied to every retail electric service as set forth in the Company's Rate Schedule EPS-1.

2. The bill is subject to the Power Supply Adjustment factor as set forth in the Company's Rate Schedule PSA-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

3. The bill is subject to the Transmission Adjustment factor as set forth in the Company's Rate Schedule TCA-1.

4. The bill is subject to the Competition Rules Compliance Charge as set forth in the Company's Rate Schedule CRCC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

5. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Assignment Charge as set forth in the Company's Rate Schedule RCDAC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

RATES (cont)

ADJUSTMENTS (cont)

6. The bill is subject to the System Benefits Adjustment charge as set forth in the Company's Rate Schedule SBAC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

7. The bill is subject to the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of APS and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

RATE SCHEDULE E-114
CLASSIFIED SERVICE – SHARE THE LIGHT
LOWER MIAMI AND CLAYPOOL LIGHTING SERVICE

AVAILABILITY

This rate schedule is available only in the area now known as Claypool and Lower Miami near Miami.

APPLICATION

To electric service billed under the applicable Street Lighting Schedule E-58.

All provisions of the Street Lighting Schedule E-58 will apply except as specifically modified herein.

Service under this rate schedule is limited to those street lights installed prior to April 8, 1980. The Company is not obligated to install new light fixtures, poles or distribution circuits, but will continue to maintain and operate those installed prior to April 8, 1980 only while maintenance and replacement materials are available from Company stock or until this rate schedule is cancelled, whichever comes first, provided, however, under no circumstances shall poles be relocated. Interfering poles shall only be removed. The Company is authorized to collect from the sponsoring entity, any and all unpaid bills for street lighting service.

THE STREET LIGHTING SYSTEM

The Company has installed, at its own expense, a street lighting system as prescribed by the Tri-City Fire Department.

The Company agrees to submit all requests for increases or decreases in number or size of lamps, change in location, or like matters regarding Claypool and Lower Miami street lights to the Tri-City Fire Department for approval before any action is taken by the Company.

BILLING

Customers to be assessed for street lighting shall include all customers of Arizona Public Service Company located within the area now known as Claypool and Lower Miami comprising the following area: The NW 1/4 of Section 29; the NE 1/4, SW 1/4 of Section 29; the North half of NE 1/4, Section 29; the SE 1/4, SW 1/4, Section 20; the South half of SE 1/4, Section 20, the SW 1/4, SW 1/4 of Section 21; the East half of SW 1/4 of Section 21; the NW 1/4, NW 1/4, Section 28; all of Township 1 North, Range 15 East, of the G & SRB & M.

The monthly charge for street lighting is to be divided by a figure equal to the total number of residential customers for the month, plus three times the total number of commercial and industrial customers. The assessment is to be adjusted to the nearest cent. Each Claypool and Lower Miami residential customer is to be assessed the amount of the individual assessment as determined by the above method. Each Claypool and Lower Miami commercial and industrial customer is to be assessed three times the amount of individual assessment as determined by the above method. The above assessment will be added to the customer's monthly bill for service.

Only one meter in each business house is to be counted as a commercial or industrial customer and one meter in each residence as a residential customer, regardless of the number of meters installed on the customer's premises to serve any such commercial, industrial or residential customer.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

RATE SCHEDULE E-116
CLASSIFIED SERVICE – SHARE THE LIGHT
CENTRAL HEIGHTS AND COUNTRY CLUB MANOR
STREET LIGHTING

AVAILABILITY

In the area now known as Central Heights and Country Club Manor near Miami.

APPLICATION

To electric service billed under the applicable Street Lighting Schedule E-58.

All provisions of the Street Lighting Schedule E-58 will apply except as specifically modified herein.

Service under this rate schedule is limited to those streetlights installed prior to April 8, 1980. The Company is not obligated to install new light fixtures, poles or distribution circuits, but will continue to maintain and operate those installed prior to April 8, 1980 only while maintenance and replacement materials are available from Company stock or until this rate schedule is cancelled, whichever comes first, provided, however, under no circumstances shall poles be relocated. Interfering poles shall only be removed. The Company is authorized to collect from the sponsoring entity, any and all unpaid bills for street lighting service.

THE STREET LIGHTING SYSTEM

The Company has installed, at its own expense, a street lighting system as prescribed by the Central Heights Fire Department.

The Company agrees to submit all requests for increases or decreases in number or size of lamps, change in location, or like matters regarding Central Heights street lights to the Central Heights Fire Department for approval before any action is taken by the Company.

BILLING

Customers to be assessed for street lighting shall include all customers of Arizona Public Service Company located within the area now know as Central Heights, consisting of the SE 1/4 of Section 22, S 1/2 of NE 1/4 of Section 22 and the E 1/2 of SW 1/4 of Section 22, Township 1, Range 15 E., G & SRB & M and within the area now known as County Club Manor, consisting of the entire S 1/2 of the NW 1/4 of Section 22, Township 1 N, Range 15 E., G & SRB & M.

The monthly charge for street lighting is to be divided by a figure equal to the total number of residential, commercial and industrial customers. The assessment is to be adjusted to the nearest cent. Each Central Heights and Country Club Manor residential, commercial and industrial customer will be assessed a like amount as determined by the above described method. The above assessment will be added to the customer's monthly bill for service.

Only one meter in each residence or business house is to be counted as a residential, commercial or industrial customer regardless of the number of meters installed on the customer's premises to serve any such residential, commercial or industrial customer.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

APS

RATE SCHEDULE E-145
CLASSIFIED SERVICE – SHARE THE LIGHT
AJO HEIGHTS STREET LIGHTING

AVAILABILITY

In the area now known as Ajo Heights near Ajo.

APPLICATION

To electric service billed under the applicable Street Lighting Schedule E-58.

All provisions of the Street Lighting Schedule E-58 will apply except as specifically modified herein.

Service under this rate schedule is limited to those streetlights installed prior to April 8, 1980. The Company is not obligated to install new light fixtures, poles or distribution circuits, but will continue to maintain and operate those installed prior to April 8, 1980 only while maintenance and replacement materials are available from Company stock or until this rate schedule is cancelled, whichever comes first, provided, however, under no circumstances shall poles be relocated. Interfering poles shall only be removed. The Company is authorized to collect from the sponsoring entity, any and all unpaid bills for street lighting service.

THE STREET LIGHTING SYSTEM

The Company will install, at its own expense, a street lighting system as prescribed by the Ajo Heights Chamber of Commerce.

The Company agrees to submit all requests for increases or decreases in number or size of lamps, change in location, or like matters regarding Ajo Heights street lights to the Ajo Heights Chamber of Commerce for approval before any action is taken by the Company.

BILLING

For purposes of assessment, each Ajo Heights commercial or industrial customer is to be considered equivalent to six Ajo Heights residential customers. Ajo Heights customers to be assessed for street lighting shall include all residential, commercial, or industrial customers of the Company located within the following area:

The area known as Ajo Heights consisting of Section 10; the NW Quarter, the NE Quarter, and the SW Quarter of Section 15; the NW Quarter of the SE Quarter of Section 15; the West 450 feet of the SW Quarter of the SE Quarter of Section 15; the NW Quarter of Section 22; and the NW Quarter of the NW Quarter of Section 14; all located in T 12 S, R 6 W of the G & SRB & M.

The monthly charge for street lighting is to be divided by a figure equal to the total number of residential customers for the month, plus six times the number of commercial customers. This assessment is to be adjusted to the nearest cent. Each Ajo Heights residential customer is to be assessed the amount of the individual assessment as determined by the above method. Each Ajo Heights commercial customer is to be assessed six times the amount of the individual assessment as determined by the above method. The above assessment will be added to the customer's bill for service.

Only one meter in each business house is to be counted as a commercial customer and one meter in each residence as a residential customer, regardless of the number of meters installed on the customer's premises to serve any such commercial or residential customer.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

RATE SCHEDULE E-221
CLASSIFIED SERVICE
WATER PUMPING SERVICE

AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

APPLICATION

This rate schedule is applicable to Standard Offer electric service required for irrigation pumping or for water utilities for pumping potable water to serve the citizens of a city, town, or unincorporated community. Service must be supplied at one point of delivery and measured through one meter. Direct Access customers are not eligible for service under this schedule.

Rate selection is subject to paragraphs 3.2 and 3.3 of the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services.

This schedule is not applicable to breakdown, standby, supplementary, residential or resale service.

TYPE OF SERVICE

The type of service provided under this schedule will be single or three phase, 60 Hertz, at one standard voltage as may be selected by customer subject to availability at the customer's site.

RATES

The bill shall be computed at the following rates or minimum rates, whichever is greater, plus any adjustments incorporated in this schedule:

Basic Service Charge:	$0.575	per day, plus
Demand Charge:	$1.80	per kW, plus
Energy Charge:	$0.06911	per kWh for the first 275 kWh per kW, plus
	$0.05562	per kWh for all additional kWh

OPTIONAL TIME-OF-WEEK PROVISION

AVAILABILITY

The Time-Of-Week option is available to all customers eligible for Rate Schedule E-221. The customer must enter into an Electric Supply Agreement with the Company stating the customer's assigned Control Period. The type of equipment required to provide and measure time-of-week service is non-standard; therefore availability is limited and the Company cannot guarantee installation of the equipment within any specific time.

RATES (cont)

OPTIONAL TIME-OF-WEEK PROVISIONS (cont)

CONTROL PERIOD

The Control Period is the thirteen (13) hour period from 9 a.m. to 10 p.m. for one day during the week (Monday through Friday). The specific day of the Control Period will be mutually agreed upon by the Company and the customer and will be set forth in the Electric Supply Agreement.

RATE

The bill for customers on the Time-Of-Week option will be adjusted in the following manner:

When measured kWh during the specified Control Period is:	The following will be applied to the bill (before any adjustments, taxes or assessments)
1. 2 kWh per kW or less	($0.00739) per kWh for all kWh
2. Greater than 2 kWh per kW but less than or equal to 8 kWh per kW	($0.00000)
3. Greater than 8 kWh per KW	$0.00370 per kWh for all kWh

DETERMINATION OF KW

The kW charges billed in this schedule shall be based on the average kW supplied during the 15-minute period of maximum use during the month, as determined from readings of the Company's meter, or at the Company's option, by test.

MINIMUM

The bill for service under this rate schedule will not be less than $0.575 per day plus $1.80 for each kW of the highest kW established during the 12 months ending with the current month, or the minimum kW specified in the Electric Service Agreement, whichever is greater. However, such monthly minimum charge shall not be more than an amount sufficient to make the total charges for such 12 months equal to $21.60 for each of such highest kW plus $210.00, but in no instance more than the monthly minimum amount as computed above.

ADJUSTMENTS

1. The Environmental Portfolio Surcharge shall be applied to every retail electric service as set forth in the Company's Rate Schedule EPS-1.

2. The bill is subject to the Power Supply Adjustment factor as set forth in the Company's Rate Schedule PSA-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

RATES (cont)

ADJUSTMENTS (cont)

3. The bill is subject to the Transmission Adjustment factor as set forth in the Company's Rate Schedule TCA-1.

4. The bill is subject to the Competition Rules Compliance Charge as set forth in the Company's Rate Schedule CRCC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

5. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Assignment Charge as set forth in the Company's Rate Schedule RCDAC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

6. The bill is subject to the System Benefits Adjustment charge as set forth in the Company's Rate Schedule SBAC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

7. The bill is subject to the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of APS and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

CONTRACT PERIOD

The contract period for customers receiving service under this rate schedule will be one (1) year or longer. At the Company's option, the contract period will be three (3) years or longer where additional distribution construction is required to serve the customer.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

APPLICATION

This rate schedule is applicable to all Standard Offer electric service required for irrigation pumping or for water utilities for pumping potable water to serve the citizens of a city, town, or unincorporated community. Service must be supplied at one point of delivery and measured through one meter. Direct Access customers are not eligible for service under this schedule.

Rate selection is subject to paragraphs 3.2 and 3.3 of the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services.

This schedule is not applicable to breakdown, standby, supplementary, residential or resale service.

TYPE OF SERVICE

The type of service provided under this schedule will be single or three phase, 60 Hertz, at one standard voltage as may be selected by customer subject to availability at the customer's site.

RATES

The bill shall be computed at the following rates or the minimum rates, whichever is greater, plus any adjustments incorporated in this schedule:

RATE

Basic Service Charge:	\$0.851	per day, plus
Demand Charge:	\$4.21	per On-Peak kW, plus
	\$2.51	per Off-Peak kW, plus
Energy Charge:	\$0.08492	per kWh during On-Peak hours, plus
	\$0.04567	per kWh during Off-Peak hours

TIME PERIODS

For the purpose of this rate schedule, the On-Peak time period is a consecutive eight (8) hour period between 9 a.m. and 10 p.m. every day of the week. The specific On-Peak period will be mutually agreed upon by the Company and the customer and will be set forth in an Electric Supply Agreement. All hours not included in the specified On-Peak period are designated as Off-Peak hours.

Mountain Standard Time shall be used in the application of this rate schedule.

RATES (cont)

DETERMINATION OF KW

The kW charges billed in this schedule shall be based on the average kW supplied during the 15-minute period of maximum use during the month, for both On-Peak and Off-Peak periods, as determined by readings of the Company's meter, or at the Company's option, by test.

MINIMUM

The bill for service under this rate schedule will not be less than $.851 per day plus $2.51 for each kW of the highest kW established on or off peak during the 12 months ending with the current month, or the minimum kW specified in the Electric Service Agreement, whichever is greater. However, such monthly minimum charge shall not be more than an amount sufficient to make the total charges for such 12 months equal to $30.12 for each of such highest kW plus $310.44, but in no instance more than the monthly minimum amount as computed above.

ADJUSTMENTS

1. The Environmental Portfolio Surcharge shall be applied to every retail electric service as set forth in the Company's Rate Schedule EPS-1.

2. The bill is subject to the Power Supply Adjustment factor as set forth in the Company's Rate Schedule PSA-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

3. The bill is subject to the Transmission Adjustment factor as set forth in the Company's Rate Schedule TCA-1.

4. The bill is subject to a Competition Rules Compliance Charge as set forth in the Company's Rate Schedule CRCC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

5. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Assignment Charge as set forth in the Company's Rate Schedule RCDAC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

6. The bill is subject to the System Benefits Adjustment charge as set forth in the Company's Rate Schedule SBAC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

7. The bill is subject to the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of APS and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

CONTRACT PERIOD

The contract period for customers receiving service under this rate schedule will be one (1) year or longer. At the Company's option, the contract period will be three (3) years or longer where additional distribution construction is required to serve the customer.

TERMS & CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

AVAILABILITY

In the Town of Camp Verde.

APPLICATION

To electric service billed under the applicable Street Lighting Schedule E-58.

All provisions of the Street Lighting Schedule E-58 will apply except as specifically modified herein.

Service under this rate schedule is limited to those streetlights installed prior to April 8, 1980. The Company is not obligated to install new light fixtures, poles or distribution circuits, but will continue to maintain and operate those installed prior to April 8, 1980 only while maintenance and replacement materials are available from Company stock or until this rate schedule is cancelled, whichever comes first, provided, however, under no circumstances shall poles be relocated. Interfering poles shall only be removed. The Company is authorized to collect from the sponsoring entity, any and all unpaid bills for street lighting service.

THE STREET LIGHTING SYSTEM

The Company has installed, at its own expense, a street lighting system as prescribed by the Camp Verde Lions Club.

The Company agrees to submit all requests for an increase or decrease in number or size of street lights, change in location, change in assessment or like matters regarding Camp Verde street lights, to the Camp Verde Lions Club for approval. After recommendation by the Camp Verde Lions Club, such requests are to be submitted to the Arizona Corporation Commission for final approval before any action is taken by the Company.

RATES

For purposes of assessment, each Camp Verde commercial customer (not classified as rural) is to be considered equivalent to six Camp Verde residential customers. Camp Verde customers to be assessed for street lighting shall include all commercial and residential customers of the Arizona Public Service Company located within, and immediately adjacent thereto, the boundaries of the Military Reserve Addition, Blocks 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 16, 17, 18, and 19, of Camp Verde Townsite. Customers taking electric service outside of these districts shall be classified as Rural, and not subject to assessment for street lighting.

The monthly charge for street lighting is to be divided by a figure equal to the total number of residential customers for the month, plus six times the number of commercial customers. This assessment is to be adjusted to the nearest cent. Each Camp Verde residential customer is to be assessed the amount of the individual assessment as determined by the above method. Each Camp Verde commercial customer is to be assessed six times the amount of the individual assessment as determined by the above method. The above assessment will be added to the customer's bill for service.

RATES (cont)

Only one meter in each business house is to be counted as a commercial customer and one meter in each residence as a residential customer, regardless of the number of meters installed on the customer's premises to serve any such commercial or residential customer.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

RATE SCHEDULE EPR-2
CLASSIFIED SERVICE
PURCHASE RATES FOR QUALIFIED FACILITIES UNDER 100 kW FOR PARTIAL REQUIREMENTS

AVAILABILITY

In all territory served by Company.

APPLICATION

To all cogeneration and small power production facilities 100 kW or less where the facility's generator(s) and load are located at the same premise and that otherwise meet qualifying status pursuant to the Arizona Corporation Commission's Decision No. 52345 on cogeneration and small power production facilities. Applicable only to qualifying facilities (QF's) electing to configure their systems as to require only partial requirements or interruptible service from the Company in order to meet their electric requirements.

TYPE OF SERVICE

Electric sales to the Company must be single or three phase, 60 Hertz, at one standard voltage as may be selected by customer (subject to availability at the premises). The qualifying facility will have the option to sell energy to the Company at a voltage level different than that for purchases from the Company; however, the QF will be responsible for all incremental costs incurred to accommodate such an arrangement.

PAYMENT FOR PURCHASES FROM AND SALES TO THE CUSTOMER

Power sales and special services supplied by the Company to the Customer in order to meet its supplemental or interruptible electric requirements will be priced at the applicable retail rate or rates.

The Company will pay the Customer for any energy purchased as calculated on the standard purchase rate (see below).

PURCHASE RATE

Rate for pricing of energy, net of that for the customer's own use, that is delivered to the Company:

	Cents per kWh			
	Non-Firm Power		Firm Power	
	On-Peak[1/]	Off-Peak[2/]	On-Peak[1/]	Off-Peak[2/]
Summer Billing Cycles (June - October)	3.551	2.257	5.433	3.453
Winter Billing Cycles (November - May)	2.552	1.871	3.904	2.862

[1/] On-Peak Periods: 9 a.m. to 9 p.m., weekdays

[2/] Off-Peak Periods: All other hours

PURCHASE RATE (cont)

These rates are based on the Company's estimated avoided energy costs and will be updated annually to reflect changes in the Company's fuel costs.

SERVICE CHARGE

The monthly service charge shall be determined in accordance with the type of customer service characteristics as set forth below:

	Monthly Charge
Single Phase Service:	
0-200 amp service	$ 7.34
Three Phase Service:	
0-200 amp service	$ 8.87
201-400 amp service	$18.31

CONTRACT PERIOD

As provided for in the Purchase Agreement.

DEFINITIONS

1. Partial Requirements Service - A QF's system configuration whereby the output from its electric generator(s) first go to supply its own electric requirements with any excess energy (over and above its own requirements at the time) then being sold to the Company. The Company supplies the Customer's supplemental electric requirements (those not met by the QF's own generation facilities). This also may be referred to as the "parallel mode" of operation.

2. Special Service(s) - The electric service(s) specified in this section that will be provided by the Company in addition to or in lieu of normal service(s).

   - Interruptible Power - Electric energy or capacity supplied by the Company subject to interruption by the Company under specified conditions and under agreed upon lead time requirements.

3. Non-Firm Power - Electric power which is supplied by the power producer at the producer's option, where no firm guarantee is provided, and the power can be interrupted by the power producer at any time.

4. Firm Power - Power available, upon demand, at all times (except for forced outages and scheduled maintenance) during the period covered by the Purchase Agreement from the Customer's facilities with an expected or demonstrated reliability which is greater than or equal to the average reliability of the Company's firm power sources.

DEFINITIONS (cont)

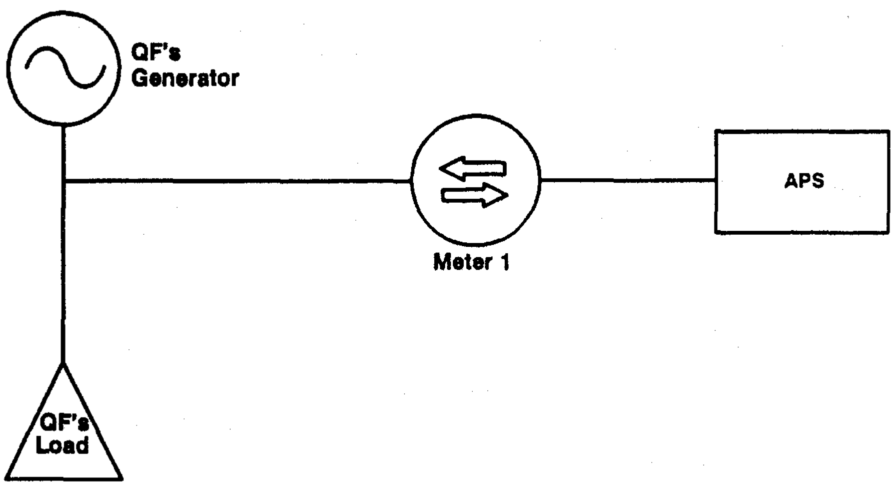
5. Time Periods - Mountain Standard Time shall be used in the application of this rate schedule. Because of potential differences of the timing devices, there may be a variation of up to 15 minutes in timing for the pricing periods.

TERMS AND CONDITIONS

Subject to Company's Terms and Conditions for Energy Purchases from Qualified Cogeneration or Small Power Production Facilities, or as it may be amended or modified from time to time by any supplemental or special Terms and Conditions pursuant to Customer's Purchase Agreement with the Company.

Customer and Company will share in the cost of the bi-directional meter used to record sales to the Customer and purchases from the Customer. Company shall be responsible for all costs up to and equal to the installed cost of a residential time-of-use meter, and Customer shall be responsible for the difference between the installed cost of the bi-directional meter compared to a standard residential time-of-use meter. Customer shall have the option to pay the incremental metering costs initially or in monthly installements over a five year time period.

METERING CONFIGURATION



AVAILABILITY

In all territory served by Company.

APPLICATION

To all small power production facilities with a nameplate rating of 10 kW or less utilizing solar/photovoltaic technology where the customer's generator(s) and load are located at the same premise and meet qualifying status pursuant to the Arizona Corporation Commission's Decision No. 52345 on cogeneration and small power production facilities. Applicable only to qualifying facilities (QF's) either: a) operating in the simultaneous buy/sell mode (whereby all the QF's generation output is fed directly into the Company's system and all of the QF's electric requirements are met by sales from the Company) or; b) QF's electing to configure their systems as to require only partial requirements or interruptible service from the company in order to meet their electric requirements.

Applicable only to those customers being served on the Company's Rate Schedule EPR-3 prior to July 1, 1996.

TYPE OF SERVICE

Electric sales to the Company must be single phase, 60 Hertz, at one standard voltage as may be selected by customer (subject to availability at the premises). The qualifying facility will have the option to sell energy to the Company at a voltage level different than that for purchases from the Company; however, the Customer will be responsible for all incremental costs incurred by APS to accommodate such an arrangement.

BILLING OPTIONS FOR PURCHASES FROM AND SALES TO THE CUSTOMER

The Customer will have the option of choosing either of the following two methods for determining the bill for purchases and sales:

A. Net Bill Method:

The energy (kWh's) sold to the Company shall be subtracted from the energy purchased from the Company. If the difference is positive, the net energy received from the Company will be priced at the applicable standard retail rate under which the Customer would otherwise purchase its full requirements service. If the difference is negative, the net energy delivered to the Company will be priced at the Monthly Purchase Rate shown below.

B. Separate Bill Method:

All sales and purchases shall each be treated separately with sales to the Customer billed on the applicable standard retail rate for full requirements service, and purchases of energy from the Customer's QF priced at the Monthly Purchase Rate shown below.

MONTHLY PURCHASE RATE

Rate for pricing of energy, net of that for the customer's own use, that is delivered to the Company under either Billing Option A or Option B:

	Cents per kWh Non-Firm Power On-Peak[1/]	Off-Peak[2/]	Firm Power On-Peak[1/]	Off-Peak[2/]
Summer Billing Cycles (June - October)	3.351	2.257	5.433	3.453
Winter Billing Cycles (November - May)	2.552	1.871	3.904	2.862

[1/] On-Peak Periods: 9 a.m. to 9 p.m., weekdays

[2/] Off-Peak Periods: All other hours

These rates are based on the Company's estimated avoided energy costs and will be updated annually to reflect changes in the Company's fuel costs.

METERING

See pages 3 and 4 Metering Configurations & Options outlining the metering options available to solar/photovoltaic QF Customers electing the simultaneous buy/sell mode or the parallel mode of operation.

CONTRACT PERIOD

As provided for in the Purchase Agreement.

DEFINITIONS

1. Full Requirements Service - Any instance whereby the Company provides all the electric requirements of a Customer.

2. Partial Requirements Service - A QF's system configuration whereby the output from its electric generator(s) first go to supply its own electric requirements with any excess energy (over and above its own requirements at the time) then being sold to the Company. The Company supplies the Customer's supplemental electric requirements (those not met by the QF's own-generation facilities). This also may be referred to as the "parallel mode" of operation.

3. Special Service(s) - The electric service(s) specified in this section that will be provided by the Company in addition to or in lieu of normal service(s).

   Interruptible Power - Electric energy or capacity supplied by the Company subject to interruption by the Company under specified conditions and under agreed upon lead time requirements.

DEFINITIONS(cont)

3. Non-Firm Power - Electric power which is supplied by the power producer at the producer's option, where no firm guarantee is provided, and the power can be interrupted by the power producer at any time.

4. Firm Power - Power available, upon demand, at all times (except for forced outages and scheduled maintenance) during the period covered by the Purchase Agreement from the Customer's facilities with an expected or demonstrated reliability which is greater than or equal to the average reliability of the Company's firm power sources.

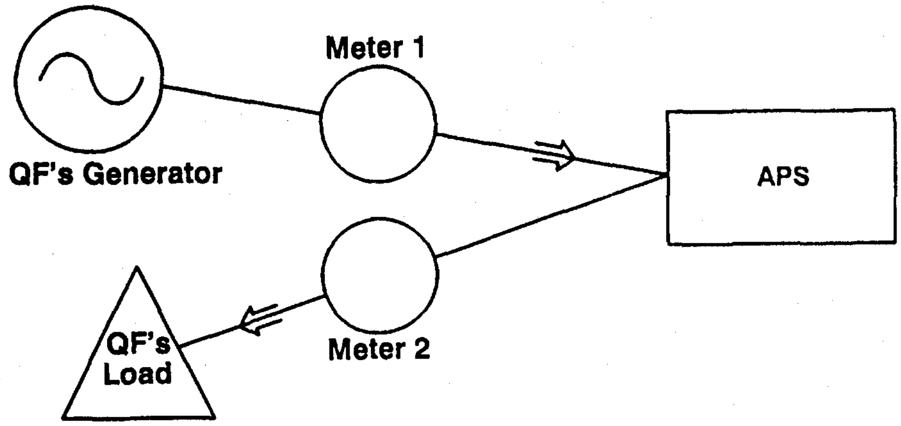
5. Net Energy - The total kilowatthours (kWh's) sold to the Customer by the Company less the total kWh's purchased by the Company from the Customer's QF. "Net energy" applies only to those QF's operating in the simultaneous buy/sell mode.

6. Time Periods - Mountain Standard Time shall be used in the application of this rate schedule. Because of potential differences of the timing devices, there may be a variation of up to 15 minutes in timing for the pricing periods.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

METERING CONFIGURATIONS & OPTIONS
FOR SOLAR/PHOTOVOLTAIC QF APPLICATIONS 10 KW OR LESS
(Simultaneous Buy/Sell Mode)



APS

METERING OPTIONS

	Type of Meter (Meter 1)	Type of Meter (Meter 2)
Qualifying Facilities Utilizing Solar/Photovoltaic Technology 10 kW or less:		
f on an Energy Only (kWh) Type Rate*	TOU[a/]	kWh[b/]
f on a Time-of-Use Type Rate*	TOU[c/]	TOU[d/]

* Refers to the Customer's otherwise applicable standard retail rate for firm purchases from the Company.

a/ A Time-of-use (TOU) meter that registers kWh's only during peak and off-peak periods as specified in the "Monthly Purchase Rate" section of this rate schedule.

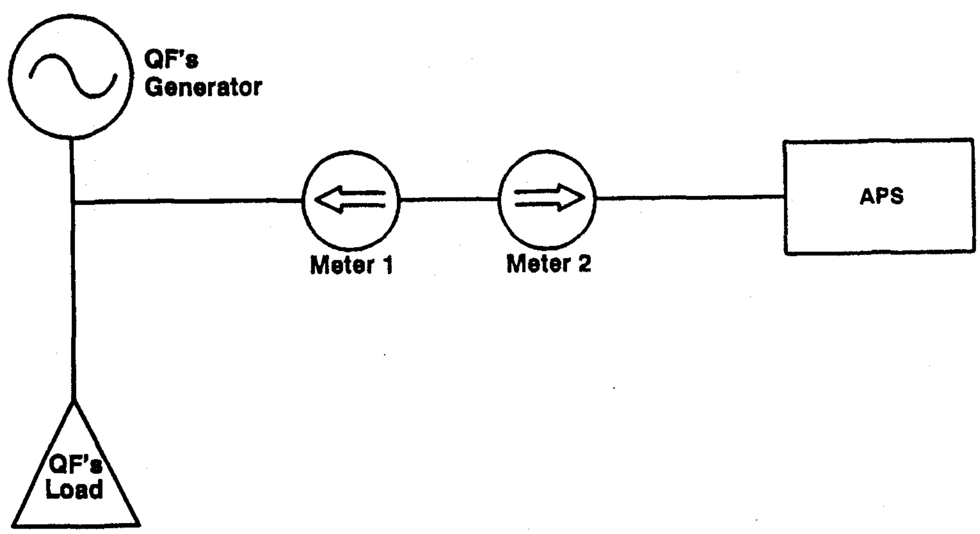
b/ A non-timed watthour meter that registers kWh's only.

c/ A TOU meter that registers kWh's only during peak and off-peak periods concurrent with those periods used in measuring energy for billing purposes by Meter 2.

d/ As per applicable rate schedule.

NOTE: APS shall be responsible for providing all required meters for the Simultaneous Buy/Sell Mode under the EPR-3 Metering Configuration.

METERING CONFIGURATIONS & OPTIONS
FOR SOLAR/PHOTOVOLTAIC QF APPLICATIONS 10 KW OR LESS
(Parallel Mode of Operation)



METERING OPTIONS

	Type of Meter (Meter 1)	Type of Meter (Meter 2)
Qualifying Facilities Utilizing Solar/Photovoltaic Technology 10 kW or less:		
If on an Energy Only (kWh) Type Rate*	kWh[a/]	TOU[b/]
If on a Time-of-Use Type Rate*	TOU[c/]	TOU[d/]

*Refers to the Customer's otherwise applicable standard retail rate for firm purchases from the Company.

a/ A non-timed watthour meter that registers kWh's only.

b/ A Time-of-use (TOU) meter that registers kWh's only during peak and off-peak periods as specified in the "Monthly Purchase Rate" section of this rate schedule.

c/ As per applicable rate schedule.

NOTE: APS shall be responsible for providing all required meters for the parallel mode of operation under the EPR-3 Metering Configuration.

PURCHASE RATES FOR RENEWABLE QUALIFYING FACILITES 10 kW OR LESS FOR PARTIAL REQUIREMENTS

AVAILABILITY

In all territory served by Company.

APPLICATION

To all small power production facilities with a nameplate rating of 10 kW or less utilizing renewable resource technologies where the customer's generator(s) and load are located at the same premise and meet qualifying status pursuant to the Arizona Corporation Commission's Decision No. 52345 on cogeneration and small power production facilities. Applicable only to qualifying facilities (QF's) electing to configure their systems as to require only partial requirements or interruptible service from the Company in order to meet their electric requirements.

TYPE OF SERVICE

Electric sales to the Company must be single phase, 60 Hertz, at one standard voltage as may be selected by customer (subject to availability at the premises). The qualifying facility will have the option to sell energy to the Company at a voltage level different than that for purchases from the Company; however, the Customer will be responsible for all incremental costs incurred by APS to accommodate such an arrangement.

PAYMENT FOR PURCHASES FROM AND SALES TO THE CUSTOMER

Power sales and special services supplied by the Company to the Customer in order to meet its supplemental or interruptible electric requirements will be priced at the applicable retail rate or rates.

The Company will pay the Customer for any energy purchased as calculated on the standard purchase rate (see below).

PURCHASE RATE

Rate for pricing of energy, net of that for the customer's own use, that is delivered to the Company:

	Cents per kWh			
	Non-Firm Power		Firm Power	
	On-Peak[1/]	Off-Peak[2/]	On-Peak[1/]	Off-Peak[2/]
Summer Billing Cycles (June - October)	3.351	2.257	5.433	3.453
Winter Billing Cycles (November - May)	2.552	1.871	3.904	2.862

[1/] On-Peak Periods: 9 a.m. to 9 p.m., weekdays

[2/] Off-Peak Periods: All other hours

These rates are based on the Company's estimated avoided energy costs and will be updated annually to reflect changes in the Company's fuel costs.

CONTRACT PERIOD

As provided for in the Purchase Agreement.

DEFINITIONS

1. Partial Requirements Service - A QF's system configuration whereby the output from its electric generator(s) first go to supply its own electric requirements with any excess energy (over and above its own requirements at the time) then being sold to the Company. The Company supplies the Customer's supplemental electric requirements (those not met by the QF's own-generation facilities). This also may be referred to as the "parallel mode" of operation.

2. Special Service(s) - The electric service(s) specified in this section that will be provided by the Company in addition to or in lieu of normal service(s).

   - Interruptible Power - Electric energy or capacity supplied by the Company subject to interruption by the Company under specified conditions and under agreed upon lead time requirements (Non-Firm Power).

3. Non-Firm Power - Electric power which is supplied by the power producer at the producer's option, where no firm guarantee is provided, and the power can be interrupted by the power producer at any time.

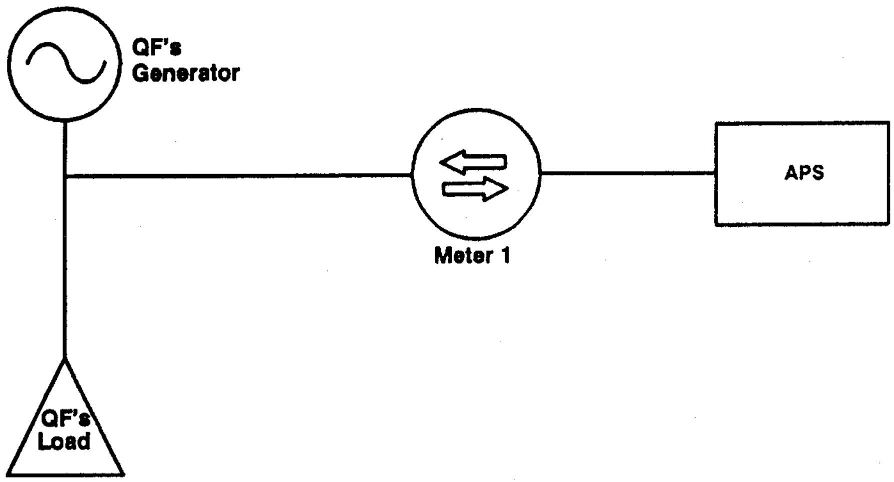
4. Firm Power - Power available, upon demand, at all times (except for forced outages and scheduled maintenance) during the period covered by the Purchase Agreement from the Customer's facilities with an expected or demonstrated reliability which is greater than or equal to the average reliability of the Company's firm power sources.

5. Time Periods - Mountain Standard Time shall be used in the application of this rate schedule. Because of potential differences of the timing devices, there may be a variation of up to 15 minutes in timing for the pricing periods.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

METERING CONFIGURATION



RATE SCHEDULE EQF-M
CLASSIFIED SERVICE
SCHEDULED MAINTENANCE SERVICE
FOR QUALIFIED FACILITIES

AVAILABILITY

This rate scheulde is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage can be made available to the site to be served and when all applicable provisions listed in the Special Provisions section of this schedule have been met.

APPLICATION

This rate schedule is applicable only to qualified cogeneration and small power production facilities 100 kW or less that meet qualifying status pursuant to the Arizona Corporation Commission's Decision No. 52345 on cogeneration and small power production facilities capable of producing firm power, where the facility's generator(s) and load are located at the same site. To electric service for agreed kW quantities of contracted maintenance capacity, taken during scheduled periods, to a customer who is not taking full requirements service from the Company but nevertheless desires a permanent electric connection with the Company as a maintenance power source.

RATE

The applicable rate for service taken under this schedule shall be ECT-1R, except that any provisions in the rate that may prohibit such type service as specified under this schedule is hereby waived, and the interval of integration for the determination of kW capacity for billing purposes (e.g., 15 minutes, 1 hour, etc.) shall be the same as that under the customer's normally applicable rate for firm service. All other provisions of the rate shall be effective.

SPECIAL PROVISIONS

1. Agreement For Service: A contract for a minimum period of one year is required for service under this schedule. All provisions outlining service under this schedule shall be contained in the Agreement For Service.

2. KW QF Contract Capacity: The levels of contract capacity for both firm service (if applicable) and maintenance service shall be specified in the Agreement For Service. Unless otherwise agreed to by the Company, the contract capacity for maintenance power shall not exceed the aggregate nameplate rating(s) of the customer's generating source.

   Customer will be permitted to increase contracted firm power and/or maintenance power amounts upon 30 days written notice to the Company, provided, however, a new Agreement For Service incorporating these changes is signed for a period lasting no less than one year. Except as provided otherwise in the following paragraph, contracted maintenance capacity amounts shall not be changed unless actual changes in the capacity of the customer's generating facilities have been made. Decreases in a customer's contracted firm capacity amount will not be allowed until expiration of the contract period.

   If customer exceeds contracted amount for maintenance capacity, customer's firm contract capacity will be increased by said excess. If customer is not presently receiving firm service, such service shall be instituted for an amount no less than that which may have exceeded the contracted maintenance capacity level stated in the Agreement For Service, under the appropriate rate for such service.

3. Firm Power: For purposes of this rate, firm power shall be defined to be power available, upon demand, at all times (except for forced outages and scheduled maintenance) during the period covered by the Agreement For Service from the customer's facilities with an expected or demonstrated reliability which is greater than or equal to the average reliability of the Company's firm power sources.

SPECIAL PROVISIONS (cont)

4. Scheduled Maintenance Periods: For purposes of this rate, scheduled maintenance periods shall be defined as those periods specified by the Company during which customer can take electric power under this schedule. Currently, the designated periods during which the customer may take maintenance power are:

October 1 - January 31	At all times
February 1 - May 31	Only between the hours of 10:00 p.m. to 7:00 a.m.
June 1 - September 30	No maintenance shall be permitted at any time

The use of maintenance power during periods other than those specified above is prohibited. The Company reserves the right to periodically change these periods from time to time as conditions warrant.

Optional Procedure: Customer may take power in order to perform maintenance on his facility provided the time and duration of such outages are scheduled in advance with the concurrence of the Company. Reasonable periods will be allowed for major equipment repairs or overhaul, not to exceed four weeks in duration, provided such periods do not exceed one per 12 month period. The Company will make every effort possible to accommodate the customer's requirements; however, the Company's operational circumstances will determine when such scheduling shall be permitted.

5. Metering Facilities: Service under this rate schedule will be provided on a time-of-day basis requiring appropriate metering equipment. Customer shall submit requirements for service to the Company so that adequate service and metering facilities can be determined in order to meet the needs of the customer's facility. Said facilities shall be specified in the Agreement For Service.

6. Use of Maintenance Power During Unauthorized Periods: Customer shall not be permitted to utilize maintenance power at any time other than that specifically authorized by the Company as outlined in Special Provision 4 of this schedule. Unauthorized use of maintenance power shall be treated in the following manner:

   a) For the first breach of this provision within a 12 month period of time, the customer shall receive a written notice thereof from the Company.

   b) In the event of a second breach of this provision during the same 12 month period, in addition to the payments calculated under this rate schedule, customer shall be required to pay:

      1) 50% of the capacity charge of the applicable rate for standby service for qualifying cogeneration or small power production facilities multiplied by customer's contracted amount for maintenance capacity multiplied by the number of months previously receiving service on this schedule (however, not to exceed 12); and

      2) Customer shall be placed on the applicable standby rate. Customer will be eligible again for the maintenance rate after a 12 month period during which time it has been demonstrated that customer's facility can be operated within the constraints of the scheduled maintenance periods.

7. Charge for Facilities: The Company reserves the right to establish a minimum charge in order to recover the costs of facilities required to serve such load. Said charge shall be specified in the Agreement For Service.

SPECIAL PROVISIONS (cont)

8. Reconnect Charge: If the customer terminates service under this schedule and elects to re-initiate service at the same premises within a 12 month period of time, the reconnect charge shall be equal to the minimum charge the customer would have otherwise been required to pay had service not been terminated.

9. Conflicts: In case of an inconsistency between any provision of the Agreement For Service, this rate schedule and/or the Terms and Conditions for the Sale of Electric & Gas Service, the inconsistency shall be resolved by giving priority to the Agreement For Service, the rate and then the Terms and Conditions in said respective order. Any provisions in the customer's normally applicable rate for firm service that prohibits partial requirements type service(s) is hereby waived.

10. Refusal to Serve Maintenance Power: The Company reserves the right to refuse to provide maintenance service to a customer's facility during such periods of time when supplying such power may contribute to a system emergency. In addition, the Company reserves the right to refuse maintenance service to cogeneration or small power production facilities when, in the Company's opinion, service to such a facility may constitute a hazard to the Company's or other customer's facilities.

TIME PERIODS

Mountain Standard Time shall be used in the application of this rate schedule. In addition, to prevent radical changes in the system loads, the beginning and ending hours for individual customers may be varied by up to one hour (total hours in each time period to remain unchanged) and because of potential differences of the timing devices, there may be a variation of up to 15 minutes in timing for the pricing periods.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

APS

RATE SCHEDULE EQF-S
CLASSIFIED SERVICE
STANDBY ELECTRIC SERVICE
FOR QUALIFIED FACILITIES

AVAILABILITY

This rate schedule is available in all territory served by Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the premises served and when all applicable provisions listed in the Special Provisions section of this schedule have been met.

APPLICATION

This rate schedule is applicable only to qualified cogeneration and small power production facilities 100 kW or less that meet qualifying status pursuant to the Arizona Corporation Commission's Decision No. 52345 on cogeneration and small power production facilities capable of producing firm power, where the facility's generator(s) and load are located at the same premises. To electric service for agreed kW quantities of contracted standby capacity to a customer who is not taking full requirements service from the Company but nevertheless desires a permanent electric connection with the Company as a standby power source.

RATE

The bill shall be the greater of the amount computed under A. or B. below, including the applicable Adjustments.

A) The bill for standby service taken as computed under the ECT-1R rate schedule; or

B) Customer's contract standby capacity amount multiplied by 1/2 the on-peak capacity charge in the ECT-1R rate schedule; plus the Basic Service Charge in ECT-1R.

Any provisions in the ECT-1R rate that may prohibit such type service as specified under this schedule is hereby waived. The interval of integration for the determination of kW capacity for billing purposes (e.g., 15 minutes, 1 hour, etc.) shall be the same as that under the customer's normally applicable rate for firm service. All other provisions of the rate shall be effective.

SPECIAL PROVISIONS

1. Agreement For Service: A contract for a minimum period of one year is required for service under this schedule. All provisions outlining service under this schedule shall be contained in the Agreement For Service.

2. KW QF Contract Capacity: The levels of contract capacity for both firm service (if applicable) and standby service shall be specified in the Agreement For Service. Unless otherwise agreed to by the Company, the contract capacity for standby power shall not exceed the aggregate nameplate rating(s) of the customer's generating source.

   Customer will be permitted to increase contracted firm power and/or standby power amounts upon 30 days written notice to the Company, provided, however, a new Agreement For Service incorporating these changes is signed for a period lasting no less than one year. Except as provided otherwise in the following paragraph, contracted standby capacity amounts shall not be changed unless actual changes in the capacity of the customer's generating facilities have been made. Decreases in a customer's contracted firm capacity amount will not be allowed until expiration of the contract period.

SPECIAL PROVISIONS (cont)

2. (cont) If customer exceeds contracted amount for standby capacity, customer's firm contract capacity will be increased by said excess. If customer is not presently receiving firm service, such service shall be instituted, for an amount no less than that which may have exceeded the contracted standby capacity level stated in the Agreement For Service, under the appropriate rate for such service.

3. Firm Power: For purposes of this rate, firm power shall be defined to be power available, upon demand, at all times (except for forced outages and scheduled maintenance) during the period covered by the Agreement For Service from the customer's facilities with an expected or demonstrated reliability which is greater than or equal to the average reliability of the Company's firm power sources.

4. Standby Power: For purposes of this rate, standby power shall be defined to be electric capacity and associated energy, in excess of customer's contracted capacity for firm service, supplied by the Company to replace power ordinarily generated by the customer's generation facility during scheduled or unscheduled outages of said facility.

5. Metering Facilities: Service under this rate schedule will be provided on a time-of-day basis requiring appropriate metering equipment. Customer shall submit requirements for service to the Company so that adequate service and metering facilities can be determined in order to meet the needs of the customer's facility. Said facilities shall be specified in the Agreement For Service.

6. Charge for Facilities: The Company reserves the right to establish a minimum charge in order to recover the costs of facilities required to serve such load. Said charge shall be specified in the Agreement For Service.

7. Reconnect Charge: If the customer terminates service under this schedule and elects to re-initiate service at the same premises within a 12 month period of time, the reconnect charge shall be equal to the minimum charge the customer would have otherwise been required to pay had service not been terminated.

8. Conflicts: In case of an inconsistency between any provision of the Agreement For Service, this rate schedule and/or the Terms and Conditions for the Sale of Electric & Gas Service, the inconsistency shall be resolved by giving priority to the Agreement For Service, the rate and then the Terms and Conditions in said respective order. Any provisions in the customer's normally applicable rate for firm service that prohibits partial requirements type service(s) is hereby waived.

9. Refusal to Serve Standby Power: The Company reserves the right to refuse to provide standby service to a customer's facility during such periods of time when supplying such power may contribute to a system emergency. In addition, the Company reserves the right to refuse standby service to cogeneration or small power production facilities when, in the Company's opinion, service to such a facility may constitute a hazard to the Company's or other customer's facilities.

TIME PERIODS

Mountain Standard Time shall be used in the application of this rate schedule. In addition, to prevent radical changes in the system loads, the beginning and ending hours for individual customers may be varied by up to one hour (total hours in each time period to remain unchanged) and because of potential differences of the timing devices, there may be a variation of up to 15 minutes in timing for the pricing periods.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

RATE SCHEDULE SOLAR-1
CLASSIFIED SERVICE
PHOTOVOLTAIC SERVICE PILOT PROGRAM

AVAILABILITY

Company will offer power generated by a Company owned and maintained photovoltaic system to customers who cannot be economically connected by extension of Company distribution system. Available within Company's service territory to customers who 1) are requesting new (not previously existing) service and 2) are located in areas where a line extension for regular electric service is less economical than the photovoltaic system as determined by the ACC "Staff Guidelines on Photovoltaics Versus Line Extensions".

Customer's system must be in a location that is reasonably accessible by standard Company vehicles. It will be located on the customer's property. If the system is not installed at the customer's permanent residence (that at which customer resides for at least six months a year) the customer will be required to post a five year surety bond for the amount of the photovoltaic system Net Installed Cost.

This pilot program is only available until January 1, 1996 or until the total Company investment in the Photovoltaic Service Pilot Program reaches $250,000.

APPLICATION

Company has the sole right to determine the customer's eligibility for service under this schedule. Service under this schedule is limited to photovoltaics of 0.2 kW or greater having a Net Installed Cost of more than $1,500 but less than $50,000.

Applicable only to those customers being served on the Company's Rate Schedule Solar-1 prior to August 1, 1996.

TYPE OF SERVICE

The system typically will include a photovoltaic module array, the module array mounting structure, the control structure, the control equipment, any necessary wiring, batteries, and any other equipment necessary to provide service at a mutually agreed upon point of delivery. Company will own, maintain, and make any necessary repairs to the photovoltaic system. If the system is damaged or in need of repairs, customer shall notify Company promptly.

This service is a substitute for and is in lieu of the customer being connected to the Company's electric distribution system. Any back-up, supplemental, or alternate power generation shall be the customer's responsibility, and Company assumes no obligation to provide or arrange for such back-up, supplemental or alternative power. Any back-up power equipment must meet Company technical specifications, and be connected to the photovoltaic system only at a Company designated point.

INITIAL FEE

An Initial Fee equal to five percent of the estimated Total Installed Cost of the photovoltaic system is required from the customer at the time the Photovoltaic Facilities Agreement is executed. The Initial Fee is a contribution in-aid-of-construction and will be deducted from the Total Installed Cost of the photovoltaic array and system wiring to yield the Net Installed Cost. The Initial Fee shall be non-refundable unless Company determines that it will not install the photovoltaic system.

RATE

The total bill is based on the type of system installed and the rate formula specified below. The exact charge will be specified in the Photovoltaic Facilities Agreement. Since each system is designed to meet the customer's specific needs, the rate will vary based on the following formula:

$20.00 monthly service fee, plus

A maximum of 1.6 percent times the portion of the Net Installed Cost of the photovoltaic system parts with a life expectancy of more than 10 years, such as the photovoltaic Array, but not less than marginal cost,

plus

3.1 percent times the portion of the Net Installed Cost of the photovoltaic system parts with a life expectancy of 10 years or less, such as inverter and batteries,

plus

any applicable sales tax and regulatory assessments.

TERMINATION OF SERVICE

Upon discontinuance of the use of any photovoltaic facilities due to termination of service, termination of the Photovoltaic Facilities Agreement, or otherwise:

a) For the purposes of this initial and only pilot program the customer has the option to terminate without the facility termination charge as described below, section (b), when the Photovoltaic Facilities Agreement expires and customer has paid to Company all other monies to which company may be legally entitled.

b) Customer shall pay to Company on demand (in addition to all other monies to which company may be legally entitled by virtue of such termination) a facility termination charge defined as the Net Installed Cost, plus the removal cost less the market salvage value for the photovoltaic facilities to be removed.

c) Upon termination of service, either by Company or customer, customer will have the option to purchase the photovoltaic facilities based on Company's Net Installed Cost less accumulated straight-line depreciation.

SYSTEM MODIFICATIONS

Company will reasonably respond to customer requests for improvement to the performance of the photovoltaic system. However, Company has the sole right to determine if and when a modification to the existing system shall be made and such modification will be at the customer's expense by adjusting the monthly fee. If such improvements cost less than $1000, then no deposit is required. For improvements greater than $1000, an initial fee equal to 5 percent of the total modification cost shall be required prior to installation. The initial fee is non-refundable unless Company determines that the modification is not warranted. If the total modification costs exceed one half of the total installed cost or $5000, a new Photovoltaic Facilities Agreement shall be required. Total modification cost will include the cost of all modifications installed in the current fiscal year.

SYSTEM MODIFICATIONS (cont)

Company shall notify the customer of any modifications or improvements to the system by providing the Customer a restated investment/monthly billing statement. Company shall adjust the monthly bill accordingly. The Net Modification Cost will be equal to the total modification cost less the 5% Initial Fee. The Net Modification Cost will be added to the existing Net Installed Cost to yield a revised Net Installed Cost that will henceforth be used to compute the bill.

CONTRACT PERIOD

As provided for in the Photovoltaic Facilities Agreement.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

APS

RATE SCHEDULE SOLAR-2
CLASSIFIED SERVICE
INDIVIDUAL SOLAR ELECTRIC SERVICE

AVAILABILITY

Available within Company's service territory to customers who are requesting new service requiring a new line extension and are located in areas where a line extension for regular electric service is less economical than Individual Solar Electric Service. Company has the right to refuse service at unsecured locations which in the company's opinion is a high risk area for vandalism, theft, or other damage.

Customer's system must be in a location that is determined by the Company to be reasonably accessible by standard Company vehicles. It will be located on the customer's property. If the system is not installed at the customer's permanent residence (that at which customer resides for at least six months a year) the customer may be required to post security as determined by the Company for the amount of the Solar Electric system Net Installed Cost.

This service is only available until the Company investment in the Individual Solar Electric Service reaches the ACC approved funding limit.

APPLICATION

Company has the sole right to determine the customer's eligibility for service under this schedule. Service under this schedule is limited to solar electric systems with name plate ratings of 200 watts or greater and having a Net Installed Cost of more than $1,500.

TYPE OF SERVICE

Company will offer power generated by a Company owned and maintained Solar Electric system for customers who cannot be economically connected by extension of Company distribution system. The system typically will include a photovoltaic module array, the module array mounting structure, the control structure, the control equipment, any necessary wiring, batteries, and any other equipment necessary to provide service that meets all applicable building and safety codes at a mutually agreed upon point of delivery. Company will own, maintain, and make any necessary repairs to the Solar Electric system. If the system is damaged or in need of repairs, customer shall notify Company promptly.

This service is a substitute for and is in lieu of the customer being connected to the Company's electric distribution system. Any back-up, supplemental, or alternate power generation source may be contracted with the Company. Company assumes no obligation to provide or arrange for such back-up, supplemental or alternative power unless it is part of the Solar Electric Service Agreement and not interconnected to the normal Company system. Any back-up power equipment must meet Company technical specifications, and be connected to the Solar Electric system only at a Company designated point.

INITIAL FEE

An Initial Fee equal to five percent or more of the estimated Total Installed Cost of the Solar Electric system is required from the customer at the time the Contract is executed. The Initial Fee will be deducted from the Total Installed Cost, starting with the system component with the longest life, to yield the Net Installed Cost by system component. The Initial Fee shall be non-refundable unless Company subsequently determines that it will not install the Solar Electric system. Customer has the option to pay a higher initial fee to reduce the net installed cost of the system.

INITIAL FEE (cont)

The minimum Initial Fee is:

Estimated Total Installed Cost		Minimum Initial Fee
Up to	$100,000	5%
More than	$100,000	10%

RATE

The total monthly bill is based on the type of system installed and the rate formula specified below. The exact charge will be specified in the service agreement entered into between the Company and customer. Since each system is designed to meet the individual customer's specific needs, the rate will vary based on the following formula:

Monthly service fee, dependent on battery type and system size:

	System Size	
Battery	Up to 2.5 kW	Over 2.5 kW
None	$5.00	$5.00
Sealed	$45.00	$65.00
Flooded	$65.00	$85.00

plus,

Component Fee which is the summation of the Net Installed Cost by System Component times the appropriate Monthly Percentage. The monthly percentages listed are maximums that can not be reduced below marginal cost:

System Component		**Straight Line**	**Monthly**
Type	**Average Life**	**Depreciation Life**	**Percentage**
Long	Greater than 13 years	20 Years	1.41%
Medium	Between 7 and 13 years	10 Years	1.83%
Short	Less than 7 years	5 Years	2.75%

plus,

any applicable sales tax and regulatory assessments.

The Company may offer an accelerated payment schedule to accelerate equipment depreciation allowing the customer to purchase the system for a lower book value.

TERMINATION OF SERVICE

Upon termination of service for any reason other than the Contract terms:

a) Customer shall pay to Company on demand (in addition to all other monies to which Company may be legally entitled by virtue of such termination) a facility termination charge defined as the Net Installed Cost less depreciation (based on customer's payment selection), plus the removal cost less the market salvage value for the Solar Electric facilities to be removed. Market salvage value is defined as new reconstruction cost of the system less depreciation for the same time period as the existing system.

b) Upon termination of service, either by Company or customer, customer will have the option to purchase the Solar Electric facilities based on Company's Net Installed Cost less accumulated depreciation.

If the system is damaged because of vandalism, theft, or abuse Company has the right to terminate service and remove the remaining equipment.

SYSTEM MODIFICATIONS

Company will reasonably respond to customer requests for improvement to the performance of the Solar Electric system. However, Company has the sole right to determine if and when a modification to the existing system shall be made. Such modification will be reflected in customer's monthly bill with a Solar Electric Service Agreement modification. An initial fee of at least 5 percent of the total modification cost shall be required prior to installation. The initial fee is non-refundable unless Company determines that the modification is not warranted.

Company shall adjust the monthly bill by adding the Net Modification Cost to the existing Net Installed Cost to yield a revised Net Installed Cost that will hence forth be used to compute the monthly bill. The Net Modification Cost will be equal to the total modification cost less the Initial Fee for the modification. Company shall provide the customer the revised Net Installed Cost and monthly billing with the revised or amended Solar Electric Service Agreement.

CONTRACT PERIOD

As provided for in the Solar Electric Service Agreement.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

APS

RATE SCHEDULE SP-1
CLASSIFIED SERVICE
SOLAR PARTNERS

AVAILABILITY

This rate schedule is available within the Company's service territory to standard offer residential and business customers on a pre-established service who wish to purchase solar generated electricity for their home and/or business. The total amount sold shall not exceed APS' solar resources. This program may be terminated by the Company at any time without notice.

APPLICATION

Service under this schedule provides a portion of the customer's regular electric service from solar electric generating systems producing AC electricity and delivered via the Company's electric power grid. All provisions of the customer's current applicable rate schedule will apply in addition to this service.

TYPE OF SERVICE

The Company will offer power generated by solar electric generating systems through the Company's electric distribution system.

The customer shall contract for a specific number of increments from solar generating facilities. Based upon the average annual output of solar system resources, each increment shall equal approximately 15 kWh/month. The monthly charge is based upon the number of increments and the cost of Solar power in excess of the current rates. The Company may assign limits to the number of kWh increments sold per customer.

SERVICE CHARGES

The bill, for service under this tariff, shall be $2.64 per month for each 15 kWh monthly increment of solar energy.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

ADJUSTMENTS

APS

RATE SCHEDULE CRCC-1
COMPETITION RULES COMPLIANCE CHARGE

APPLICATION

The Competition Rules Compliance Charge (" CRCC") shall apply to all retail electric schedules, excluding those which are for solar service. All provisions of the customer's current applicable rate schedule will apply in addition to this charge.

RATES

The bill shall be calculated at the following rate:

CRCC		
All kWh	$0.000353	per kWh

ADDITIONAL REQUIREMENTS

The A.C.C. authorized in Decision XXXXXX that the amortized amount of $51,433,000 is to be recovered over five years according to the method described in the filed "Competition Rules Compliance Plan for Administration." The CRCC will be canceled once the amortized amount is fully recovered.

RATE SCHEDULE EPS-1
ENVIRONMENTAL PORTFOLIO SURCHARGE

APPLICATION

The Environmental Portfolio Surcharge shall be applied to every metered and/or non metered retail electric service, excluding those services which are for a solar service. All provisions of the customer's current applicable rate schedule will apply in addition to this surcharge.

RATES

The bill shall be calculated at the following rates:

All kWh	$ 0.000875	per kWh

SURCHARGE LIMITS

The monthly total of the Environmental Portfolio Surcharge shall not exceed the following limits:

Residential Customers	$ 0.35	per service per month
Non-residential Customers	$13.00	per service per month
Non-residential Customers with demand of 3,000 kW or higher per month for three consecutive months	$39.00	per service per month

APPLICATION

The Power Cost Component Factor (" PCCF") and Amortization Charge shall apply to all Standard Offer retail electric schedules, excluding those which are for solar and E-36 Station Use service. All provisions of the customer's current applicable rate schedule will apply in addition to this charge.

PCCF SEMI-ANNUAL ADJUSTMENT

Standard Offer rate schedules covered by this charge include an Average Retail Power Supply Cost (" ARPSC") of $0.023 per kilowatt-hour. In accordance with A.C.C. Decision No. XXXXX, a semi-annual adjustment to the ARPSC will be made through a change in the PCCF that is based upon the rolling twelve-month totals of actual retail power supply costs and retail energy sales. The calculation method is set forth in the filed "Power Supply Adjustment Plan for Administration" (the "Plan"). This Adjustment will be applied to kilowatthour sales under applicable electric schedules. The PCCF cannot exceed the bandwidth limits described in the Plan. The Amortization Charge is not included in the bandwidth calculations.

BALANCING ACCOUNT

The Company shall establish and maintain a Balancing Account ("Account") for the schedules subject to this provision. Entries shall be made to the Account each month as set forth in the Plan. The Account will include interest applied to over- and under-collected balances based on the non-financial three-month commercial paper rate for each month contained in the Federal Reserve Statistical Release, H-15, or its successor publication. The Plan establishes a maximum amount, or Threshold for the Account balance. If the Account's Threshold is exceeded in a given month then the existing balance will be converted to a kilowatthour charge based on a 12 month amortization period. The result is the Amortization Charge. The Amortization Charge will be charged to the applicable rate schedules until the amortization period is over. The Account's beginning balance for the next month will be set at zero.

RATES

The bill shall be calculated at the following rate:

PCCF		
All kWh	$0.000000	per kWh
Amortization Charge		
All kWh	$0.000000	per kWh

MONTHLY INFORMATIONAL FILINGS

The Company shall make a monthly Power Supply Adjustment information filing with Commission Staff to include any and all information required by A.C.C. Decision No. XXXXX.

ADDITIONAL REQUIREMENTS

A special review is required if the Account exceeds its Threshold amount, an over-collection or under-collection of $50 million. The Company must file an application for an adjustment within forty five (45) days of exceeding the Threshold, or contact the Commission to discuss why an Amortization Charge is not necessary at that time. The Commission, upon review, may authorize the balance to be amortized and converted to an Amortization Charge included as part of the PSA charges for a specified period. If the Threshold is not exceeded but the Company has reason to believe that it can not significantly reduce a large balance in a reasonable amount of time it can file a request with the Commission to adjust the balance through an amortization of all, or part, of the current balance.

DIRECTLY ASSIGNED POWER SUPPLY COSTS

In cases when power supply costs are incurred for a specific customer or group of customers, the customer or group of customers will be charged the identified costs directly. Power supply costs recovered through direct assignments for both existing and returning customers will be excluded from the computation of the above charges applied to other Standard Offer customers.

APPLICATION

The Returning Customers Direct Assignment Charge (" RCDAC") shall apply to customers or groups of customers over 3 MW's who left Standard Offer retail service or special contract service for competitive generation suppliers and desire to return to Standard Offer service (or customers who were Direct Access customers since origination of service and request Standard Offer service) and for whom APS has not planned resource acquisitions. All provisions of the customer's current applicable rate schedule will apply in addition to this charge.

RATE

The adjustment will be identified in the Electric Service Agreement between the Customer and APS and will be in addition to the Standard Offer service charges.

RATE SCHEDULE SBAC-1
SYSTEM BENEFIT ADJUSTMENT CHARGE

APPLICATION

The System Benefit Adjustment Charge ("SBAC") shall be applied monthly to every metered and/or non-metered retail electric service with the exception of solar service. All provisions of the customer's currently applicable rate schedule will apply in addition to this surcharge.

RATE

The bill shall be calculated at the following rate:

SBAC		
All kWh	$0.000000	per kWh

RATE SCHEDULE TCA-1
TRANSMISSION COST ADJUSTMENT

APPLICATION

The Transmission Cost Component Factor ("TCCF") and Amortization Charge shall apply to all Standard Offer retail electric schedules, excluding those which are for solar service. All provisions of the customer's current applicable rate schedule will apply in addition to this charge.

TCCF ANNUAL ADJUSTMENT

Standard Offer rate schedules covered by this charge include an Average Transmission and Ancillary Service Cost ("ATASC") of $0.00476 per kilowatt-hour. In accordance with A.C.C. Decision No. XXXXX, an annual adjustment to the ATASC will be made through a change in the TCCF that is based upon the prior year's annual Transmission and Ancillary Service costs and retail energy sales. The calculation method is set forth in the filed "Transmission Cost Adjustment Plan for Administration" (the "Plan"). This Adjustment will be applied to kilowatthour sales under applicable electric schedules.

BALANCING ACCOUNT

The Company shall establish and maintain a Balancing Account ("Account") for the schedules subject to this provision. Entries shall be made to the Account each month as set forth in the Plan. The Account will include interest applied to over- and under-collected balances based on the non-financial three-month commercial paper rate for each month contained in the Federal Reserve Statistical Release, H-15, or its successor publication. If the Account's balance grows too large then the Company will file a request with the Arizona Corporation Commission to convert the existing balance to a kilowatthour charge based on appropriate amortization period. The result is the Amortization Charge. The Amortization Charge will be charged to the applicable rate schedules until the amortization period is over.

RATES

The bill shall be calculated at the following rate:

TCCF		
All kWh	$0.000000	per kWh
Amortization Charge		
All kWh	$0.000000	per kWh

ANNUAL INFORMATIONAL FILINGS

Annually, the Company shall make a Transmission Cost Adjustment information filing with Commission Staff to include any and all information required by A.C.C. Decision No. XXXXX.

SERVICE SCHEDULES

The following TERMS AND CONDITIONS and any changes authorized by law will apply to Standard Offer and Direct Access services made available by Arizona Public Service Company (Company), under the established rate or rates authorized by law and currently applicable at time of sale.

1. General

1.1 Services will be supplied in accordance with these Terms and Conditions and any changes required by law, and such applicable rate or rates as may from time to time be authorized by law. However, in the case of the customer whose service requirements are of unusual size or characteristics, additional or special contract arrangements may be required.

1.2 These Terms and Conditions shall be considered a part of all rate schedules, except where specifically changed by a written agreement.

1.3 In case of a conflict between any provision of a rate schedule and these Terms and Conditions, the provisions of the rate schedule shall apply.

1.4 Company will supply electric service at the standard voltages specified in the Electric Service Requirements Manual published by Company and is responsible for distribution services, emergency system conditions, outages and safety situations related to Company's distribution system.

2. Establishment of Service

2.1 Application for Service - Customers requesting service may be required to appear at Company's place of business to produce proof of identity and sign Company's standard form of application for service or a contract before service is supplied by Company.

2.1.1 In the absence of a signed application or contract for service, the supplying of Standard Offer and/or Direct Access services by Company and acceptance thereof by the customer shall be deemed to constitute a service agreement by and between Company and the customer for delivery of, acceptance of, and payment for service, subject to Company's applicable rates and rules and regulations.

2.1.2 Where service is requested by two or more individuals, Company shall have the right to collect the full amount owed Company from any one of the applicants.

2.1.3 In mobile home parks identified by Company as being seasonal parks, Company may install or connect a meter as its scheduling permits; however, the customer will only be responsible for energy and demand recorded on and after their requested service turn on date.

2.2 Service Establishment Charge - A service establishment charge of $25.00 for residential and $35.00 non-residential plus any applicable tax adjustment will be assessed each time Company is requested to establish, reconnect or re-establish electric service to the customer's delivery point, or to make a special read without a disconnect and calculate a bill for a partial month. Billing for the service charge will be rendered as part of the service bill, but not later than the second service bill.

The service establishment charges above may be assessed when a customer changes their rate selection from Direct Access to Standard Offer.

2.2.1 The customer may additionally be required to pay a trip charge of $17.50 when an authorized Company representative travels to the customer's site and is unable to complete the customer's requested services due to lack of access to meter panel.

2.2.2 The customer may additionally be required to pay an after-hour charge of $75.00 should the customer request service, as defined in A.A.C. R14-2-203.D.3, be established, reconnected, or re-established during a period other than regular working hours, or on the same day of their request, regardless of the time the order may be worked by Company.

2.2.3 The charge for Company work, requested by the customer to be worked after hours or on a Company holiday that does not meet the definition of A.A.C. R14-2-203.D.3 will be billed at current hourly rates as determined by Company.

2.3 Direct Access Service Request (DASR) - A Direct Access Service Request charge of $10.00 plus any applicable tax adjustment will be assessed to the Electric Service Provider (ESP) submitting the DASR each time Company processes a Request (RQ) type DASR as specified in the Company's Schedule 10, Terms and Conditions for Direct Access.

2.4 Grounds for Refusal of Service - Company may refuse to connect or reconnect Standard Offer or Direct Access service if any of the following conditions exist:

2.4.1 The applicant has an outstanding amount due with Company for the same class of service and is unwilling to make payment arrangements that are acceptable to Company.

2.4.2 A condition exists which in Company's judgment is unsafe or hazardous.

2.4.3 The applicant has failed to meet the security deposit requirements set forth by Company as specified under Section 2.6 hereof.

2.4.4 The applicant is known to be in violation of Company's tariff.

2.4.5 The applicant fails to furnish such funds, service, equipment, and/or rights-of-way or easements required to serve the applicant and which have been specified by Company as a condition for providing service.

2.4.6 The applicant falsifies his or her identity for the purpose of obtaining service.

2.4.7 Service is already being provided at the address for which the applicant is requesting service.

2.4.8 Service is requested by an applicant and a prior customer living with the applicant owes a delinquent bill.

2.4.9 The applicant is acting as an agent for a prior customer who is deriving benefits of the service and who owes a delinquent bill.

2.4.10 The applicant has failed to obtain all required permits and/or inspections indicating that the applicant's facilities comply with local construction and safety codes.

2.5 Establishment of Credit or Security Deposit

2.5.1 Residential Establishment of Credit - Company shall not require a security deposit from a new applicant for residential service if the applicant is able to meet any of the following requirements:

2.5.1.1 The applicant has had service of a comparable nature with Company within the past two (2) years and was not delinquent in payment more than twice during the last twelve (12) consecutive months or disconnected for nonpayment.

2.5.1.2 Company receives an acceptable credit rating, as determined by Company, for the applicant from a credit rating agency utilized by Company.

2.5.1.3 In lieu of a security deposit, Company receives deposit guarantee notification from a social or governmental agency acceptable to Company or a surety bond as security for Company in a sum equal to the required deposit.

2.5.2 Residential Establishment of Security Deposit - When credit cannot be established as provided for in Section 2.5.1 hereof or when it is determined that the applicant left an unpaid final bill owing to another utility company, the applicant will be required to:

2.5.2.1 Place a cash deposit to secure payment of bills for service as prescribed herein, or

2.5.2.2 Provide a surety bond acceptable to Company in an amount equal to the required security deposit.

2.5.3 Nonresidential Establishment of Security Deposit - All nonresidential customers may be required to:

2.5.3.1 Place a cash deposit to secure payment of bills for service as prescribed herein, or

2.5.3.2 Provide a non-cash security deposit in the form of a Surety Bond, Irrevocable Letter of Credit, or Assignment of Monies in an amount equal to the required security deposit.

2.6 Reestablishment of Security Deposit

2.6.1 Residential - Company may require a residential customer to establish or re-establish a security deposit if the customer becomes delinquent in the payment of two (2) or more bills within a twelve (12) consecutive month period or has been disconnected for non-payment during the last twelve (12) months.

2.6.2 Nonresidential - Company may require a nonresidential customer to establish or re-establish a security deposit if the customer becomes delinquent in the payment of two (2) or more bills within a six (6) consecutive month period or if the customer has been disconnected for non-payment during the last twelve (12) months, or when the customer's financial condition may jeopardize the payment of their bill, as determined by Company based on the results of using a credit scoring worksheet. Company will inform all customers of the Arizona Corporation Commission's complaint process should the customer dispute the deposit based on the financial data.

2.7 Security Deposits

2.7.1 Company reserves the right to increase or decrease security deposit amounts applicable to the services being provided by the Company:

2.7.1.1 If the customer's average consumption increases by more than ten (10) percent for residential accounts within a twelve (12) consecutive month period and five (5) percent for nonresidential accounts within a twelve (12) consecutive month period; or,

2.7.1.2 If the customer chooses to change from Standard Offer to Direct Access services, the deposit may be decreased by an amount which reflects that portion of the customer's service being provided by a Load Serving ESP. However if the Load Serving ESP is providing ESP Consolidated Billing pursuant to Company's Schedule 10 Section 7, the entire deposit will be credited to the customer's account; or,

2.7.1.3 If the customer chooses to change from Direct Access to Standard Offer service, the requested deposit amount may be increased by an amount pursuant to Section 2.5, which reflects that APS is providing bundled electric service.

2.7.2 Separate security deposits may be required for each service location.

2.7.3 Customer security deposits shall not preclude Company from terminating an agreement for service or suspending service for any failure in the performance of customer obligation under the agreement for service.

2.7.4 Cash deposits held by Company six (6) months/183 days or longer shall earn interest at the established one year Treasury Constant Maturities rate, effective on the first business day of each year, as published on the Federal Reserve Website. Deposits on inactive accounts are applied to the final bill when all service options become inactive, and the balance, if any, is refunded to the customer of record within thirty (30) days. For refunds resulting from the customer changing from Standard Offer to Direct Access, the difference in the deposit amounts will be applied to the customer's account.

2.7.5 If the customer terminates all service with Company, the security deposit may be credited to the customer's final bill.

2.7.6 Residential security deposits shall not exceed two (2) times the customer's average monthly bill as estimated by Company for the services being provided by the Company.

2.7.6.1 Deposits or other instruments of credit will automatically expire or be returned or credited to the customers account after twelve (12) consecutive months of service, provided the customer has not been delinquent more than twice, unless Customer has filed bankruptcy in the last 12 months.

2.7.7 Nonresidential security deposits shall not exceed two and one-half (2-1/2) times the customer's maximum monthly billing as estimated by Company for the service being provided by the Company.

2.7.7.1 Deposits and non-cash deposits on file with Company will be reviewed after twenty-four (24) months of service and will be returned provided the customer has not been delinquent more than twice in the payment of bills or disconnected for non-payment during the previous twelve (12) consecutive months unless the customer's financial condition warrants extension of the security deposit.

2.8 Line Extensions - Installations requiring Company to extend its facilities in order to establish service will be made in accordance with Company's Schedule #3, Conditions Governing Extensions of Electric Distribution Lines and Services filed with the Arizona Corporation Commission.

3. Rates

3.1 Rate Information - Company shall provide, in accordance with A.A.C. R14-2-204, a copy of any rate schedule applicable to that customer for the requested type of service. In addition, Company shall notify its customers of any changes in Company tariffs affecting those customers.

3.2 Rate Selection – The customer's service characteristics and service requirements determine the selection of applicable rate schedule. If the customer is being served on a Standard Offer rate, Company will use reasonable care in initially establishing service to the customer under the most advantageous Standard Offer rate schedule applicable to the customer. However, because of varying customer usage patterns and other reasons beyond its reasonable knowledge or control, Company cannot guarantee that the most economic applicable rate will be applied. Company will not make any refunds in any instances where it is determined that the customer would have paid less for service had the customer been billed on an alternate applicable rate or provision of that rate.

3.3 Standard Offer Optional Rates – Certain optional Standard Offer rate schedules applicable to certain classes of service allow the customer the option to select the rate schedule to be effective initially or after service has been established. A customer desiring service under an alternate rate schedule after service has been established must make such request in writing to Company. Billing under the alternate rate will become effective from the next meter reading, or when the appropriate metering equipment is installed. No further rate schedule changes, however, may be made within the succeeding twelve-month period. Where the rate schedule or contract pursuant to which the customer is provided service specifies a term, the customer may not exercise its option to select an alternate rate schedule until expiration of that term.

3.4 Direct Access rate selection will be effective upon the next meter read date if DASR is processed fifteen (15) calendar days prior to that read date and the appropriate metering equipment is in place. If a DASR is made less than fifteen (15) days prior to the next regular read date the effective date will be at the next meter read date thereafter. The above timeframes are applicable for customers changing their selection of Electric Service Providers or for customers returning to Standard Offer service.

3.5 Any customer making a Direct Access rate selection may return to Standard Offer service in accordance with the rules, regulations, and orders of the Commission. However, such customer will not be eligible for Direct Access for the succeeding twelve (12) month period. If a customer returning to Standard Offer, in accordance with the rules, regulations and orders of the Commission, was not given the required notification in accordance with the rules and regulations of the Commission by their Load Serving ESP of its intent to cease providing competitive services then the above provision will only apply if the customer fails to select another ESP within sixty (60) days of returning to Standard Offer.

4. Billing and Collection

4.1 Customer Service Installation and Billing - Service billing periods normally consist of approximately 30 days unless designated otherwise under rate schedules, through contractual agreement, or at Company option.

4.1.1 Company normally meters and bills each site separately; however, adjacent and contiguous sites not separated by private or public property or right of way and operated as one integral unit under the same name and as a part of the same business, will be considered a single site as specified in Company's Schedule 4, Totalized Metering of Multiple Service Entrance Sections at a Single Site for Standard Offer and Direct Access Service.

4.1.2 The customer's service installation will normally be arranged to accept only one type of service at one point of delivery to enable service measurement through one meter. If the customer requires more than one type of service, or total service cannot be measured through one meter according to Company's regular practice, separate meters will be used and separate billing rendered for the service measured by each meter.

4.2 Collection Policy - The following collection policy shall apply to all customer accounts:

4.2.1 All bills rendered by Company are due and payable no later than fifteen (15) days from the billing date. Any payment not received within this time frame shall be considered delinquent. All delinquent bills for which payment has not been received shall be subject to the provisions of Company's termination procedure. Company reserves the right to suspend or terminate the customer's service for non-payment of any Arizona Corporation Commission approved services. All delinquent charges will be subject to a late charge at the rate of eighteen percent (18%) per annum.

4.2.2 If the customer, as defined in A.A.C. R 14-2-201.9 , has two or more services with Company and one or more of such services is terminated for any reason leaving an outstanding bill and the customer is unwilling to make payment arrangements that are acceptable to Company, Company shall be entitled to transfer the balance due on the terminated service to any other active account of the customer for the same class of service. The failure of the customer to pay the active account shall result in the suspension or termination of service thereunder.

4.2.3 Unpaid charges incurred prior to the customer selecting Direct Access will not delay the customer's request for Direct Access. These charges remain the responsibility of the customer to pay. Normal collection activity, including discontinuing service, may be followed for failure to pay.

4.3 Responsibility for Payment of Bills

4.3.1 The customer is responsible for the payment of bills until service is ordered discontinued and Company has had reasonable time to secure a final meter reading for those services involving energy usage, or if non-metered services are involved until the Company has had reasonable time to process the disconnect request.

4.3.2 When an error is found to exist in the billing rendered to the customer, Company will correct such an error to recover or refund the difference between the original billing and the correct billing. Such adjusted billings will not be rendered for periods in excess of the applicable statute of limitations from the date the error is discovered. Any refunds to customers resulting from overbillings will be made promptly upon discovery by Company. Underbillings by Company shall be billed to the customer who shall be given an equal length of time such as number of months underbilled to pay the backbill without late payment penalties, unless there is evidence of meter tampering or energy diversion. Except in situations where the account is billed on a special contract or non-metered rate, where service has been established but no bills have been rendered, or where there is evidence of meter tampering or energy diversion, underbillings for residential accounts shall be limited to three (3) months and non-residential accounts shall be limited to six (6) months.

4.3.3 Where Company is responsible for rendering the customer's bill, Company may provide a one time incentive of up to $10.00 per customer to customers who elect to pay their bills using Company's electronically transmitted payment options.

4.3.4 Where Company is responsible for rendering the customer's bill, Company may provide a one time incentive of $5.00 per customer for a customer electing to forego the presentation of a paper bill.

4.4 Dishonored Payments - If Company is notified by the customer's financial institution that they will not honor a payment tendered by the customer for payment of any bill, Company may require the customer to make payment in cash, by money order, certified check, or other means which guarantee the customer's payment to Company.

4.4.1 The customer shall be charged a fee of $15.00 for each instance where the customer tenders payment of a bill with a payment that is not honored by the customer's financial institution.

4.4.2 The tender of a dishonored payment shall in no way (i) relieve the customer of the obligation to render payment to Company under the original terms of the bill, or (ii) defer Company's right to terminate service for nonpayment of bills.

4.4.3 Where the customer has tendered two (2) or more dishonored payments in the past twelve (12) consecutive months, Company may require the customer to make payment in cash, money order or cashier's check for the next twelve (12) consecutive months.

4.5 Field Call Charge - Company may require payment of a Field Call Charge of $15.00 when an authorized Company representative travels to the customer's site to accept payment of a delinquent account, notify of service termination, make payment arrangements or terminate the service. This charge will only be applied for field calls resulting from the termination process.

4.5.1 If a termination is required at the pole, a reconnection charge of $100.00 will be required; if the termination is in underground equipment, the reconnection charge will be $125.00.

4.5.2 To avoid termination of service, the customer may make payment in full, including any necessary deposit in accordance with Section 2.5 hereof or make payment arrangements satisfactory to Company.

4.6 On-site Evaluation – Company may require payment of an On-site Evaluation Charge of $90.00 when an authorized Company field investigator performs an on-site visit to evaluate how the customer may reduce their energy usage. This charge may be assessed regardless of if the customer actually implements Company suggestions.

5. Service Responsibilities of Company and Customer

5.1 Service Voltage –Company will deliver electric service at the standard voltages specified in the Electric Service Requirements Manual published by Company and as specified in A.A.C. R14-2-208.F.

5.2 Responsibility: Use of Service or Apparatus

5.2.1 The customer shall save Company harmless from and against all claims for injury or damage to persons or property occasioned by or in any way resulting from the services being provided by Company or the use thereof on the customer's side of the point of delivery. Company shall have the right to suspend or terminate service in the event Company should learn of service use by the customer under hazardous conditions.

5.2.2 The customer shall exercise all reasonable care to prevent loss or damage to Company property installed on the customer's site for the purpose of supplying service to the customer.

5.2.3 The customer shall be responsible for payment for loss or damage to Company property on the customer's site arising from neglect, carelessness or misuse and shall reimburse Company for the cost of necessary repairs or replacements.

5.2.4 The customer shall be responsible for payment for any equipment damage and/or estimated unmetered usage resulting from unauthorized breaking of seals, interfering with, tampering with, or by-passing the meter.

5.2.5 The customer shall be responsible for notifying Company of any failure in Company's equipment.

5.3 Service Interruptions: Limitations on Liability of Company

5.3.1 Company shall not be liable to the customer for any damages occasioned by Load Serving ESP's equipment or failure to perform, fluctuations, interruptions or curtailment of electric service except where due to Company's willful misconduct or gross negligence. Company may, without incurring any liability therefore, suspend the customer's electric service for periods reasonably required to permit Company to accomplish repairs to or changes in any of Company's facilities. The customer needs to protect their own sensitive equipment from harm caused by variations or interruptions in power supply.

5.3.2 In the event of a national emergency or local disaster resulting in disruption of normal service, Company may, in the public interest and on behalf of Electric Service Providers or Company, interrupt service to other customers to provide necessary service to civil defense or other emergency service agencies on a temporary basis until normal service to these agencies can be restored.

5.4 Company Access to Customer Sites - Company's authorized agents shall have unassisted access to the customer's sites at all reasonable hours to install, inspect, read, repair or remove its meters or to install, operate or maintain other Company property, or to inspect and determine the connected electrical load. If, after six (6) months (not necessarily consecutive) of good faith efforts by Company to deal with the customer, Company in its opinion does not have unassisted access to the meter, then Company shall have sufficient cause for termination of service or denial of any existing rate options where access is required. The remedy for unassisted access will be at Company discretion and may include the installation by Company of a specialized meter. If such specialized meter is installed, the customer will be billed the difference between the otherwise applicable meter for their rate and the specialized meter. If service is terminated as a result of failure to provide unassisted access, Company verification of unassisted access may be required before service is restored.

5.5 Easements

5.5.1 All suitable easements or rights-of-way required by Company for any portion of the extension which is on sites owned, leased or otherwise controlled by the customer shall be furnished in Company's name by the customer without cost to Company and in reasonable time to meet proposed service requirements. All easements or rights-of-way obtained on behalf of Company shall contain such terms and conditions as are acceptable to Company.

5.5.2 When Company discovers that the customer or the customer's agent is performing work, has constructed facilities, or has allowed vegetation to grow adjacent to or within an easement or right-of-way or Company-owned equipment, and such work, construction, vegetation or facility poses a hazard or is in violation of federal, state, or local laws, ordinances, statutes, rules or regulations, or significantly interferes with Company's safe use, operation or maintenance of, or access to, equipment or facilities, Company shall notify the customer or the customer's agent and shall take whatever actions are necessary to eliminate the hazard, obstruction, interference or violation at the customer's expense.

5.6 Load Characteristics – The customer shall exercise reasonable care to assure that the electrical characteristics of its load, such as deviation from sine wave form (a minimum standard is IEEE 519) or unusual short interval fluctuations in demand, shall not impair service to other customers or interfere with operation of telephone, television, or other communication facilities. The deviation from phase balance shall not be greater than ten percent (10%) at any time. Customers receiving service at voltage levels below 69 kV shall maintain a power factor of 90% lagging but in no event leading unless agreed to by Company. In situations where Company suspects that a customer's load has a non-conforming power factor, Company may install at its cost the appropriate metering to monitor such loads. If the customer's power factor is found to be non-conforming, the customer will be required to pay the cost of installation and removal of VAR metering and recording equipment.

6. Metering and Metering Equipment

6.1 Customer Equipment - The customer shall install and maintain all wiring and equipment beyond the point of delivery. Except for Company's meters and special equipment, the customer's entire installation must conform to all applicable construction standards and safety codes and the customer must furnish an inspection or permit if required by law or by Company.

6.1.1 The customer shall provide, in accordance with Company's current service standards and/or Electric Service Requirements Manual, at no expense to Company, and close to the point of delivery, a sufficient and suitable space acceptable to Company's agent for the installation, accessibility and maintenance of Company's metering equipment. A current version of the Electric Service Requirements Manual is available on-line at http://esp.apsc.com/resource/metering.

6.1.2 If telephone lines or any other devices are required to read the customer's meter, the customer is responsible for the installation, maintenance, and usage fees at no cost to Company.

6.1.3 Where a customer requests, and Company approves, a special meter reading device to accommodate the customer's needs, the cost for such additional equipment shall be the responsibility of the customer.

6.2 Company Equipment

6.2.1 A Load Serving ESP or their authorized agents may remove Company's metering equipment pursuant to Company's Schedule 10. Meters not returned to Company or returned damaged will be charged the replacement costs less five (5) years depreciation plus an administration fee of fifteen percent (15%).

6.2.2 Company will lease lock ring keys to Load Serving ESP's and/or their agents authorized to remove Company meters pursuant to the terms and conditions of Company's Schedule 10 at a refundable charge of $70.00 per key. The charge will not be refunded if a key is lost, stolen, or damaged. If Company must replace ten percent (10%) of the issued keys within any twelve (12) month period due to loss by the ESP's agent, Company may, rather than leasing additional lock ring keys, require the ESP to arrange for a joint meeting. All lock ring keys must be returned to Company within five (5) working days if the Load Serving ESP and/or their authorized agents are:

1) No longer permitted to remove Company meters pursuant to conditions of the Company's Schedule 10;
2) No longer authorized by the Arizona Corporation Commission to provide services; or
3) The ESP Agreement has been terminated.

6.2.3 If the Load Serving ESP, the customer, and/or its' agent request a joint site meeting for removal of Company metering and associated equipment and/or lock ring, a base charge will be assessed of $70.00 per site. Company may assess an additional charge, based on the current hourly rate as determined by Company, for joint site meetings that exceed thirty (30) minutes. In the event Company must temporarily replace the ESP's meter and/or associated metering equipment as necessary during emergency situations or to restore power to a customer, the above charges may apply.

6.3 Service Connections - Company is not required to install and maintain any lines and equipment on the customer's side of the point of delivery except its meter. For overhead service, the point of delivery shall be where Company's service conductors terminate at the customer's weatherhead or bus rider. For underground service, the point of delivery shall be where Company's service conductors terminate in the customer's service equipment. The customer shall furnish, install and maintain any risers, raceways and/or termination cabinet necessary for the installation of Company's underground service conductors. For the mutual protection of the customer and Company, only authorized employees or agents of Company or the Load Serving ESP are permitted to make and energize the connection between Company's service wires and the customer's service entrance conductors. Such employees carry credentials which they will show on request.

6.4 Measuring Customer Service - All the energy sold to the customer will be measured by commercially acceptable measuring devices by Company or the Load Serving ESP pursuant to the terms and conditions of Company's Schedule 10. Where it is impractical to meter loads, such as street lighting, security lighting, or special installations, consumption will be determined by Company.

6.4.1 For Standard Offer customers, or where Company is the Meter Reading Service Provider (MRSP), the readings of the meter will be conclusive as to the amount of electric power supplied to the customer unless there is evidence of meter tampering or energy diversion, or unless a test reveals the meter is in error by more than plus or minus three percent (3%).

6.4.2 If there is evidence of meter tampering or energy diversion, the customer will be billed for the estimated energy consumption that would have registered had all energy usage been properly metered. Additionally, where there is evidence of meter tampering, energy diversion, or by-passing the meter, the customer may also be charged the cost of the investigation as determined by Company.

6.4.3 If after testing, a meter is found to be more than three percent (3%) in error, either fast or slow, proper correction shall be made of previous readings and adjusted bills shall be rendered or adjusted billing information will be provided to the ESP.

6.4.4 Customer will be billed for the estimated energy and demand that would have registered had the meter been operating properly. Where Company is the MRSP, Company shall, at the request of the customer or the ESP, reread the customer's meter within ten (10) working days after such request by the customer. The cost of such rereads is $20.00 and may be charged to the customer or the ESP, provided that the original reading was not in error.

6.4.5 Where the ESP is the Meter Service Provider (MSP) or (MRSP), and the ESP and/or its' agent fails to provide the meter data to Company pursuant to Company's Schedule 10 Section 8.16, Meter Reading Data Obligations, Company may obtain the data, or may estimate the billing determinants. The charge for such reread is $20.00 and may be charged to the ESP.

6.5 Meter Testing - Company tests its meters regularly in accordance with a meter testing and maintenance program as approved by the Arizona Corporation Commission. Company will, however, individually test a Company owned/maintained meter upon customer or ESP request. If the meter is found to be within the plus or minus three percent (3%) limit, Company may charge the customer or the ESP $30.00 for the meter test if the meter is removed from the site and tested in the meter shop, and $100.00 if the meter remains on site and is tested in the field.

6.6 Master Metering

6.6.1 Mobile Home Parks - Company shall refuse service to all new construction and/or expansion of existing permanent residential mobile home parks unless the construction and/or expansion is individually metered by Company.

6.6.2 Residential Apartment Complexes, Condominiums and Other Multiunit Residential Buildings - Company shall refuse service to all new construction of apartment complexes and condominiums which are master metered unless the building(s) will be served by a centralized heating, ventilation and/or air conditioning system and the contractor can provide to Company an analysis demonstrating that the central unit will result in a favorable cost/benefit relationship as stated in A.A.C. R14-2-205.

7. Termination of Service

7.1 With Notice - Company may without liability for injury or damage, and without making a personal visit to the site, disconnect service to any customer for any of the reasons stated below, provided Company has met the notice requirements established by the Arizona Corporation Commission:

7.1.1 A customer violation of any of the applicable rules of the Arizona Corporation Commission or Company tariffs.

7.1.2 Failure of the customer to pay a delinquent bill for services provided by Company.

7.1.3 The customer's breach of a written contract for service.

7.1.4 Failure of the customer to comply with Company's deposit requirements.

7.1.5 Failure of the customer to provide Company with satisfactory and unassisted access to Company's equipment.

7.1.6 When necessary to comply with an order of any governmental agency having jurisdiction.

7.1.7 Failure of a prior customer to pay a delinquent bill for utility services where the prior customer continues to reside on the premises.

7.1.8 Failure to provide or retain rights-of-way or easements necessary to serve the customer.

7.2 Without Notice - Company may without liability for injury or damage disconnect service to any customer without advance notice under any of the following conditions:

7.2.1 The existence of an obvious hazard to the health or safety of persons or property.

7.2.2 Company has evidence of meter tampering or fraud.

7.2.3 Company has evidence of unauthorized resale or use of electric service.

7.2.4 Failure of the customer to comply with the curtailment procedures imposed by Company during a supply shortage.

7.3 Restoration of Service - Company shall not be required to restore service until the conditions which resulted in the termination have been corrected to the satisfaction of Company.

8. Removal of Facilities - Upon termination of service, Company may without liability for injury or damage, dismantle and remove its facilities installed for the purpose of supplying service to the customer, and Company shall be under no further obligation to serve the customer. If, however, Company has not removed its facilities within one (1) year after the termination of service, Company shall thereafter give the customer thirty (30) days written notice before removing its facilities, or else waive any reestablishment charge within the next year for the same service to the same customer at the same location.

For purposes of this Section notice to the customer shall be deemed given at the time such notice is deposited in the U.S. Postal Service, first class mail, postage prepaid, to the customer at his/her last known address.

9. Successors and Assigns - Agreements for Service shall be binding upon and for the benefit of the successors and assigns of the customer and Company, but no assignments by the customer shall be effective until the customer's assignee agrees in writing to be bound and until such assignment is accepted in writing by Company.

10. Warranty - THERE ARE NO UNDERSTANDINGS, AGREEMENTS, REPRESENTATIONS, OR WARRANTIES, EXPRESS OR IMPLIED (INCLUDING WARRANTIES REGARDING MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE), NOT SPECIFIED HEREIN OR IN THE APPLICABLE RULES OF THE ARIZONA CORPORATION COMMISSION CONCERNING THE SALE AND DELIVERY OF SERVICES BY COMPANY TO THE CUSTOMER. THESE TERMS AND CONDITIONS AND THE APPLICABLE RULES OF THE ARIZONA CORPORATION COMMISSION STATE THE ENTIRE OBLIGATION OF COMPANY IN CONNECTION WITH SUCH SALES AND DELIVERIES.

SCHEDULE 2
TERMS AND CONDITIONS FOR ENERGY PURCHASES FROM QUALIFIED COGENERATION AND SMALL POWER PRODUCTION FACILITIES

The following TERMS AND CONDITIONS and any changes authorized by law, regulation, rule or order of applicable governmental authority will apply to the purchase of electric energy under the established rate or rates authorized by law and currently applicable at time of purchase; and these TERMS AND CONDITIONS shall be considered a part of all of Company's rate schedules for purchases except where specifically changed by written agreement.

1. <u>DEFINITIONS</u>

1.1 <u>Point Of Interconnection</u> - The point where Company's service conductors are connected to Customer's service conductors.

1.2 <u>Qualifying Facility (QF)</u> - Any cogeneration or small power production facility that meets the criteria for size, fuel use, efficiency, and ownership as promulgated in 18 CFR, Chapter I, Part 292, Subpart B of the Federal Energy Regulatory Commission's Regulations.

1.3 <u>Purchase Agreement</u> - The agreement entered into between Customer and Company detailing the provisions for the purchase of electric energy by Company from Customer's QF, and the sale, if any, of power by Company to Customer.

1.4 <u>Cogeneration Facility</u> - Any facility that sequentially produces electricity, steam or forms of useful energy (e.g., heat) from the same fuel source and which are used for industrial, commercial, heating, or cooling purposes.

1.5 <u>Small Power Production Facility</u> - A facility that uses primarily biomass, waste, or renewable resources, including wind, solar, and water to produce electric power.

2. <u>CUSTOMER'S OBLIGATIONS</u>

2.1 Customer agrees not to commence interconnected operation of its QF with Company's system, until the installation has been inspected by an authorized Company representative and final written approval is received from Company to commence interconnected operation. Customer shall give reasonable notice to Company when initial startup is to begin. Company shall have the right to have a representative present during initial energizing and testing of Customer's system.

2.2 Customer shall own and be fully responsible for the costs of designing, installing, operating and maintaining:

2.2.1 The QF in accordance with the requirements of all applicable electric codes, laws and governmental agencies having jurisdiction.

2.2.2 Control and protective devices to protect its facilities from abnormal operating conditions such as, but not limited to, electrical overloading, abnormal voltages, and fault currents. Such protective devices shall promptly disconnect the QF from Company's system in the event of a power outage on Company's system.

2.2.3 A gang operated load break disconnect switch, capable of being locked in a visibly open position that will completely isolate the QF from Company's system. Such disconnect switch shall be installed in a place easily accessible to Company's personnel. Company shall have the right to lock open the disconnect switch without notice to Customer when interconnected operation of the QF with Company's system could adversely affect Company's system or endanger life or property.

2.2.4 Interconnection facilities on Customer's premises as may be required to deliver power from Customer's QF to Company's system at the agreed Point Of Interconnection.

2.3 Electric sales to Company must be single or three phase, 60 Hertz, at one standard voltage (12,500; 2400/4160; 480; 277/480; 120/240 or 120/208 volts as may be selected by Customer subject to availability at the premises). Customer's facilities shall also maintain a minimum ninety percent (90%) leading to ninety percent (90%) lagging power factor as measured at the Point Of Interconnection.

2.4 The electrical output of Customer's QF shall not contain harmonic content which may cause disturbances on or damage to Company's electrical system, or other party's systems, such as but not limited to communication systems.

2.5 Customer shall operate and maintain the QF in accordance with those practices and methods, as they are changed from time-to-time, that are commonly used in prudent engineering and electric utility operations and shall operate the QF lawfully and in a safe, dependable and efficient manner.

2.6 Customer shall submit to Company written equipment specifications and detailed plans to Company for the installation and operations of its QF, interconnection facilities, control and protective devices and facilities to accommodate Company's meter(s) for review and advance written approval prior to their actual installation. After Company's approval Customer shall not change or modify equipment specifications, plans, control and protective devices, metering and in general the QF's system configuration. If Customer desires to make such changes or modifications, Customer shall resubmit to Company plans describing said changes or modifications for approval by Company. No such change or modification may be made without the prior written approval of Company.

2.7 In the event it is necessary for Company to install interconnection facilities on its system (including, but not limited to control or protective devices, or any other facilities) in order to receive or continue to receive or to deliver electric power under the terms of the Purchase Agreement, Company shall inform Customer of the cost thereof in advance of incurring the costs of such facilities and Customer shall reimburse Company for the costs incurred by Company in connection with such facilities to the extent that said costs exceed those normally incurred by Company with respect to those customers which it serves who do not have self generation facilities.

2.8 If Customer utilizes the Company's system to facilitate start-up of its QF, the voltage flicker level shall not exceed Company standards.

3. METERING PROVISIONS

3.1 Customer shall provide and install at no expense to Company, and in accordance with Company's service standards, meter sockets and metering cabinets in a suitable location to be determined by Company's representatives.

3.2 Company shall furnish, own, install and maintain all meters that register the sales of power to, and the purchases of energy from Customer. The responsibility for the costs of providing and maintaining the required meters shall be as outlined in the applicable Rate for Purchase, or as specified in the Purchase Agreement.

3.3 The readings of all said meters will be conclusive as to the amount of electric power and energy supplied to the QF and/or purchased by Company unless, upon test, the meters are found to be in error by more than three percent (3%). The expense of any meter test requested by Customer will be borne by Customer unless such test shows the meter(s) to be in error by more than three percent (3%).

4. MUTUAL UNDERSTANDINGS

4.1 Company shall be allowed to install on Customer's premises any instrumentation equipment for research purposes. Such equipment shall be owned, furnished, installed and maintained by Company.

4.2 Company's approvals given pursuant to the Purchase Agreement shall not be construed as any warranty or representation to Customer or any third party regarding the safety, durability, reliability, performance or fitness of Customer's generation and service facilities, its control or protective devices or the design, construction, installation or operation thereof.

4.3 Company (including its employees, agents, and representatives) shall have the right to enter Customer's premises at all reasonable times to (a) inspect Customer's QF, protective devices and to read or test instrumentation equipment that Company may install, provided that as reasonably possible, notice is given to Customer prior to entering its premises; (b) maintain Company equipment relative to the purchase of electric energy from Customer; (c) read or test the meters; and (d) disconnect the QF without notice if, in Company's opinion, a hazardous condition exists and such immediate action is necessary to protect persons, or Company's facilities or other customers' or third parties' property and facilities from damage or interference caused by Customer's QF, or improperly operating protective devices.

4.4 All suitable easements or rights-of-way (required by Company in order to accommodate inter-connection of Company's system with the QF), which are either on premises owned, leased or otherwise controlled by Customer, or upon other property, shall be furnished in Company's name by Customer without cost to or condemnation by Company and in reasonable time to meet the requirements of the Purchase Agreement. All easements or rights-of-way obtained on behalf of Company shall contain such terms and conditions as are acceptable to Company.

4.5 Company is not obligated to pay for electric energy or capacity from Customer during any periods when such purchases would result in costs greater than those which Company would otherwise incur had Company generated said energy itself or purchased the energy from another source. Company will give reasonable notice to Customer when such periods exist, so that Customer can discontinue deliveries of energy to Company or elect to continue to sell to Company at a rate, lower than the standard purchase rate, estimated to be the avoided system cost for the period during which such situations exist.

4.6 Company will not install and maintain any lines or equipment on Customer's side of the Point Of Interconnection except its meter (and possibly some research equipment). For the mutual protection of Customer and Company, only authorized employees of Company are permitted to make and energize the interconnection between Company's system and that of Customer's QF. Such employees carry credentials which they will show to Customer upon request.

4.7 The particular rate for purchases applicable to a QF may be dependent on the system configuration of its facilities. Because of the varied and diverse requirements and operating characteristics associated with such facilities, it will be the QF's responsibility to evaluate and determine which system configuration and attendant purchase rate is most appropriate. Company will cooperate with Customer by providing suitable information to enable the Customer to assess the options available; provided, however, that no such information or assistance shall be deemed a representation or warranty by Company with respect to the contents of such information or any particular option available to Customer.

4.8 Service billing periods normally consist of approximately 30 days unless designated otherwise under rate schedules or at Company's option.

4.9 The interconnection of Company's system with that of Customer will normally be arranged to accept only one type of standard service at one Point Of Interconnection. However, if Customer's QF requires a special type of service (e.g., supplemental, back-up, maintenance or interruptible power in addition to its normal service), or its sales to Company are at a different voltage level than that of its purchases from Company, such service(s) will be provided pursuant to the specific terms outlining such requirements in the Purchase Agreement, applicable rate schedules, and/or other supplemental or special terms and conditions governing such service.

4.10 Each premises owned or controlled by Customer which is served by Company under the Purchase Agreement shall be metered and billed separately. As used herein, the term "premises" shall be deemed to mean a single tract of land owned or controlled by Customer, or separate adjacent or contiguous tracts of land owned or controlled by Customer, operated by it as one tract under the same name or as part of the same business, and not separated by any private or public lands or rights-of-way owned or controlled by third parties.

4.11 All bills rendered for Company services provided to Customer under the provisions of the Purchase Agreement are due and payable upon presentation and are past due fifteen calendar days after mailing of bill. Company reserves the right to suspend or terminate Customer's service for non-payment of service bills past due, for non-payment of interconnection charges, and for non-payment of meter test charges. Past-due service bill amounts, past-due interconnection charges and past-due meter test charges, are subject to an additional charge at the rate of 1-1/2% per month during the period of delinquency.

5. SERVICE RENDERED UNDER SPECIAL AGREEMENT

Purchases will be made from Customer's QF in accordance with the Purchase Agreement, these terms and conditions and any changes required by law, regulation, rule, or order of applicable governmental authority, and such applicable rate or rates as may from time to time be authorized by law. However, in the case of QF's, whose requirements are of unusual size or characteristics, additional or special rate and contract arrangements may be required.

6. REGULATORY AUTHORITY

The rates, terms and other contract provisions governing electric power sold to Customer and the rates or other contract provisions for purchases by Company from Customer are subject to the jurisdiction of the Corporation Commission (ACC) and nothing contained herein shall be construed as affecting or limiting in any way the right of Company (a) to make unilateral filings of changed rates, terms and other contract provisions, which shall be effective when filed, or within a specified number of days thereafter as specified therein, such rates or other contract provisions specified in such filing to be subject to modification if required by a final decision of the ACC, or (b) to unilaterally make application to the ACC for changes in such rates or other contract provisions, following a hearing and decision as permitted by law and the ACC's rules and regulations.

7. INDEMNITY AND INSURANCE

Each Party hereby agrees to indemnify the other Party, its officers, agents, and employees against all loss, damages, expenses and liability to third persons for injury to or death of person or injury to or loss of property, proximately caused by the indemnifying Party's construction, ownership, operation, or maintenance of, or by failure of, any of such Party's works or facilities used in connection with the Purchase Agreement. The indemnifying Party shall, on the other Party's request, defend any suit asserting a claim covered by this indemnity. The indemnifying Party shall also pay all costs and expenses that may be incurred by the other Party in enforcing this indemnity.

8. UNCONTROLLABLE FORCES

No Party shall be considered to be in default in the performance of any of its obligations under the Purchase Agreement (other than obligations of said Party to pay sums to be paid by it hereunder, and other costs and expenses) when a failure of performance shall be due to an uncontrollable force. The term "uncontrollable force" shall be any cause beyond the control of the Party affected, including but not restricted to failure of or threat of failure of facilities, flood, earthquake, tornado, storm, fire, lightning, epidemic, war, riot, civil disturbance or disobedience, strikes, labor or material shortage, sabotage, restraint by court order or public authority, and action or non-action by or in- ability to obtain the necessary authorizations or approvals from any governmental agency or authority, which by exercise of due diligence such Party could not reasonably have been expected to avoid and which by exercise of due diligence it shall be unable to overcome. Nothing contained herein shall be construed so as to require a Party to settle any strike or labor dispute in which it may be involved. Either Party rendered unable to fulfill any of its obligations under this Agreement by reason of an uncontrollable force shall give prompt written notice of such fact to the other Party and shall exercise due diligence to remove such inability with all reasonable dispatch.

9. NOTICES

Any notice, demand or request required or permitted to be given by either Party to the other and any instrument required or permitted to be tendered or delivered by either Party to the other may be so given by certified or registered mail, addressed to the Party or personally delivered to the Party at the place designated in the applicable section of the Purchase Agreement. Changes in such designation may be made by notice similarly given.

10. CONFLICTS

10.1 In case of an inconsistency or conflict between any provision of the Purchase Agreement, a rate schedule and/or these terms and conditions, the inconsistency shall be resolved by giving priority to the Purchase Agreement, the rate and then the terms and conditions in said respective order.

11. SUCCESSORS AND ASSIGNS

Purchase Agreement shall be binding upon and for the benefit of the successors and assigns of Customer and Company, but no assignment by Customer shall be binding until accepted in writing by Company (which acceptance shall not be unreasonably withheld) and until the assignee in writing assumes the obligations of Customer under the Agreement.

SCHEDULE 3
CONDITIONS GOVERNING EXTENSIONS OF ELECTRIC DISTRIBUTION LINES AND SERVICES

Provision of electric service from Arizona Public Service Company (Company) may require construction of new facilities or upgrades to existing facilities. Costs for construction depend on the customer's location, load size, and load characteristics. This schedule establishes the terms and conditions under which Company will extend its facilities to provide new or upgraded facilities.

All extensions are made on the basis of economic feasibility. Construction allowance and revenue basis methodologies are offered below for use in circumstances where feasibility is generally accepted because of the number of extensions made within the construction allowance and dollar limits.

All extensions shall be made in accordance with good utility construction practices, as determined by Company, and are subject to the availability of adequate capacity, voltage and company facilities at the beginning point of an extension also as determined by Company.

The following policy governs the extension of overhead and underground electric facilities, and underground facilities as specified in Section 6, to customers whose requirements are deemed by Company to be usual and reasonable in nature.

1. <u>CONSTRUCTION ALLOWANCE - RESIDENTIAL ONLY</u>

1.1 <u>GENERAL POLICY</u> - Construction allowance extensions may be made only if all of the following conditions exist:

1.1.1 The applicant is a new permanent residential customer or group of new permanent residential customers. Customers specified in Section 4 below are not eligible for this allowance.

1.1.2 The total extension does not exceed a total construction cost of $25,000.

1.1.3 No construction allowance will be permitted beyond the shortest practical route to the nearest practical point of delivery on each customer's site as determined by Company.

1.2 <u>FREE EXTENSIONS</u> - May be made if the conditions specified in Section 1.1 are met and such free extension does not exceed a total construction cost of $3,500.

1.3 <u>EXTENSIONS OVER THE FREE ALLOWANCE</u>

For extensions which meet the conditions specified in Section 1.1 above, and which exceed the free Construction Allowance specified in Section 1.2, Company may extend its facilities up to the maximum allowed in Section 1.1.2 provided the customer or customers will sign an extension agreement and make a non-refundable contribution for the difference between the maximum allowed in Section 1.2 and Company's estimated cost of the extension.

2. <u>REVENUE BASIS - NON-RESIDENTIAL</u>

2.1 <u>GENERAL POLICY</u> - Revenue basis extensions may be made only if all of the following conditions exist:

2.1.1 Applicant is or will be a permanent customer or group of permanent customers. Customers specified in Sections 4.1, 4.2, or 4.3 are not eligible for this basis.

2.1.2 Such extension does not exceed a total construction cost of $25,000.

2.2 FREE EXTENSIONS

Such extension shall be free to the customer where the conditions specified in Section 2.1 herein are met and the estimated annual revenue based on Company's then currently effective rate for distribution service (excluding taxes, regulatory assessment and other adjustments) multiplied by six (6.0) is equal to or greater than the total construction cost less nonrefundable customer contributions.

2.3 EXTENSIONS OVER THE FREE LIMITS

For extensions which meet the conditions specified in Section 2.1, above, and which exceed the free limits specified in Section 2.1.2, Company may extend its facilities up to a cost limitation of $25,000, provided the customer or customers will sign an extension agreement and advance a sufficient portion of the construction cost so that the remainder satisfies the requirements of Section 2.2. Advances are subject to refund as specified in Section 5.

3. ECONOMIC FEASIBILITY BASIS

3.1 GENERAL POLICY - Extensions may be made on the basis of economic feasibility only if all of the following conditions exist:

3.1.1 The applicant is or will be a permanent customer or group of permanent customers. Customers specified in Sections 4.1, 4.2, or 4.3 are not eligible for this basis.

3.1.2 The total construction cost exceeds $25,000 except for extensions specified in Sections 4.4 or 7.7.

3.2 FREE EXTENSIONS

Such extensions shall be free to the customer where the conditions specified in Section 3.1 are met and the extension is determined to be economically feasible. "Economic feasibility", as used in this policy, shall mean a determination by Company that the estimated annual revenue based on Company's then currently effective rate for distribution service (excluding taxes, regulatory assessment and other adjustments) less the cost of service provides an adequate rate of return on the investment made by Company to serve the customer.

3.3 EXTENSIONS OVER THE FREE LIMITS

For extensions which meet the conditions specified in Section 3.1, above, Company, after special study and at its option, may extend its facilities to customers who do not satisfy the definition of economic feasibility as specified in Section 3.2, provided such customers sign an extension agreement and advance as much of the construction cost and/or agree to pay such higher special rate (facilities charge) as is required to make the extension economically feasible. Advances are subject to refund as specified in Section 5.

4. OTHER CONDITIONS

4.1 IRRIGATION CUSTOMERS

Customers requiring construction of electric facilities for service to agricultural irrigation pumping will advance the total construction cost. Advances are subject to refund as specified in Section 5.2. Non-agricultural irrigation pumping will be extended as specified in Section 2 or 3.

4.2 TEMPORARY CUSTOMERS

Where a temporary meter or construction is required to provide service to the customer, then the customer, in advance of installation or construction, shall make a non-refundable contribution equal to the cost of installing and removing the facilities required to furnish service, less the salvage value of such facilities. When the use of service is discontinued or agreement for service is terminated, Company may dismantle its facilities and the materials and equipment provided by Company will be salvaged and remain Company property.

4.3 DOUBTFUL PERMANENCY CUSTOMERS

When, in the opinion of Company, permanency of the customer's residence or operation is doubtful, the customer will be required to advance the total construction cost. Advances are subject to refund as specified in Section 5.3.

4.4 REAL ESTATE DEVELOPMENT

Extensions of electric facilities within real estate developments including residential sub divisions, industrial parks, mobile home parks, apartment complexes, planned area developments, etc., may be made in advance of application for service by permanent customers, as specified in Section 3. Anticipated revenue for Residential Real Estate extensions shall be calculated from information provided by the developer.

4.4.1 MOBILE HOME PARKS - Company shall refuse service to all new construction and/or expansion of existing permanent residential mobile home parks unless the construction and/or expansion is individually metered by the utility.

4.4.2 RESIDENTIAL APARTMENT COMPLEXES, CONDOMINIUMS AND OTHER MULTI UNIT RESIDENTIAL BUILDINGS - Company shall refuse service to all new construction and/or expansion of apartment complexes and condominiums unless the construction and/or expansion is individually metered by the utility. Master metering will only be allowed for buildings utilizing centralized heating, ventilation and/or air conditioning system where the contractor can provide an analysis demonstrating that the central unit will result in a favorable cost/benefit relationship as stated in R14-2-205 of Corporation Commission's Administrative Rules and Regulations.

5. REFUNDS

5.1 REVENUE AND ECONOMIC FEASIBILITY BASIS REFUNDS

5.1.1 Customer advances over $50.00 are subject to full or partial refund, provided that a survey based on conditions of the extension, not including laterals or extensions from the extension being surveyed as specified in Section 5.1.2 existing at the time of survey, results in an advance lower than the amount actually advanced. Except as provided for in Section 5.3, such surveys shall not be made for customers extended to under the basis specified in Section 4.1, 4.2, or 4.3. A survey will be conducted by Company five (5) years after signing the extension agreement under the extension policy in force at the time of the extension . Upon request, the customer will be entitled to intermediate surveys within the five (5) year period after the end of six (6) months following the date of signing the extension agreement and subsequent surveys at intervals of not less than one (1) year thereafter. Company will refund the difference between the amount advanced and the amount that would have been advanced had the advance been calculated at the time of survey. In no event shall the amount of any refund exceed the amount originally advanced.

5.1.2 Laterals or extensions from an extension being surveyed shall not be considered in the survey when the lateral or extension was extended on the basis "extensions over the free limits" of Sections 2.2 or 3.2, or is not connected directly to the extension being surveyed. In real estate developments extended to under the basis specified in Section 4.4, the survey may include laterals and extensions to serve permanent customers located within the real estate development described in the extension agreement for the extension being surveyed.

5.1.3 In lieu of surveys, Company will determine the refund based on the number of permanent connections to the extension for residential real estate development. In such event, Company shall specify in the extension agreement the amount of refund per permanent customer connection.

5.2 REFUNDS FOR EXTENSIONS TO IRRIGATION CUSTOMERS

Customer advances over $50.00 are subject to refund of twenty-five (25) percent of the annual accumulation of twelve (12) monthly bills based on Company's then currently effective rate for distribution service (excluding taxes, regulatory assessment and other adjustments) in excess of the annual minimum bill, for service to the irrigation pump specified in the agreement for the extension being surveyed, commencing with the date of signing the agreement. In no event shall the amount of any refund exceed the amount originally advanced.

5.3 REFUNDS TO CUSTOMERS OF DOUBTFUL PERMANENCY

Customer advances over $50.00 are subject to full or partial refund pursuant to surveys based on the Revenue or Economic Feasibility Basis as specified in Section 5.1.1. In no event shall the refund exceed twenty-five (25) percent of the annual accumulation of twelve (12) monthly bills based on Company's then currently effective rate for distribution service (excluding taxes, regulatory assessment and other adjustments) in excess of the annual minimum bill for the customer specified in the extension agreement. In no event shall the amount of any refund exceed the amount originally advanced.

5.4. GENERAL REFUND CONDITIONS

5.4.1 Customer advances of $50.00 or less are not subject to refund.

5.4.2 No refund will be made to any customer for an amount more than the unrefunded balance of the customer's advance.

5.4.3 Any unrefunded balance of the customer's advance shall become nonrefundable five (5) years from the date of Company's receipt of the advance.

5.4.4 Company reserves the right to withhold refunds to any customer whose account is delinquent and apply these refund amounts to past due bills.

6. UNDERGROUND CONSTRUCTION

6.1 GENERAL UNDERGROUND CONSTRUCTION POLICY - With respect to all underground installations, Company may install underground facilities only if all of the following conditions are met:

6.1.1 The extension meets feasibility requirements as specified in Sections 1, 2, 3, or 4.

6.1.2 The customer or developer provides all earthwork including, but not limited to, trench, boring or punching, conduits, backfill, compaction, and surface restoration in accordance with Company specifications.

(Company may provide all earthwork and the customer or developer will make a nonrefundable contribution equal to the cost of such work provided by Company.)

6.2 THREE-PHASE UNDERGROUND CONSTRUCTION - Where it is determined that three phase is required to serve the customer, Company may install three-phase facilities if the conditions specified in Section 6.1 are met, and the customer provides the following:

6.2.1 Installation of equipment pads, pull-boxes, manholes, and conduits as required in accordance with Company specifications. In lieu of providing conduits, the customer may provide a nonrefundable contribution equal to the estimated difference in cost between overhead and underground facilities.

6.2.2 A nonrefundable contribution for excess service footage required by the customer equal to the increased estimated cost of installed service lines over what would be required with a maximum 40-foot service at 480 volts and 20-foot service at 120/208 or 240 volts.

6.2.3 Transformer pad and secondary conduits in accordance with Company specifications. (Company may provide pad and conduits, and the customer or developer will make a non-refundable contribution equal to the cost of such work provided by Company.)

7. GENERAL CONDITIONS

7.1 VOLTAGE

The extension will be designed and constructed for operation at standard voltages used by Company in the area in which the extension is located.

7.2 THREE PHASE

Extensions for three phase service can be made under this extension policy where the customer has installed major three phase equipment. Motors with a name-plate rating of 7-1/2 HP or more or single air conditioning units of 6 tons or more or where total horsepower of all connected three phase motors exceeds 12 HP or total load exceeding 100 kVa demand shall qualify for three phase. If the estimated load is less than the above horsepower or connected kVa specifications, Company may, at its option and when requested by the customer, serve three phase and require a nonrefundable contribution equal to the difference in cost between single phase and three phase construction, but in no case less than $100.

7.3 EASEMENTS

All suitable easements or rights-of-way required by Company for any portion of the extension which is either on premises owned, leased or otherwise controlled by the customer or developer, or other property required for the extension, shall be furnished in Company's name by the customer without cost to or condemnation by Company and in reasonable time to meet proposed service requirements. All easements or rights-of-way obtained on behalf of Company shall contain such terms and conditions as are acceptable to Company.

7.4 GRADE MODIFICATIONS

If subsequent to construction of electric distribution lines and services, the final grade established by the customer or developer is changed in such a way as to require relocation of Company facilities or the customer's actions or those of his contractor results in damage to such facilities, the cost of relocation and/or resulting repairs shall be borne by Customer or developer.

7.5 OWNERSHIP

Except for customer-owned facilities, all construction, including that for which customers have made advances and/or contributions, will be owned, operated and maintained by Company.

7.6 MEASUREMENT AND LOCATION

7.6.1 Measurement must be along the proposed route of construction.

7.6.2 Construction will be on public streets, roadways, highways, or easements acceptable to Company.

7.6.3 The extension must be a branch from, the continuation of, or an addition to, one of Company's existing distribution lines.

7.7 UNUSUAL CIRCUMSTANCES

In unusual circumstances as determined by Company, when the application and provisions of this policy appear impractical, or in case of extension of lines to be operated on voltages other than specified in the applicable rate schedule, or when Customer's estimated load will exceed 3,000 kW, Company will make a special study of the conditions to determine the basis on which service may be provided. Additionally, Company may require special contact arrangements as provided for in Section 1.1 of Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Service.

7.8 NON-STANDARD CONSTRUCTION

Company's construction practices employ contemporary methods and equipment and meet current industry standards. Where extensions of electric facilities require construction that is in any way nonstandard, as determined by Company, or if unusual obstructions are encountered, the customer will make a non- refundable contribution equal to the difference in cost between standard and non-standard construction, in addition to other applicable costs involved.

7.9 ABNORMAL LOADS

Company, at its option, may make extensions to serve certain abnormal loads (such as: transformer-type welders, x-ray machines, wind machines, excess capacity for test purposes and loads of unusual characteristics), provided the customer makes a nonrefundable contribution equal to the total cost of such extension, including transformers.

7.10 RELOCATIONS AND/OR CONVERSIONS

7.10.1 Company will relocate or convert its facilities for the customer's convenience or aesthetics, providing the customer makes a nonrefundable contribution equal to the total cost of relocation or conversion.

7.10.2 When the relocation or conversion is in conjunction with added revenue, as determined by Company and is not for the customer's convenience or aesthetics, then the relocation or conversion costs plus the costs to serve will be used to determine the customers advance on the basis specified in Section 2 or 3.

7.11 CHANGING OF MASTER METER TO INDIVIDUAL METER

Company will convert its facilities from master metered system to a permanent individually metered system at the customer's request provided the customer makes a nonrefundable contribution equal to the residual value plus the removal costs less salvage of the master meter
facilities to be removed. The new facilities to serve the individual meters will be extended on basis specified in Section 2 or 3.

7.12 CHANGE IN CUSTOMER'S SERVICE REQUIREMENTS

Company will rebuild or revamp existing facilities to meet the customer's added load or change in service requirements on the basis specified in Section 2 or 3.

7.13 DESIGN DEPOSIT

Any applicant requesting Company to prepare detailed plans, specifications, or cost estimates may be required to deposit with Company an amount equal to the estimated cost of preparation. Where the applicant authorizes Company to proceed with construction of the extension, the deposit shall be credited to the cost of construction; otherwise the deposit shall be nonrefundable. Company will prepare, without charge, a preliminary sketch and rough estimate of the cost to be paid by the customer for a line extension upon request.

7.14 CUSTOMER CONSTRUCTION OF COMPANY DISTRIBUTION FACILITIES

The customer may provide construction related services, e.g. engineering, survey, materials and/or labor, associated with new distribution facilities to serve the customer's new or added load, provided the customer meets all of the requirements set forth by Company. All work and/or materials provided by the customer shall comply with Company standards in effect at the time of construction. The customer shall receive written approval from Company prior to performing any construction related services. Company will perform an Economic Feasibility Analysis prior to the approval of any proposed customer provided construction to ensure the proposed scope of work results in mutual benefits to the customer and Company.

7.15 SETTLEMENT OF DISPUTES

Any dispute between the customer or prospective customer and Company regarding the interpretation of these "Conditions Governing Extensions of Electric Distribution Lines and Services" may, by either party, be referred to the Arizona Corporation Commission or a designated representative or employee thereof for determination.

7.16 INTEREST

All advances made by the customer to Company in aid of construction shall be non-interest bearing.

7.16 EXTENSION AGREEMENTS

All line extensions requiring payment by the customer shall be in writing and signed by both the customer and Company.

7.17 ADDITIONAL PRIMARY FEED

Company will provide an additional primary (alternate) feed as requested by the customer provided the customer pays the added cost for the additional feed as a nonrefundable contribution in aid of construction and pays the applicable rate for the additional feed requested.

SCHEDULE 4
TOTALIZED METERING OF MULTIPLE SERVICE ENTRANCE SECTIONS AT A SINGLE SITE FOR STANDARD OFFER AND DIRECT ACCESS SERVICE

Arizona Public Service Company (Company) customers at a single site whose load requires multiple points of delivery through multiple service entrance sections (SESs) may be metered and billed from a single meter through Adjacent Totalized Metering or Remote Totalized Metering as specified in this schedule.

Totalized Metering (Adjacent or Remote) is the measurement for billing purposes on the appropriate rate, through one meter, of the simultaneous demands and energy of a customer who receives electric service at more than one SES at a single site.

A. Totalized metering will either be Adjacent or Remote and shall be permitted only if conditions 1 through 7 are all satisfied.

1. The customer's facilities must be located on adjacent and contiguous sites not separated by private or public property or right-of-way and must be operated as one integral unit under the same name and as a part of the same business or residence (these conditions must be met to be considered a single site, as specified in Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Service, Section 4.1.1) ; and

2. Power will generally be delivered at no less than 277/480 volt (nominal), three phase, four wire or 120/240 volt (nominal) single phase three wire; and

3. Three phase and single phase service entrance sections can not be combined for totalizing purposes; and

4. For Standard Offer customers, totalized metering must be accomplished by a physical wire interconnection of metering information with the customer providing conduit between the SES'; for Direct Access customers the customer's Electric Service Provider may provide electronically totalized demand and energy reads in compliance with Company's Schedule 10, Terms and Conditions for Direct Access; and

5. The customer shall provide vault or transformer space, which meets Company specifications, on the customer's property at no cost to Company; and

6. If the customer operates an electric generation unit on the premise, totalized metering will be permitted when the customer complies with all of Company's requirements for interconnection, pays all costs for any additional special metering required to accommodate such service from totalized service sections, and takes service on an applicable rate schedule for interconnected customer owned generation; and

7. Written approval by Company's authorized representative is required before totalized metering may be implemented.

B. Adjacent Totalized Metering will apply when conditions A.1-A.7 and the following conditions are met:

1. The customer's <u>total</u> load to be totalized requires a National Electrical Code (NEC) service entrance size of over 3,000 amps three phase or 800 amps single phase; and

2. Company requires that load be split and served from multiple SESs; and

3. The customer must locate SESs to be totalized within 10 feet of each other.

There will be no additional charge to the customer's monthly bill for Adjacent Totalized Metering.

C. Remote Totalized Metering will apply when conditions A.1-A.7 are met, multiple SESs are separated from one another by more than 10 feet, and the following conditions are met:

1. Each of the customer's service entrance sections to be totalized requires an NEC section size of 3,000 amps three phase or 800 amps single phase or greater; and

2. The customer's total load to be totalized has a minimum demand of 2,000 kVa or 1,500 kW three phase or 100 kVa or 80 kW single phase; and

3. The customer has made a non-refundable contribution for the net additional cost to Company of the meter totalizing connection and equipment.

When the total capital investment by Company to provide service at multiple points of delivery, as computed by Company, is equal to or less than the cost to serve a single point of delivery, then no additional monthly charge shall be made to the customer receiving Remote Totalized Metering. However, lower capital investment which results from the customer's contribution, other than the meter costs in C.3 above, shall not be considered.

For customers where the total capital investment by Company to provide service at multiple points of delivery, as computed by Company, is greater than the cost to serve at a single point of delivery, then there shall be an additional charge. The additional monthly charge for each delivery point above one shall consist of 1% of the totalized bill, plus $500.00, plus all applicable taxes and adjustments.

D. Removal of Totalized Metering Configuration

In some cases, it may be to the customer's benefit to remove all totalized metering equipment, or remove selected totalized metering equipment from the totalized account. This will be permitted under the following conditions:

1. The customer must submit a written request to Company stating the reason for the removal and the specific equipment to be removed.

2. After removal of the equipment, the customer may not ask for services to be totalized for one (1) year from the removal date. At the end of one (1) year, if the customer does request services to be totalized, the applicable conditions listed above must be met.

3. The customer will be required to make a nonrefundable contribution for the costs associated with the removal of the meter totalizing connection and equipment.

1. Company shall have no liability of obligation for claims arising out of the procedures for curtailment or interruption of electric service effected by it in accordance with such guidelines or such supplemental, amendatory or implementary guidelines or regulations as may hereafter be established and as provided by law.

2. Company shall endeavor to identify any electric customer(s) who might be classified as having either essential or critical loads. In the event that any customer of Company is dissatisfied by the classification of Customer by Company, or with the amount of such customer's load (if any) classifie4d by the Company as critical or essential, the Customer may bring the matter to either the Company or the Commission and request a determination in regard thereto. However, until such redetermination is made by the Commission or the Company, customer's original classification for purposes of electric curtailment under this Schedule shall be unaffected.

3. Company shall endeavor to, as circumstances permit and as further discussed in the Company's detailed Electric Load and Curtailment Plan, to notify County emergency personnel, or similar local authorities, of existing or developing situations involving the curtailment or interruption of APS customers pursuant to this Schedule #5.

4. DEFINITIONS

4.1 Essential Loads – Loads necessary to serve facilities used to protect the heath and safety of the public, such as: hospitals, 911 Centers, national defense installations, sewage facilities and domestic water facilities. Loads necessary to serve 911 Centers, police stations, and fire stations, which do not have independent back-up generation and require APS' electric service for operation of essential emergency equipment.

4.2 Critical Loads – That portion of the electric load of nonresidential customers, which in the event of 100 percent curtailment of service, would cause excessive damage to equipment or material being processed, or where such interruption would create grave hazards to employees or the public.

4.3 Major Use Customers/Others (With Notice) – Those customers having relatively large loads (over 1000 kW) or a substantial number of employees or other special circumstances that make it appropriate to schedule blackouts or curtailments different from typical customers. Customers who qualify as Major Use/Others (With Notice) can take 100 percent curtailment when sufficient notice is provided. These loads will be interrupted after the required notification period. "Sufficient", "required", and "appropriate" notice is that notice that APS, after consultation with the affected customer, has determined will allow the customer to curtail in a safe and efficient manner. Such notice necessarily varies from customer to customer.

4.4 Others (With or Without Notice) – All customers not meeting the above definitions. These customers will be interrupted (with or without notice) if voluntary curtailment measures are not sufficient to alleviate the situation.

5. GUIDELINES TO BE APPLICABLE IN EVENT OF INTERRUPTION OR CURTAILMENT OF ELECTRIC SERVICE BY COMPANY TO ITS CUSTOMERS DUE TO POWER SUPPLY INTERRUPTIONS, FUEL SHORTAGE OR TRANSMISSION EMERGENCY PURSUANT TO CORPORATION COMMISSION RULE R14-2-208, PROVISION OF SERVICE, PARAGRAPH E.

5.1 Operating Procedures Prior to Customer Load Curtailment

5.1.1 The following items shall be pursued concurrently.

5.1.1.1 Reschedule maintenance of transmission components and generating units, where practical.

5.1.1.2 Utilize spinning reserve.

5.1.1.3 Discontinue all non-firm wholesale sales during any period of involuntary curtailment or when an involuntary curtailment is anticipated.

5.1.1.4 Do not enter into any new wholesale sales during any period of involuntary curtailment or when an involuntary curtailment is anticipated.

5.1.1.5 Start all standby units.

5.1.1.6 Contact other utilities and/or agencies for emergency assistance.

5.1.1.7 Invoke emergency and short-term contractual schedules with other utilities and/or agencies.

5.1.1.8 Reduce system voltage, where practical.

5.1.1.9 Reduce non-essential Company uses such as flood lighting, sign lighting, display lighting, office lighting, electric cooling and heating, etc., where practical.

5.1.1.10 Provide information through the media or other appropriate medians to the public which will contain instructions on how customers can assist Company in case of an emergency power outage.

5.2 Voluntary Customer Load Curtailment

5.2.1 Public Appeal

5.2.1.1 An advisory message procedure will be used when Company has advance indications that it will not be able to meet future peak loads. These messages will request voluntary load reduction during specific hours on specific days.

5.2.1.2 An emergency bulletin procedure will be used for instant notification to the public in the event there is no advance indication of a power shortage. These bulletins will request the immediate voluntary cooperation of all customers in reducing electric loads.

5.2.1.2.1 These bulletins will request all customers to reduce the use of all electrically operated equipment and devices, where possible.

5.2.1.2.2 Company will have a prepared statement to read which will give current information on the Power Supply Interruption, Fuels Shortage or Transmission Emergency.

5.3 Contractually Interruptible Load

5.3.1 Company shall invoke contractual interruption provisions to the extent appropriate.

5.3.2 Company shall interrupt non-firm wholesale customer(s) as appropriate.

5.4 Involuntary Customer Load Curtailment

5.4.1 If the load reduction realized from application of the voluntary curtailment procedures is not sufficient to alleviate the power shortage, Company will reduce voltage if and to the extend practical and in accordance with normal applicable electric utility operation standards.

5.4.2 If further load reduction is required, load will be reduced as follows:

5.4.2.1 Circuits not classified with "Major Use/Others With Notice, Critical or Essential" customers will be interrupted on a rotating basis. The frequency and duration of such interruptions will be dependent upon the magnitude and nature of the power shortage. The frequency and duration of such interruptions shall also consider the circumstances of Major Use Customers.

5.4.2.2 Accurate records will be kept to ensure that these circuits are rotated in an equitable and technically feasible manner.

5.4.2.3 Circuits classified as "Major Use/Others" will be interrupted upon the giving of appropriate notice.

5.4.2.4 Customers on circuits which serve critical loads will be required to curtail the non-critical portion of their loads. Thereafter, circuits which serve critical loads will be identified and will not be interrupted unless an area must be dropped to maintain stability of the electric system. However, loads otherwise classifiable as critical may be curtailed if they possess back-up generation sufficient to meet their entire load requirement. If a customer having a critical load refuses or fails to curtail his electric consumption down to the critical load, he shall thereupon not be considered to have a critical load for purposes of this Schedule.

5.4.2.5 Circuits which serve essential loads will be identified and will not interrupted unless an area must be dropped to maintain stability of the electric system. However, loads otherwise classifiable as essential may be curtailed if they possess back-up generation sufficient to meet their entire load requirement.

5.5 Sudden Shortages of Power

In the event that time does not allow for the implementation of the Electric Curtailment Guidelines, Company may resort to its emergency operations procedures, with or without notice.

5.6 Automatic Load Shedding

In the event that there is a major electrical disturbance threatening the interconnected Southwest system with blackout conditions, emergency devices such as under frequency load shedding, transfer tripping, etc., will be utilized to maintain the optimum system stability.

6. ELECTRIC CURTAILMENT OF FIRM WHOLESALE CUSTOMERS

6.1 The term "firm wholesale customer" shall be defined as those APS customers who purchase, on a firm basis, electricity from the Company for purposes of resale.

6.2 In any given instance where a curtailment of wholesale power deliveries is involved, and subject to any required approvals of the Federal Energy Regulatory Commission or contractual provisions to the contrary, Company shall notify its firm wholesale customers, requesting that they curtail electric service to their retail customers during the period that Company's system is affected by power shortages. In the event that Company is unable to obtain the cooperation of a firm wholesale customer, it may seek an order from appropriate governmental authority requiring the firm wholesale customer to accept a reduction of electricity deliveries proportionate to the curtailment being effected on Company's system.

7. ELECTRIC LOAD AND CURTAILMENT PLAN

A detailed electric load and curtailment plan shall be kept on file with the Arizona Corporation Commission. This plan shall contain specific procedures for implementation of the above, along with the name(s) and telephone number(s) of the appropriate Company personnel to contact in the event implementation of the plan becomes necessary. This plan shall be updated at least annually, and it or amendments thereto shall become effective upon submission to the Arizona Corporation Commission.

7.1 Company shall contact the Director, Utilities Division, or their designee, as soon as practical for any curtailment pursuant to this Schedule #5.

SCHEDULE 7
ELECTRIC METER
TESTING AND MAINTENANCE PLAN

General Plan

This schedule establishes a monitoring plan for electric meters in order to ensure an acceptable degree of performance in the registration of the energy consumption of Arizona Public Service Company (Company) customers. Company will file an annual report with the Arizona Corporation Commission summarizing the results of the performance monitoring plan.

Specific Plan

1. Single-Phase Self Contained Meters - Non-Solid State Hybrids and Electro-Mechanical

   1.1 Meters shall be separated into groups having common physical attributes and the average performance of each group will be determined based on the weighted average of the meter's percentage registration at light load (LL) and at full load (FL) giving the full load registration a weight factor of four (4).

   Reference: ANSI C12.1-2001 sections 5.1.4 through 5.1.5.4 or as may be amended by ANSI

   1.2 Analysis of the test results for each group evaluated shall be done in accordance with the statistical formulas outlined in ANSI/ASQC Z1.9 – 1993 Formulas B-3, Tables A-1, A-2 and B-5. The minimum sample size shall be 100 meters when possible.

2. Single Phase Self Contained Meters – Solid State

   Company will monitor performance of these types of meters through the Company Metering and Billing systems.

3. Three Phase Self-Contained Meters - Non-Solid State Hybrids and Electro-Mechanical

   Company shall monitor installations with the following types of meters for accuracy and recalibrate as necessary according to the following schedule:

   3.1 Three-phase meters with surge-proof magnets and without demand registers or pulse initiators: 16 years.

   3.2 Three phase block-interval demand-register-equipped kWh meters with surge-proof magnets: 12 years.

   3.3 Three phase lagged-demand meters: 8 years.

4. Three Phase Self-Contained Meters – Solid State

   Company will monitor performance for these types of meters through the Company Metering and Billing systems.

5. Three Phase Transformer-Rated Meter Installations – Solid State Hybrids and Electro-Mechanical

Company will conduct a periodic testing program whereby three phase transformer-rated meter installations along with their associated equipment shall be inspected and tested for accuracy according to the following schedule:

5.1 Installations with 500 to 1,000 kW load: 4 years.

5.2 Installations with 1001 kW to 2000 kW load: 2 years.

5.3 Installations over 2000 kW load: 1 year.

The following terms and conditions and any changes authorized by law will apply to Arizona Public Service Company (Company), Energy Service Providers (ESPs), and their agents that participate in Direct Access under the Arizona Corporation Commission's (ACC) rules for retail electric competition (A.A.C. R14-2-1601, *et seq.*, referred to herein as the "Rules"). "Direct Access customer" refers to any Company retail customer electing to procure its electricity and any other ACC authorized Competitive Services directly from ESPs as defined in the Rules.

Customer Selections

All Company retail customers shall obtain service under one of two options:

1. Standard Offer Service. With this election, retail customers will receive all services from Company, including metering, meter reading, billing, collection and other consumer information services, at regulated rates authorized by the ACC. Any customer who is eligible for Direct Access who does not elect to procure Competitive Services shall remain on Standard Offer Service. Direct Access customers may also choose to return to Standard Offer Service after having elected Direct Access.

2. Competitive Services (Direct Access). This service election allows customers who are eligible for Direct Access to purchase electric generation and other Competitive services from an ACC certificated ESP. Direct Access customers with single premise demands greater than 20 kW or usage of 100,000 kWh annually will be required to have Interval Metering, as specified in Section 3.6.1. Pursuant to the Rules, and any restrictions herein, the ESP serving these customers will have options available for choosing to offer Meter Services, Meter Reading Services and/or Billing Services on their own behalf (or through a qualified third party), or to have Company provide those services (when permitted by the Rules) as specified within.

1. General Terms

1.1. Definitions. The definitions of principal terms used in this Schedule shall have the same meaning as ascribed to them in the Rules, unless otherwise expressly stated in this Schedule.

1.1.1. Customer - Unless otherwise stated, all references to Customer in this agreement refer to Company customers who are eligible for and have elected Direct Access.

1.1.2. Service Account - Unless otherwise stated, all references to "Service Account" in this agreement shall refer to an installed service, identified by a Universal Node Identifier (UNI).

1.1.3. Local Arizona Time – All time references in this Schedule are in Local Arizona Time, which is Mountain Standard Time (MST).

2. General Obligations of Company

2.1. Non-Discrimination

2.1.1. Company shall discharge its responsibilities under the Rules in a non-discriminatory manner as to providers of all Competitive Services. Unless otherwise authorized by the ACC, the Federal Energy Regulatory Commission ("FERC") or applicable affiliate transactions rules, Company shall not:

2.1.1.1. Represent that its affiliates or customers of its affiliates will receive any different treatment with regard to the provision of Company services than other, unaffiliated services providers as a result of affiliation with Company; or

2.1.1.2. Provide its affiliates, or customers of its affiliates, any preference based on the affiliation including but not limited to terms and conditions of service, information, pricing or timing over non-affiliated suppliers or their customers in the provision of Company services.

2.2. Transmission and Distribution Service

Company will offer transmission and distribution services under applicable tariffs, schedules and contracts for delivery of electric generation to Direct Access customers under the provisions of State law, the terms of the ACC's Rules and Regulations, this Schedule, the ESP Service Acquisition Agreement, applicable tariffs and applicable FERC rules.

3. General Obligations of ESPs

3.1. Timeliness, Due Diligence and Security Requirements

3.1.1. ESPs shall exercise due diligence in meeting their obligations and deadlines under the Rules to facilitate customer choice. ESPs shall make all payments owed to Company in a timely manner.

3.1.2. ESPs shall adhere to all credit, deposit and security requirements specified in the ESP Service Acquisition Agreement and Company tariffs and schedules.

3.2. Arrangements with ESP Customers

ESPs shall be solely responsible for having appropriate contractual or other arrangements with their customers necessary to implement Direct Access. Company shall not be responsible for monitoring, reviewing or enforcing such contracts or arrangements.

3.3. Responsibility for Electric Purchases

ESPs will be responsible for the purchase of their Direct Access customers' electric generation needs and the delivery of such purchases to designated receipt points as set forth on schedules given to the Scheduling Coordinators ("SCs").

3.4. Company Not Liable for ESP Services

To the extent the customer elects to procure services from an ESP, Company has no obligations to the customer with respect to the services provided by the ESP.

3.5. Load Aggregation for Procuring Electric Generation/Split Loads

3.5.1. ESPs may aggregate individually-metered electric loads for procuring competitive electric generation only. Load aggregation shall not be used to compute Company charges or for tariff applicability.

3.5.2. Customers requesting Direct Access Services may not partition the electric loads of a Service Account among electric service options or providers. The entire load of a Service Account must be provided by only one (1) ESP. This provision shall not restrict the use of separate parties for metering and billing services.

3.6. Interval Metering

3.6.1. "Interval Metering" refers to the purchase, installation and maintenance of electricity metering equipment capable of measuring and recording minimum data requirements, including hourly interval data required for Direct Access settlement processes and distribution billing. Interval Metering is required for all customers that elect Direct Access and reach a single site maximum demand in excess of 20 kW one or more times or annual usage of 100,000 kWh or more. Interval Metering is provided by the ESP, at no cost to Company. Interval Metering is optional for those customers with single site maximum demands that are 20 kW or less or annual usage of less than 100,000 kWh.

3.6.2. Company shall determine if Customer meets the requirements for Interval Metering based on historical data, or an estimated calculation of the demand and/or usage for new customers.

3.7. Meter Data Requirements

Minimum meter data requirements consist of data required to bill Company distribution tariffs and determine transmission settlement. Company shall have access to meter data necessary for regulatory purposes or rate-setting purposes pursuant to mutually agreed upon terms with the ESP for such data access.

3.8. Statistical Load Profiles

Pursuant to R14-2-1604(B)(3) Company will offer statistical load profiles in place of Interval Metering, for qualifying Customers to estimate hourly consumption for settlement and scheduling purposes. Statistical load profiles will be applied as authorized by FERC.

3.9 Fees and Other Charges

Direct Access customers shall pay all applicable fees, surcharges, impositions, assessments and taxes on the sale of energy or the provisions of other services as authorized by law. The ESP and Company will each be respectively responsible for paying such fees to the taxing or regulatory agency to the extent it is their obligation to do so. Both the ESP and Company will be responsible for providing the authorized billing agent the information necessary to bill these charges to the customer.

3.10. Liability In Connection With ESP Services

3.10.1. "Damages" shall include all losses, harm, costs and detriment, both direct and indirect, and consequential, suffered by Customer or third parties.

3.10.2. Company shall not be liable for any damages caused by Company conduct in compliance with, or as permitted by, Company's electric rules and tariffs, the ESP Service Acquisition Agreement, the Rules, and associated legal and regulatory requirements related to Direct Access service, or as otherwise set forth in Company Schedule #1.

3.10.3. Company shall not be liable for any damages caused to Customer by any ESP, including failure to comply with Company's electric rules and tariffs, the ESP Service Acquisition Agreement, the Rules, and associated legal and regulatory requirements related to Direct Access service.

3.10.4. Company shall not be liable for any damages caused by the ESP's failure to perform any commitment to Customer.

3.10.5. An ESP is not a Company agent for any purpose. Company shall not be liable for any damages resulting from acts, omissions, or representations made by an ESP in connection with soliciting customers for Direct Access or rendering Competitive Services.

3.10.6 Under no circumstances shall Company be liable to Customer, ESP (including any entity retained by it to provide competitive services to the customer) or third parties for lost revenues or profits, indirect or consequential damages or punitive or exemplary damages in connection with Direct Access Services. This provision shall not limit remedies otherwise available to customers under Company's schedules and tariffs and applicable laws and regulations.

4. Customer Inquiries and Data Accessibility

4.1 Customer Inquiries – For customers requesting information on Direct Access, Company shall make available the following information:

4.1.1 Materials to consumers about competition and consumer choices.

4.1.2 A list of ESPs that have been issued a Certificate of Convenience and Necessity to offer Competitive Services within Company's service territory. Company will provide the list maintained by the ACC, but Company is under no obligation to assure the accuracy of this list. Reference to any particular ESP or group of ESPs on the list shall not be considered an endorsement or other form of recommendation by Company.

4.2. Access to Customer Usage Data. For Company customers on Standard Offer Service, Company shall provide customer specific usage data to ESP or to Customer, subject to the following provisions:

4.2.1. ESPs may request Customer usage data prior to submission of a Direct Access Service Request ("DASR") by obtaining and submitting to Company the Customer's written authorization on a Customer Information Service Request ("CISR") form. Company may charge for customer usage data.

4.2.2. Company will provide the most recent twelve (12) months of customer usage data or the amount of data available for that Customer if there is less than twelve (12) months of usage history.

4.3 Customer Inquires Concerning Billing Related Issues

4.3.1 Customer inquiries concerning Company charges or services shall be directed to Company.

4.3.2 Customer inquiries concerning ESP charges or services shall be directed to the ESP.

4.4. Customer Inquiries Related to Emergency Situations and Outages

4.4.1. Company shall be responsible for responding to all Standard Offer Service or, in the case of Direct Access customers, distribution service emergency system conditions, outages and safety situation inquiries related to Company's distribution system. Customers contacting an ESP with such inquiries are to be referred directly to Company for resolution. ESPs performing consolidated billing must show Company's emergency telephone number on their bills.

4.4.2. Company may shed or curtail customer load as provided by its ACC-approved tariffs and schedules, or by other ACC rules and regulations.

5. ESP Service Establishment

5.1. Before the ESP or its agents can offer Direct Access services in Company distribution service territory they must meet the applicable provisions as listed:

5.1.1. All ESPs must obtain a Certificate of Convenience and Necessity from the ACC which authorizes the ESP to offer Competitive Services in Company's distribution service territory.

5.1.2. All ESPs must register to do business in the State of Arizona and obtain all other licenses and registrations needed as a legal predicate to the ESP's ability to offer Competitive Services in Company's distribution service territory.

5.1.3. Load Serving ESPs must satisfy creditworthiness requirements as specified in the ESP Service Acquisition Agreement if the ESP chooses the ESP Consolidated Billing option. If the ESP chooses Company UDC Consolidated Billing, they must enter into a Customized Billing Services Agreement.

5.1.4 Load Serving ESPs must enter into an ESP Service Acquisition Agreement with Company.

5.1.5. All ESPs must satisfy any applicable ACC electronic data exchange requirements including:

5.1.5.1. The ESP and/or its designated agents must complete to Company's satisfaction all necessary electronic interfaces between the ESP and Company to exchange DASRs and general communications.

5.1.5.2. The ESP or its agent must complete to Company's satisfaction all electronic interfaces between the ESP and Company to exchange meter reading and usage data. This includes communication to and from the Meter Reading Service Provider's (MRSP) server for sharing of meter reading and usage data.

5.1.5.3. The ESP must have the capability to electronically exchange data with Company. Alternative arrangements may be acceptable at Company's option.

5.1.5.4. The ESP and its agents must use Electronic Data Interchange (EDI) using Arizona Standard Formats to exchange billing and remittance data with Company when offering ESP Consolidated Billing or Company UDC Consolidated Billing. The ESP and its agents must use the Arizona Standard Format to exchange meter reading data with Company when providing meter reading services. Alternative arrangements may be allowed at Company's option.

5.1.6. For Company UDC Consolidated Billing or ESP Consolidated Billing options, compliance testing is required. Both parties must demonstrate the ability to perform data exchange functions required by the ACC and the ESP Service Acquisition Agreement. Any change of the billing agent will require a revalidation of the applicable compliance testing. Provided the ESP is acting diligently and in good faith, its failure to complete such compliance testing shall not affect its ability to offer electric generation to Direct Access customers. Dual Company/ESP Billing will be performed until the compliance testing is completed to Company's satisfaction.

5.1.7. Compliance testing will be required for a Load Serving ESP or its MRSP when providing meter reading services to ensure that meter data can be delivered successfully. Any change of the MRSP's system, or any change to the Arizona Standard 867 EDI format, will require a revalidation of the applicable compliance testing.

6. Direct Access Service Request (DASR)

6.1 A DASR is submitted pursuant to the terms and conditions of the Arizona DASR Handbook, the ESP Service Acquisition Agreement and this section, and shall also be used to define the Competitive Services that the ESP will provide the customer.

6.2 ESPs shall have a CC&N from the ACC; shall have entered into an ESP Service Acquisition Agreement with Company, if required, and shall have successfully completed data exchange compliance testing before submitting DASRs.

6.3 The customer's authorized ESP must submit a completed DASR to Company before Customer can be switched from Standard Offer Service or Competitive Service provided by another ESP. The DASR process described herein shall be used for customer Direct Access elections, updates, cancellations, customer-initiated returns to Company Standard Offer Service, or requests for physical disconnection of service and ESP- or customer-initiated termination of an ESP/customer service agreement.

6.4. A separate DASR must be submitted for each service delivery point. Each of the five (5) DASR operation types [Request (RQ), Termination of Service Agreement (TS), Physical Disconnect (PD), Cancel (CL) and Update/Change (UC)] has specific field requirements that must be fully completed before the DASR is submitted to Company. A DASR that does not contain the required field information or is otherwise incomplete may be rejected. In accordance with the provisions of the applicable Service Acquisition Agreement, Company may deny the ESP or customer request for service if the information provided in the DASR is false, incomplete, or inaccurate in any material respect. ESPs filing DASRs are thereby representing that they have their customer's authorization for such transaction.

6.5. Company requires that DASRs be submitted electronically using Electronic Data Interchange (EDI) or Comma Separated Value (CSV) formats through the Company's web site (http://esp.apsc.com).

6.6. DASRs will be handled on a first-come, first-served basis. Each request shall be time and date stamped when received by Company.

6.7. Once the DASR is submitted, the following timeframes will apply:

6.7.1. Company will respond to RQ, TS, CL and UC DASRs within two (2) working days of the time and date stamp. Company will exercise best efforts (no later than five (5) working days) to provide the ESP with a DASR status notification informing them whether the DASR has been accepted, rejected or placed in a pending status awaiting further information. If accepted, the effective switch date will be determined in accordance with Sections 6.8, 6.9, and 6.12 and will be confirmed in the response to the ESP and the former ESP if applicable. If a DASR is rejected, Company shall provide the reasons for the rejection. If a DASR is held pending further information, it shall be rejected if the DASR is not completed with the required information within thirty (30) working days, or a mutually agreed upon date, following the status notification. Company will send written notification to the customer once the RQ DASR has been processed.

6.7.2. When a customer requests electric services to be disconnected, the ESP is responsible for submitting a PD DASR to Company on behalf of the customer, regardless of the Meter Service Provider (MSP).

6.7.2.1. When Company is acting as the MSP, Company shall perform the physical disconnect of the service. The PD DASR must be received by Company at least three (3) working days prior to the requested disconnect date. Company will acknowledge the PD DASR status within two (2) working days of the time and date stamp.

6.7.2.2 When Company is not acting as the MSP, the ESP is responsible for performing the physical disconnect. The ESP shall notify Company by DASR of the date of the physical disconnect. Disconnect reads must be posted to the server within three (3) working days following the disconnection.

6.8. DASRs that do not require a meter exchange must be received by Company at least fifteen (15) calendar days prior to the next scheduled meter read date. The actual meter read date would be the effective switch date. DASRs received less than fifteen (15) calendar days prior to the next scheduled meter read date will be scheduled for switch to Direct Access on the following month's read date.

6.9 DASRs that require a meter exchange will have an effective change date to Direct Access as of the meter exchange date. Notification of meter exchange dates shall be coordinated between the ESP, MSP and Company's Meter Activity Coordinator ("MAC").

6.10. If more than one (1) RQ DASR is received for a service delivery point within a Customer's billing cycle, only the first valid DASR received shall be processed in that period. All subsequent DASRs shall be rejected.

6.11. Upon acceptance of an RQ DASR, a maximum of twelve (12) months of customer usage data, or the available usage for that customer switching from Standard Offer, shall be provided to the ESP. If there is an existing ESP currently serving that customer, that ESP shall be responsible for submitting the customer usage data to the new ESP. In both cases, the customer usage data will be submitted to the appropriate ESP no later than five (5) working days before the scheduled switch date.

6.12. Customers returning to Company Standard Offer service must contact their ESP. The ESP shall be responsible for submitting the DASR on behalf of the customer.

6.13. ESPs requesting to return a Direct Access customer to Company Standard Offer service shall submit a TS DASR and shall be responsible for the continued provision of the customer's electric supply service, metering, and billing services until the effective change date.

6.14. Customers requesting to return to Company Standard Offer service are subject to the same timing requirements as used to establish Direct Access Service.

6.15. Company may assess a fee for processing DASRs. All fees are payable to Company within fifteen (15) calendar days after the invoice date. All unpaid fees received after this date will be assessed applicable late fees pursuant to Schedule 1. If an ESP fails to pay these fees within thirty (30) days after the due date, Company may suspend accepting DASRs from the ESP unless a deposit sufficient to cover the fees due is currently available or until such time as the fees are paid. If an ESP is late in paying fees, a deposit or an additional deposit may be required from the ESP.

6.16. A customer moving to new premises may retain or start Direct Access immediately. The customer must first contact Company to establish a Service Account. The customer will be provided the necessary information that will enable its ESP to submit a DASR. The same timing requirements apply as set forth in Section 6.8 and 6.9.

6.17. Billing and metering option changes are requested through a UC DASR and cannot be changed more than once per billing cycle.

6.18. Company shall not hold the ESP responsible for any customer unpaid billing charges prior to the customer's switch to Direct Access. Unpaid billing charges shall not delay the processing of DASRs and shall remain the customer's responsibility to pay Company. Company's Schedule 1 applies in the event of customer non-payment, which includes the possible disconnection of distribution services. Company shall not accept any DASRs submitted for customers who have been terminated for nonpayment and have not yet been reinstated. Disconnection by Company of a delinquent customer shall not make Company liable to the ESP or third-parties for the customer's disconnection.

6.19 Company shall not accept DASRs that specify a switch date of more than sixty (60) calendar days from the date the DASR is submitted.

7. Billing Service Options and Obligations

7.1 ESPs may select among the following billing options:

7.1.1 COMPANY UDC CONSOLIDATED BILLING

7.1.2 ESP CONSOLIDATED BILLING

7.1.3 DUAL COMPANY/ESP BILLING

7.2 COMPANY UDC CONSOLIDATED BILLING

7.2.1 The customer's authorized ESP sends its bill-ready data to Company, and Company sends a consolidated bill containing both Company and ESP charges to the Customer.

7.2.2 Company Obligations:

7.2.2.1 Company shall bill the ESP charges and send the bill either by mail or electronic means to the customer. Company is not responsible for computing or determining the accuracy of the ESP charges. Company is not required to estimate ESP charges if the expected bill ready data is not received nor is Company required to delay Company billing. Billing rendered on behalf of the ESP by Company shall comply with A.A.C. R14-2-1612.

7.2.2.2 Company bills shall include in Customer's bill a detailed total of ESP charges and applicable taxes, assessments and billed fees, the ESP's name and telephone number, and other information provided by the ESP.

7.2.2.3 If Company processes Customer payments on behalf of the ESP, the ESP shall receive payment for its charges as specified in Section 7.7.

7.2.3 ESP Obligations

7.2.3.1 Once a billing election is in place as specified in the ESP Service Acquisition Agreement, the ESP may offer Company UDC Consolidated Billing services to Direct Access customers pursuant to the terms and conditions of the applicable ACC approved tariff.

7.2.3.2. The ESP shall submit the necessary billing information to facilitate billing services under this billing option by Service Account, according to Company's meter reading schedule, and pursuant to the applicable tariff. Timing of billing submittals is provided for in Section 7.2.4 below.

7.2.4 Timing Requirements

7.2.4.1. Bills under this option will be rendered once a month. Nothing contained in this Schedule shall limit Company's ability to render bills more frequently consistent with Company's existing practices. However, if Company renders bills more frequently than once a month, ESP charges need only to be calculated based on monthly billing periods.

7.2.4.2. Except as provided in Section 7.2.4.1, Company shall require that all ESP and Company charges be based on the same billing period data.

7.2.4.3. ESP charges for normal monthly customer billing and any adjustments for prior months' metering or billing errors must be received by Company in EDI "810" format no later than 4:00 p.m. Local Arizona Time on the third working day following the Last Meter Read/First Bill Date. If billing charges have not been received from the ESP by this deadline, Company will render a bill for Company charges only. The ESP must wait until the next billing cycle, unless there is a mutual agreement for Company to send an interim bill. If Company renders the bill for Company charges only, Company will include a note on the bill stating that ESP charges will be forthcoming. An interim bill issued pursuant to this Section may also include a message that Company charges were previously billed.

7.2.4.4. ESP charges for a Physical Disconnect Final Bill must be received by 4:00 p.m. Local Arizona Time on the sixth working day following the actual disconnect date. If final billing charges have not been received from the ESP by this date, Company will render the customer's final bill for Company charges only, without the ESP's final charges. If Company renders the bill for Company charges only, Company will include a note on the bill stating that ESP charges will be forthcoming. The ESP must send the final charges to Company. Company will produce and send a separate bill for the final billing charges.

7.2.5. Restrictions

Company UDC Consolidated Billing shall be an option for individual customer bills only, not an aggregated group of customers. Nothing in this Section precludes each individual customer in an aggregated group, however, from receiving the customer's individual bills under Company UDC Consolidated Billing.

7.3. ESP CONSOLIDATED BILLING

7.3.1 Company calculates and sends its bill-ready data to the ESP. The ESP in turn sends a consolidated bill to its customer. The ESP shall be obligated to provide the customer detailed Company charges to the extent that the ESP receives such detail from Company. The ESP is not responsible for the accuracy of Company charges.

7.3.2 Company Obligations:

7.3.2.1 Company shall calculate all its charges once per month based on existing Company billing cycles and provide these to the ESP to be included on the ESP consolidated bill or as otherwise specified. Company and the ESP may mutually agree to alternative options for the calculation of Company charges.

7.3.2.2 Company shall provide the ESP with sufficient detail of its charges, including any adjustments for prior months' metering and billing error, by EDI "810" format. Company charges that are not transmitted to the ESP by 4:00 p.m. Local Arizona Time on the third working day following the Last Meter Read/First Bill Date need not be included in the ESP's bill. If Company's billing charges have not been received by such date, the ESP may render the bill without Company charges unless there is a mutual agreement to have the ESP send an interim bill to the customer including Company charges. The ESP will include a message on the bill stating that Company charges are forthcoming.

7.3.2.3 For a Physical Disconnect Final Bill, Company will provide the ESP with Company's final bill charges by 4:00 p.m. Local Arizona Time on the sixth working day following the actual disconnect date. If Company's billing charges have not been received by such date, the ESP may render the bill without Company charges. The ESP shall include a message on the bill stating that Company charges are forthcoming. Company will send the final bill charges to the ESP, and the ESP will produce and deliver a separate bill for Company charges.

7.3.3 ESP Obligations:

7.3.3.1 Once an ESP Service Acquisition Agreement is entered into, including an appropriate billing election, and all other applicable prerequisites are met, the ESP may offer consolidated billing services to Direct Access customers they serve.

7.3.3.2 The ESP bill shall include any billing-related details of Company charges. Company charges may be printed with the ESP bill or electronically transmitted. Billing rendered on behalf of Company by the ESP shall comply with A.A.C. R14-2-1612.

7.3.3.3 Other than including the billing data provided by Company on the customer's bill, the ESP has no obligations regarding the accuracy of Company charges or for disputes related to these charges. Disputed charges shall be handled according to ACC procedures.

7.3.3.4 The ESP shall process customer payments and handle collection responsibilities. Under this billing option, the ESP must pay all charges due to Company and not disputed by the customer as specified in Section 7.7.2.1.

7.3.3.5 Subject to the limitations of this Section and with the written consent of the Customer, the ESP may offer customers customized billing cycles or payment plans which permit the Customer to pay the ESP for Company charges in different amounts than Company charges to the ESP for any given billing period. Such plans shall not, however, affect in any manner the obligation of the ESP to pay all Company charges in full. Should Customer select an optional payment plan, all Company charges must be billed in accordance with A.A.C. R14-2-210(G).

7.3.4 Timing Requirements

ESPs may render bills more or less frequently than once a month. However, Company shall continue to bill the ESP each billing cycle period for the amounts due by the customer for that billing month.

7.4 DUAL COMPANY/ESP BILLING

Company and the ESP each separately bill the customer directly for services provided by them. The billing method is the sole responsibility of Company and the ESP. Company and the ESP shall process only the customer payments relating to their respective charges.

7.5 Billing Information and Inserts

7.5.1 All customers, including Direct Access customers, shall receive mandated legal, safety and other notices equally in accordance with A.A.C. R14-2-204 (B). If the ESP is providing consolidated billing, Company shall make available one (1) copy of these notices to the ESP for distribution to customers or, at the ESP's request, in electronic format to the ESP for production and communication to electronically billed Customers. If Company is providing Consolidated billing services, Company shall continue to provide these notices.

7.5.2 Under Company UDC Consolidated Billing, ESP bill inserts may be included pursuant to the applicable Company tariff.

7.6 Billing Adjustments for Meter and Billing Error

7.6.1 Meter and Billing Error

7.6.1.1 The MSP (including the ESP or Company if providing such services) shall resolve any meter errors and must notify the ESP and Company, as applicable, so any billing adjustments can be made. All other affected parties, including the appropriate Scheduling Coordinator, shall be notified by the ESP.

7.6.1.2 A billing error is the incorrect billing of Customer's energy or demand. If the MSP, MRSP, ESP or Company becomes aware of a potential billing error, the party discovering the billing error shall contact the ESP and Company, as applicable, to investigate the error. If it is determined that there is in fact a billing error, the ESP and Company will make any necessary adjustments and notify all other affected parties in a timely manner.

7.6.1.3 Company UDC Consolidated Billing

7.6.1.3.1 Company shall be responsible for notifying Customer and adjusting the bill for its charges to the extent those charges were affected by the meter or billing error.

7.6.1.3.2 The ESP shall be responsible for any recalculation of the ESP charges. Following the receipt of the recalculated charges from the ESP, the charges or credits will be applied to Customer's next normal monthly bill, unless there is mutual agreement to have Company send an interim bill to the Customer including the ESP's charges.

7.6.1.4 ESP Consolidated Billing

7.6.1.4.1 The ESP shall be responsible for notifying the Customer and adjusting the bill for ESP charges to the extent those charges were affected by the meter or billing error. The Customer shall be solely responsible for obtaining refunds of ESP electric generation overcharges from its current and prior ESPs, as appropriate.

7.6.1.4.2 Company shall transmit its adjusted charges and any refunds to the ESP with Customer's next normal monthly bill. The ESP shall apply the charges to Customer's next normal monthly bill, unless there is a mutual agreement to have the ESP send an interim bill to Customer including Company charges.

7.6.1.5 Dual Company/ESP Billing

7.6.1.5.1 Company and the ESP shall be separately responsible for notifying Customer and adjusting its respective bill for their charges.

7.7 Payment and Collection Terms

7.7.1 Company UDC Consolidated Billing

7.7.1.1 Company shall remit payments to the ESP for the total ESP charges collected from Customer within three (3) working days after Customer's payment is received. Company is not required to pay amounts owed to the ESP for ESP charges billed but not received by Company.

7.7.1.2 Customer is obligated to pay Company for all undisputed Company and ESP charges consistent with existing tariffs and other contractual arrangements for service between the ESP and the customer.

7.7.1.3 The ESP is responsible for all collections related to the ESP services on the Customer's bill, including, but not limited to, security deposits and late charges unless otherwise agreed upon in the customized billing services agreement between ESP and Company.

7.7.1.4 Payment for any Company charges for Consolidated Billing is due in full from the ESP within fifteen (15) calendar days of the date Company charges are rendered to the ESP. Any payment not received within this time frame will be assessed applicable late charges pursuant to Schedule 1. If an ESP fails to pay these charges prior to the next billing cycle, Company may revert the billing option for that ESP's customers to Dual Billing pursuant to Section 7.10.4. If an ESP is late in paying charges a deposit or additional deposit as provided for in Section 7.11 may be required.

7.7.2 ESP Consolidated Billing

7.7.2.1 Payment is due in full from the ESP within fifteen (15) calendar days after the date Company's charges are rendered to the ESP. The ESP shall pay all undisputed Company charges regardless of whether Customer has paid the ESP. All payments received after fifteen (15) calendar days will be assessed applicable late charges pursuant to Schedule 1. If an ESP fails to pay these charges prior to the next billing cycle, Company may revert the billing option for that ESP's customers to Dual Billing pursuant to Section 7.10.4. If an ESP is late in paying charges a deposit or additional deposit as provided for in Section 7.11 may be required.

7.7.2.2 Company shall be responsible for any follow-up inquiries with the ESP if there is question concerning the payment amount.

7.7.2.3 Company has no payment obligations to the ESP for Customer payments under ESP Consolidated Billing services.

7.7.3 Dual Company/ESP Billing

Company and the ESP are separately responsible for collection of Customer payment for their respective charges.

7.8 Late or Partial Payments and Unpaid Bills

7.8.1 Company UDC Consolidated Billing

7.8.1.1 Company shall not be responsible for ESP's Customer collections, collecting the unpaid balance of ESP charges from Customers, sending notices informing Customers of unpaid ESP balances, or taking any action to recover the unpaid amounts owed the ESP. The ESP shall assume any collection obligations and/or late charge assessments for late or unpaid balances related to ESP charges under this billing option.

7.8.1.2 All Customer payments shall be applied first to unpaid balances identified as Company charges until such balances are paid in full, then applied to ESP charges. A Customer may dispute charges as provided by A.A.C. R14-2-212, but a Customer will not otherwise have the right to direct partial payments between Company and the ESP.

7.8.1.3 ACC rules shall apply to late or non-payment of all Company customer charges. Undisputed Company delinquent balances owed on a customer account shall be considered late and subject to Company late payment procedures.

7.8.2 ESP Consolidated Billing

The ESP shall be responsible for collecting both unpaid ESP and Company charges, sending notices informing Customers of unpaid ESP and Company balances, and taking appropriate actions to recover the amounts owed. Company shall not assume any collection obligations under this billing option and ESP is liable to Company for all undisputed payments owed Company.

7.8.3 Dual Company/ESP Billing

Company and the ESP are responsible for collecting their respective unpaid balances, sending notices to Customers informing them of the unpaid balance, and taking appropriate actions to recover their respective unpaid balances. Customer disputes with ESP charges must be directed to the ESP and Customer disputes with Company charges must be directed to Company.

7.9 Service Disconnects and Reconnects

In accordance with ACC rules, Company has the right to disconnect electric service to the Customer for a variety of reasons, including, but not limited to, the non-payment of Company's final bills or any past due charges by Customer, or evidence of safety violations, energy theft, or fraud, by Customer. The following provides for service disconnects and reconnects.

7.9.1 Company shall notify Customer and Customer's ESP of Company's intent to disconnect electric service for the non-payment of Company charges prior to disconnecting electric service to the Customer. Company shall further notify the ESP at the time Customer has been disconnected. To the extent authorized by the ACC, a service charge shall be imposed on Customer if a field call is performed to disconnect electric service.

7.9.2 Company shall reconnect electric service for a fee when the criteria for reconnection have been met to Company's satisfaction. Company shall notify the ESP of a Customer's reconnection.

7.9.3 Company shall not disconnect electric service to Customer for the non-payment of ESP charges by Customer. In the event of non-payment of ESP charges by Customer, the ESP may submit a DASR requesting termination of the service agreement and request return to Company Standard Offer Service. Company will then advise the Customer that they will be placed on Company Standard Offer Service unless a DASR is received from another ESP on their behalf.

7.10. Involuntary Service Changes

7.10.1. A Customer may have its service of electricity, billing, or metering from an ESP changed to another provider, including Company, involuntarily in the following circumstances:

7.10.1.1. The ACC has decertified the ESP or the ESP otherwise receives an ACC order that prohibits the ESP from serving the customer.

7.10.1.2 The ESP, including its agents, has materially failed to meet its obligations under the terms of its ESP Service Acquisition Agreement with Company (including applicable tariffs and schedules) so as to constitute an Event of Default under the terms of the ESP Service Acquisition Agreement, and Company exercises its contractual right to terminate the ESP Service Acquisition Agreement.

7.10.1.3 The ESP has materially failed to meet its obligations under the terms of the ESP Service Acquisition Agreement (including applicable tariffs and schedules) so as to constitute an Event of Default and Company exercises a contractual right to change billing options.

7.10.1.4 The ESP ceases to perform by failing to provide schedules through a Scheduling Coordinator whenever such schedules are required, or the ESP fails to have a Service Acquisition Agreement in place with a Scheduling Coordinator.

7.10.1.5. The Customer fails to meet its Direct Access requirements and obligations under the ACC rules and Company tariffs and schedules.

7.10.2. Change of Service Election in Exigent Circumstances

In the event Company finds that an ESP or the Customer has materially failed to meet its obligations under this Schedule or the ESP Service Acquisition Agreement such that Company elects to invoke its remedies under Section 7.10 (other than termination of ESP Consolidated Billing under Section 7.10.1.3) and the failure constitutes an emergency (defined as posing a substantial threat to the reliability of the electric system or to public health and safety), or the failure relates to ESP's sale of unscheduled energy, Company may initiate a change in the Customer's service election, or terminate an ESP's ability to offer certain services under Direct Access. In such case, Company shall initiate the change or termination by preparing a DASR, but the change or termination may be made immediately notwithstanding the applicable DASR processing times set forth in this Schedule. Company shall provide such notice and opportunity to remedy the problem if there are reasonable circumstances prevailing. Additionally, Company shall notify the ACC of the circumstances that required the change or the termination and the resulting action taken by Company. The ESP and/or Customer shall have the right to seek an order from the ACC restoring the customer's service election and/or the ESP's ability to offer services. Unless expressly ordered by the ACC, the provisions of this section shall not disconnect electric service provided to Customer other than as provided in Section 4.4.2 .

7.10.3. Change in Service Election Absent Exigent Circumstances

7.10.3.1. In the event Company finds that an ESP has materially failed to meet its obligations under this Schedule or the ESP Service Acquisition Agreement such that Company seeks to invoke its remedies under Section 7.10 (other than termination of ESP Consolidated Billing under Section 7.10.1.3), and the failure does not constitute an emergency (as defined in Section 7.10.2) or involve an ESP's unauthorized energy use, Company shall notify the ESP and the ACC of such finding in writing stating the following:

7.10.3.1.1. The nature of the alleged failure;

7.10.3.1.2. The actions necessary to remedy the failure;

7.10.3.1.3. The name, address and telephone number of a contact person at the Company authorized to discuss resolution of the failure.

7.10.3.2. The ESP shall have thirty (30) calendar days from receipt of such notice to remedy the alleged failure or reach an agreement with Company regarding the alleged failure. If the failure is not remedied and no agreement is reached between Company and the ESP following this thirty (30) day period, Company may initiate the DASR process set forth in this Schedule to accomplish its remedy and shall notify the customers of such remedy. Unless expressly ordered by the ACC, the provisions of this section shall not disconnect electric service provided to the customer other than as provided in Section 4.4.2.

7.10.4. Termination of ESP Consolidated Billing

7.10.4.1. Company may terminate ESP Consolidated Billing under the following circumstances:

7.10.4.1.1. The Company shall notify affected Customers that ESP Consolidated Billing services will be terminated, and the Company may switch affected Customers to Dual Company/ESP billing as promptly as possible if any of the following occur:

7.10.4.1.1.1 Company finds that the information provided by the ESP in the ESP Service Acquisition Agreement is materially false, incomplete, or inaccurate.

7.10.4.1.1.2 The ESP attempts to avoid payment of Company charges.

7.10.4.1.1.3 The ESP files for bankruptcy.

7.10.4.1.1.4 The ESP fails to have an involuntary bankruptcy proceeding filed against the ESP dismissed within sixty (60) calendar days.

7.10.4.1.1.5 The ESP admits insolvency.

7.10.4.1.1.6 The ESP makes a general assignment for the benefit of creditors.

7.10.4.1.1.7 The ESP is unable to pay its debts as they mature.

7.10.4.1.1.8 The ESP has a trustee or receiver appointed over all, or a substantial portion, of its assets.

7.10.4.1.2. If the ESP fails to pay Company (or dispute payment pursuant to the procedures set forth in this Schedule) the full amount of all Company charges and fees by the applicable due date, Company shall notify the ESP of the past due amount within two (2) working days of the applicable past due date. If the ESP incurs late charges on more than two (2) occasions or fails to pay overdue amounts including late charges within five (5) working days of the receipt of notice by Company, Company may notify the ESP's customers and the ESP that ESP Consolidated Billing services will be terminated, and that Customers shall be switched to Dual Billing.

7.10.4.1.3. If the ESP fails to comply within thirty (30) calendar days of the receipt of notice from Company of any additional credit, security or deposit requirements set forth in Sections 5.1.3 and 7.11, Company may notify the ESP that ESP Consolidated Billing services will be terminated, and that Customers shall be switched to Dual Billing.

7.10.4.2. Upon termination of ESP Consolidated Billing pursuant to Section 7.10.4, Company may deliver a separate bill for all Company charges which were not previously billed by the ESP.

7.10.4.3 Company may reinstate the ESP's eligibility to engage in ESP Consolidated Billing upon a reasonable showing by the ESP that the problems causing the revocation of ESP Consolidated Billing have been cured, including payment of any late charges, reestablishing credit requirements in compliance with Sections 5.1.4 and 7.11, and payment to Company of all costs associated with changing ESP customers' billing elections to and from dual billing.

7.10.4.4 In the event Company terminates ESP Consolidated Billing, Company will return any security posted by the ESP pursuant to the ESP Service Acquisition Agreement.

7.10.5. Termination of Company UDC Consolidated Billing

7.10.5.1. Company may terminate Company UDC Consolidated Billing and revert to Dual Billing upon providing thirty (30) calendar days notice to an ESP if ESP fails to pay Company charges in connection with Company UDC Consolidated Billing or otherwise fails to comply with its obligations under Section 7.2.

7.10.5.2 Company may terminate Consolidated Billing upon providing thirty (30) days notice to an ESP if Company cancels or changes the tariff governing Company UDC Consolidated Billing.

7.10.6. Upon termination of ESP Direct Access services pursuant to Section 7.10, the provision of the affected service(s) shall be assumed by another eligible ESP from which the Customer elects to obtain the affected service(s). Absent an election by Customer, Company shall provide such services, until such time that Customer makes an election.

7.10.7. Company shall not use involuntary service changes in an anticompetitive or discriminatory manner.

7.11. ESP Security Deposits

7.11.1. Company may, at its discretion, require cash security deposits from any ESP that has on more than one occasion failed to pay Company charges or ACC-approved Direct Access charges within the established time frame, such as DASR fees, meter or billing error or service fees, and other fees applicable to an ESP through Schedule 10 and Company's other tariffs and schedules.

7.11.2. The amount of the security deposit required shall not exceed two and one-half times the estimated maximum monthly bill to the ESP for such charges, and a separate security deposit may be required for separate categories of ESP or Direct Access charges.

7.11.3. Security deposits required pursuant to Section 7.11 shall be in the form of a cash deposit accruing interest as specified in Section 2.7.4 of Company Schedule 1. Company shall issue the ESP a nonnegotiable receipt for the amount of the deposit.

7.11.4. Company may refuse to accept DASRs from, or provide other Company services to, an ESP that fails to comply within thirty (30) calendar days to a demand that the ESP establish a security deposit pursuant to Section 7.11.

8. Meter Services

8.1 Under Direct Access, ESPs may offer certain metering services for Direct Access implementation, including meter ownership, MSP and MSRP services.

8.2 Company has the right to offer the following meter services:

8.2.1 Metering and Meter Reading for Residential Load-Profiled Customers

8.2.2 Services as authorized by the ACC.

8.2.3 Company reserves the right to perform meter disconnects, regardless of meter ownership, in cases of potential safety hazards or non-payment for Company charges.

8.3 A Load Serving ESP may sub-contract Metering or Meter Reading Services to a certificated third party. If the ESP sub-contracts any of the components of these services to a third party, the ESP shall, for the purposes of this Schedule, remain responsible for the services.

8.4 Load Serving ESPs providing Metering or Meter Reading Services to Direct Access customers either on their own or through a third party assume full responsibility for meeting the applicable meter and communication standards, as well as assuming responsibility for the safe installation and operation of the meter and any personal injuries and damage caused to customer or Company property by the meter or its installation. This liability will lie with the ESP regardless of whether the ESP or its subcontractors perform the work.

8.5 Meter Specifications

8.5.1 The Director of Utilities Division of the ACC has determined the following specifications and standards shall apply to competitive metering where applicable (see Performance Metering Specifications and Standards document):

8.5.2 Metering standards (American National Standards Institute):

ANSI C12.1	Code for Electricity Metering
ANSI C12.6	Marketing & Arrangement of Terminals for Phase Shifting Devices used in Metering
ANSI C12.7	Watt-hour Meter Socket
ANSI C12.10	Electromechanical Watt-hour Meters
ANSI C12.13	Electronic TOU Registers for Electricity Meters
ANSI C12.18	Type 2 Optical Port
ANSI C12.20	0.2% & 0.5% Accuracy Class Meters
ANSI C37.90	Surge Withstand Test
ANSI 57.13	Instrument Transformers (All CTs & PTs)
ANSI Z1.4	Sampling Procedures and Tables for Inspection
ANSI Z1.9	Sampling Procedures and Tables for Inspection

8.5.3 EEI Electricity Metering Handbook

8.5.4 Electric Utilities Service Equipment Requirements Committee (EUSERC)

8.5.5 NEC & Local Requirements by jurisdictions

8.5.6 Company's Electric Service Requirements Manual (ESRM)

8.5.7 National Electrical Safety Code (NESC)

8.5.8 ESPs or their contractors providing competitive metering services shall also comply with such other specifications or standards determined to be applicable or appropriate by the ACC's Director of Utilities Division.

8.6 Meter Conformity

8.6.1 All Direct Access meters shall have a visual kWh display and must have a physical interface to enable on-site interrogation of all stored meter data. All meters installed must support the Company's rate schedules.

8.6.2 If Company is providing MRSP functions for the ESP, pursuant to the Rules, meters must be compatible with Company's meter reading system.

8.6.3 No meter or associated metering equipment shall be set or allowed to remain in service if it is determined that the meter or its associated equipment did not meet approved specifications, as set forth in Company's ESRM, or is in violation of any code listed in Section 8.5.

8.7 Meter Testing

8.7.1 If a manufacturer's sealed meter has not previously been set and the meter was tested within the last twelve (12) months, the meter shall be deemed in compliance with ACC standards without additional testing.

8.7.2 Any meter removed from service shall be processed according to the following table prior to its re-installation:

METER TYPE	REMOVAL REASON	ACTION REQUIRED
1 Ph kWh Electro-Mechanical	Routine	Meter Inspection
1 Ph kWh Electro-Mechanical	Trouble	Meter Test
1 Ph kWh Hybrid or Solid State	Routine	Meter Test
1 Ph TOU (all)	Trouble	Meter Test
3 Ph Meters (all)	All	Meter Test
1 Ph or 3 Ph IDR Meters	All	Meter Test

8.7.3 Meter tests are to be conducted in accordance with ANSI C12.1 recommended testing standards.

8.7.4 Records on meter testing shall be maintained by the MSP and provided to the requesting parties within three (3) working days of such a request for such records. The latest meter test record shall be kept as long as the meter is in service.

8.8 Meter Test Requests

Pursuant to A.A.C. R14-209(F), either party may request that the other party perform a meter test, in which instance the requesting party is entitled to witness the test if it so chooses. The requesting party shall be notified of the test date and written test results from the testing party. If the meter is found to be within ACC-approved standards, the requesting party shall reimburse the other party for all costs incurred in the process of testing the meter (per ACC approved tariffs). The MSP shall take reasonable measures to detect meter error. The MSP shall notify Company as soon as it becomes aware of any meter that is not operating in compliance with ACC performance specifications. The MSP shall make any repairs or changes required to correct the error. ESPs and Company shall use a form approved by the ACC Process Standardization Working Group (PSWG) to initiate and respond to such action.

8.9 Meter Identification

8.9.1 The ESP or its agent shall install a Company provided unique number on each meter. Company will provide the unique numbers printed on stickers in blocks of up to 1,000 numbers. These stickers must be readily visible from the front of the meter. The number assigned to that meter shall remain solely with that meter while in use in Company's service territory.

8.9.2 When an ESP installs either its own meter or a customer owned meter, the ring or lock ring must be secured with a blue seal that is imprinted with the name and/or logo of the ESP or their agent.

8.10 Installation of metering equipment

8.10.1 All metering equipment shall be installed according to all applicable ACC requirements and Company's Electric Service Requirements Manual.

8.10.2 An ESP or its agent must be authorized by Company to remove a Company owned meter. The Existing Meter Information (EMI) form will be sent to the ESP and MSP within five (5) working days within receiving the DASR acceptance notification indicating a pending meter exchange. When the MSP intends to remove a Company meter, Company must receive a Meter Data Communication Request (MDCR) format at least five (5) working days prior to the exchange. Upon completion of the meter exchange, the MSP will return the Meter Installation/Removal Notification (MIRN) form to Company by the end of business, three (3) working days from the day of the exchange.

8.10.3 The ESP or its agent shall inform Company of all meter activity, such as meter installations or exchanges, via the Meter Activity Coordination (MAC) Form within the time frames specified above. If final meter reads are not provided to Company, are inaccurate, or otherwise result in Company not being able to render accurate final bills to customers pursuant to ACC Rules and Regulations, the ESP shall be responsible for any unbilled, disputed, or unrecoverable amounts and applicable late charges.

8.10.4 The ESP or its agent shall return the existing meter to Company at one of Company's designated locations identified in the meter drop off list within fifteen (15) working days after its removal, or be charged the cost of the meter and metering equipment and /or any other charges per the applicable ACC-approved tariff. The ESP or its agent shall be responsible for damage to the meter occurring during shipment.

8.11 On-Site Inspections/Site Meets

8.11.1 Company may perform on-site inspections of meter installations. The ESP shall be notified if the inspections uncover any material non-compliance by the MSP with the approved specifications and standards.

8.11.2 For new construction, the party installing the meter shall ensure that the owner/builder has met the construction standards outlined in Company's ESRM, and Company's Transmission and Distribution construction manual, as well as local municipal agency requirements, and any updates, supplements, amendments and other changes that may be made to these manuals and requirements. Company shall perform a preinstallation inspection on all new construction. Local city/county clearances may also be required prior to energizing any new construction.

8.11.3 Company may require a site meet for: the exchange or removal of an IDR meter which requires an optical device to retrieve interval data; the exchange or removal of equipment at an existing totalized metering installation; a restricted access location for which Company forbids key access; cogeneration sites, bi-directional or detented metering sites; or upon request of an ESP or MSP. The ESP and Company's MAC shall coordinate the time of the site meet. If the ESP or MSP miss two (2) site meets, Company may cancel the applicable DASR. Company may charge for a site meet requested by the ESP or MSP, or if the ESP or MSP fails to arrive within thirty (30) minutes of the appointment time, or if the ESP fails to cancel a site meet at least one (1) working day in advance of the appointment time.

8.12 Meter Service Options and Obligations

8.12.1 Meter Ownership shall be limited to Company, an ESP, or the customer. The customer must obtain the meter through Company or an ESP. Although a customer may own the electric meter, maintenance and servicing of the metering equipment shall be limited to Company, the ESP, or the ESP's qualified representative (MSP).

8.12.2 Company shall own the CTs, PTs and associated equipment.

8.12.3 All CT-rated meter installations shall utilize safety test switches, and all self-contained commercial metering shall utilize safety-test blocks as provided in Company's ESRM. During meter exchanges, the ESP or its agent's employees who are certificated to perform the related MSP activities may install, replace or operate Company test switches and operate Company-sealed customer-owned test blocks.

8.13 Installation Options

8.13.1 The ESP is responsible for Direct Access customer meter installation. Company may optionally provide meter installation pursuant to the Rules.

8.13.2 ESPs or their agents must be certificated by the ACC in order to offer MSP services. The policies and procedures described in this Section 8.13 assume that the MSP and their meter installers have ACC certification. ESPs may elect to offer metering services by:

8.13.2.1 Becoming a certificated MSP.

8.13.2.2 Subcontracting with a third party that is a certificated MSP.

8.13.2.3 Subcontracting with Company under the circumstances described in Section 8.2.

8.14 As part of providing metering services, ESPs or their agents shall:

8.14.1 Obtain lock ring keys for meters originally installed by Company or request site meets with Company. Company will issue lock ring keys to certified MSPs upon receipt of a refundable deposit. The deposit will not be refunded if a key is either lost or stolen, and a fee will be applied to replace lost or damaged keys. For more information about the cost of lock rings, standard rings, or lock ring keys, please consult the Company MAC.

8.14.2 If lock rings are used they shall meet Company requirements. If a meter is installed and the readings are obtained from a source other than a physical inspection, a lock ring must be utilized. Lock rings may be purchased from Company.

8.14.3 Provide information to Company on the specifications and other specifics on meters not purchased from or installed by Company.

8.14.4 Allow Company to remove the customer's meter, or schedule a site meet to remove the meter transferring from Direct Access to Standard Offer service. If the ESP allows Company to remove meters, ESP shall coordinate with Company regarding the return of the meters.

8.14.5 Be responsible for obtaining and providing reads from any meter that it installs from the time it is installed to the time it is removed or until meter reading responsibilities are assumed by another ESP or the customer returns to Standard Offer service.

8.14.6 Ensure that ESP and MSP employees working in Company's territory follow ACC and other applicable safety standards.

8.14.7 Company shall notify the ESP immediately and the ESP shall notify Company immediately of any suspected unauthorized energy use when a safety hazard exists. In instances where there is not a safety hazard, each party will notify each other within twenty-four (24) hours. The ESP shall ensure that a lock ring is installed to secure any meter that does not require a monthly local (i.e., manual) meter read. The Parties agree to preserve any evidence of unauthorized energy use. Once unauthorized energy use is suspected, Company, in its sole discretion, may take any or all of the actions permitted under Company's tariffs and schedules and shall notify the ACC of any such action taken.

8.14.8 Take no action to impede Company's safe and unrestricted access to a customer's service entrance.

8.14.9 Glass over any socket when a meter is removed and a new meter is not installed.

8.15 MSRP Services provided as a responsibility of an ESP

Only certificated MRSP's acting on the ESP's behalf in accordance with ACC regulations shall perform MRSP functions. The MRSP for each Direct Access customer will be specified on the DASR received from the ESP. Any changes to Customers MRSP will be updated by the ESP with a "UC" DASR at least ten (10) days prior to the next schedules read date. MSRP obligations and responsibilities are stated in the ACC's Rules and Regulations and include:

8.15.1 Meter data for Direct Access Customers shall be read, validated, edited, and transferred pursuant to Arizona's Validation, Editing, and Estimation Process (VEE). It is the responsibility of the MRSP to comply with this process. In cases where validated data is unavailable for transfer by the posting deadline, it is the responsibility of the MRSP to provide an estimated data file for the entire read cycle until actual meter data is available. At such time as actual data becomes available, a corrected data file shall be posted immediately.

8.15.2 Both Company and the ESP shall have 24-hour/7 days per week access to the MRSP server.

8.15.3 Meter read data shall include beginning and ending reads as well as the validated usage for load-profiled customers. Validated interval data shall be provided for all interval metering customers. Data must be posted to the MRSP server using the Arizona Standard EDI "867" format. Estimated data shall contain applicable reason codes pursuant to the 867 guidelines.

8.15.4 The MRSP shall provide Company with access to meter data at the MRSP server as required to allow the proper performance of billing and settlement.

8.15.5 MRSPs must have a CC&N from the ACC authorizing it to offer MSRP services, and must be certified in Company territory.

8.15.6 MRSPs shall read Customer's meter based on the scheduled read date per Company's Yearly Meter Read Schedule. The billing cycle for each meter shall contain the full period from read date to the following read date. Interval data cycles shall be considered from 00:15 on the read date to 00:00 on the following read date (i.e. 9/1/00 00:15 through 10/1/00 00:00). The first complete interval timestamp shall begin at 00:15 in each cycle. For meter exchanges to Direct Access, the first complete interval through the first read date at 00:00 shall constitute the billing cycle. For meter exchanges back to Standard Offer, every interval shall be included up to the last full interval prior to the exchange. It is the responsibility of the MRSP to provide estimation of any intervals that are necessary to constitute the full billing cycle.

8.15.7 The MRSP shall provide re-reads or read verifies within ten (10) working days of a request by Company or Customer. The requesting party may be charged per the applicable ACC tariff if the original read was not in error.

8.16 Meter Reading Data Obligations

8.16.1 Accuracy for all meters.

8.16.1.1 Meter clocks shall be maintained according to Arizona time within +/- three (3) minutes of the National Time Standard.

8.16.1.2 Meter read date and time shall be accurate.

8.16.1.3 All meter reading data shall be validated with the pursuant to the approved Arizona VEE guidelines.

8.16.2 Timeliness for Validated Meter Reading Data

Pursuant to guidelines established by the Utilities Division Director, one hundred percent (100%) of the validated meter data shall be available by 3:00 p.m. Local Arizona Time (MST) on the third working day after the scheduled read date. If the meter data is not posted, is unavailable, or clearly contains errors by this deadline, the billing determinants including usage (kWh) and demand (kW) may be estimated by Company and the ESP shall be charged an approved charge for this service.

8.16.3 Proof of Operational Ability

Prior to performing MRSP services in Company's distribution service territory, or prior to making any significant change in MRSP service methodology, each MRSP will perform compliance testing to demonstrate its ability to read meters, validate data, edit data, estimate missing data and post validated data in Company-compatible EDI format to the MRSP server. In addition, upon installation of the initial meter on Direct Access accounts in Company's distribution service territory, each MRSP shall prove its ability to read its meters and post validated data in Company-compatible EDI format to the MRSP server. If the MRSP is unsuccessful in its attempts to meet these requirements, all subsequent requests for meter exchanges will be postponed until the MRSP successfully demonstrates its operational ability.

8.16.4 Retention and Format for Meter Reading Data

8.16.4.1 All meter reading data for a Customer shall remain posted on the MRSP server for five (5) working days and will be recoverable for at least three (3) years.

8.16.4.2 Meter reading data posted to the MRSP server shall be stored in Company-compatible EDI format.

8.17 Company performing MSP and MRSP functions:

If Company is eligible to perform Direct Access related MSP and MRSP functions as defined in section 8.2, the following restriction applies:

The validated meter read will be posted in EDI format no later than 6 working days following the scheduled read date.

8.18 Non-Conforming Meters, Meter Errors and Meter Reading Errors

8.18.1 Whenever Company, the ESP or its agents becomes aware of any non-conforming meters, erroneous meter services and/or meter reading services that impact billing, it shall promptly notify the other parties and the affected Customer. Bills found to be in error due to non-conforming meters or errors in meter services or meter reading services will be corrected by the appropriate parties.

8.18.2 In cases of meter failure or non-compliance, the ESP or its agents shall have five (5) working days to correct the non-compliance. If the non-compliance is not remedied within five (5) working days, the following actions may apply:

8.18.2.1 A site meeting may be required when services are being performed. The non-compliant party may be charged an ACC-approved tariff for the meeting.

8.18.2.2 Company may repair the defect, and the other party shall be responsible for all related expenses.

8.18.2.3 Company shall adhere to the approved Performance Monitoring Standards and follow the steps outlined to address non-compliance by an MRSP.

8.18.3 Company may refuse to enter into a new ESP Service Acquisition Agreement, or cancel an existing ESP Service Acquisition Agreement pursuant to section 7.10.1.1.2, with any ESP or its agents that has a demonstrated pattern of uncorrected non-compliance as established above. This provision shall not apply if the alleged demonstrated pattern of non-compliance or correction thereof is disputed and is pending before any agency or entity with jurisdiction to resolve the dispute.

SCHEDULE 15
CONDITIONS GOVERNING THE PROVISION OF SPECIALIZED METERING

Arizona Public Service Company (Company) will provide specialized metering upon customer request, provided the customer agrees to the following conditions:

1. The customer must contact their Company Account Representative to request and coordinate the purchase and installation of specialized metering such as KYZ pulse meters, IDR meters, or IDR and KYZ pulse meters. The customer must specify whether a modem will be required.

2. If the customer requests a meter with a modem option, the customer will be required to install communication equipment and connections which shall include a RJ11 or RJ12 jack. A coil of communication cable with either an RJ11 or RJ12 jack is to be provided within five to ten feet of the meter panel location and in such a manner that will provide for ease of attachment of the jack to the meter panel by Company. The phone line must be installed prior to the installation of the meter. The customer must provide Company with a phone number and any other communication access information to the meter(s) prior to Company installation of the meter(s).

3. If a customer requests kWh pulses, Company shall furnish an isolation relay and maintain the output wire and connections from this relay to an approved terminal block to be furnished by the customer. The terminal block shall be located in a lockable junction box mounted adjacent to (but not within) the Company metering compartment and not on the face of the Company metering panel.

4. The customer will be required to make a non-refundable contribution in aid of construction to Company for the requested meter(s) installation. The non-refundable contribution amount will be determined at the time of the request as follows:

   4.1 If a meter currently exists on the customer site, the charge is based on Company's total equipment and installation costs for the requested specialized metering less the equipment cost of Company's existing meter.

   4.2 If a meter has not been installed on the customer site, the charge is based on Company's total equipment and installation costs for the requested specialized metering less 100% of the AUC cost of a Company standard meter.

   4.3 If a specialized meter is existing on a customer's site and the customer requests an upgrade to a different type of meter, the customer will be responsible for 100% of the cost (installation and equipment) associated with the requested meter.

   Company will not place an order for a requested meter(s) until payment has been received from the customer. The typical lead time for procurement of meters is six (6) to eight (8) weeks. Once the requested meter(s) have been received, Company will schedule the installation of the meter(s) with the customer or a designated representative.

   Company will retain ownership of all meters and Company installed metering equipment.

   If a customer makes a nonrefundable contribution for the installation of a specialized meter and then terminates service or requests Company to remove and/or replace the specialized meter, the customer will not be eligible for a refund.

Company will provide general maintenance of the specialized meter; however, in the event the meter should become damaged, obsolete or inoperable, the customer will be responsible for 100% of the replacement cost (installation and equipment) associated with the specialized meter.

Company will not be responsible for the installation, maintenance, or usage fees associated with any phone lines or related communication equipment.

5. Under no circumstances shall the customer stop the operation or in any way affect or interfere with the operation of the isolation relay and the related output wiring. The integrity of Company's billing metering equipment within the sealed metering compartment shall be maintained.

6. Company reserves the right to interrupt the specialized metering circuit for emergencies or to perform routine or special tests or maintenance on its billing metering equipment, and in so doing assumes no responsibility for affecting the operation of the customer's demand control or other equipment. However, Company will make a good faith effort to notify the customer prior to any interruption of the specialized metering circuit.

7. The possible failure or malfunction of an isolation relay and subsequent loss of kWh contact closures to the customer's control equipment shall in no way be deemed to invalidate or in any way impair the accuracy and readings of Company's meters in establishing the kWh and demand record for billing purposes.

8. The accuracy of the customer's equipment is entirely the responsibility of the customer. Should the customer's equipment malfunction, Company will reasonably cooperate with the customer to the extent of assuring that no malfunction exists in Company's equipment. Work of this nature will be billed to the customer, unless the actual source of the malfunction is found within Company's equipment.

9. If Company provides pulse values in kWh, customer's equipment must be capable of readjustment or recalibration to adjust to new contact closure values and rates should it become necessary for Company to adjust the pulse values due to changes in Company's equipment.

10. No circuit for use by the customer shall be installed from Company's billing metering potential or current transformer secondaries.

11. Company reserves the right, without assuming any liability or responsibility, to disconnect and/or remove the pulse delivery equipment at any time upon 30 days written notice to the customer.

12. Upon request by Company, the customer shall make available to Company monthly load analysis information.

13. References to electric kWh pulses above shall mean isolation relay contact closures only; the customer is required to furnish operating voltage service. Isolation relay contacts are rated 5 amps, 28 volts DC or 120 volts AC.

14. The customer assumes all responsibility for, and agrees to indemnify and save Company harmless against, all liability, damages, judgments, fines, penalties, claims, charges, costs and fees incurred by Company resulting from the furnishing of specialized metering.

15. A waiver at any time by either party, or any default of or breach by the other party or any matter arising in connection with this service, shall not be considered a waiver of any subsequent default or matter.

16. Prior written approval by an authorized Company representative is required before electric kWh pulses service may be implemented.

APS-2

EXHIBIT

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APS-2

admitted

DIRECT TESTIMONY OF STEVEN M. WHEELER

On Behalf of Arizona Public Service Company

Docket No. E-01345A-03-_____

June 27, 2003

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DIRECT TESTIMONY OF STEVEN M. WHEELER
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-03-____)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, ADDRESS AND OCCUPATION.

A. My name is Steven M. Wheeler. I am Senior Vice President, Regulation, System Planning and Operations for Arizona Public Service Company ("APS" or "Company"). In that role, I am responsible for all rate and regulatory matters affecting the Company before the Arizona Corporation Commission ("Commission") and the Federal Energy Regulatory Commission ("FERC"). I am also responsible for the planning and operation of the APS transmission system and for the Company's resource planning in general.

Q. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. I received a Bachelors degree from Princeton University in 1971. I graduated from Cornell University School of Law in 1974. From 1974 until 2001, I was an attorney with Snell & Wilmer LLP in Phoenix, Arizona, involved in general business, real estate, environmental and public utility issues. During my 27 years at the firm, I represented APS and other public utilities in numerous state and FERC proceedings involving utility rate and service matters, generation and transmission siting, electric industry restructuring, resource planning and prudence reviews.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS PROCEEDING?

A. My testimony will summarize the substance of and philosophy behind the Company's rate request, with special attention to certain of the core issues that I hope will prompt a positive Commission response in this proceeding. In this regard, I will sponsor Schedules A-1 and D-4 of the Company's rate application. I also provide a statistical overview of APS and identify some of the Company's actions to maintain reliability, manage costs, improve efficiency, enhance customer service, promote safety and corporate responsibility, and support development of a competitive wholesale market in the Southwest. I further explain how the Company has accomplished these goals while still protecting APS customers from market uncertainties. Finally, I will discuss our understanding of the role of APS in the aftermath of the Commission's "Track A" Order, Decision No. 65154 (September 10, 2002).

Q. HAS APS SUBMITTED DIRECT TESTIMONY IN SUPPORT OF ITS APPLICATION?

A. Yes. In addition to my testimony, APS has filed testimony by the following witnesses in the following areas:

Donald G. Robinson:	Pro forma Adjustments and Financial Results
Ajit P. Bhatti:	Pinnacle West Energy Corporation ("PWEC") Assets
Chris N. Froggatt:	Cost of Capital, Accounting Issues and Total Working Capital
Laura L. Rockenberger:	Depreciation Study, Reconstruction Cost New (less) Depreciation ("RCND") Study and Lead/Lag Study
Alan Propper:	Cost of Service Study and Rate Design
David J. Rumolo:	Service Schedule Changes
Dr. William H. Hieronymus:	PWEC Assets
Dr. John H. Landon :	Evaluation of Wholesale Market Conditions
Dr. Charles E. Olson:	Cost of Equity
Dr. Kenneth Gordon:	Regulatory Policy and Vertical Integration

II. SUMMARY

Q. WOULD YOU PLEASE SUMMARIZE YOUR DIRECT TESTIMONY?

A. After more than a decade of rate reductions totaling some $ 1.74 billion, APS is compelled to seek higher revenues beginning in the third quarter of 2004. The requested 9.8% increase, or approximately $175 million on an annual basis, will, if granted, still leave APS rates below the level they were in 1989. In that same period, general inflation has increased the prices of other goods and services by some 51%. Although we all wish that lower and lower rates could continue indefinitely, we also know that to be an unreasonable and unrealistic scenario. The requested increase is necessary if APS is to continue as the type of financially strong utility that can ensure APS customers continued reliable service, on demand, and at reasonable prices into the future.

APS has based its rate request on a historical test period, calendar year 2002, and a cost of common equity of 11.5%. The use of such a test year is consistent with Commission rules and regulations, and the cost of equity is at the midpoint of the range found reasonable by Dr. Olson, the Company's cost of capital expert. For APS to recover its cost-of-capital, it must receive a fair rate of return of 6.67% on a fair value rate base of $5,467,466,000.

APS has made various adjustments, both up and down, to that test period. These adjustments will make the historical test period more representative of both a "typical" year and of the period in which the new rates authorized by the Commission will take effect.

Perhaps the most significant of those 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 throughout most of the period since the comprehensive settlement agreement between the Company and the Commission in 1999 ("1999 Settlement"). That 1999 Settlement resulted in the past five rate decreases implemented by APS, the last of which will take effect on July 1, 2003.

APS is also seeking to restore the $234 million write-off of prudently-incurred costs that resulted from the 1999 Settlement, as well as the full cost of preparing to divest its generation in conformance with both the 1999 Settlement and the Commission's Electric Competition Rules. With the Commission's decision modifying the terms of the 1999 Settlement, it is only fair that APS be fully compensated for its detrimental reliance.

Another issue presented in this proceeding is the Company's request to include certain PWEC generating assets into the APS rate base at cost-of-service. Those assets were prudently constructed to serve APS, have done so, and will be "used and useful" in providing service to the Company's customers in the future. Thus, I believe they are entitled to cost-of-service rate treatment under traditional criteria previously established by this Commission. Their construction by PWEC (rather than at APS) was necessary because of regulatory restrictions imposed on the Company, and their unification at APS serves to address one of most significant adverse consequences of the Track A Order. That Order prevented the Commission-mandated divestiture of APS generation to PWEC, which divestiture had been the fundamental reason for PWEC's existence and the basis upon which PWEC had undertaken the task of assuring the availability of reasonably-priced generation for APS customers. Along with reversal of the

1999 Settlement's $234 million write-off, rate basing the PWEC assets will significantly mitigate the unaddressed impacts resulting from that Order.

Rate basing the PWEC generation also helps to answer, in a positive and constructive manner, two critical questions insufficiently resolved by recent regulatory actions of the Commission and the Legislature: who is responsible for assuring reliable supplies of electricity to APS customers, and what are the permitted structures and means by which that obligation should be discharged? APS believes that its track record as a vertically-integrated utility—one with the ability to build, buy, or otherwise acquire resources that are thereafter recovered in rates based on their cost-of-service—provides a model that best fits Arizona's current circumstances and yet is consistent with the future development of the wholesale market. Such a structure also best serves and protects the reliability interests of APS customers. The wisdom of this model was recently reinforced by the results of the Commission's Track B solicitation, which demonstrated that the competitive market is as of yet too immature to assume the prominent role originally envisioned by the Electric Competition Rules and cannot be relied upon to reasonably meet APS customers' needs at all times and under all market conditions. Any Commission decision in this Docket should be consistent with maintaining and supporting the integration within APS of the generation necessary to serve APS customers.

APS is Arizona's largest electric utility. It has committed itself to the goals of reliability, value and customer service. The Company has taken many steps to further these goals and has been successful in achieving them. APS has accomplished this during the most difficult times in the history of the electric industry and in the face of unprecedented challenges created by Arizona's rapid growth. At the same time, APS has coped with changing regulatory regimes and the often-conflicting demands placed upon it by regulators. Yet, the Company has maintained its focus on customers, employees and public service.

Finally, APS has submitted its recently executed Track B power agreement with PWEC for Commission review as required by Section 3.4 of such agreement. Although promptly rate basing the PWEC assets essentially eliminates the need for the Commission to approve the contract and provide assurance of its future rate recovery, APS is making this filing to protect its rights under the PWEC contract, which is critical to meeting the needs of APS customers pending the Commission's consideration of the Company's rate request.

III. DESCRIPTION OF THE APS RATE REQUEST

A. Nature of the Request

Q. WOULD YOU PLEASE SUMMARIZE THE COMPANY'S REVENUE REQUEST?

A. APS is seeking to increase rates by some $175 million, or 9.8% on average, based on annualized test period sales. This produces a 6.67% return on the Company's fair value rate base of $5,467,466,000. *See* Schedule A-1 to the Application. Such return is equal to APS' cost-of-capital (expressed in terms of return on original cost rate base) of 8.67%. Consistent with Commission practice for many years, fair value rate base is simply the arithmetic average of original cost rate base and reconstruction cost new rate base. These two calculations are themselves sponsored by Mr. Robinson, Mr. Froggatt and Ms. Rockenberger.

APS has assigned the proposed increase on an equal percentage basis to all of the Company's major customer classes. However, specific rate schedules may receive greater or lesser increases and individual customers will experience larger or smaller impacts based on their individual circumstances.

The revenue requirement incorporates the Company's latest cost of capital. That cost of capital is, in turn, premised on an 11.5% cost of common equity, which is the mid-point of Dr. Olson's recommendation.

Other major components of the Company's rate filing include:

- the incorporation in rates of significant increases in fuel and purchased power costs, including the results of the recent purchases through the Commission's Track B process;
- the acquisition and rate basing of PWEC generation assets; and
- the recovery of amounts previously written off by APS in compliance with the terms of the 1999 Settlement, which settlement was thereafter modified by the Track A Order.

These latter two issues are closely linked to the need to address the consequences of the Commission's change of direction in the Track A Order and to bring some final closure to the 1999 Settlement. I will address in more detail all three of the above issues later in my testimony.

APS is requesting that its rate request become effective July 1, 2004. APS is also requesting the Commission approve new depreciation and amortization rates for certain of the Company's tangible and intangible property and to approve a specific accounting and ratemaking treatment of Statement of Financial Accounting Standards ("SFAS") No. 143 costs. Ms. Rockenberger discusses these specific requests in her direct testimony, and I will not further address these issues.

B. Philosophy of the Request

Q. WHAT IS APS' OVERALL GOAL IN THESE RATE PROCEEDINGS?

A. APS asks that the Commission establish rates in this proceeding that will allow the Company to have the financial integrity to continue its record of providing both current and future customers the reliability, reasonable prices, and customer service to which they are entitled. To achieve this, APS must be given a reasonable opportunity to earn, on a consistent basis, a fair return on the property and investment it has devoted to public service—a return that will enable APS to attract capital, both debt and equity, on reasonable terms to finance future expansion, replacement and technological innovation, and a return commensurate with businesses of comparable risk.

Please note that I have purposely intertwined three critical concepts into my statement of the Company's goals. Each is equally important, each is inseparable from the others, and each depends upon a combination of managerial skill and commitment with regulatory support for the achievement of these goals.

The first concept is that of "reliable service." To customers this often means nothing more than unquestioned confidence that the lights will go on when they throw the switch. To APS, however, "reliability" requires long-range planning, the right mix of generating resources, robust delivery infrastructure, and responsive customer service. It involves the integration of new technologies with time-tested processes, quality construction and maintenance of facilities, and skillful operation of a complicated and interdependent system. And all of this must be accomplished in a manner that promotes a safe working environment for APS employees and for APS customers, and which is in compliance with all relevant state and federal laws.

The definition of "reasonable prices" is more subjective. It cannot be conveniently "benchmarked" against the prices charged by other entities under dissimilar circumstances. It is also independent of what individual customers would be willing or can afford to pay for electric service. Rather, under Arizona's traditional regulatory principles, APS must be able to recover its reasonable costs of providing service.

The third concept embodies the Company's obligation to stand ready to serve both existing and future customers. Unlike competitive enterprises, which are free to enter and exit markets as they wish, or limit their participation in the market to selected customers and lines of business, the Commission expects and requires APS to be ready and willing to serve all customers within its authorized service territory both today and for the indefinite future. Thus, the Commission's approved prices, terms and conditions of service represent a unilateral and irrevocable offer on the part of the Company to serve all within that territory, present and future, which apply for such service. That sort of obligation requires the Company to remain financially healthy, flexible and able to respond to changing conditions and the demands of a growing Valley and state.

C. Key Issues

Q. WHAT ARE THE KEY DRIVERS BEHIND THE NEED TO RAISE RATES FOR THE FIRST TIME SINCE 1991?

A. There are several. Clearly fuel and purchased power costs have increased very significantly over the levels reflected in current APS rates. Second, APS is proposing to include PWEC's generating assets in rates at cost-of-service. Although this addition to the Company's rate base is more than offset by the complete amortization of most of the Company's regulatory assets, as well as the off-system sales, fuel and purchased power savings and tax benefits produced by these units, the role of the PWEC assets and their ratemaking treatment present major issues that must be resolved in this proceeding. Third, APS is asking to recover the $234 million write-off in 1999 of prudent costs incurred by APS under terms of the 1999 Settlement and the additional costs incurred by APS to comply with the Commission's Electric Competition Rules.

Q. COULD YOU ADDRESS EACH OF THESE ISSUES IN MORE DETAIL?

A. Yes, although Mr. Robinson is specifically responsible for the pro forma adjustments that measure the revenue requirements impact of each of the above elements to the Company's rate filing.

1. Fuel and Purchased Power

Q. HAVE APS FUEL AND PURCHASED POWER COSTS INCREASED SINCE THE TEST PERIOD USED FOR THE 1999 SETTLEMENT?

A. Yes. Since 1996, which was the test period used for purposes of the 1999 Settlement, APS annual fuel and purchased power costs have increased by some $300 million through the end of 2002. And although increases or decreases in such costs will be handled by APS' currently pending power supply adjuster ("PSA") mechanism after June 30, 2004, just bringing up the base allowance for these costs to better reflect current levels both for sales and prices has increased APS costs by $121 million over those recorded during the 2002 test period. This accounts for the majority of the requested revenue increase.

Q. COULD YOU EXPLAIN THE REASONS FOR THESE DRAMATIC INCREASES?

A. As was discussed at great length during the PSA hearing in April of 2003, rapid load growth has left APS increasingly dependent upon purchased power and gas generation to meet the needs of its customers. These particular components of the Company's energy supply mix have been extremely volatile. For example, APS' average delivered cost of gas has increased by 68% just since the end of the test period. Because gas is the marginal fuel for electric generation during most times of the year, higher gas prices almost always translate into higher purchased power prices. This in large part explains the 63% change in purchased power prices, although part of that increase is also related to the higher per kW investment cost of new merchant generation compared to the older, depreciated generation costs embodied in current APS rates.

Another factor, ironically, has been the Company's own success is managing these costs. As I will discuss later in my testimony, APS' largely coal and nuclear-based energy generation has kept APS fuel costs at relatively low levels for many years. However, these base-load units have pretty much exhausted their ability to produce any additional amounts of energy, making almost all of the Company's marginal growth in energy sales come from the volatile gas fuel and purchased power markets.

2. Inclusion of the PWEC Assets in APS Rate Base

Q. IS APS SEEKING TO INCLUDE CERTAIN OF PWEC'S GENERATION IN ITS FAIR VALUE RATE BASE?

A. Yes. If the Commission agrees that Redhawk Units 1 and 2 ("Redhawk-1" and "Redhawk-2"), West Phoenix Combined Cycle Units 4 and 5 ("West Phoenix-4" and "West Phoenix-5"), and Saguaro Combustion Turbine Unit 3 ("Saguaro CT-3") should be included in the Company's rates at their full cost-of-service, APS will acquire those units from PWEC at their then depreciated book value. Upon acquisition, the existing contract between APS and PWEC would be terminated—a transaction akin to converting a short-term summer lease into year-round perpetual ownership. Because it is not anticipated that the

Commission will rule on this request until the end of the second quarter in 2004, APS has included the PWEC assets in its proposed rate base at their projected June 30, 2004 book value. That is some $73.4 million less than the original cost to PWEC of constructing those plants as a result of the accumulated depreciation from their in-service dates through June 30, 2004. Over the remaining life of these same PWEC assets, that reduction in the Company's acquisition cost will save APS customers approximately $ 214 million in future revenue requirements using the Company's proposed cost-of-capital. If I were to factor in the impact of deferred income taxes, which also reduce the book value of the PWEC assets, the savings would be even greater. And, as compared to the cost of APS constructing new generation assets in 2004 of comparable size and type, life cycle savings increase to nearly $500 million.

Q. WHY IS APS MAKING THIS PARTICULAR REQUEST?

A. The reasons are basically three-fold:

- The PWEC assets are essential to serve APS customers. They are "used and useful" by any reasonable definition of the term and for a variety of reliability-related, economic, and operational reasons;
- Both the past behavior of the wholesale market and the Company's future expectations concerning that market support a resource plan that relies on regulated utility generation for a large portion of customer needs as a hedge against both extreme but expected market volatility and unanticipated market blowouts; and
- Combining the PWEC generation with existing APS generation fulfills a basic objective of the 1999 Settlement that was left unaddressed by the Commission's Track A Order and promotes the continued vertical integration of APS, both of which are beneficial to APS customers and equitable to APS and its affiliates.

Q. WOULD YOU ELABORATE ON EACH OF THESE POINTS?

A. Yes. Let me address them separately.

I do not intend to duplicate the analyses presented by both Mr. Bhatti and Dr. Hieronymus concerning the planning, necessity, benefits and economics of the PWEC generation. Suffice it to say that the PWEC generation:

- Provides needed capacity to meet the peak demands of APS customers;
- Provides substantial energy throughout the year to meet those same needs;
- Provides critical local generation within the Valley during "must-run" periods of the year;
- Provides opportunities for off-system sales that can reduce overall revenue requirements;
- Hedges market risk;
- Displaces older, less efficient and less economical resources in the APS dispatch order;
- Provides additional fuel diversity to APS' existing heavily coal and nuclear generation mix; and
- Promotes continued vertical integration of APS, as envisioned by the Commission's Track A Order, and the attendant advantages thereof discussed by Dr. Landon and Dr. Gordon.

I must also point out that those Western utilities that depended on the vagaries of the wholesale market in 2000 and 2001 are still digging themselves out of a mountain of debt and facing huge future purchase power obligations. Those utilities such as APS that are now dependent on that market (even with the PWEC generation) are faced with potential counter-parties having little or no creditworthiness, an uncertain national regulatory policy, and an increasing paucity of risk-mitigating hedging opportunities. Although some may believe the years of market excesses to be an aberration or the result of market manipulation, while our present situation of market disintegration is only temporary, I think it is more likely to be merely the first cycle of "boom and bust" discussed in Dr. Hieronymus' testimony.

The Company's own experience in the recent Track B solicitation underscores my concerns. Without PWEC's bids, APS did not receive enough offers of power to meet even this summer's expected peak. Offers of power for delivery after 2005 were virtually non-existent. This was not the fault of APS, the Commission, or the merchant community, but underscores the essential difference between a vertically-integrated utility's obligation and ability to plan for and provide for the resources needed to assure reliability and the market's concern for profit maximization. And it is consistent with both Dr. Hieronymus' and Mr. Bhatti's conclusions as to an impending "boom" in the generation market, which could well be a "bust" for APS customers without the price hedge that the PWEC assets can provide.

In the case of the Valley's local generation needs, the absence of bids was not surprising because only PWEC has built new generation within the Valley that is available to APS. And it is unlikely that even if others constructed resources there in the future that they could compete successfully on a cost basis against established and already well-depreciated facilities such as West Phoenix-4 and West Phoenix-5.

But even aside from these reliability, economic and risk management arguments for rate base treatment of the PWEC generation, there are a second group of arguments for such regulatory action that I collectively refer to as "equitable considerations." Although these are not the conventional reasons presented by the Company in support of rate base inclusion during past Commission proceedings, the past few years have hardly been "conventional" in any sense of that word.

APS and its affiliates made concessions of considerable value and have relied in good faith to their ultimate detriment on the restructuring requirements of the Electric Competition Rules and the promises of the 1999 Settlement. Under both, PWEC (an entity created in reliance on and in conformance with the Electric Competition Rules and the 1999 Settlement) was entitled to receive all of the Company's existing generation, and the Commission made specific findings that such a transaction would be in the public interest. This was hardly surprising because it was the Commission's directive in the Electric Competition Rules that mandated divestiture, a position APS opposed and challenged in court until its challenge was withdrawn as part of the 1999 Settlement's attempt to implement the Commission's then restructuring vision. The combination of APS generation and the new generation constructed at PWEC to serve APS would have provided PWEC a fuel-diverse and highly competitive portfolio of assets under a single, investment-grade financial umbrella and a common regulatory regime. And PWEC would have had enough "critical mass" to survive in an industry dominated by far larger generating companies. This also would have benefited APS because under normal market conditions, that portfolio could easily compete for as much of APS needs as APS and this Commission found to be prudent. During times of market excess, whether they are caused by manipulation or the sort of natural "boom/bust" commodity cycles discussed by Dr. Hieronymus, the combined APS/PWEC assets would still be available to assure APS customers of reliable service.

The Track A Order left the PWEC assets cut off from the Company's generation This problem is accentuated by the increasingly onerous affiliate restrictions placed on interactions between the two generation "halves" of Pinnacle West by this Commission—restrictions that also are directly contrary to the terms of the 1999 Settlement. Rate basing the PWEC assets will restore the unity of purpose, economies of scale and scope, and commonality of regulatory treatment that APS sought from the beginning in the 1999 Settlement and for which it gave up so much.

Q. DOES NOT APS ALREADY HAVE SOME OF THE BENEFITS FROM THE PWEC ASSETS BY VIRTUE OF THE RECENTLY AWARDED TRACK B CONTRACT WITH PWEC?

A. Yes, but only partially and only through 2006, which is just about when many experts, including the Company's, expect those benefits to become far more valuable to APS customers. Under the recently awarded Track B contract with PWEC, APS has no rights to the PWEC units except during the months of June through September, thus missing out on many of the opportunities for off-system sales margins and for economic displacement of other less efficient generation resources or of higher priced purchased power. Also, APS has reliability needs even in non-summer months when faced with major outages of APS-owned generation, such as this fall's replacement of a steam generator at the Palo Verde Nuclear Generating Station ("Palo Verde"). Finally, the Track B contract does not solve the problem of having the generation constructed to serve APS bifurcated into two entities, one regulated by the Commission as a public service corporation and the other not, with separate financial structures, and with separate objectives and responsibilities.

Q. WHY SHOULD THE PWEC ASSETS BE RATE BASED AT THEIR 2004 BOOK VALUE?

A. But for the prohibition imposed by the Electric Competition Rules, the PWEC assets would have been constructed by APS just as have other generating units over the years. The Commission has repeatedly held that APS-owned generation is subject to regulation on the basis of cost-of-service, rather than on reconstruction cost, a constantly-changing market value, or some other selective, retrospective or opportunistic basis. These alternative valuation methods are even more suspect if they are the products of a dysfunctional market or, as Dr. Hieronymus discusses, fail to adequately capture such a market's inherent volatility.

The issue, therefore, is simply whether the PWEC generation represented a prudent investment by Pinnacle West to assure reliable APS service at the time it was made and given the circumstances presented APS by the Electric Competition Rules. Stated another way, if the investment will be devoted to public service and was reasonable when made, it should be included in the Company's rate base and earn a return that is not less than the cost-of-capital. Although Staff made no prejudgment on the ultimate merits of the Company's rate base request, this was precisely the point that APS and Staff were referencing in the December 13, 2002 "Principles for Resolution," which Staff filed in Docket No. E-01345A-02-0707:

> The Parties [APS and Staff] expressly recognize that the Commission will consider prudence, used and usefulness, and reasonable operating costs in the course of considering rate base treatment for the assets.

Principles of Resolution at 2.

Q. CAN'T THE COMMISSION AT LEAST PUT THIS ISSUE OFF UNTIL A SUBSEQUENT PROCEEDING SINCE THE PWEC UNITS ARE POTENTIALLY UNDER CONTRACT FOR THE MOST CRITICAL MONTHS OF THE YEAR THROUGH 2006?

A. No. Just as APS is short on capacity and energy after 2003, PWEC will be long on those commodities (*i.e.,* it will have surplus to sell) and presently unhedged through forward sales because of the dedication of these assets to APS from their earliest planning. PWEC will have to sell forward a significant amount, perhaps all, of its resources during the eight months of the year not presently under contract with APS pending a rate base determination. And neither APS nor the Commission can reasonably expect PWEC to continue to hold any of its capacity and energy in reserve for APS and its customers, if its undertaking to provide long term reliability to APS at cost has been rejected, not once (in the 2001 PPA filing), but twice (in this proceeding). This would leave the Company either wholly dependent upon what the Commission itself has characterized as a "dysfunctional" wholesale market at the likely beginning point of a new boom or in the unenviable position of having to construct additional new capacity itself by 2007 just to replace the less-expensive depreciated PWEC assets offered at cost in this proceeding.

Even in the Track A Order, the Commission recognized that this present rate case was the occasion to decide, once and for all, the fate of the PWEC generation constructed to serve APS. The Track B contract gives APS some assurance that it can keep the lights on until that decision is made. But the rate base request is on the table now and should be either timely accepted or, alternatively, rejected in no uncertain terms such that both the Company and PWEC can pursue other alternatives.

3. Reversal of the $234 Million Write-Off from 1999 and the Recovery of Competition Rules Compliance Costs

Q. WHY IS APS SEEKING TO RECOVER THE $234 MILLION IN WRITE-OFFS IT TOOK UNDER THE 1999 SETTLEMENT?

A. APS took more than $234 million in write-offs under the 1999 Settlement, as I will discuss later in this section of my testimony. However, this particular write-off related directly to past costs already found just and reasonable by the Commission, rather than what in 1999 were largely the future costs of compliance with the Electric Competition Rules.

Q. DID THE $234 MILLION RELATE TO THE CALCULATION OF STRANDED COSTS?

A. Yes, but the restoration of that write-off has nothing to do with the actual level of stranded costs either incurred by the Company or collected in rates from customers seeking Direct Access. What is relevant now is that if APS had not written off this $234 million, it would have continued to recover that amount in rates during the years 1999 through 2004.

Q. PLEASE EXPLAIN FURTHER.

A. Under both the Electric Competition Rules and a Commission order entered in 1998 [Decision No. 60977 (June 22, 1998)], APS was entitled to recover 100% of its "Stranded Costs." Stranded costs referred to the difference between the regulated cost of service for competitive electric assets, in this case generation, and what was then believed to be their market value. Please note that recovery of stranded costs would not have provided APS one nickel more than the Company already was entitled to under then existing law. And unlike utilities in other parts of the country or even in Arizona, APS did not request the ability to recover those prudently incurred costs on an accelerated schedule. Rather, they were collected at precisely the same rate and in the same manner as would have occurred absent the Electric Competition Rules. Indeed, for Standard Offer customers, what was termed the "Competition Transition Charge" ("CTC") was merely subsumed in the cost-of-service established under traditional Arizona regulatory principles and had absolutely zero impact on either Standard Offer customer rates or the Company, except in the following respects.

The first and far more significant of these impacts was that APS agreed to absorb or write-off, on a present value basis, $183 million of its just and reasonable cost of providing service for the period ending December 31, 2004. Undiscounted, that present value figure accounted for the $234 million write-off APS took to regulatory assets otherwise recoverable in rates.

Second, APS actually did collect somewhat less than $1 million in CTC charges from the handful of APS customers that have pursued direct access since 1999. That small amount of both stranded costs and stranded cost recovery has been credited against the Company's deferred Electric Competition Rules compliance costs, as called for under terms of the 1999 Settlement.

Q. WHY WOULD APS AGREE TO GIVE UP RECOVERY OF $234 MILLION IN COSTS IT WAS ALREADY ENTITLED TO RECOVER UNDER THE ELECTRIC COMPETITION RULES AND A PRIOR ORDER OF THE COMMISSION?

A. The 1999 Settlement was just that, a settlement. It was entered into at the express urging of the Commission, and APS made significant concessions in direct reliance on the Commission's fulfillment of its own commitments under the Settlement and in order to facilitate the transition to the Commission's then vision of competition while minimizing the damage to the Company. One of the primary aspects of the Company's damage mitigation efforts was the ability to divest APS generation to an affiliate, PWEC, rather than to an unrelated entity as had originally been proposed by Commission Staff. PWEC was thereafter to be treated by the Commission no differently than other wholesale generators in Arizona. Obviously, neither aspect of that objective has been or will be realized in light of the Track A and Track B Orders. Nor does APS seek to take back the rate decreases it previously agreed to in exchange for the 1999 Settlement. That being the case, a significant restoration to the Company's pre-Settlement position can be accomplished by allowing APS to reverse this write-off in conjunction with the rate basing of the PWEC generation.

Q. IF THE $234 MILLION WAS TAKEN AWAY FROM THE COMPANY'S REASONABLE AND PRUDENT COSTS OF PROVIDING SERVICE THROUGH YEAR-END 2004, WHY IS THE COMPANY PROPOSING TO RESTORE IT OVER THE MUCH LONGER PERIOD OF 15 YEARS?

A. This was done to mitigate customer impacts, while still allowing APS partial recovery for its detrimental reliance on the 1999 Settlement.

Q. PLEASE DISCUSS WHY APS IS SEEKING TO RECOVER ELECTRIC COMPETITION RULES COMPLIANCE COSTS IT HAS PREVIOUSLY EXPENSED.

A. Most of those costs are described by Mr. Robinson, and I will try not to duplicate his efforts. I will focus on the one-third of divestiture related costs that APS was required to forego under the terms of Decision No. 61973 (October 6, 1999), which Decision approved and adopted the 1999 Settlement.

Decision No. 61973 made it clear that this was the "price" for APS divesting its assets as it wished and when it wished, although the Commission itself had already mandated such disposition. As noted in response to an earlier question, that "sale" never was consummated through no fault of APS, and not surprisingly, APS is requesting its "earnest money" back.

Q. IF THESE THREE ISSUES ARE RESOLVED IN THE MANNER REQUESTED BY THE COMPANY, DOES THIS MEAN THAT APS WILL HAVE RECOVERED EVERYTHING IT OR ITS AFFILIATES GAVE UP IN THE 1999 SETTLEMENT?

A. No. APS is still out hundreds of millions of dollars in revenue on account of the rate decreases given between 1999 and 2003. Pinnacle West has incurred and will continue to incur millions of dollars in higher financing costs related to constructing the PWEC units. Moreover, PWEC will never recoup its increased costs from its failure to receive APS generation or the foregone revenues from its decision to not sell the PWEC assets into the California market and, instead, use them to protect APS customers.

IV. FUTURE ROLE OF APS

Q. DO THE ELECTRIC COMPETITION RULES, AS MODIFIED BY THE TRACK A AND B ORDERS, ALONG WITH THE RELEVANT PORTIONS OF THE LEGISLATURE'S 1998 ARIZONA COMPETITION ACT (HB2663), PROVIDE A CLEAR, COMPREHENSIVE AND CONSISTENT ARTICULATION OF WHAT IS EXPECTED FOR ELECTRIC UTILITIES SUCH AS APS?

A. No. APS believes that there has been no clear articulation of its future role and responsibilities, the means by which the Company can meet those responsibilities, or how the Commission will evaluate the Company's actions in that regard. In addition, the Company seemingly is asked to bear multiple and to some degree, contradictory obligations and to further sometimes mutually exclusive goals.

It is clear after the Track A Order that Arizona is no longer pursuing the restructuring model represented by the Electric Competition Rules. Under that

Whatever the reason, the Company never lost its focus on the problem nor did it have the luxury of depending on an amorphous and unaccountable entity called "the market" to satisfy what has been its historical mandate to maintain and protect reliable service to customers. Thus, despite a requirement that APS divest all of its generation to facilitate the development of a competitive retail market, and despite the lack of clear "rules of the road" as to how the Company was to ensure reliability, the direct and carefully planned actions taken by APS and its affiliates stand in stark contrast to the muddled thinking that led to disaster in California and other Western states.

Q. WHAT WERE THE STEPS APS TOOK TO ADDRESS THE "RELIABILITY GAP" EVEN BEFORE THE COMMISSION'S TRACK A ORDER?

A. APS undertook a series of steps to fulfill its public service obligation. APS negotiated the 1999 Settlement with the Commission to ensure that divestiture would only take place to PWEC. PWEC went on to install expensive temporary generation and constructed the new resources needed to assure the Company's access to sufficient generation to serve its customers without the sort of panicked buying that characterized neighboring states. PWEC and APS also negotiated a cost-based PPA that provided for all the Company's essential reliability needs while allowing APS access to the competitive wholesale market for economic purchases and supplemental requirements.

By no coincidence, APS reliability was maintained, and the Company was in a position to carry out its promised rate reductions without building up either a mountain of debt or other deferred costs for future APS customers to deal with or without the loss of its financial integrity. Moreover, the prudent actions of APS and its affiliates have left the Commission and the State with significant future flexibility to continue moving in a cautions and deliberate manner toward integrating competition with the best of traditional regulation.

Q. DID THE TRACK A ORDER MARK A CHANGE IN THE DIRECTION OF RESTRUCTURING?

A. Yes. The Track A Order clearly required APS to remain vertically-integrated and reinforced what APS believed all along was the Company's obligation to provide reliable service. What was not clear from Track A was where this change in the direction of Arizona's regulatory policy was leading now that the 1996-2002 restructuring initiative was no longer the objective. But whatever that new direction is, it must do more than simply assign responsibility for reliability. Indeed, stating that APS has an "obligation to serve," without more, confuses responsibility with authority. The Commission should also authorize and encourage APS to use all appropriate means to resolve the "reliability gap" left over from the model of the Electric Competition Rules and provide the regulatory tools and support for that task.

Q. HOW CAN THE COMMISSION ADDRESS THIS PROBLEM?

A. First, the Commission must decide not only who it expects to be responsible for reliable service, an obligation which the Track A Order appears to clearly reaffirm as remaining on APS, but also how this obligation is to be met and how the traditional "regulatory compact," to use Dr. Gordon's term, will govern the Commission's evaluation of the Company's efforts to meet that obligation. The Electric Competition Rules were silent on how reliability concerns would be met except through implicit faith that somehow the "market will provide," while at the same time imposing restrictions and limitations on UDCs. The Electric Competition Rules were equally vague on how the Commission would evaluate and provide cost recovery for long-term resource commitments, whether in the form of long-term power contracts or new generation construction. It is that latter and more fundamental lack of certainty, and not so much whether this or that specific resource cost will be recovered, that risks imperiling the needs of customers for reliable service.

Q. WHAT DOES APS BELIEVE IS ITS APPROPRIATE ROLE AFTER THE COMMISSION'S "CHANGE IN DIRECTION" IN TRACK A?

A. For the reasons discussed in Dr. Landon's and Dr. Gordon's testimony, APS believes the role for which it is best suited, and more to the point, the role that best serves the interests of APS customers, is for APS to remain a vertically-integrated electric utility. As such, the Company would continue to have the option, subject to this Commission's traditional regulatory authority, of constructing, acquiring and/or contracting for such electric supplies as are believed necessary and appropriate in the good faith discretion of APS management. And APS would continue to be regulated by this Commission on general cost-of-service principles. This permits the Company to continue to use its demonstrated resource procurement expertise without unnecessary and counterproductive restrictions.

Q. WHY IS VERTICAL INTEGRATION OF APS STILL APPROPRIATE?

A. It is all about the "reliability gap" to which I previously referred. Without the ability to own and control generation resources, a UDC is essentially unable to assure reliable service at reasonable prices. If we have learned no other lesson from the 2000-2001 debacle in California, Nevada, and elsewhere, I would think that the risk of market dependency would be burned indelibly into our psyche.

However, one need not focus solely on history to draw this same conclusion. Just look at today's headlines.

Q. ARE THERE OTHER REASONS TO BE WORRIED ABOUT RELIABILITY OTHER THAN THE "RELIABILITY GAP" LEFT OVER FROM THE ELECTRIC COMPETITION RULES?

A. Yes. The regulatory, market, economic and political factors that affect our ability to provide reliable service have never been in such disarray, thus making our job ever so much more difficult. We all remember the service disruptions, curtailments, brown-outs and capacity shortages on the West Coast in 2000-2001 and the extraordinary measures APS and PWEC were forced to take in the summer of 2001 to avoid those problems in Arizona. These concerns have not faded into distant memory. The challenges facing the resource planners at APS are very real and, I am sure, are of equal concern to the Commission. Consider the following:

1. By virtually all accounts, the wholesale power market is insufficiently robust, deep or transparent. For example, the Track A Order found that because the wholesale market has "faltered," "is not currently workably competitive," and FERC lacked "an effective regulatory and oversight approach," it calls into question the reasonableness of wholesale prices. This makes it difficult to transact business with full assurance that economically efficient pricing is being achieved. Adding to this problem is the evolving (and therefore highly uncertain) nature and schedule of the FERC-mandated standard market design.

2. After the initial frenzy of merchant generation announcements several years ago, virtually no new generation is planned in Arizona or throughout the western region that would be accessible to APS.

For example, according to a Merrill Lynch report dated June 12, 2003, only some 1400 megawatts are expected to be added throughout the entire non-California WECC in 2004 and 2005. Compounding the dearth of new capacity is the raft of cancellations in recent years. More than 9800 MW of the 26,057 announced for Arizona have been cancelled or indefinitely suspended. And, of the 50,505 MW announced for the Arizona-New Mexico-Southern Nevada-West Texas sub-region, more than 20,000 MW have been cancelled or suspended as of June 2003. Moreover, the boom in generation now appears to be over before it ever got to the Valley. No party other than PWEC has built or proposed to build generation or transmission to alleviate the APS "must-run" constraints during peak summer periods.

3. Against this lack of planned new generation additions, power demand throughout the region continues to grow at significant rates. This is illustrated in Mr. Bhatti's and Dr. Hieronymus' testimonies, both of which discuss the impending end of the current oversupply of generation in the West and especially in the Southwest.

4. The capital markets are reluctant (some might say loathe) to finance new plant construction as a result of the events of the last several years and the disappointing performance of the seemingly indestructible, high-flying merchant enterprises announced not so very long ago.

5. Even those survivors in the generation business have evidenced little willingness to make long-term and sufficient power supplies available to APS. The recent Track B initial solicitation process, although widely publicized and anticipated in one form or another, for several years, drew so few bids in such meager quantities for so little

duration that the outside merchant industry's ability to meet APS customer needs in even the short run is seriously in doubt.

6. Even the sellers with capacity interested in doing business with APS pose risks. The credit quality of those entities is, in many respects, declining and may not meet minimum acceptable standards. And of the merchant plants built or under construction in the Arizona-New Mexico-Southern Nevada-West Texas region, more than 5675 MW carry a junk bond rating from either Moody's or Standard and Poor's.

7. New legal impediments are arising to the market. Both buyers and sellers of power are now resorting to the courts in an unprecedented attempt to abrogate their contractual commitments in a manner which, if successful, will seriously undermine the "rule of law" and the ability to rely on the expected performance, particularly long-term, of counter-parties who may later wish to renege on their deals.

8. Insufficient transmission investment is being made to support a burgeoning wholesale market. Although APS has recently spent hundreds of millions of dollars on transmission improvements, and its filed 10-year plan indicates an intent to commit more than half a billion dollars over the next few years in new transmission, these improvements were designed, in large measure, to meet the needs of the Company's native load customers. APS cannot, and should not be expected to finance inter-regional lines or merchant generation pathways out of state without merchant generator participation. Indeed, in the Track A Order, this Commission emphasized that the merchant community was to share in the "burden and obligation" of constructing transmission infrastructure needed to promote wholesale competition. To date, it has not done so.

Now I do not want to beat a dead horse on the reliability issue, but it is an issue critical to customers and an essential part of the Company's public service mandate. The wholesale market is not a safe place to be these days without a high tolerance for risk or a large hedge of generation to fall back on when things turn ugly. APS and its customers are not among the former and would like to remain among the latter. That is why our resource planning group has always been quite concerned about excessive reliance on the wholesale market, whose participants' actions are beyond the Company's (and to a large extent this Commission's) power to control. It is also why rate basing of the PWEC assets makes good sense and allowing APS to maintain its role as a traditional vertically-integrated utility should be both encouraged and supported.

Q. ARE YOUR PRECEDING COMMENTS INTENDED TO BE CRITICAL OF THE DESIRE TO SEE WHOLESALE COMPETITION DEVELOP IN A MANNER THAT WILL BENEFIT ALL ELECTRIC CUSTOMERS WHILE STILL BEING FAIR TO INCUMBENT UTILITIES?

A. No, not at all. The Commission and its Staff have been quite zealous in promoting policies that are intended to advance the public interest in competitive markets, adequate infrastructure, and reasonable rates. I would specifically draw attention to the Commission Staff's biennial assessments of transmission adequacy, the Commission and Staff roles in the CATS process, and the recently finalized RMR study for the Valley. The Commission and its Staff have also taken leadership roles in promoting and approving needed transmission infrastructure projects in Arizona and in urging merchant generator participation in those efforts. Finally, the Commission and Staff have fought to assure adequate gas supplies for Arizona and for rational FERC and Congressional electric policies that respect legitimate state interests. And, in all of these efforts, they have allowed all interested parties to participate and share their views during Commission deliberations.

My testimony is offered on behalf of a utility whose essential business purpose for over 100 years has been focused on its retail customers and on the development of this State. Because APS was here well before the tumult and change of recent years and intends to fulfill its service commitment long into the future, and after markets have matured into a sustainable long-term equilibrium, we have strong views on the "Whats, "Hows," and "Whens" of attempts to transform this vital infrastructure industry. And we cannot help but focus on the sometimes arcane but critically important "details" of cost recovery, long-term planning, regulatory certainty, and customer service, details that are essential to keep the lights on and the machinery of Arizona's industry running. Thus, when the "theory" of competitive market benefits bumps into the "reality" of serving daily customer power needs, we believe it appropriate to offer what are hopefully constructive comments and suggestions.

Q. **DOES THIS MEAN APS WILL GO BACK TO THE TYPE OF UTILITY IT WAS IN THE 1980S AND BEFORE, WHEN IT PROVIDED VIRTUALLY ALL OF ITS CAPACITY AND ENERGY NEEDS THROUGH UTILITY-OWNED GENERATION?**

A. No. Despite its many problems, the wholesale market for electricity has been irrevocably changed by the opening of the transmission network on a non-discriminatory basis and, to a lesser extent, the development of more robust generation technology. This has subjected the entire power industry to increased competitive pressures to improve efficiency and manage risk. Similarly, the development of a trading market for electricity, albeit greatly slowed by the aftermath of Enron, will allow for the monetization of electricity as a commodity that could not even have been imagined in 1980. What these developments mean is that utilities will likely never again be the islands unto themselves they once were. This is what Dr. Gordon refers to as the "new vertical integration" of electric utilities—an integration that allows the utility to provide the reliability and price stability of traditional regulation while fully exploiting the opportunities of the developing wholesale market, and being subject to the discipline of that market, in ways that add value for utility customers.

Q. DO THE COMPANY'S PLANS REFLECT THIS "NEW VERTICAL INTEGRATION?"

A. Yes. As is shown in Mr. Bhatti's testimony, APS' own long-range forecast of loads and resources no longer even attempts to self-build for all future APS customer needs. APS understands that the wholesale market is not just some place where utilities dump their unneeded energy or take advantage of each other's relative economies of generation. It is a viable and necessary resource that can and should be incorporated into a broad-based portfolio of resources used to serve customer needs. This is why APS supports a vibrant and robust wholesale market and why it has taken significant steps to encourage that market. These include: (1) leadership roles in developing the WestConnect RTO and resolving regional "seams" issues; (2) expedited interconnection of merchant generators; (3) regional interconnection and reserve sharing activities; and (4) the implementation of new and more economical retail rates for backup and supplemental power needs for merchant generators within its retail service area.

V. DESCRIPTION OF APS

A. General Facts

Q. MR. WHEELER, WOULD YOU PLEASE PROVIDE A GENERAL OVERVIEW OF APS?

A. APS is a wholly owned subsidiary of Pinnacle West Capital Corporation. APS is a Phoenix-based company with approximately 6000 employees, assets of about $6.5 billion and unadjusted gross revenues in 2002 of $2.1 billion. The Company generates, delivers and sells electricity to about 902,000 customers in its service area, which is totally within the state of Arizona. The Company is a regulated public utility serving about half the population of the greater Phoenix metropolitan area, about half the population of Arizona, and 11 of the state's 15 counties. As I will discuss later in my testimony, the rural and somewhat rugged nature of much of our service territory presents challenges to cost control and reliability that APS has readily accepted and consistently met.

APS owns nuclear, coal, oil and gas-fired generating stations that together with long-term contracts (including those awarded in Track B) give it total generation resources of about 6570 MW. With several other utilities, APS jointly owns, but is the sole operator of Palo Verde, the largest nuclear power facility in the U.S. and the single largest producer of electricity of any kind in the country. APS also jointly owns and operates the Four Corners and Cholla power plants, which are coal-fired. In addition, the Company owns part of another coal-fired station, Navajo, which is operated by Salt River Project, as well as several smaller oil- and gas-fired units.

APS has a diverse generation mix. Including the PWEC units that APS is asking to include in rate base, by 2004 our generation mix (based on capacity) will consist roughly of 44% coal, 31% nuclear and 25% natural gas. This diversity is a powerful tool over the long run in our efforts to manage risk in the face of changing wholesale market and fuel prices.

There are a number of factors that have allowed APS to improve service while substantially lowering rates. First, although APS has added customers at about three times the national average, the consequences and demands of which are discussed below, through the prudent use of technology and other means, APS serves considerably more customers per employee than a decade ago. In addition, through efficiency improvements such as better heat rates and shorter refueling and maintenance outages, APS has kept our nuclear and coal production costs below the national average.

B. Rates, Generation Performance, the Challenges of Growth, and Customer Service Issues

Q. HOW HAVE APS RATES FARED AGAINST INFLATION SINCE YOUR LAST RATE INCREASE IN 1991?

A. Driven by operational improvements at every level of the Company since our last rate increase more than a dozen years ago, APS has compiled a rate reduction and cost containment record that has served our customers well. Attachment SMW-1 illustrates APS price performance versus inflation over most of the period since our last rate increase. Since 1991, APS' rates have already fallen by 14.5% while the consumer price index – the most widely cited measure of inflation – has increased by 32%. APS soon will implement our ninth rate decrease in a decade (a 1.5% decrease effective July 1, 2003). By the time any rate change could take effect from this general rate case, APS' rates will have fallen by 16% while the CPI will have increased by more than 36%. As shown on Attachment SMW-1, by the end of this year APS' rates will have dropped dramatically in "real" or inflation-adjusted terms. Stated another way, since 1991, these decreases will have provided APS customers with savings of $1.74 billion. While Californians and residents of many other Western states experienced large rate increases over the last few years, APS customer received rate decreases. APS has accomplished this while improving service to customers and while maintaining an investment-grade rating on our corporate debt.

Q. HOW HAVE YOUR POWER GENERATING STATIONS PERFORMED IN RECENT YEARS?

A. Extremely well. For example, Palo Verde was the most productive single power station in the country in 2002, bettering its own previous high, with record output of 30.8 billion kWh. This marked the eleventh straight year Palo Verde has held this distinction. Last year, Palo Verde also set a best-ever 94.4% capacity factor record. Palo Verde Unit 1 operated for its entire fuel cycle – running "breaker to breaker" for a unit record 502 consecutive days, one of the best operational performances between refueling outages in station history. This kind of performance between refueling outages was achieved even as APS continues to reduce the amount of time per refueling.

Q. HOW DO YOU MEASURE POWER PLANT PERFORMANCE?

A. The industry generally measures large base-load plant performance by capacity factor because such plants are intended to be "on line" and operating most of the time. Smaller peak-load plants, however, are intended to operate only for a few days or weeks per year and therefore have much lower capacity factors than base-load plants. Because capacity factor does not adequately reflect the purpose or measure the reliability of smaller plants, their performance is most often stated in terms of equivalent availability factor ("EAF"). EAF is simply the percentage of time the unit was available for use by customers weighted by the percent of the unit's capacity that was available. For example, if a unit had 90% of its capacity available 90% of the time, its EAF would be 81% (90% x 90%).

Q. HOW DID THE COMPANY'S OTHER GENERATION ASSETS PERFORM USING THE ABOVE MEASUREMENT?

A. Company fossil plants also performed extremely well in 2002. All five Four Corners units had high EAFs and achieved an overall capacity factor of 83%, placing the site among the top 20% of coal plants in the nation. Units 4 and 5, the largest of the Four Corners units, ranked in the top 10% in capacity factor. Cholla, another base-load coal station, achieved an EAF of more than 90%, the station's best since 1997. The gas and oil plants at Ocotillo, Saguaro, West Phoenix, Yucca and Douglas combined for an EAF of more than 90%.

A longer-term perspective provides an even more representative picture of our generation performance. From 1992-96, the capacity factor at Palo Verde averaged 78.6%, above the 75% target established by the Commission when Palo Verde came into service in the 1980s; but from 1997-2001 the five-year average increased to 91.4%. Over those same years, Palo Verde's average forced outage rate (the percent of time a unit is off line for unscheduled events such as equipment failures) fell from 4.3 to 1.8% per year. And its scheduled outage factor (essentially the amount of time needed for refueling) fell from 17% to 7.7%. Most impressively, over these same periods, its five-year average total production (APS' share only) increased from 7.37 million MWH per year to 8.69 million MWH per year. At Four Corners, the capacity factor from 1992-96 averaged 80% per year; the five-year average from 1997-2001 was 82.6%. At

Cholla the five-year average capacity factor increased over these same time periods from 73.2% to 77.4%.

Q. DID YOUR IMPROVED PERFORMANCE HELP YOU MEET INCREASING CUSTOMER DEMAND?

A. Yes, without this continued high level of performance, APS would not have been able to cope with the price and reliability challenges of Western power markets. High capacity factors from our large generating units helped keep prices down, but high availability from smaller units meant APS had the power when APS needed it during times of peak demand. APS' customers set a new demand peak record last July of 5,803 MW. That marked an increase of nearly 26% in five years.

During 2000 and 2001, California and other Western states experienced rolling blackouts and threats of blackouts. APS' customers, by contrast, experienced no rolling blackouts or outages caused by a lack of generating resources. By relying on APS' own generation resources and those of PWEC, supplemented by stable long-term contracts and timely short-term purchases and hedging, APS was able to avoid the price volatility and supply interruptions that wreaked havoc on many Western utilities and their customers.

Q. HOW HAS RAPID GROWTH IN THE COMPANY'S SERVICE TERRITORY AFFECTED APS?

A. Meeting the demands of growth in APS' service territory is a significant challenge for APS. Attachment SMW-2 shows a comparison of growth in retail electric sales for APS versus the country as a whole. Since 1990, total retail electricity sales for APS has grown by 53%, or 22% faster than total U.S. energy demand.

APS' growth should come as no surprise. At its current rate of growth, Arizona as a whole adds around 150,000 to 160,000 new people annually, which is equivalent to adding a city the size of Tempe each year. All of these people need homes to live in, places to work, and businesses at which to shop. All of which explains why Arizona continues to rank so highly across the country in such indicators of economic growth as housing construction and growth in jobs. Typically, almost half of this growth occurs in the APS service territory. In order to keep all of these new homes and businesses supplied with electricity, APS must invest in new electric generation, transmission, and distribution facilities on an on-going basis.

If growth were constant from year to year, planning for and adding these new facilities would be a fairly routine matter. But, growth is not constant every year and, in fact, can be quite volatile depending on economic conditions. Although some of this volatility can be anticipated, particularly in the near-term, forecasting economic growth and the associated demand for electricity is at best an imprecise science. Therefore, the Company's plans must account for this uncertainty. With reliability as the cornerstone of the supply plans, this means that APS must add generation and distribution facilities in advance of demand growth and during periods of heightened volatility, such investment may lead the demand growth by several years.

Q. HOW DOES GROWTH IN ARIZONA COMPARE WITH OTHER REGIONS OF THE COUNTRY?

A. Arizona has always been and, for the foreseeable future, is expected to be one of the fastest-growing states in the country. For each decade in the 20th century, Arizona consistently ranked among the top five states for population growth in percentage terms and is poised to do so again through at least the first decade of the 21st century. Often, one of the reasons that a region may have a large percentage increase in population is because a relatively modest absolute number of people is added to a small existing base. This was the case for Arizona when it was a small state (as measured by population) even as late as the 1970s, but is less the case now as Arizona grows in size. This is currently the case for Nevada and is why Nevada routinely leads the nation in percentage growth. However, Arizona is now the 19th largest state in the country and yet still continues to grow at very high rates.

To put this in context with national averages, Attachment SMW-3 shows how Arizona's population has grown since 1990 relative to U.S. population growth. Population levels are indexed against 1990 for both Arizona and the U.S. so that an easy comparison can be made between the two. It is apparent from the chart how much difference in total population a growth rate three times the national average will make over a 10 or 15 year period. By 2002, Arizona's population had increased by 28% more than the U.S. population over the same period.

Q. HOW SIGNIFICANT ARE THE CHANGES IN GROWTH RATES FROM YEAR TO YEAR IN DEVELOPING YOUR COMPANY'S PLANS?

A. Very significant. Population and household growth varies with the strength of the national economy, and this fact will be reflected in the number of <u>new</u> customers APS will serve in any given year. These new customers include both residential homes and apartments as well as new commercial and industrial business establishments. Attachment SMW-4 shows the changes in APS average annual retail customer growth over the last 20 years. One can see that there are periods of very high growth, such as in the mid to late 1990s, and there are periods of very low growth which tend to be concentrated in and around periods of economic recession.

Not only are the absolute number of new customers important each year, but also their size. In strong economic growth periods where wages and incomes are growing rapidly, new homes tend to be larger, a larger share of all new homes are single family (which are on average larger than apartments), and more commercial floor space is constructed. When economic growth slows, the opposite generally occurs.

The strength of the economy also affects how customers use electricity at their homes and businesses. In more robust economic periods, customers are more likely to add electricity-using appliances and equipment in homes and businesses, so the average use per customer tends to rise at a faster rate than during slower economic periods. In contrast, households and businesses are more likely to cut back on their usage during slower economic growth periods. Households may adjust thermostat settings to manage their overall bill better. Manufacturers are more likely to be using equipment less as demand for their product remains low. These fluctuations have an impact on the amount of additional electricity consumption APS will see in any given year.

All of these factors taken together highlight the additional growth pressures that are present in Arizona and the APS service territory over and above those seen at the national level. It also highlights why APS has to be so concerned about its future ability to meet the challenges of such growth, both from the standpoint of its financial strength and the consistency of its regulation.

Q. ARE THERE OTHER FACTORS THAT ADD TO THE UNCERTAINTY OF ELECTRICITY DEMAND GROWTH?

A. Yes. A large portion of the electricity demand APS serves is weather-sensitive, so the natural fluctuations in weather from year to year can have a dramatic effect on the peak demand APS resources must meet and the total amount of energy that must be supplied in any given time period. Also, unique factors emerge from time to time that have impacts on electricity demand beyond those related to overall economic growth or weather. The decline in the relatively energy-intensive copper mining industry, even during a period of economic strength, has affected the growth in demand recently. Another recent event worth highlighting is the extent of conservation undertaken by our customers in the summer of 2001 in response to the threat of California-like blackouts spreading to Arizona and other Western states.

Q. DOES APS EXPECT GROWTH TO CONTINUE INTO THE FUTURE?

A. APS' current forecast expects energy sales to grow at an average annual rate of 4.3% to 2010, with higher growth rates occurring in the near term as the economy and associated electricity demand recovers from the downturn in business activity. In Mr. Bhatti's testimony, APS has provided a forecast of peak loads, showing an estimated growth of roughly 1300 MW over the next five years, or some 4.2% per year.

Q. HAS GROWTH ALSO AFFECTED THE DELIVERY SIDE OF APS?

A. Yes. On the transmission, distribution and customer service side of APS' business, the challenges match, or perhaps even exceed, those on the generation side. The delivery challenges of meeting customer growth - while maintaining high levels of reliability at a reasonable cost - are multifaceted and formidable.

As noted earlier, over the last decade, APS has experienced annual customer growth of about 3.8%, adding nearly 280,000 new customers. This growth has not been exclusively a Phoenix phenomenon; growth in APS' five divisions has averaged between 2.9 and 4.1% per year over the decade. At the same time, APS has gone from 7053 employees to roughly 6000 employees, primarily through voluntary, targeted workforce reduction programs that responsibly balance employee concerns with reliability and overall economics.

Despite this rapid growth, APS now provides better service with fewer employees per customer. In 1993, APS served 93 customers per employee; in 2002, APS served 148 customers per employee, an increase in productivity of 59%.

To service its over 900,000 customers, APS Delivery owns and maintains 364 substations, 4981 miles of transmission lines and 24,371 miles of distribution lines. One aspect of the APS service territory often overlooked is that APS serves a large rural and sparsely populated area in addition to the urbanized Valley region. Consequently, APS serves just 19 customers per square mile. In contrast, SRP and Tucson Electric Power – the other two large Arizona electric utilities – serve 233 and 282 customers per square mile, respectively. And compared to urban areas, service territories with low customer density are more expensive to serve per customer. This is because both the costs of wires, transformers and other items must be recovered over a smaller base and the costs themselves are greater. It can also be more difficult to maintain reliable service because service lines are long and are subject to more opportunities for interruption due to factors such as fire or storm damage.

Q. WHAT ARE SOME OF THE SPECIFIC WAYS YOU HAVE MET THE CHALLENGES OF GROWTH?

A. First, APS has made significant investments in necessary facilities. Over the last decade (1993-2002), APS has invested $1.7 billion on transmission and distribution infrastructure just to keep up with the increased usage per customer as well as rapid growth in the number of customers. APS has plans to invest up to another half billion dollars in the next five years just on transmission. In addition, APS spent $300 million on planned maintenance to assure continued higher levels of reliability.

APS has turned those expenditures into some impressive total increases in electrical infrastructure. To serve the 280,000 new customers APS has added and built over the last decade:

- 3059 MW of distribution substation capacity, a 42.4% increase,
- 1752 MW of transmission capacity, a 9.3% increase.
- 38 new distribution substations and 4 new transmission substations.
- 249 new distribution feeders giving us an additional 3120 MW of feeder capacity, an increase of 43.7%.
- 818 miles of transmission lines.

In addition, APS has completed nearly 5000 miles of distribution lines, an increase of about 26%.

Transmission siting has become increasingly difficult but also even more essential over the last decade. APS is a 50% partner in a transmission project that includes a new 500-kilovolt transmission line from Palo Verde to Rudd, a new substation in the West Valley, and two 230-kilovolt transmission lines from West Phoenix to the White Tanks substation, with a loop from White Tanks to

Rudd. This project resulted in an increase in the Company's Phoenix area import capacity of about 600 MW. It also improved the reliability of APS service to the growing load in the West Valley.

To accommodate increased load within the Valley, APS also rebuilt a 230-kilovolt line from the West Phoenix plant to the Lincoln Street substation. These delivery enhancements not only will serve the growing customer demand in the Phoenix area, they provide better voltage support and operating flexibility.

Q. HAVE YOU SPED UP CONSTRUCTION AND CUT COSTS WITH ANY INNOVATIVE CONSTRUCTION TECHNIQUES?

A. APS has made many changes with the help of computer technology and standardization of design and construction techniques. For example, APS has made crucial changes that accelerate and reduce the cost of building new or expanding existing substations. The major savings in time and money have come from the use of standard designs and prefabricated materials. Switching to computer-aided design of substations has reduced the time required to produce a new design by nearly 70%.

When actually building the substations, APS assembles all of the 12-kilovolt bus structures (our standard distribution voltage bus) at our metal fabrication shop. APS then transports the assembled structures to the site for installation. In addition, the control houses are prefabricated and taken to the site. Using these and other techniques, APS has greatly reduced the time and labor required to build a substation. Just ten years ago, construction would have required from two to three months with a six or seven person crew. Today, APS can construct the same substation in three to four weeks with a three to four person crew.

Without these better and faster techniques, it would have been very difficult to keep up with the customer growth APS has experienced over the last decade, let alone reduce the number of APS employees needed to serve those customers.

Q. IN MANAGING GROWTH, HAVE YOU PARTNERED WITH OTHER BUSINESS GROUPS?

A. Yes. APS has formed a working partnership with the homebuilders to meet the in-service dates for new developments, to "energize" homes as they are completed and to improve air quality around construction sites by providing temporary electrical service earlier in the construction of homes (thereby avoiding the need for portable generators).

APS has accomplished this with a variety of improvements:

- Providing a single point of contact for each homebuilder and developer;
- Working with builders and other utilities to have a "joint trench" to reduce the builder's costs;
- Meeting monthly with the Home Builders Association; and
- Providing educational materials and training to enable builders to educate consumers about their energy and conservation options.

Q. HOW HAVE YOU IMPROVED YOUR MAINTENANCE PROCEDURES FOR TRANSMISSION AND DISTRIBUTION SYSTEMS?

A. APS is adopting reliability-centered maintenance ("RCM"), an innovation that has been used successfully by the airlines, the military and nuclear and fossil power plants. The benefits of an RCM approach include elimination of unnecessary and premature preventive maintenance tasks, while at the same time decreasing the need for corrective maintenance and reducing forced outages. This not only improves overall availability, it allows APS to increase the focus of maintenance resources on critical systems and equipment.

APS is laying the groundwork for RCM implementation. Work is progressing on obtaining the tools and developing the techniques to assess the condition of equipment. With these tools, APS can make maintenance decisions based upon equipment condition, instead of rigidly following mere time-based maintenance schedules. These RCM tools include thermography, oil sampling for various combustion gases (indicating insulation breakdown), and a wide battery of electrical tests.

Another key aspect of RCM is failure cause identification and corrective action. In 2001, APS identified the four primary interrupting/failure modes, which constitute 10% of our outages yet caused over 80% of customer interruptions. Since that time, APS has actively developed solutions to address each of the identified areas and has begun implementation of these solutions._

APS' vegetation management program has resulted in the Company being recognized by the National Arbor Day Foundation as a "Tree Line Utility." It also has reduced tree-related outages since 1997 by 41%. Over the last eight years, APS has been able to move from a costly initial clearing of circuit paths to only removing new growth in many areas, thus reducing our cost per tree from about $67 to $27.41. To be a "Tree Line Utility," a utility must follow stringent (ANSI A-300) pruning guidelines, provide annual tree worker training, and a tree-planting program. APS has received this recognition for the last seven consecutive years.

Q. WHAT PROGRAMS OR ENHANCEMENTS HAVE YOU FOCUSED ON TO IMPROVE CUSTOMER SERVICE?

A. APS has developed a number of programs and initiatives in this area. I will mention only a few.

With the information and technology explosion that has occurred in the past decade, APS customers' expectations have changed. The demand and need for timely and accurate information about electric outages has skyrocketed. With better training and computer technology, in most instances APS is now able to satisfy customers' demands for information about outages. When APS detects a problem, the boundaries of the outage are quickly determined and entered into the APS telephone system. With this information in the APS system, even customers waiting "on hold" can immediately find out that APS is aware of the power interruption. In most cases APS can provide customers with a reasonable estimate of when the power will be restored. Also, as customers provide information about interruptions in their area, customer service representatives can pass that information along, via computers, to APS Operations employees. This coordinated information sharing often dramatically shortens the length of outages.

One key to APS' better performance in this area is the APS customer call center, a centralized facility staffed with employees trained to handle a variety of customer inquiries and outfitted with sophisticated software and telecommunications equipment to link customer information with electrical system (such as outage) information, as well as financial records. APS call center performance has been one of the anchors of improved customer satisfaction. APS has found that it's just as important for customers to have quick access to timely information about outages, for example, as it is to restore power quickly. In addition, APS has achieved our target of answering 80% of calls within 20 seconds in all but one of the last 42 months. In 2001, the most recent year for which complete data is available as of the time this testimony was prepared, APS' service level performance ranked second among 59 Edison Electric Institute and American Gas Association member utilities.

APS continues to offer customers greater flexibility and convenience, and reduces costs through its utility web site, APS.com. In recognition of these efforts, APS.com was named Best Web Site for 2002 by the Web Marketing Association. APS provides extensive information about energy conservation on APS.com, including an on-line energy audit for residential customers that has had approximately 30,000 visits in the last two years. On this web site, customers can also order or download 14 residential and 18 commercial "Energy Answers" fact sheets and other energy efficiency materials.

To provide APS customers even more flexibility, APS has greatly expanded available payment options. APS traditionally offered mail, walk-in and automatic debit (SurePay) options. In addition to those, APS now offers self-service office payment, electronic payments via the internet, and pay-by-phone options using check and credit or debit cards.

Q. DOES APS KEEP CUSTOMERS INFORMED ABOUT THEIR ENERGY USAGE AND CONSERVATION OPTIONS?

A. Yes. APS provides customers with referrals to heating/cooling contractors who meet high training requirements and professional standards. Since 1998, APS has provided referrals for over 10,000 customers seeking AC/heat pump service or replacement and has helped provide training for over 3000 local contractor technicians. APS has helped to educate consumers by distributing over 15,000 copies of the 20 page "Consumer's Guide to an Energy Efficient AC System".

To help promote the value of energy efficient new homes, APS works with builders and vendors to allow those builders to provide homebuyers with a heating/cooling cost guarantee. All participating homes are guaranteed to be at least 30% more efficient than the International Energy Conservation Code. To date, there more than 3000 lots committed in the program. APS has helped to educate homebuyers about energy efficient new home features by distributing almost 10,000 copies of the 28 page "Homebuyer's Guide to New Construction - Energy Efficient Ideas to Build Upon".

For residential customers that have been with the Company for at least six months, APS now provides an "annual use" letter that provides a summary of the previous year's electric consumption as well as informative messages about payment options and other messages tailored to their situation. For example, time-of-use customers receive tips on shifting energy usage to off-peak hours. APS also invites its customers to promote the development and use of solar energy through the APS Solar Partners program. As Solar Partners, customers pay a small monthly fee to have a portion of their home or business electricity needs met by solar power produced at APS solar facilities around the state. In addition to mass mailings, APS has provided energy conservation information through a wide variety of venues. Working with homebuilders and their association, APS helps promote the value of energy efficient new homes. APS has sponsored research to help builders and contractors improve residential energy efficiency. For example, by focusing on problems with air conditioning and heat pump installation, APS has identified ways to reduce duct leakage by two-thirds. APS' infrared studies have been influential in getting homebuilders to improve the insulation standards in walls and ceilings of new homes.

For the past two years, APS has promoted a voluntary energy-savings program for commercial customers. Nearly 100 customers have participated each summer.

APS has promoted a variety of energy efficiency projects in partnership with the Arizona Energy Office ("AEO"). These joint projects include building science training for builders, a program that helps builders identify construction details that can bring energy efficiency improvements. More than 2500 building industry professionals have attended the training, including all of the top ten builders in Phoenix. APS also partnered with the AEO to develop a user-friendly system for APS.com that allows commercial customers to easily access and analyze their bills so they can better identify opportunities for additional savings.

Q. WITH THE COMPANY'S EMPHASIS ON MANAGING GROWTH, COST CONTAINMENT AND CUSTOMER SERVICE, IS APS ALSO CONTINUOUSLY SEEKING TO IMPROVE OTHER ASPECTS OF ITS PERFORMANCE?

A. Yes. APS emphasizes continuous improvement in its safety record. In 2000, the last year for which comparison data is available, APS placed second out of companies of similar size and structure in an EEI comparison of OSHA injuries. Last year, APS again reduced its number of recordable injuries among employees.

APS also goes to great lengths to educate the public about electrical safety. While it's impossible to cite a specific correlation between APS' efforts and improved safety, APS has seen a reduction in the kind of incidents addressed in the Company's safety education program. For example, prior to the mid-1990s, the state was experiencing several fatal accidents annually involving tree care workers and landscapers coming into contact with electrical facilities. APS began an aggressive education program by providing free annual safety seminars to tree care workers and landscapers in addition to a statewide public service announcement campaign. Since the implementation of these programs, APS has not had a tree care worker or landscaper fatality in our service territory. While APS can never know how many potential incidents are avoided because of the education it provides, APS attempts to reach a variety of audiences with a broad array of safety materials. APS targets teachers, students, overhead power line contractors, tree trimmers and landscapers, cable TV installers, well drillers, underground line contractors, safety directors and "first responders" (fire and police personnel) with small-group presentations. In the last five years APS has put on hundreds of these presentations and reached thousands of individuals. APS also strives to reach the general public with brochures, bill stuffers, billboards, radio ads, public service announcements and the Arizona Family Internet Site. APS has even sent out electrical safety fliers attached to pizza boxes.

Again last year, APS earned the top rating (AAA) for environmental, economic and social performance from Innovest, an international investment advisory firm. The firm ranked us number two out of 28 electric utilities included in the S&P 500. APS also was presented with the Better Business Bureau of Central and Northern Arizona's Business Ethics Award.

VI. COMMISSION REVIEW OF PWEC/APS CONTRACT

Q. WHY HAS APS SUBMITTED ITS RECENTLY EXECUTED TRACK B POWER CONTRACT WITH PWEC TO THE COMMISSION FOR APPROVAL AND ASSURANCE OF COST RECOVERY?

A. Under Section 3.4 of the APS/PWEC contract, APS must submit the contract for Commission review because it calls for deliveries after January 1, 2006. This provision was added to the master contract used by the Company during the Track B process as a compromise on the issue of prior Commission approval of longer term power agreements. If Commission approval and provision for full cost recovery are not forthcoming within 12 months, both PWEC and APS have the unilateral right to terminate the contract for deliveries in 2006.

Q. HOW DOES THIS CONTRACT FILING AFFECT THE COMPANY'S REQUEST TO RATE BASE THE PWEC ASSETS?

A. It doesn't. APS intends to secure dedication of the PWEC assets long-term by acquiring them and including them in its regulated cost-of-service. Such a decision would result in a mutually-agreed upon termination of the APS/PWEC agreement and render any specific finding by the Commission relative to the APS/PWEC contract unnecessary. However, APS cannot afford to jeopardize its rights under the contract for even the period prior to 2006 by failing to follow the requirements of Section 3.4. As the Commission is aware from the results of the Track B solicitation, the PWEC offer for the four summer months of 2003 through 2006 was the most competitive offer presented to the Company and represented savings to the Company as compared to the market at the time the contract was executed. APS has previously provided the Commission a copy of the APS/PWEC contract (under provisions of confidentiality) as part of the Company's "Report on the Track B Solicitation Process" dated May 27, 2003.

VII. CONCLUSION

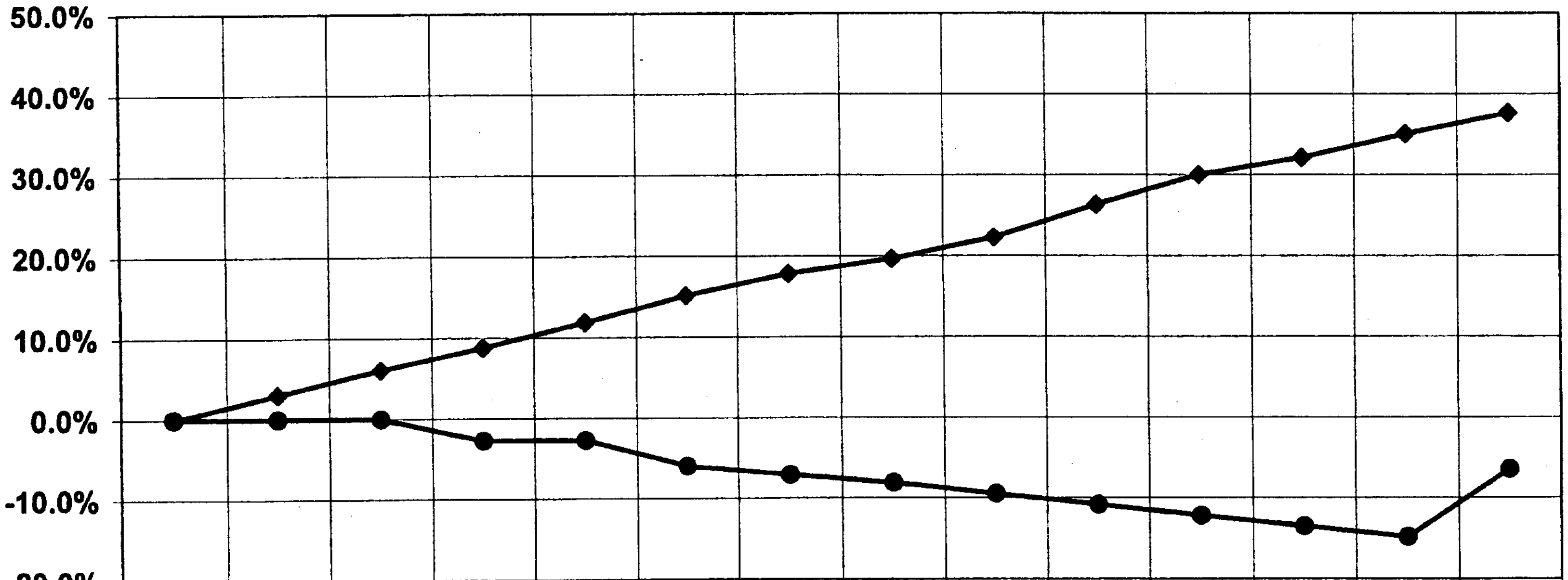
Q. DO YOU HAVE ANY CONCLUDING REMARKS?

A. Yes. Rate cases are never enjoyable for the Company, its customers, or the Commission. They are, however, sometimes necessary. This is one such instance. In this proceeding, the Commission must recognize the need to set rates that reflect the higher costs APS is incurring to provide reliable service to its customers. There is also the unfinished business of restoring to the Company some of the losses it suffered in reliance on a settlement that the Commission encouraged and approved, but later found necessary to amend in a way that denied to APS the benefit of its bargain. Lastly, the Commission has the further opportunity to express its views as to how reliability should be maintained in a challenging and unsettled industry. APS believes now is not the time for another experiment with unproven regulatory or industry structures and urges the Commission to support the Company's efforts to return to the traditional vertically-integrated utility that has served Arizona reliably for over a century.

Q. DOES THAT CONCLUDE YOUR PREFILED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes, it does.

Changes in Consumer Price Index And APS Prices Since 1991

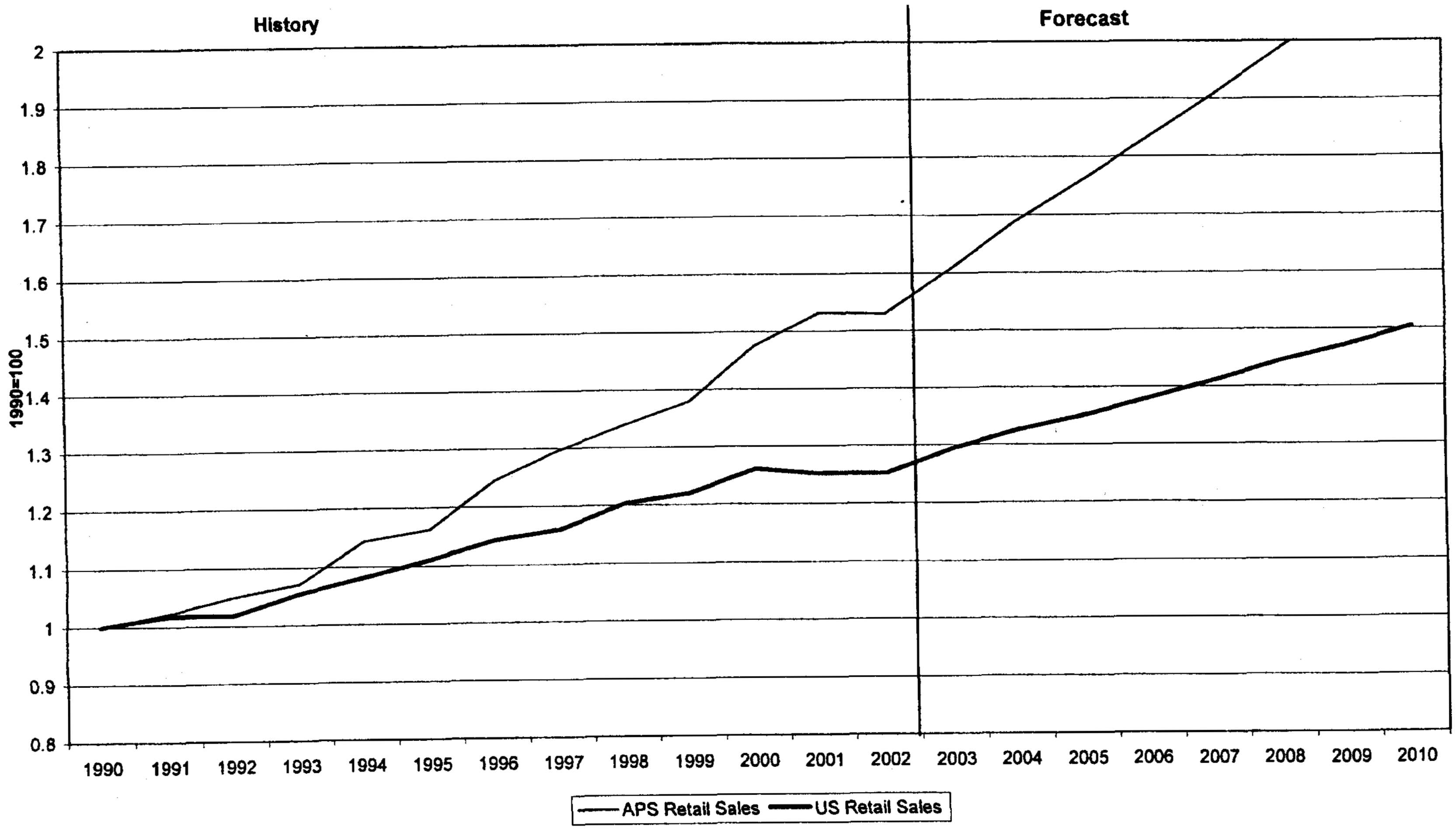


	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
CPI	0	0.0301	0.0609	0.0881	0.1188	0.1516	0.1785	0.1968	0.2232	0.2636	0.3003	0.3216	0.351	0.3767
APS	0	0	0	-0.027	-0.027	-0.06	-0.071	-0.081	-0.095	-0.109	-0.122	-0.135	-0.148	-0.065

Sources: CPI from U.S. Bureau of Labor Statistics; APS from APS Pricing Department

Attachment SMW-2

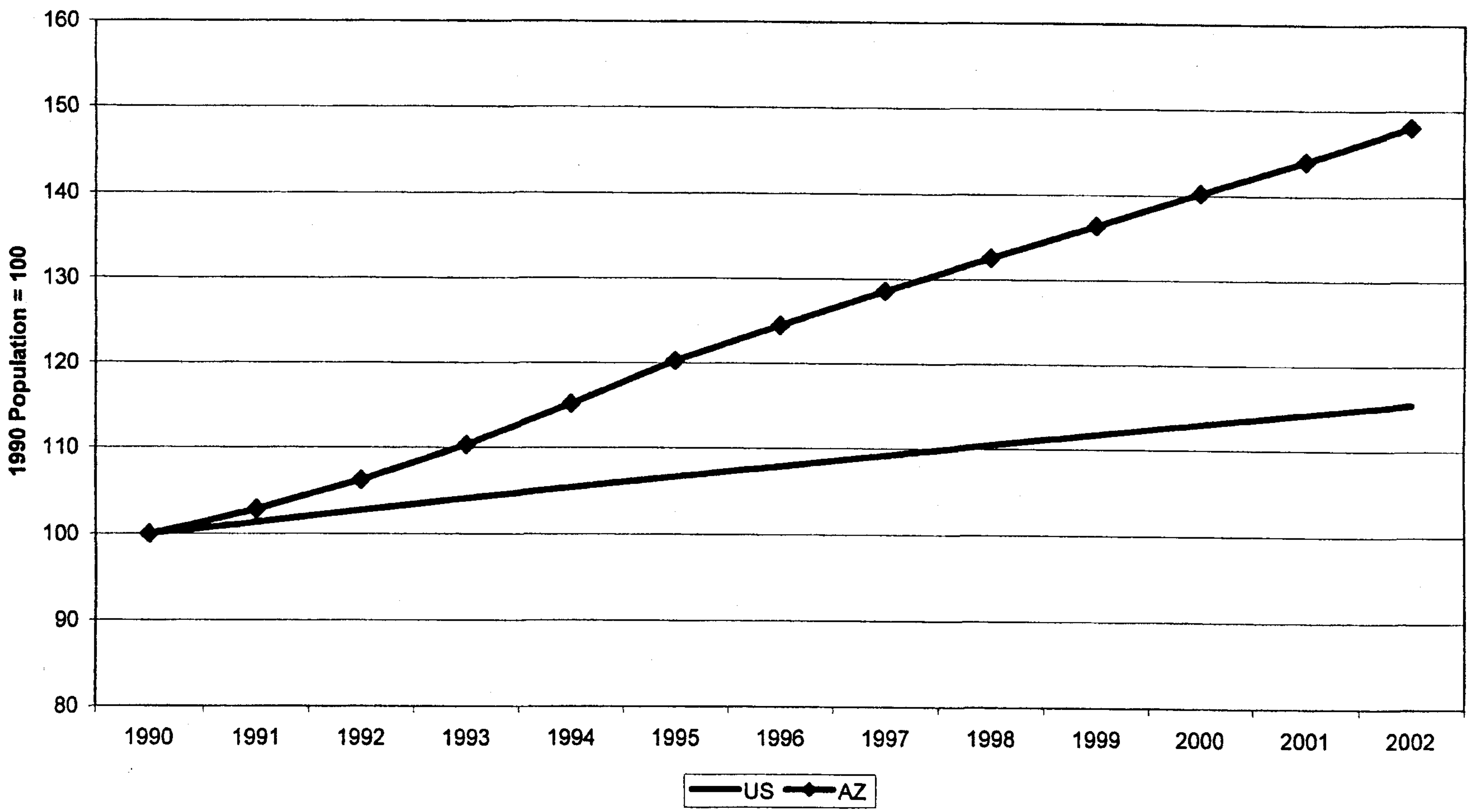
Retail Sales Growth
APS vs U.S.
Indexed to 1990



Sources: U.S. Department of Energy; Energy Information Administration; APS Forecasting Department

Attachment SMW-3

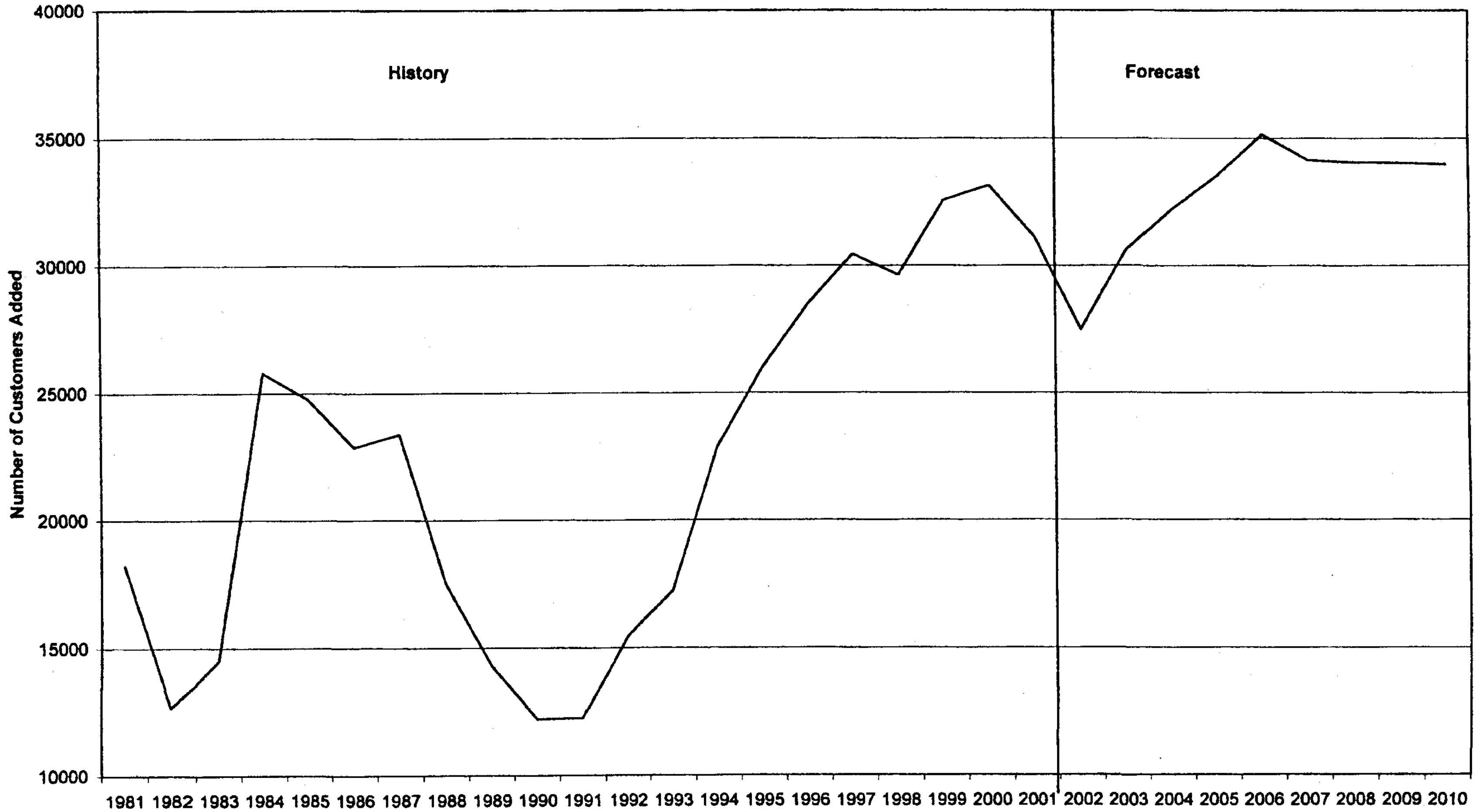
1990 - 2002 Population Growth
Arizona vs U.S.



Sources: U.S. Department of Commerce; U.S. Census Bureau; AZ Department of Commerce; AZ Census Bureau

Attachment SMW-4

APS Retail Customer Growth
Number of Customers Added Each Year



Source: APS Forecasting Department

APS-3

EXHIBIT
APS-3
admitted

DIRECT TESTIMONY OF DONALD G. ROBINSON

On Behalf of Arizona Public Service Company

Docket No. E-01345A-

June 27, 2003

Table of Contents

DIRECT TESTIMONY OF DONALD G. ROBINSON
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-03-____)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, ADDRESS AND OCCUPATION.

A. My name is Donald G. Robinson. I am Vice President of Finance and Planning for Arizona Public Service Company ("APS" or "Company"). My business address is 400 North Fifth Street, Phoenix, Arizona 85004.

Q. ARE YOUR EDUCATIONAL AND PROFESSIONAL QUALIFICATIONS SET FORTH IN APPENDIX A TO YOUR DIRECT TESTIMONY?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I will testify to the Company's financial results and the projections shown on Schedules A and F of the Arizona Corporation Commission's ("Commission") standard filing requirements ("SFRs" or "SFR Schedules"). Additionally, I will identify and support the various adjustments to rate base and operating income set forth in the SFR "B" and "C" schedules. Specifically, I am sponsoring the projected year information provided in SFR Schedules A-2 through A-5, the Total Company amounts shown on SFR Schedules B-2 and C-1b through C-2, and the projected information portion of SFR Schedules F-1 through F-4.

II. SUMMARY

Q. WOULD YOU PLEASE SUMMARIZE YOUR TESTIMONY?

A. APS' requested rate increase is necessary for the Company to achieve financial ratios consistent with maintaining a relatively low investment grade rating. The

Company does not believe that this request will allow it to improve its credit rating to a more desirable BBB+ or single A level, but it should be adequate to maintain a BBB level. The request also would allow APS the opportunity to earn a return on equity equal to its cost of equity.

APS has selected a calendar 2002 test period consistent with Commission rules and prior Commission precedent. That test period was then adjusted to make it more representative of normal operations at the time new rates in this Docket are approved by the Commission. Those adjustments include, among other things, the net impact of including new generation in the Company's rate base and the restoration of certain write-offs previously taken by APS pursuant to its 1999 Settlement Agreement with the Commission ("1999 Settlement" or "Settlement").

As adjusted, APS has a test period jurisdictional rate base of $4,207,476,000 and test period operating income of $263,870,000. This produced an overall rate of return of 6.27%, which is significantly less than APS' cost of capital of 8.67%.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. I will first discuss the Company's financial results. Then I will discuss the pro forma adjustments to Original Cost Rate Base and Operating Income. Finally, I explain the Company's requested surcharge amounts to recover certain costs incurred by APS to comply with the Commission's Electric Competition Rules.

Q. ARE YOU SPONSORING ANY ATTACHMENTS TO YOUR TESTIMONY IN ADDITION TO THOSE PORTIONS OF THE SFR'S DESCRIBED ABOVE?

A. Yes. My testimony includes the following Attachments:

1) DGR-1 – APS Financial Indicators at Proposed Rates,

2) DGR-2 – APS Financial Indicators at Current Rates,

3) DGR-3 – Cost of Long-Term Debt,

4) DGR-4 – Rate Base Pro Forma Adjustments,

5) DGR-5 – Income Statement Pro Forma Adjustments, and

6) DGR-6 – Amounts Deposited in Decommissioning Trusts Included in Cost-Of-Service.

III. <u>FINANCIAL RESULTS</u>

Q. MR. ROBINSON WOULD YOU PLEASE DISCUSS THE CURRENT FINANCIAL CONDITION OF APS?

A. Yes. But in order to do that, I first should put our filing in perspective. More than nine years ago, we instituted the first of a series of rate decreases. The rate decreases, which ultimately resulted in a cumulative reduction of 16%, were the result of several settlement agreements, each of which this Commission approved. As part of the 1999 Settlement, the Company made the commitment to the public and to the Commission that if certain reasonable requests were granted, the Company, absent extraordinary circumstances, would institute annual rate decreases for the period 1999 through 2003. Thanks in part to (1) the Commission's actions in issuing Decision No. 61973 (October 6, 1999), and (2) the Company's continuing efforts to minimize costs and implement numerous additional operating efficiencies, the Company has been able to keep its promise to its customers and this Commission. Also, it should be recognized that the test period used in the 1999 Settlement was 1996, and thus none of the investments in new facilities or increases in operating costs since 1996 are being reflected in the rates charged to our customers.

Although APS' rates have been declining, the Company has, until recently, also been able to keep its commitment to its investors to provide an adequate return. However, the Company's ability to earn a fair return and meet the financial criteria necessary to maintain its corporate credit rating is now jeopardized without the additional rate relief requested by the Company.

Let me explain what that means in terms of the Company's current financial condition. In Attachment DGR-1, I provide some key financial indicators for two historic (2001 and 2002) and three projected (2003, 2004 and 2005) years, with the proposed rate increase effective July 1, 2004, including: (1) adjusted pre-tax interest coverage ratio; (2) adjusted funds from operations interest coverage; (3) funds from operations to adjusted average total debt; (4) adjusted total debt to total capital; (5) return on average common equity; and (6) adjusted return on average common equity. Attachment DGR-1 reflects the financial impact of all of the rate decreases that have or will take effect through July 2003.

As demonstrated in this Attachment, the adjusted return on average common equity ("ROE") has declined from 2001 to 2002 and is anticipated to further decline in 2003. The projected 6.7% ROE in 2003 is substantially below the ROE range that APS witness Dr. Charles E. Olson has determined to be APS' cost of equity.

Q. PREVIOUSLY YOU MENTIONED FINANCIAL CRITERIA NEEDED TO MAINTAIN THE COMPANY'S CREDIT RATING. WHAT ARE THESE FINANCIAL CRITERIA, AND HOW DO THEY IMPACT THE COMPANY'S RATINGS?

A. Rating agencies have established certain financial results and ratios as guidelines for achieving and maintaining an investment grade credit rating. For example, the primary financial criteria used by Standard & Poor's ("S&P") to simply maintain our current BBB investment grade rating include:

1) Pre-tax interest coverage ratio – 3.3 to 2.2 times,
2) Funds from operations ("FFO") interest coverage – 3.8 to 2.7,
3) FFO to total debt – 24.5% to 17.5%, and
4) Total debt to total capital – 49.5% to 57.0%.

Other rating agencies use similar criteria.

Q. WHY DO THE RATING AGENCIES CONSIDER THE FINANCIAL CRITERIA IMPORTANT?

A. Financial criteria are a way to measure a company's financial health, performance and risk. The pre-tax interest coverage ratio is used to determine if earnings are sufficient to pay for interest costs. Although there is a strong relationship between earnings and cash flow, analysis of cash flow can reveal a debt-servicing capability that is either stronger or weaker than might be apparent from earnings ratios. FFO interest coverage is used to measure the sufficiency of a company's cash flow versus its interest costs. FFO to total debt is another cash flow measurement. Total debt to total capital measures a company's leverage.

Q. HOW DO CURRENT APS FINANCIAL RATIOS COMPARE WITH THOSE NEEDED TO MAINTAIN A BBB RATING?

A. As you can see in Attachment DGR-1, most of APS' financial ratios have been slipping with one of the projected 2003 ratios, adjusted total debt to total capital, falling below that acceptable for the BBB range.

Q. WHAT WOULD BE THE IMPACT ON THE COMPANY'S FINANCIAL CONDITION SHOULD THE COMMISSION REJECT APS' RATE REQUEST?

A. In Attachment DGR-2, I show APS financial ratios assuming the denial of the instant rate application. Certain key indicators now fall below the BBB rating range. Common equity returns decline to 6%, clearly a small fraction of what Dr. Olson has determined to be APS' cost of equity.

Additionally, as discussed by Dr. Olson, without the Pinnacle West Energy Corporation ("PWEC") generating units ("PWEC Units"), the Company will be more reliant on the wholesale power market and will, therefore, be judged by the investment community as inherently more risky.

Q. COULD APS RETAIN ITS BBB RATING UNDER THE ABOVE CIRCUMSTANCE?

A. I doubt it. First, the financial results themselves may not support a continued BBB rating, especially in light of the continued deterioration trend. Second, the Company could not hold out to rating agencies much hope of stopping further declines, let alone future improvement in its financial ratios, without a dramatic turnaround in the Commission's treatment of APS.

Rating agencies also monitor more than just the numbers. They also look at qualitative factors, one of the most important being regulatory treatment. Failure by this Commission to recognize the need contained in this request would be a very significant negative indicator to the rating agencies. Such action could be interpreted by the rating agencies that the Commission will not support utilities taking steps to ensure reliability of their systems or responsibly address the impacts of changes in policy. This could adversely impact their view of all Arizona regulated utilities.

Q. PLEASE DESCRIBE THE CONSEQUENCES OF A DOWNGRADE IN APS' RATING.

A. There would be an immediate increase in the cost of commercial paper, a significant increase in the cost of new debt and equity and an even greater increase in current and future revenue requirements. In Attachment DGR-3, I have compared the long-term debt costs of various ratings over the period 2000 through 2002. The average difference in cost between BBB and a BBB- rated long-term debt was 68 basis points over the period shown (calculated by taking the difference of the 3-year averages shown: 7.73% - 7.05%). This basis point difference would mean a significant increase in cost to APS customers due to higher interest expense.

APS has extensive on-going transmission, distribution and APS generation-related construction programs and also has considerable refinancing requirements. For example, as shown on SFR Schedule F-3, the Company projects capital expenditures during the period 2003 through 2005 to be nearly $1.4 billion. Additionally, during 2004 and 2005, the Company will be required to refinance more than $600 million in long-term debt. If the Company were forced to finance these levels with the additional 68 basis points, the cost to customers would be $13.6 million per year in additional interest expense. The recent turmoil in the capital markets related to utilities only increases the Company's concern about its ability to access the capital markets on reasonable terms and obtain the financing needed to support these construction and refinancing programs.

Q. WOULD THERE BE BENEFITS TO CUSTOMERS OF THE COMPANY'S RATING BEING UPGRADED TO BBB+ OR EVEN A?

A. Yes, the cost of new debt and equity would decrease with a resulting decrease in revenue requirements. In Attachment DGR-3, I have also included the cost of both BBB and single-A bonds for the period 2000 through 2002. The average difference in cost was approximately 100 basis points. This difference would mean a significant decrease in cost to APS customers due to lower interest rates.

Q. WHAT ARE THE FINANCIAL CRITERIA NEEDED TO OBTAIN THE SINGLE-A RATING?

A. The financial criteria used by S&P for a single-A investment grade rating for utilities include:

1) Pre-tax interest coverage ratio – 4.0 to 3.3 times,
2) FFO interest coverage – 4.5 to 3.8,
3) FFO to total debt – 30.5 to 24.5%, and
4) Total debt to total capital – 43.0% to 49.5%.

Q. BECAUSE APS IS A SUBSIDIARY OF PINNACLE WEST CAPITAL CORPORATION ("PINNACLE WEST"), IS APS' CORPORATE RATING STILL IMPORTANT?

A. Absolutely. I believe it would be a mistake for this Commission to assume that it is somehow "safe" to allow APS' financial ratios and financial ratings to deteriorate. The Company's construction program to provide for new customers is substantial and as noted above, existing debt issues will require refinancing. In addition, Pinnacle West's ability and willingness to provide equity capital to APS depends on the ability of APS to earn a fair return on such equity. It is imperative that the Company maintain its financial strength, and that can only be done through granting the rate relief requested.

IV. PRO FORMA ADJUSTMENTS

A. Test Year

Q. WHAT TEST YEAR HAS APS PROPOSED IN ITS APPLICATION?

A. The twelve months ending December 31, 2002 is our proposed Test Year. This represents the most recent historical calendar period for which complete cost of service information was available at the time we prepared our filing.

Q. SHOULD THE COMMISSION BASE ITS DECISION IN THIS PROCEEDING SOLELY ON THE UNADJUSTED FINANCIAL RESULTS ACHIEVED BY THE COMPANY DURING THE TEST YEAR?

A. Of course not. The Test Year must be adjusted for changes in operating expenses, revenues, plant-in-service, etc., which are known, measurable, and capable of being reconciled with the Test Year without creating a significant mismatching of costs and revenues. Otherwise, rates would not reflect conditions expected to exist at the time they become effective.

Q. WHAT DOES A "KNOWN AND MEASURABLE" ADJUSTMENT MEAN?

A. I consider an adjustment to be "known" when, given all the circumstances, its probability of occurrence is significantly greater than the chance it will not occur. An adjustment is "measurable" if it can be quantified in a meaningful fashion such that the recognition of at least part of its effect on Test Year results will make the Test Year "more representative" than if the adjustment were omitted altogether.

Q. WHAT DOES IT MEAN THAT AN ADJUSTMENT MUST BE RECONCILED WITH TEST YEAR OPERATIONS?

A. This is simply stated as the matching principle. This principle argues that making only part of an adjustment is improper. For example, it would be wrong to pro forma increased electric sales without recognizing some level of increased costs to produce these sales. As with the concepts of "known and measurable," one cannot insist on a perfect matching for all adjustments without effectively requiring a constantly updated Test Year. The issue is one of degree and of fairness.

Q. DID APS MAKE PRO FORMA ADJUSTMENTS TO TEST YEAR RATE BASE AND OPERATING INCOME?

A. Yes. Test Year pro forma adjustments can be categorized into three basic classes:

1) Accounting, *i.e.*, adjustments that remove expenses or revenues recorded during the Test Year but that are properly associated with previous periods, or adjustments that include expenses or revenues in the Test Year that were erroneously (at least for ratemaking purposes) recorded in an earlier period;

2) Annualizations, *i.e.*, adjustments that merely annualize the full effect of events taking place during the Test Year; and

3) Known and measurable changes to expenses or revenues that took place or will take place after the end of the Test Year, and which are of such significance that they should be recognized for ratemaking purposes.

Q. HAS THE COMMISSION PREVIOUSLY ACCEPTED PRO FORMA ADJUSTMENTS TO THE COMPANY'S TEST YEAR?

A. Yes. It has been the consistent practice of the Commission to accept pro forma adjustments to Test Year rate base and operating income in APS' litigated cases. For example, in APS' last two fully litigated cases, Decision Nos. 55228 (October 9, 1986) and 55931 (April 1, 1988), the Commission accepted pro forma adjustments proposed both by the Company and other parties. Also, by approving a settlement agreement in Decision No. 57649 (December 6, 1991), the Commission effectively accepted many of the Company's pro forma adjustments. Such adjustments also are specifically recognized in A.A.C. R14-2-103.

B. Pro forma Adjustments to Rate Base

Q. HAS APS MADE PRO FORMA ADJUSTMENTS TO TEST YEAR RATE BASE?

A. Yes. These adjustments are shown in "Total Company" amounts on SFR Schedule B-2. The total rate base adjustment is net of the corresponding deferred income taxes. The jurisdictional allocations of each proposed rate base adjustment were calculated by APS witness Alan Propper and are also shown on SFR Schedule B-2. The Total Company portion of this SFR Schedule directly corresponds with Attachment DGR-4, pages 1 through 5. For convenience sake, I will refer in my testimony to Attachment DGR-4.

1. PWEC Units

Q. WHY HAS APS MADE A RATE BASE PRO FORMA ADJUSTMENT ON ATTACHMENT DGR-4, PAGE 1 OF 5, FOR THE PWEC UNITS?

A. As explained in the testimony of APS witnesses Steven M. Wheeler and Ajit P. Bhatti, the Company is proposing to acquire the PWEC Units and include them in APS' rate base. The rate base pro forma adjustment shown on Attachment DGR-4, page 1 of 5, reflects this inclusion in the amount of $895,109,000.

Q. PLEASE DESCRIBE THE PWEC UNITS THAT ARE BEING INCLUDED.

A. The PWEC Units consist of Redhawk Combined Cycle ("CC") Units No. 1 and 2, West Phoenix CC Units No. 4 and 5 and the Saguaro Combustion Turbine Unit No. 3.

Q. WHAT WAS THE BASIS FOR DETERMINING THE PWEC UNITS RATE BASE PRO FORMA?

A. The pro forma adjustment was calculated using the PWEC Units' depreciated original cost, or book value, as of June 30, 2004, one day prior to the date rates can become effective. Because APS would acquire the assets at approximately that time and at their depreciated book value, the pro forma adjustment includes projections for gross plant, accumulated depreciation and accumulated deferred income taxes. To determine a mid-year 2004 book value, the average of the projected year-end 2003 and 2004 book balances was calculated.

Q. IS THERE A CORRESPONDING OPERATING INCOME PRO FORMA ADJUSTMENT FOR THE PWEC UNITS?

A. Yes. As discussed later in my testimony, a corresponding pro forma adjustment related to operating income is shown on Attachment DGR-5, page 9 of 27.

2. Regulatory assets

Q. PLEASE DESCRIBE THE RATE BASE ADJUSTMENT ON ATTACHMENT DGR-4, PAGE 2 OF 5, FOR REGULATORY ASSETS.

A. This pro forma adjustment reflects the removal from rate base of the regulatory assets amortized under a prior settlement in 1996. The December 31, 2002 balance for this Regulatory Asset was $104 million, resulting in a rate base adjustment of ($62,920,000). Because the $104 million of regulatory assets will be fully amortized by June 30, 2004, which again is the day before rates can become effective, it is appropriate to remove this asset from rate base.

Q. IS THERE A CORRESPONDING OPERATING INCOME PRO FORMA ADJUSTMENT FOR REGULATORY ASSETS?

A. Yes. As discussed later in my testimony, a corresponding pro forma adjustment related to operating income is shown on Attachment DGR-5, page 20 of 27.

3. **ISFSI**

Q. ATTACHMENT DGR-4, PAGE 3 OF 5, SHOWS A RATE BASE ADJUSTMENT FOR INDEPENDENT SPENT FUEL STORAGE INSTALLATION ("ISFSI"). COULD YOU PLEASE EXPLAIN?

A. ISFSI is a dry storage facility for spent nuclear fuel from the Company's Palo Verde Nuclear Generating Station ("Palo Verde"). The fuel pools where the spent nuclear fuel is currently stored will soon reach the allowed maximum capacity. The U.S. Department of Energy has been delayed in siting and constructing permanent spent nuclear fuel storage facilities. Therefore, the continued operation of the Palo Verde plant requires an alternative interim storage solution. Spent nuclear fuel will be transferred from the fuel pools to the ISFSI.

Q. HOW HAVE THE COSTS ASSOCIATED WITH ISFSI BEEN RECORDED IN THE PAST?

A. APS has recorded a regulatory asset that represents the deferral of ISFSI costs from the time the Palo Verde units were placed in service through December 31, 2002 with a corresponding offset in the accumulated provision for nuclear fuel amortization. The liability is recorded based on the generation of electricity from Palo Verde. The basis for recording this as a regulatory asset is A.A.C. R14-2-1608 ("Rule 1608"), which provides for the recovery of spent fuel through the System Benefits Charge ("SBC"). Article II.2.6 of the 1999 Settlement provides for the deferral of SBC costs not then reflected in rates when such costs were incurred for full recovery at a later date.

Q. PLEASE EXPLAIN THE RATE BASE PRO FORMA ADJUSTMENT FOR ISFSI.

A. The pro forma adjustment to rate base of $2,614,000 shown on Attachment DGR-4, page 3 of 5, reflects the amount of ISFSI costs anticipated to be accrued between the end of the Test Year and the implementation of rates that recover the deferred asset - January 1, 2003 through June 30, 2004. It should be noted that if the ISFSI costs had not been deferred during the Test Year, they would have been properly recorded as fuel expense and would have been included in unadjusted Test Year expenses.

Q. IS THERE A CORRESPONDING OPERATING INCOME PRO FORMA ADJUSTMENT FOR ISFSI?

A. Yes. As discussed later in my testimony, corresponding pro forma adjustments related to operating income are shown on Attachment DGR-5, pages 14 of 27 and 21 of 27.

4. Reversal of Settlement write-off

Q. HAS APS MADE A PRO FORMA ADJUSTMENT ON ATTACHMENT DGR-4, PAGE 4 OF 5, FOR REVERSAL OF THE SETTLEMENT WRITE-OFF?

A. Yes. As discussed in Mr. Wheeler's testimony, the Company is proposing to reverse the $234 million write-off that was taken by the Company as a result of the 1999 Settlement. This write-off was taken in consideration of the benefits previously agreed to under that Settlement.

Q. WHAT IS THE RESULTING PRO FORMA ADJUSTMENT?

A. The Company removed $234 million pre-tax from ongoing regulatory cash flows and this was recorded as a net reduction of regulatory assets. The reduction was reported as an extraordinary charge on the consolidated income statement. The pro forma adjustment to rate base to reverse that write-off is $141,570,000.

Q. IS THERE A CORRESPONDING OPERATING INCOME PRO FORMA ADJUSTMENT FOR THE REVERSAL OF THE SETTLEMENT WRITE-OFF?

A. Yes. As discussed later in my testimony, a corresponding pro forma adjustment related to operating income is shown on Attachment DGR-5, page 22 of 27.

5. Transmission assets

Q. WHY HAS APS MADE A PRO FORMA ADJUSTMENT ON ATTACHMENT DGR-4, PAGE 5 OF 5, FOR TRANSMISSION ASSETS?

A. Under Federal Energy Regulatory Commission ("FERC") rules, APS is required to take transmission service and related ancillary service for APS Standard Offer customers under the APS Open Access Transmission Tariff ("OATT"). Additionally, APS is required to bill itself for transmission and related ancillary services for APS Standard Offer customers under the APS OATT. Mr. Propper's testimony describes the methodology for determining this rate base pro forma adjustment. The net pro forma adjustment to rate base is ($648,643,000).

Q. IS THERE A CORRESPONDING OPERATING INCOME PRO FORMA ADJUSTMENT FOR TRANSMISSION?

A. Yes. As discussed later in my testimony, a corresponding pro forma adjustment related to operating income is shown on Attachment DGR-5, page 15 of 27.

6. Total rate base adjustments

Q. WOULD YOU PLEASE SUMMARIZE THE ADJUSTED TEST YEAR ORIGINAL COST RATE BASE PROPOSED BY APS?

A. Yes. On SFR Schedule B-1, APS has an adjusted jurisdictional original cost rate base of $4,207,476,000.

C. Pro forma Adjustments to Operating Income

Q. HAS APS ALSO MADE PRO FORMA ADJUSTMENTS TO TEST YEAR OPERATING INCOME?

A. Yes. They are set forth in Schedule C-2 of the Company's application as part of the Commission's SFRs. SFR Schedule C-2 provides total Company figures and Mr. Propper's jurisdictional allocation of my adjustments. The Total Company portion of this SFR Schedule directly corresponds with Attachment DGR-5, pages 1 through 27. Again, for convenience, I will refer in my testimony to Attachment DGR-5.

Q. IS INCOME TAX EXPENSE INCLUDED IN EACH OF YOUR OPERATING INCOME PRO FORMA ADJUSTMENTS?

A. Yes. Each pro forma adjustment identified in Attachment DGR-5 includes an income tax calculation, at the current statutory combined state and federal income tax rate, so that the impact on net income for each adjustment can be determined. However, throughout most of my testimony I will be referring to pre-tax pro forma adjustment amounts.

1. Regulatory assessments and franchise fees

Q. PLEASE EXPLAIN THE COMPANY'S PROPOSED TREATMENT OF REGULATORY ASSESSMENTS AND FRANCHISE FEES.

A. This pro forma adjustment is being made so that all revenue-based taxes and assessments are treated as an "add-on" in accordance with our proposed tariff. Currently, both regulatory assessments and sales taxes are add-ons. The Company is proposing that franchise fees also be a direct add-on rather than included in base rates. Under the Company's previous methodology, all customers pay the same franchise fee percentage regardless of the actual franchise fees charged to APS by their community. The proposal to treat franchise fees as a community specific add-on will ensure that customers in areas charging lower franchise fees to the Company will pay only those lower fees. While APS' existing base rate treatment of franchise fees is administratively easier, the proposed treatment is more equitable. Additionally, the proposed treatment of franchise fees is consistent with the ratemaking treatment of franchise fees for the majority of the other utilities in the state and this pro forma adjustment results in no change to operating income.

Q. **HOW WAS THE SPECIFIC PRO FORMA ADJUSTMENT DETERMINED?**

A. The pro forma adjustment amounts were determined by an analysis of the amount charged to expense Account 928, "Regulatory Commission Expenses" and the amount charged to Account 927, "Franchise Requirements." We then removed both the revenues and expenses for the test year to be consistent with the Company's tariff proposal to treat franchise fees as an "add-on."

2. Annualize ACC rate levels

Q. **PLEASE EXPLAIN THE PRO FORMA ADJUSTMENT ON ATTACHMENT DGR-5, PAGE 2 OF 27, TO ANNUALIZE RATE LEVELS.**

A. This pro forma adjustment is being made so that the revenue deficiency calculation can be expressed in terms of the base revenues in effect at the time new rates are anticipated to become effective. Under the terms of the 1999 Settlement, APS instituted a rate decrease effective July 1, 2002 and will institute another rate decrease effective July 1, 2003. This pro forma adjustment reflects an additional six months for the 2002 decrease and a full twelve months for the 2003 decrease. The amount was calculated on a month-by-month basis using actual Test Year billing quantities for each class of customer and results in an adjustment to pre-tax operating income of ($37,005,000).

3. Normalize weather conditions

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED PRO FORMA ADJUSTMENT TO NORMALIZE TEST YEAR WEATHER CONDITIONS.

A. Attachment DGR-5, page 3 of 27, which is based on the same methodology previously accepted by the Commission, shows the reduction to Test Year revenues and expenses that would have occurred if normal weather conditions had been experienced during the Test Year. Actual Test Year weather conditions should be normalized to produce a more reasonable basis for establishing future rate levels. The pre-tax operating income effect of the pro forma adjustment is ($4,159,000).

Q. HOW WAS NORMAL WEATHER DETERMINED?

A. Using data from the National Weather Service at Phoenix Sky Harbor, an analysis of weather for the ten years ending December 31, 2002 was performed to determine normal weather so that normal consumption can be calculated. This analysis is done on a month-by-month basis for each class of customer. Normal weather for winter months is determined using an analysis of each month's heating degree days. Normal summer weather includes an analysis of both cooling degree days and relative humidity.

Q. WHAT IS THE NEXT STEP IN CALCULATING THE WEATHER NORMALIZATION PRO FORMA ADJUSTMENT?

A. The ten-year average ("normal") was calculated and then compared to the Test Year weather. The difference between normal weather and Test Year weather is then converted to kWh consumption by using a weather coefficient. The weather coefficient is determined by using a mathematical regression analysis of the effect of weather on consumption for each class of customer. The weather normalized kWh consumption is then applied to the December 31, 2003 rate levels. This calculation was made on a month-by-month basis for each class of customer.

Q. ARE CORRESPONDING EXPENSES NORMALIZED?

A. Yes. Test Year expenses directly affected by kWh consumption are normalized by multiplying the weather normalized kWh consumption by the Test Year average fuel and purchased power expense and the Test Year average OATT expense. Test Year average fuel and purchased power expense was calculated by dividing the Test Year own load fuel and purchased power expense by Test Year own load sales. Test Year average OATT expense was determined by using the actual amount APS billed to APS for retail network transmission service and ancillary services. The total OATT charges were then divided by the corresponding OATT-billed kWh to determine the Test Year average OATT expense.

4. Annualize customer levels

Q. PLEASE DESCRIBE THE ADJUSTMENT TO ANNUALIZE CUSTOMER LEVELS.

A. Attachment DGR-5, page 4 of 27, shows the increase in Test Year revenues and expenses if the December 31, 2002 level of customers had been receiving service during each month of the Test Year. This adjustment is consistent with previous Commission decisions adopting pro forma adjustments for year-end customer levels. Because new customers connect and old customers disconnect on a continual basis, it is necessary to calculate annualized revenue at year-end to produce the most reasonable Test Year possible. The pro forma adjustment to pre-tax operating income is $14,570,000.

Q. DID YOU SIMPLY MULTIPLY THE END OF TEST YEAR NUMBER OF CUSTOMERS TIMES THE AVERAGE TEST YEAR CONSUMPTION PER CUSTOMER?

A. No. That would mask the seasonality of the Company's customer base, which is always greater during the winter than the summer.

Q. HOW WAS THE ANNUAL NUMBER OF CUSTOMERS DETERMINED?

A. The customer annualization pro forma adjusts the number of customers each month to be consistent with the number of customers at the end of the Test Year, while preserving the natural seasonality inherent in customer levels. The "ratio of customer change" is the mechanism by which this is accomplished. The ratios are based on the midpoint of each month. Customers added during the first half of the month are assumed to have been billed for consumption during the entire month, while customers added during the second half of the month are assumed to have been billed for zero consumption for that month. Accordingly, for December 2002, customers assumed added during the second half of the month have not been billed for 1/24th of the test year. Customers added after the midpoint of November 2002 represent 3/24th of the annual increase in customers, which would have been billed for November if they had been in effect as of the start of November. Likewise, 5/24th for customers added after the midpoint of October 2002, 7/24th for customers added after the midpoint of September 2002, and so forth.

Q. PLEASE DESCRIBE HOW THE CONSUMPTION IS DETERMINED.

A. The monthly adjustments to customer counts are then multiplied by the weather normalized kWh usage for residential and general service classes, or the actual usage for the other classes, which are not weather normalized. The resulting kWh adjustment is then applied to the December 31, 2003 rate levels. This calculation was made on a month-by-month basis for each class of customer.

Q. DO CORRESPONDING EXPENSES NEED TO BE ADJUSTED?

A. Yes. As is done in the weather normalization pro forma adjustment, Test Year expenses are then normalized by applying the kWh adjustment to the Test Year average fuel and purchased power expense and the Test Year average OATT expense. Additionally, an increase in customer accounts expense is included in the pro forma because, in addition to fuel and purchased power and OATT expenses, non-payroll related customer accounts and customer service and information expenses increase incrementally as the number of customers increases.

Q. HOW WAS THE ADJUSTMENT FOR CUSTOMER ACCOUNTS EXPENSE DETERMINED?

A. The customer accounts expense was determined using Test Year Customer Accounts Expenses (FERC Accounts 901 through 905) and Customer Service and Informational Expenses (FERC Accounts 907 through 910) and removing the payroll expenses associated with these accounts. Payroll expenses are removed because incremental increases in the number of customers are not expected to significantly impact the time associated with customer accounts and customer service expenses. The remaining amount was allocated to each customer class, divided by 12 to arrive at a monthly average then divided by the average number of customers during the 12 months ending December 31, 2002. The resulting cost per customer per month was multiplied by the monthly customer adjustment by customer class to arrive at an amount for the pro forma adjustment.

Q. **WHAT IS THE INTENDED OVER-ALL EFFECT OF THE APS CUSTOMER ANNUALIZATION, WEATHER NORMALIZATION AND RATE ANNUALIZATION PRO FORMA ADJUSTMENTS YOU JUST DISCUSSED?**

A. The impact of combining these three pro forma adjustments is to apply an annualized year-end 2003 rate level to adjusted 2002 consumption.

Q. **HAS THE COMMISSION PREVIOUSLY ACCEPTED SUCH ADJUSTMENTS?**

A. Yes, several times. For example, in Decision Nos. 55228 and 55931, the Commission accepted similar pro forma adjustments.

5. Schedule 1 changes

Q. **WHY HAS APS MADE AN ADJUSTMENT IN ATTACHMENT DGR-5, PAGE 5 OF 27, FOR SCHEDULE 1 CHANGES?**

A. As discussed in APS witness David J. Rumolo's testimony, the Company is proposing changes to Schedule 1, which sets forth the general terms and conditions of service. The pro forma adjustment shown on Attachment DGR-5, page 5 of 27, reflects the impact to operating income associated with the proposed APS Schedule 1 changes. The revenue impact was calculated by comparing the difference between the proposed and current charges and applying that difference to the actual number of times work was performed during the Test Year. Operations expense was decreased to reflect the savings to APS when a customer chooses to forego a paper bill and, instead, uses the Internet to review and pay for electric service. These savings were calculated by estimating the reduced cost to APS when a bill is not printed or mailed ($4.176 annually per customer), as well as the net reduced cost of using electronic payment processing rather than payment by check ($1.08 annually per customer). This amount was almost entirely offset by the $5.00 incentive given to customers for foregoing paper bills. The net savings were then applied to the number of customers foregoing paper bills in the Test Year. The pre-tax operating income pro forma adjustment is $82,000.

6. Base rate component of EPS

Q. PLEASE DESCRIBE THE PRO FORMA ON ATTACHMENT DGR-5, PAGE 6 OF 27, RELATED TO THE BASE RATE COMPONENT OF THE COMPANY'S SYSTEM BENEFITS CHARGE ("SBC"), WHICH IS USED TO FUND THE ENVIRONMENTAL PORTFOLIO STANDARD ("EPS").

A. This pro forma adjustment merely reflects the Company's accounting for the $6 million authorized in the SBC to partially fund the EPS. On a monthly basis, during the Test Year, an accounting entry was recorded to remove that component of the SBC from revenues and record it as a contribution-in-aid-of-construction. Because the amounts were charged to that balance sheet account rather than an Operation and Maintenance ("O&M") account, they are not reflected in the Test Year operating results. The pro forma adjustment is needed to properly reflect for ratemaking treatment revenues and expenses related to the base rate portion of the SBC used to fund the EPS. The pro forma adjustment to pre-tax operating income is ($737,000).

Q. HOW WAS THE PRO FORMA INCREASE TO OPERATING REVENUES CALCULATED?

A. The pro forma amount to be included in revenues for the base rate component of EPS was arrived at by an analysis of the actual revenue amounts recorded during the Test Year. While originally booked as revenues, the revenue amounts were reversed with corresponding accounting entries made to offset the costs associated with compliance with the EPS. The pro forma adjustment merely restores the original accounting treatment of these amounts as revenues.

Q. HOW WAS THE PRO FORMA ADJUSTMENT TO EXPENSES DETERMINED?

A. The pro forma amount to be included for expense reflects the amount (in this case $6,000,000) previously allowed by the Commission in base rates for the EPS.

Q. WHY IS THERE A DIFFERENCE BETWEEN THE REVENUE PRO FORMA AMOUNT AND THE EXPENSE PRO FORMA AMOUNT?

A. This is merely the result of a small timing difference between the date an EPS expenditure was made and the date revenues were collected.

7. Fuel, purchased power and off-system sales

Q. WHY WAS IT NECESSARY TO CALCULATE A PRO FORMA ADJUSTMENT TO TEST YEAR FUEL AND PURCHASED POWER EXPENSE AS SHOWN ON ATTACHMENT DGR-5, PAGE 7 OF 27, AND TEST YEAR OFF-SYSTEM SALES AS SHOWN ON ATTACHMENT DGR-5, PAGE 8 OF 27?

A. There are two primary reasons to normalize Test Year fuel and purchased power expense. First, the fuel and purchased power expense should be adjusted to reflect normalized outages at the generation facilities and known changes to generating capability, both of which affect the number of kWh produced by a particular generating unit. Second, Test Year fuel and purchased power expense should be recalculated using fuel and purchased power prices more closely resembling those anticipated to occur when the rates requested in this proceeding would become effective. Such prices not only impact the per kWh cost of a particular generator, but also the number of kWh that generator would have produced given its duty cycle. The off-system sales pro forma adjustment is a direct result of and uses the same fuel and purchased power prices as the pro forma adjustment to fuel and purchased power.

Q. WHAT WERE THE ASSUMPTIONS USED TO CALCULATE THE PRO FORMA ADJUSTMENT FOR FUEL AND PURCHASED POWER EXPENSE?

The assumptions used in the development of the fuel and purchased power expense and off-system sales pro forma adjustments are basically the same as those used in the development of the 2003 Fuel Budget and the January 2003 resource and needs assessment filed with the Commission for Track B [see Decision No. 65743 (March 14, 2003)]. Those adjustments have been updated, however, to reflect the effects of the Track B results and other known changes to fuel and purchased power costs.

Q. HOW IS THE PRO FORMA ADJUSTMENT FOR FUEL AND PURCHASED POWER EXPENSE DETERMINED?

A. Using the output of a computer modeling run, an average ¢/kWh for fuel and purchased power cost is calculated and compared to the average Test Year fuel and purchased power costs. The difference is then multiplied by Test Year retail kWh sales as adjusted for weather and customer level annualization. This produces a pro forma adjustment increasing fuel and purchased power costs and thereby adjusting pre-tax operating income by ($120,584,000).

Q. DOES A FUEL AND PURCHASED POWER PRO FORMA REQUIRE A CORRESPONDING OFF-SYSTEM SALES PRO FORMA?

A. Yes. The assumptions underlying the fuel and purchased power pro forma adjustment, such as using 2003 purchased power price and gas prices, 2003 budgeted consumption, etc., dictate that the amount and price of off-system sales also will change for two primary reasons. First, the market price for power and natural gas determine when it is economical for the Company to make off-system sales and the potential quantity of such sales. Second, the APS generation is first used to economically serve native load with the balance of the generation being made available for off-system sales. The use of the 2003 budgeted consumption changes the amount of native load being served by APS generation and, therefore, the amount of generation available for off-system sales. The off-system sales adjustment associated with the fuel and purchased power pro forma adjustment results in a pro forma adjustment to pre-tax operating income of $23,668,000.

8. PWEC Units

Q. WHY HAS APS MADE AN ADJUSTMENT AS SHOWN IN ATTACHMENT DGR-5, PAGE 9 OF 27, FOR THE PWEC UNITS?

A. As described above and in the testimony of Mr. Wheeler and Mr. Bhatti, APS is proposing to include the PWEC Units in base rates. The pro forma adjustment shown on Attachment DGR-5, page 9 of 27, reflects the operating income impact of inclusion of these assets.

Q. DOES THE OPERATING INCOME PRO FORMA ADJUSTMENT HAVE SEVERAL COMPONENTS? IF SO, WOULD YOU LIST ALL OF THESE COMPONENTS?

A. Yes. There are nine components to this pro forma adjustment:

1) Fuel and purchased power expense,

2) Off-system sales,

3) Operations expense,

4) Maintenance expense,

5) Depreciation and amortization expense,

6) Administrative and general expense,

7) Property tax,

8) Change in overall cost of capital, and

9) Income taxes, including the effect of increased interest deductions.

Q. WOULD YOU PLEASE EXPLAIN THE FIRST TWO COMPONENTS?

A. The pro forma adjustment reflects the fuel and purchased power savings associated with dispatching the more efficient PWEC Units rather than using APS existing units or buying economy energy and also includes the additional net margin that will result from increased off-system sales.

Q. WAS A SIMULATION OF THE APS SYSTEM DISPATCH USED TO CALCULATE THE OFF-SYSTEM SALES AND FUEL EXPENSE?

A. Yes. A simulation was performed using the same assumptions as were used in the fuel and purchased power and off-system sales pro forma adjustments, except that the PWEC Units were included in the generation dispatch. The modeling parameters for the PWEC Units are consistent with the Track B contract specifications with the exception that West Phoenix CC No. 5 is modeled as if it had been available beginning January 1, 2003. This modeling assumption overstates West Phoenix CC No. 5's impact, at least in 2003, and thus benefits APS customers. The planned maintenance outages are adjusted to reflect a 6-year average outage cycle. The simulation provided information to calculate the average ¢/kWh of fuel and purchased power. This value was compared to the fuel and purchased power costs as adjusted in the previous pro forma. The difference was then multiplied by adjusted Test Year kWh sales.

Q. PLEASE EXPLAIN COMPONENTS THREE THROUGH SEVEN.

A. Components three through seven are additional operating expenses associated with the PWEC Units.

Component three, operations expense, reflects the 2003 budgeted operations expense for each of the PWEC Units, except that operations expense for West Phoenix CC Unit No. 5 has been normalized to reflect a full year of operation.

Component four, maintenance expense, includes two major pieces. The first piece is routine maintenance and is based on the 2003 budget for each of the PWEC Units, except that maintenance expense for West Phoenix CC Unit No. 5 has been normalized to reflect a full year of operation. The second piece is for overhaul maintenance. This amount was determined in two parts. Because the Company expects the turbine overhauls for the PWEC combined cycle units to occur on a 12-year cycle, the amount was calculated using a 12-year average. A 6-year average was used for other major and minor overhaul expenses. Because the PWEC Units have no historical basis for calculating overhaul expenses, the forecasted 12- and 6-year maintenance budgets were used. Future amounts were restated in 2003 dollars, and an average was calculated.

Component five, depreciation and amortization expense for the PWEC Units, reflects one full year of depreciation for each of the units. The depreciation expense was calculated based on the depreciable plant in service at December 31, 2002 for the West Phoenix CC No. 4, Saguaro, and Redhawk Units. The estimated plant in service at the planned commercial operations date, June 2003, was used to calculate the depreciation expense for West Phoenix CC No. 5.

Component six, administrative and general expenses ("A&G"), includes 2003 budgeted A&G expenses at each of the PWEC Units. Included in many of the components discussed are allocated costs from the APS and Pinnacle West shared services organizations.

Component seven, property taxes for the PWEC Units, were forecasted for 2005 based on anticipated December 31, 2003 plant in service balances and the current valuation factor, assessment rate and property tax rates.

Q. HAVE YOU INCLUDED IN THE PRO FORMA ADJUSTMENT THE BENEFIT TO CUSTOMERS OF A REDUCED WEIGHTED COST OF DEBT AND A CHANGE IN THE COMPANY'S CAPITAL STRUCTURE?

A. Yes. I have included in the Electric Operating Revenue line the benefit to customers of including the PWEC Units related debt as part of the Company's permanent capital structure. As part of APS' acquisition of the PWEC Units, the debt owed by PWEC to APS will be cancelled and the loans obtained by APS in May 2003 will be treated as utility debt for ratemaking purposes. The impact of including this $500 million debt lowers the Company's overall long-term weighted cost of debt from 5.8% to 5.7% and changes the percentage of debt in the capital structure from approximately 50% to 55%. This lowers the overall cost of capital from 8.67% to 8.31%. The change in the rate of return has been applied to the Test Year and pro forma adjustment rate base amounts with the resulting savings included in the PWEC Units pro forma adjustments.

The general income tax benefit associated with the additional tax deductions for interest associated with the $500 million debt issuance in our capital structure also has been reflected in the pro forma. The final component, the income tax calculation, includes this benefit and also includes a specific additional deduction for the synchronized interest expense associated with the addition of the PWEC Units to rate base. The deduction was determined using the Test Year interest rate and capital structure.

Q. WHAT IS THE TOTAL NET INCOME PRO FORMA ADJUSTMENT FOR THE PWEC UNITS?

A. The total after-tax pro forma adjustment for the PWEC Units is an increase in operating income of $12,776,000.

9. Annualize payroll

Q. DID APS ANNUALIZE TEST YEAR PAYROLL?

A. Yes. Attachment DGR-5, page 10 of 27, shows an adjustment to Test Year pre-tax operating income of ($1,031,000). This annualizes the payroll and payroll tax expense levels to 2002 year-end employee levels and March 2003 wage levels. The adjustment is a net increase in Test Year operating expenses, with the higher costs associated with a rising average salary partially offset by reductions in employee levels resulting from the Company's 2002 voluntary severance program. The payroll adjustment is consistent with payroll annualization adjustments authorized by the Commission in prior APS cases.

Q. HOW DID APS CALCULATE THE PAYROLL ANNUALIZATION?

A. The first step in calculating the payroll annualization was to determine the Test Year monthly employee counts and wages. Because there are different employee categories (*e.g.*, union, performance review), the calculation was done for each of the various categories and was determined separately for APS, Pinnacle West and Marketing & Trading ("M&T"). Pinnacle West and M&T are included because they provided various services to APS during the Test Year. The escalated March 2003 average wage was calculated and compared to each month's average wage for each employee category for each entity. This amount was multiplied by the actual employee count to determine the wage annualization.

Next, the December 2002 employee count was compared to each month's employee count for each employee category for each company. This difference was then multiplied by the escalated March 2003 wage to arrive at the employee annualization. The addition of the wage annualization and the employee annualization results in a total payroll annualization. Payroll taxes were then calculated using the annualized payroll and the statutory tax rates.

Q. DOES THE TOTAL PAYROLL ADJUSTMENT GO TO O&M?

A. No. The total payroll and payroll taxes annualizations need to be allocated to exclude from O&M payroll and taxes that, for example, are capitalized. This was accomplished by calculating the percentage of APS O&M payroll to total payroll during the Test Year for each entity. The resulting O&M payroll and payroll taxes were allocated to fuel, operations (excluding fuel) and maintenance based on the Test Year payroll amounts booked to each of these activities.

10. Employee severance

Q. DID APS OFFER A VOLUNTARY EMPLOYEE SEVERANCE DURING THE TEST YEAR?

A. Yes. During the Test Year, the Company offered a voluntary severance package to employees. The benefit of the employee reductions is reflected in the previous payroll annualization adjustment.

Q. WHAT WAS THE TEST YEAR EXPENSE ASSOCIATED WITH THE VOLUNTARY EMPLOYEE SEVERANCE?

A. Test Year O&M expenses include costs associated with employees accepting the voluntary severance package. APS proposes, for ratemaking purposes, to levelize this severance amount over three years. However, because all of the severance cost was actually booked in the Test Year, two-thirds of the recorded expense and amounts to be recovered from power plant participant owners for their share of the severance cost needed to be removed from the Test Year. The pro forma adjustment to pre-tax operating income is $23,155,000.

11. Employee benefits adjustment

Q. PLEASE EXPLAIN THE NEED FOR THE EMPLOYEE BENEFITS PRO FORMA ADJUSTMENT.

A. This adjustment is necessary to appropriately recognize the costs associated with pension, Other Post-retirement Employee Benefit ("OPEB") and Employee Savings plans costs.

While the Company's pension and OPEB funds have performed well both historically and in recent years, the steep decline in the overall investment markets has caused the market value of the plan funds to decrease significantly. The decreased value of the funds combined with much lower interest rates and increased medical costs means the Company will incur increased expenses related to the plans. Lower interest rates are a significant driver in determining pension and OPEB obligations, which in turn increases the related costs. These factors are responsible for approximately 90% of the employee benefits pro forma adjustment. The pro forma adjustment also recognizes the increased costs associated with the Employee Savings Plan.

Q. HOW WAS THE EMPLOYEE BENEFITS PRO FORMA ADJUSTMENT DETERMINED?

A. First, the total change in pension, OPEB and Employee Savings Plan expenses was determined. The total amount included all of the Pinnacle West Companies and was the difference between actual 2002 and the 2003 expenses determined by our actuaries, Towers Perrin.

Q. HOW DID YOU DETERMINE THE AMOUNT OF INCREASED BENEFITS COSTS PROPERLY ALLOCABLE TO APS O&M?

A. An allocation factor was calculated and applied to the total change in benefit cost. This allocation factor was determined by analyzing 2002 actual benefits expense booked to APS O&M versus the total benefit costs for Pinnacle West's pension, OPEB and Employee Savings plans. A final allocation to fuel, operations (excluding fuel) and maintenance was then done based on the Test Year payroll percentage of each of these types of expenses to total Test Year O&M payroll. The pro forma adjustment to pre-tax operating income is ($24,818,000).

12. On-going Electric Competition Rules compliance

Q. IS THERE AN OPERATING INCOME PRO FORMA ADJUSTMENT RELATED TO COMPLIANCE WITH THE ELECTRIC COMPETITION RULES?

A. Yes. As shown on Attachment DGR-5, page 13 of 27, there is a pro forma adjustment for the on-going costs of complying with the Electric Competition Rules.

Q. PLEASE EXPLAIN WHY THE PRO FORMA ADJUSTMENT SHOWN ON ATTACHMENT DGR-5, PAGE 13 OF 27, IS NEEDED.

A. The Test Year operating costs do not include the costs the Company incurred to comply with the Electric Competition Rules because these costs were deferred as a Regulatory Asset. This adjustment is necessary to allow APS full and timely recovery of the on-going portion of costs. Treatment of the deferred regulatory asset is discussed later in my testimony.

Q. HOW WAS THE ADJUSTMENT CALCULATED?

A. An analysis of amounts booked in 2002 to the Electric Competition Rules compliance deferred asset was performed to determine which costs would continue to be incurred to comply with the Electric Competition Rules. Payroll-related costs were included, as well as the incremental on-going costs associated with information technology. APS' share of the Arizona Independent Scheduling Administrator's ("AISA") current 2003 budget amount also was included. The summation of these costs results in a pre-tax operating income pro forma adjustment for ongoing Electric Competition Rules compliance activities of ($1,477,000).

13. ISFSI

Q. PLEASE EXPLAIN THE INCOME STATEMENT PRO FORMA ADJUSTMENTS FOR SBC WHICH IS USED TO FUND THE ISFSI.

A. APS is requesting recovery through regulated rates of (1) the on-going costs associated with ISFSI and (2) an amortized portion of the previously discussed deferred amounts. The proposed treatment for on-going ISFSI costs is shown on Attachment DGR-5, page 14 of 27, and the pro forma adjustment for deferred amounts is shown on Attachment DGR-5, page 21 of 27.

Q. PLEASE EXPLAIN THE PRO FORMA ADJUSTMENT FOR ON-GOING ISFSI COSTS.

A. The on-going ISFSI pro forma adjustment includes both pre-shutdown activities and post-shutdown activities. APS plans on placing as much of the costs associated with post-shutdown activities into the external qualified decommissioning trusts as allowed under the federal income tax rules. To qualify for favorable tax treatment, the amounts placed into the qualified decommissioning trusts must actually be collected from ratepayers as part of cost-of-service. This requires a specific ruling from the Commission. Attachment DGR-6 contains, for each Palo Verde generating unit, the cost-of-service amounts to actually be collected from retail ratepayers. Such a schedule should be attached to any Commission order accepting these amounts. The pre-tax operating income impact of on-going ISFSI, both pre- and post-shutdown for all three Palo Verde units is ($2,881,000).

Q. WHY DOES THE PRO FORMA ADJUSTMENT SHOWN ON ATTACHMENT DGR-5, PAGE 14 OF 27, APPEAR AS A FUEL EXPENSE?

A. The ongoing ISFSI expense is properly booked to FERC Account 518, "Nuclear Fuel Expense." However, for ratemaking purposes, these amounts will be functionalized to the SBC pursuant to Rule 1608.

Q. PLEASE EXPLAIN THE PRO FORMA ADJUSTMENT FOR ISFSI ASSETS.

A. This pro forma adjustment is needed to amortize the regulatory asset, which I discussed previously. Similar to the on-going ISFSI pro forma adjustment, the ISFSI regulatory asset pro forma adjustment contains both pre-shutdown and post-shutdown elements. The Company proposes to amortize the costs associated with pre-shutdown activities over a five-year period. For costs associated with post-shutdown activities the Company proposes: (1) for Units 1 and 3, to amortize the costs over the license period (through December 31, 2024 and March 25, 2027, respectively); and (2) for Unit 2, over the term of the sale/leaseback agreement (through December 31, 2015). APS plans to place as much of these amortized amounts associated with the post-shutdown amortization into the external qualified decommissioning trusts as allowed under the federal income tax rules. To qualify for the favorable tax treatment, the amounts placed into the qualified decommissioning trusts must actually be collected from ratepayers as part of cost-of-service. This requires a specific ruling from the Commission. Attachment DGR-6 contains, for each Palo Verde generating unit, the cost-of-service amounts to actually be collected from retail ratepayers. Such a schedule should be attached to any Commission order accepting these amounts. Additionally, for ratemaking purposes, these amounts will be functionalized to the SBC pursuant to Rule 1608. This pro forma adjustment for both pre- and post-shutdown ISFSI regulatory asset amortization of ($4,963,000) to after-tax operating income also includes the "interest synchronization" adjustment to income taxes associated with the rate base pro forma adjustment.

14. Transmission expense

Q. WHY IS APS MAKING AN OPERATING INCOME PRO FORMA ADJUSTMENT REGARDING TRANSMISSION EXPENSES?

A. As previously discussed, APS is proposing to remove all Test Year transmission rate base and expenses and replace those costs with an expense calculated using the OATT rate. The pro forma adjustment shown on Attachment DGR-5, page 15 of 27, merely reflects the operating income impact of that proposal. Mr. Propper's testimony describes the methodology for determining the pre-tax pro forma adjustment. After synchronizing the interest associated with the rate base pro forma, the after-tax operating income adjustment is ($43,617,000). Note that this adjustment appears much larger than is actually the case because it reflects all of the capital costs associated with transmission as an operating expense.

15. Interest on customer deposits

Q. PLEASE EXPLAIN THE ANNUALIZED ADJUSTMENT FOR CUSTOMER DEPOSIT INTEREST EXPENSE SHOWN ON ATTACHMENT DGR-5, PAGE 16 OF 27.

A. This pro forma adjustment reflects the annualized interest cost associated with customer deposits (interest expense) as an operating expense due to the treatment of the customer deposit balances at the end of the Test Year as a rate base deduction. This treatment conforms with the treatment used by the Commission in previous Company rate cases. The amount of the pro forma adjustment was calculated by applying a 2.2% annual interest rate to the December 31, 2002 outstanding deposit balance. The annual interest rate is the rate required by our tariffs to be paid customers on their deposits – the established one year Treasury Constant Maturities rate, effective on the first business day of each year, as published on the Federal Reserve Website. The 2002 interest rate was 2.2%. This resulted in a pre-tax operating income adjustment of ($875,000).

16. Normalize generation maintenance

Q. PLEASE DESCRIBE HOW YOU DEVELOPED NORMALIZED PRO FORMA ADJUSTMENTS FOR GENERATION MAINTENANCE EXPENSE.

A. In Attachment DGR-5, page 17 of 27 and page 18 of 27, I have adjusted Test Year expenses to normalize maintenance levels for the Company's production plant-in-service at December 31, 2002. Because maintenance schedules vary from year to year, this adjustment is necessary to develop a reasonable basis for the establishment of future rates. Any single year, such as the Test Year, will almost never represent the average maintenance expense levels, that can reasonably be expected when rates established in this case will be in effect. Thus, every APS rate case of which I am aware has made this sort of normalizing adjustment. For the non-nuclear units, normal maintenance levels are determined by averaging the maintenance expense at each power plant using a six-year average maintenance cycle. Normal Palo Verde expenses are based on historical expenses for a three year period. For all production units, only historical overtime labor costs were adjusted to present cost levels based on historical labor increases. Regular labor costs have been excluded from this adjustment, as anticipated permanent staffing levels already are included in the payroll annualization adjustment. Non-labor maintenance costs were adjusted to current cost levels using the Handy-Whitman cost indices.

The non-nuclear pro forma adjustment also includes the costs associated with maintaining the renewable generation resources developed under the EPS. These O&M costs were not included in the unadjusted Test Year. The costs were developed using the Company's anticipated renewable installed capacity. Although actual average O&M expenses are anticipated to be higher, the ¢/kWh was capped at 3¢/kWh. A three-year average of the anticipated O&M expense for the years 2004 through 2006 was calculated and used in the pro forma adjustment.

The total non-nuclear pre-tax operating income adjustment is $6,014,000 and the nuclear pre-tax operating income adjustment is $945,000.

17. Annualize depreciation and amortization

Q. HAS APS MADE A PRO FORMA ADJUSTMENT ON ATTACHMENT DGR-5, PAGE 19 OF 27, TO ANNUALIZE DEPRECIATION AND AMORTIZATION.

A. Yes. APS witness Laura L. Rockenberger explains in her testimony the Company's proposal regarding depreciation and amortization. The pro forma adjustment of ($3,027,000) to pre-tax operating income shown on Attachment DGR-5, page 19 of 27, merely reflects that proposal.

18. Regulatory assets

Q. PLEASE EXPLAIN THE BASIS FOR THE REGULATORY ASSETS PRO FORMA ADJUSTMENT SHOWN ON ATTACHMENT DGR-5, PAGE 20 OF 27.

A. There are two Commission Decisions relevant to this question. First, pursuant to Decision No. 59601 (April 24, 1996), APS is authorized to recover certain specified regulatory assets through July 1, 2004. Second, Decision No. 61973 changed the pattern of regulatory asset recovery set by Decision No. 59601 and allowed for the creation and amortization of certain new regulatory assets, such as the reasonable and prudent costs of compliance with the Electric Competition Rules.

Q. PLEASE EXPLAIN THE DEPRECIATION AND AMORTIZATION AMOUNT INCLUDED IN THE REGULATORY ASSETS PRO FORMA ADJUSTMENT SHOWN ON ATTACHMENT DGR-5, PAGE 20 OF 27.

A. The reduction to amortization includes the removal of $114,980,000 representing the Test Year Regulatory Asset amortization authorized in Commission Decision No. 61973. As of July 1, 2004, the date new rates are anticipated to become effective, this asset will be fully amortized and no more amortization expense for this asset will be incurred. Therefore, it is appropriate to remove this amount from depreciation and amortization expense.

Q. HAVE ADDITIONAL AMOUNTS BEEN INCLUDED IN DEPRECIATION AND AMORTIZATION?

A. Yes. The Company proposes a five-year amortization of approximately $16 million of regulatory assets, which are remaining in SFR Schedule B-1's regulatory asset and liability balances after removing the amortization through June 30, 2004 and the previously discussed ISFSI regulatory asset. The accelerated amortization pursuant to the 1999 Settlement was based upon the regulatory assets balance at that time. Since then, additional regulatory assets were booked for on-going items such as unamortized gains and losses on reacquired debt; additions/adjustments for nuclear decontamination; and the Palo Verde Unit 2 rent levelization consistent with previous Commission orders.

Q. DOES THE INCOME TAX CALCULATION TAKE INTO ACCOUNT "INTEREST SYNCHRONIZATION" FOR THE REGULATORY ASSETS RATE BASE PRO FORMA?

A. Yes. When combined with the asset amortization adjustments, this results in a pro forma adjustment to after-tax operating income of $66,893,000.

19. Reversal of settlement write-off

Q. PLEASE DESCRIBE THE PRO FORMA FOR REVERSAL OF THE SETTLEMENT WRITE-OFF.

A. As discussed previously, APS is proposing to include in its base rates the reversal of the settlement write-off. The after-tax operating income pro forma adjustment of ($7,821,000) reflects a 15-year amortization of the reversal as well as the interest synchronization impact on income taxes from the Rate Base pro forma adjustment. As discussed by Mr. Wheeler, fifteen years was selected to minimize customer impact while providing for a meaningful, timely recovery of this past write-off.

20. **Nuclear decommissioning fund**

Q. PLEASE EXPLAIN THE NUCLEAR DECOMMISSIONING FUNDS AND WHAT IS MEANT BY A "QUALIFYING" DECOMMISSIONING FUND.

A. Like all nuclear power plants, Palo Verde eventually will need to be decommissioned, an expensive and time consuming process. Regulatory agencies throughout the country, including the Commission, have required that the cost of this eventual decommissioning be recovered from APS electricity customers during the operating life of the facility.

Most of the amounts collected from ratepayers that relate to decommissioning of a nuclear power plant can be deposited into a "qualified" decommissioning trust. A trust is "qualified" to the extent it meets certain requirements set forth in the Internal Revenue Code and related regulations. A qualified decommissioning trust is afforded significant income tax benefits vis-à-vis other funding alternatives. This favorable tax treatment is twofold. First, contributions to a qualified decommissioning trust are deductible for federal income tax purposes in the year made to the extent these amounts are actually collected from ratepayers as part of cost-of-service. Furthermore, the investment earnings of the assets within the trust are taxed at a federal income rate of 20% versus 35% if the investment earnings occurred outside of the qualified decommissioning trust.

The Nuclear Regulatory Commission ("NRC") and most state regulators prefer the external funding option both because of the increased security of the funding for its intended purpose and because of the income tax benefits afforded qualified decommissioning trusts.

Q. PLEASE EXPLAIN THE NEED FOR A PRO FORMA ADJUSTMENT FOR THE NUCLEAR DECOMMISSIONING FUND.

A. Two basic components associated with determining the annual amounts to deposit into the decommissioning fund have changed. These are the escalation rate and the earnings assumption.

Projections of the decommissioning costs are done in current year's dollars. The escalation rate is used to account for the inflation that will occur between now and the time of decommissioning. The escalation rate should reflect increases in payroll and material costs. The Consumer Price Index has grown at an average annual rate of 4.14% over the past 25 years. APS is proposing to use a rounded 4% as the annual escalation rate.

The earnings assumption is used to determine how much the asset will grow between now and the time of decommissioning. APS is proposing to use an after-tax earnings assumption of 4.8%. This amount was determined using JPMorgan's investment return assumptions for Aggregate Bonds of 5.25% and Large Cap Equity of 7.5%. Using a 60% stocks/40% bonds asset allocation, the applicable tax rates for qualifying and non-qualifying funds, and the anticipated allocation between qualifying and non-qualifying funds, a 4.8% after tax earnings assumption was calculated. The revised escalation rate and earnings assumption produces an annual funding requirement of approximately $19.2 million.

Q. ARE THERE CONSEQUENCES OF UNDER-FUNDING?

A. Yes. The Participants in Palo Verde have established a series of rules relating to the decommissioning fund. Amendment 13 to the Participation Agreement provides that each Participant monitors the funding of each other's decommissioning funds to ensure that adequate funds are available at the end of the plant life. At the end of each calendar year, each Participant, including APS, has a required minimum amount that must be funded, known as the "floor." If APS falls below the floor, it must contribute additional dollars to restore the decommissioning fund to the funding curve's required level. In all likelihood, these catch-up contributions could not be contributed to the qualified decommissioning trusts, which would further exacerbate the problem. The APS fund is currently above the floor but not funded fully to the required curve.

The goal should be to adequately fund the decommissioning liability without over- or under-funding. If the liability is materially over-funded, it indicates current and past customers bore more of a burden for the liability. An under-funded plan indicates current and past customers were charged less than the full cost of power they received from Palo Verde.

Q. IS SPECIFIC COMMISSION ACTION REQUIRED?

A. Yes. As previously mentioned, to qualify for the favorable tax treatment, the amounts must actually be collected from ratepayers as part of cost-of-service. As with the on-going post-shutdown ISFSI and post-shutdown ISFSI regulatory asset amortization, this requires a specific ruling from the Commission. Attachment DGR-6 contains, for each Palo Verde generator, the cost-of-service amounts to actually be collected from retail ratepayers. Such a schedule should be attached to any Commission order accepting these amounts. The impact of this pro forma adjustment for all three Palo Verde generators on pre-tax operating income is ($7,766,000).

21. Annualize property tax

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED ADJUSTMENT TO AD VALOREM (PROPERTY) TAXES.

A. The pre-tax operating income pro forma adjustment of ($10,199,000) shown on Attachment DGR-5, page 24 of 27, reflects actual plant balances at December 31, 2002 and the 2002/2003 tax rates. This type of adjustment previously has been accepted by the Commission.

22. Financing application

Q. PLEASE EXPLAIN THE ADJUSTMENT FOR INTEREST INCOME FROM PWEC.

A. Commission Decision No. 65796 (April 4, 2003) authorized APS to issue non-secured debt in an amount not greater than $500,000,000 and loan the proceeds to PWEC. The pro forma adjustment is being made to comply with certain conditions specified in Commission Decision No. 65796. The Company has calculated the adjustment consistent with Staff's conditions in that Order, although this methodology overstates the amount of actual APS interest income. It should be noted that the need for this adjustment is independent of the inclusion of the PWEC Units in rate base and the resulting capital structure change. However, the amount of the pro forma adjustment has assumed repayment or cancellation of the PWEC/APS debt on June 30, 2004 and would change if the PWEC Units are not placed in rate base, because in that instance, repayment will likely not occur until 2007.

Q. HOW DID APS CALCULATE THE BASIS POINT (INTEREST) DIFFERENTIAL?

A. The net interest income was calculated using $500 million over 13.5 months and the prescribed 264 basis point differential. A financing end date of June 30, 2004 was used to reflect this filing's proposal to include the PWEC Units in base rates, the accompanying transfer of the assets to APS and retirement of the financing. APS is proposing to amortize the interest differential over a five-year period. The amortization will be reflected as a reduction (credit) to operating expense.

Q. DID DECISION NO. 65796 HAVE ANOTHER REQUIREMENT AS IT RELATES TO THE CALCULATION OF THIS PRO FORMA ADJUSTMENT?

A. Yes. Decision No. 65796 also required the basis point differential balance to carry an interest rate of six percent. Beginning/ending balances were calculated for each of the five years using a straight-line five-year amortization. An average balance could then be determined for each year. The six percent interest rate was applied to each year's average balance to determine each year's interest. The cumulative interest was divided by five to determine the straight-line interest amortization. The five-year straight-line interest differential amortization was added to the straight-line interest amortization to determine the annual amortization associated with the PWEC financing. As shown on Attachment DGR-5, page 25 of 27, the result of this calculation on pre-tax operating income is $3,416,000.

23. Income tax/interest synchronization

Q. PLEASE EXPLAIN THE ADJUSTMENT SHOWN ON ATTACHMENT DGR-5, PAGE 26 OF 27, FOR INCOME TAX AND SYNCHRONIZATION OF INTEREST.

A. This adjustment reflects the synchronization of interest expense using the adjusted December 31, 2002 capital structure and cost of long-term debt, as well as the use of the current statutory income tax rates. The pro forma adjusts after-tax operating income by ($5,049,000).

24. **Miscellaneous adjustments**

Q. PLEASE EXPLAIN THE ADJUSTMENT IN ATTACHMENT DGR-5, PAGE 27 OF 27, MISCELLANEOUS ADJUSTMENTS.

A. This pro forma adjusts various miscellaneous expenses from the year ended December 31, 2002. APS has eliminated a number of non-recurring or out of period expenses. APS further excluded from operating expense costs associated with certain employee programs. The total adjustment to pre-tax operating income is $6,816,000.

Q. WHAT ITEMS ARE INCLUDED IN THE MISCELLANEOUS PRO FORMA ADJUSTMENT?

A. There are seven miscellaneous adjustments. I will briefly explain each of them below.

The first adjustment removes a write-off that was taken in the Test Year, but related to a prior period, for a Four Corners pulverizer.

The second adjustment is being made to include in base rates M&T lease expenses that were not included in the Test Year.

The third adjustment is to remove a revenue write-off that was taken during the Test Year. That write-off pertained to a prior period.

The fourth adjustment removes the employee programs expense incurred during the Test Year.

The fifth adjustment removes income that was received by APS during the Test Year for the early termination of the City of Williams wholesale power agreement. That income was FERC jurisdictional.

The sixth adjustment removes certain franchise fees expenses. As with the revenue write-off, these expenses are associated with prior periods.

The final adjustment removes the asset divestiture disallowance that was expensed during the Test Year. Because the 1/3 disallowance is not an on-going expense, it is appropriate to remove this cost from Test Year expenses.

25. Total operating income adjustments

Q. WOULD YOU SUMMARIZE THE COMPANY'S ADJUSTED TEST YEAR OPERATING RESULTS?

A. Yes. After making the adjustments described in my testimony and applying the jurisdictional allocation factors developed by Mr. Propper, APS had jurisdictional operating revenues of $1,940,146,000. Jurisdictional Test Year operating expenses were $1,676,276,000. This produces adjusted jurisdictional operating income of $263,870,000.

Q. ARE THERE ANY SIGNIFICANT COSTS WHICH HAVE NOT BEEN INCLUDED IN THIS RATE REQUEST?

A. Yes. As everyone is aware, the state is experiencing a significant bark beetle infestation of the ponderosa pine forests. This infestation, which has been caused by the prolonged Arizona drought, has resulted in approximately one million dead or dying trees that pose a threat to APS power lines. There will be considerable costs associated with removing these trees, which must be done to preserve system reliability.

Q, WHY HASN'T THE COMPANY INCLUDED THOSE COSTS IN THIS REQUEST?

A. As the present time, it is unclear what the magnitude of the costs to APS would be, largely because the Governor has requested federal funds to assist in dealing with this problem and the disposition of those funds is unknown. The Company may need to reflect these costs in its filing when the issue becomes clearer.

Q. ARE THERE ANY OTHER COSTS THAT HAVE NOT BEEN INCLUDED IN THIS RATE REQUEST?

A. Yes, there are. For example, the Company has not included the costs associated with the replacement of the steam generator at Palo Verde Unit 2 which is scheduled for this fall.

Q. WHY HAS THE COMPANY CHOSEN NOT TO MAKE ADDITIONAL ADJUSTMENTS?

A. The Company's intention has been to seek a rate increase level that would produce reasonable financial results while minimizing the impact on our customers. We believe that our current request does balance these interests.

If parties to this proceeding modify the Company's adjustments, it may be necessary to include additional adjustments to maintain the Company's financial health.

26. Surcharge adjustment

Q. IS THE COMPANY REQUESTING RECOVERY OF ANY ADDITIONAL REGULATORY ASSETS BEYOND THOSE PREVIOUSLY DISCUSSED?

A. Yes. As provided in the 1999 Settlement, APS filed an adjustment mechanism to collect the costs of compliance with the Electric Competition Rules. The adjustment mechanism was titled the Competition Rules Compliance Charge or CRCC. APS is proposing to collect $49,334,000 plus interest over 5 years under the CRCC. Mr. Propper is sponsoring the base CRCC charge in his testimony and rate schedules. As shown on Schedule H-1, the ¢/kWh charge applied to the adjusted test year sales is $8,283,000.

Q. PLEASE EXPLAIN THE AMOUNTS INCLUDED IN THE CRCC.

A. The CRCC consists of three major parts: (1) costs associated with the implementation of Direct Access; (2) costs associated with divestiture of the APS generating assets; and (3) costs associated with implementation of Track B. As required by the 1999 Settlement and the proposed CRCC adjustment mechanism in Docket No. E-01345A-02-0403, the summation of 1, 2 and 3 is then credited/debited by the Competitive Transition Charge ("CTC") multiplied by retail sales consistent with the formula specified in the Settlement.

Q. HOW WAS THE AMOUNT ASSOCIATED WITH DIRECT ACCESS IMPLEMENTATION CALCULATED?

A. The asset balance at December 31, 2002 was increased to include the costs the Company will incur from the end of the Test Year (December 31, 2002) through the time rates recovering the asset amortization are anticipated to go into effect (July 1, 2004). Inclusion of future costs is appropriate because the Company must continue to remain in compliance with the Electric Competition Rules. These costs include actual amounts booked in January through April 2003 and a projection for the remaining fourteen months based on the average costs incurred from May 2002 through April 2003. The average was adjusted to reflect known decreases to costs such as the AISA budget reduction. The May 2003 projection includes the final loan payment to the AISA. Capitalized interest was added to each month's balance using the actual 2nd quarter 2003 interest rate.

Q. HOW WAS THE AMOUNT ASSOCIATED WITH THE ASSET DIVESTITURE DETERMINED?

A. Consistent with the reversal of the Settlement write-off discussed by Mr. Wheeler, the asset balance was increased to reflect a reversal of the write-off of one-third of asset divestiture costs.

Q. HOW WAS THE AMOUNT ASSOCIATED WITH THE TRACK B IMPLEMENTATION DETERMINED?

A. Actual February through April 2003 expenses associated with the Independent Monitor ("IM") and development of information systems ("IS") were determined. A forecast of additional IM and IS costs also was included. The payments by bidders were used to reduce these expenses. Capitalized interest was included for the period February 2003 through June 2004.

Q. WHAT IS THE BASIS FOR INCLUDING AN ADJUSTMENT FOR CTC COLLECTIONS?

A. The 1999 Settlement allowed APS to recover $350 million net present value through a CTC, which expires on December 31, 2004. If by December 31, 2004, APS has recovered more or less than $350 million net present value, as determined by a formula in the Settlement, the nominal dollars of the difference will be credited/debited against the costs subject to recovery under the adjustment clause allowed in the 1999 Settlement.

Q. HOW WAS THE CTC ADJUSTMENT DETERMINED?

A. Consistent with the 1999 Settlement, the amount was projected through December 31, 2004 in accordance with Exhibit B of the 1999 Settlement. Actual sales were used to calculate the annual recovery for the years 1999 through 2002. Forecasted sales were used to calculate the 2003 and 2004 CTC recovery. An 8.8% discount rate was used to calculate the net present value, resulting in a difference of approximately $2,918,000. This amount has been used in the pro forma adjustment as a reduction to the CRCC.

Q. DOES THIS MEAN THE COMPANY IS CHARGING FOR CTC UNTIL DECEMBER 31, 2004 EVEN IF RATES GO INTO EFFECT ON JULY 1, 2004?

A. No. In fact, because the Company is proposing to implement the new rate schedules (which exclude a CTC component) on July 1, 2004, should a customer choose an alternate energy supplier during the period July 1, 2004 through December 31, 2004, they will get a "free ride" and APS would not collect amounts that are being credited to customers under its proposal.

V. CONCLUSION

Q. DO YOU HAVE ANY CONCLUDING REMARKS?

A. APS' requested rate increase is necessary for the Company to achieve financial ratios consistent with maintaining even a low investment grade rating. The request also would provide APS the opportunity to earn a return on equity equal to its cost of equity.

APS has selected a test period consistent with Commission rules and prior Commission precedent. That test period was then adjusted to make it more representative of normal operations at the time new rates in this docket are approved by the Commission.

Q. DOES THAT CONCLUDE YOUR PREFILED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes.

Appendix A
Statement of Qualifications
Donald G. Robinson

Donald G. Robinson is Vice President of Finance and Planning for Arizona Public Service Company. Mr. Robinson is responsible for the Company's financial planning, corporate planning, budgeting, forecasting, accounting, risk management, tax services and supply chain management.

Mr. Robinson was previously Vice President of Regulation and Planning for Arizona Public Service Company. In this position, Mr. Robinson was responsible for the Company's regulatory policies and activities before the Arizona Corporation Commission and the Federal Energy Regulatory Commission, as well as corporate planning.

Prior to the promotion above, Mr. Robinson was Director of Accounting, Regulation and Planning for Arizona Public Service Company. Mr. Robinson had responsibility for the Company's accounting, planning and regulatory policies and activities.

Mr. Robinson joined the Company in 1978 and held a number of supervisory positions in the accounting department. In 1981, he was named manager of Regulatory Affairs and in 1998, Manager of Rates and Regulation. Mr. Robinson was a principal in the consulting firm Micon from 1992-1996. Mr. Robinson has a Bachelor of Science degree in Accounting.

ARIZONA PUBLIC SERVICE COMPANY

REGULATED FINANCIAL INDICATORS WITH PROPOSED RATE INCREASE EFFECTIVE JULY 1, 2004

			Projected		
Indicator	2001	2002	2003	2004	2005
Adjusted Pre-tax Interest Coverage Ratio[1]	3.6	2.9	2.4	3.3	3.2
Adjusted Funds from Operations Interest Coverage[1]	4.9	5.6	3.8	4.3	4.2
Funds from Operations to Adjusted Average Total Debt[1]	26%	31%	18%	21%	21%
Adjusted Total Debt to Total Capital[1]	55%	55%	59%	53%	52%
Return on Average Common Equity	12.4%	9.2%	7.9%	11.5%	10.4%
Adjusted Return on Average Common Equity[1][2]	8.0%	7.9%	6.7%	11.0%	10.4%

/1/ Adjusted for the Palo Verde 2 Sale/Leaseback.

/2/ Included in calculation is the amortization of $183 million present value stranded revenue disallowance required by the 1999 Settlement Agreement.

ARIZONA PUBLIC SERVICE COMPANY

REGULATED FINANCIAL INDICATORS
AT PRESENT RATES

Indicator	Projected 2003	Projected 2004	Projected 2005
Adjusted Pre-tax Interest Coverage Ratio[/1/]	2.4	2.6	2.1
Adjusted Funds from Operations Interest Coverage[/1/]	3.8	3.8	3.5
Funds from Operations to Adjusted Average Total Debt[/1/]	18%	18%	16%
Adjusted Total Debt to Total Capital[/1/]	59%	55%	56%
Return on Average Common Equity	7.9%	8.4%	6.0%
Adjusted Return on Average Common Equity[/1//2/]	6.7%	7.8%	6.0%

/1/ Adjusted for the Palo Verde 2 Sale/Leaseback.

/2/ Included in calculation is the amortization of $183 million present value stranded revenue disallowance required by the 1999 Settlement Agreement.

ARIZONA PUBLIC SERVICE COMPANY

COST OF LONG-TERM DEBT /1/

Bond Rating	2000	2001	2002	Three-Year Average
Single-A	6.98%	6.29%	4.84%	6.04%
BBB+	7.57%	6.83%	5.72%	6.71%
BBB	7.37%	7.18%	6.60%	7.05%
BBB-	7.72%	7.90%	7.58%	7.73%
Below investment grade	9.78%	8.95%	16.11%	11.61%

/1/ Information based on the Lehman Brothers Utility Index; includes all publicly registered deals greater than $150 million with more than 18 months.

ARIZONA PUBLIC SERVICE COMPANY

Detail of Pro Forma Adjustments to Original Cost Rate Base as Shown on Schedule B-2

Total Company

(Thousands of Dollars)

PRO FORMA ADJUSTMENT: PWEC UNITS

Adjustment to Test Year rate base to include the Pinnacle West Energy Units including West Phoenix Combined Cycle No. 4, West Phoenix Combined Cycle No. 5, Redhawk Combined Cycle No. 1, Redhawk Combined Cycle No. 2 and Saguaro Combustion Turbine No. 3.

Line No.	Description	Amount	
1.	Gross Utility Plant in Service	$	1,021,886
2.	Less: Accumulated Depreciation and Amortization	$	73,395
3.	Net Utility Plant in Service	$	948,491
4.	Less: Total Deductions	$	53,382
5.	Total Additions	$	-
6.	Total Rate Base	$	895,109

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Original Cost Rate Base as Shown on Schedule B-2
Total Company
(Thousands of Dollars)

PRO FORMA ADJUSTMENT: REMOVE REGULATORY ASSETS AMORTIZED UNDER PRIOR SETTLEMENT

Adjustment to Test Year rate base to exclude certain net regulatory assets which, pursuant to the terms of the 1999 Settlement Agreement, will be fully amortized by June 30, 2004.

Line No.	Description	Amount
1.	Gross Utility Plant in Service	$ -
2.	Less: Accumulated Depreciation and Amortization	$ -
3.	Net Utility Plant in Service	$ -
4.	Less: Total Deductions	$ (41,080)
5.	Total Additions	$ (104,000)
6.	Total Rate Base	$ (62,920)

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Original Cost Rate Base as Shown on Schedule B-2
Total Company
(Thousands of Dollars)

PRO FORMA ADJUSTMENT: INDEPENDENT SPENT FUEL STORAGE INSTALLATION ("ISFSI")

Adjustment to Test Year rate base to include the amount of System Benefits related ISFSI costs anticipated to be accrued between the end of the Test Year and June 30, 2004.

Line No.	Description	Amount
1.	Gross Utility Plant in Service	$ -
2.	Less: Accumulated Depreciation and Amortization	$ -
3.	Net Utility Plant in Service	$ -
4.	Less: Total Deductions	$ 1,707
5.	Total Additions	$ 4,321
6.	Total Rate Base	$ 2,614

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Original Cost Rate Base as Shown on Schedule B-2
Total Company
(Thousands of Dollars)

PRO FORMA ADJUSTMENT: REVERSAL OF SETTLEMENT WRITE-OFF

Adjustment to Test Year rate base to restore the pre-tax $234 million deduction taken by the Company in consideration of benefits previously agreed to under the 1999 Settlement.

Line No.	Description	Amount
1.	Gross Utility Plant in Service	$ -
2.	Less: Accumulated Depreciation and Amortization	$ -
3.	Net Utility Plant in Service	$ -
4.	Less: Total Deductions	$ 92,430
5.	Total Additions	$ 234,000
6.	Total Rate Base	$ 141,570

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Original Cost Rate Base as Shown on Schedule B-2
Total Company
(Thousands of Dollars)

PRO FORMA ADJUSTMENT: TRANSMISSION ASSETS

Adjustment to Test Year rate base to remove transmission assets and generation plant functionalized to ancillary services consistent with FERC rules requiring APS to take transmission service and related ancillary services for the APS Standard Offer customers under the APS OATT.

Line No.	Description		Amount
1.	Gross Utility Plant in Service	$	(1,264,590)
2.	Less: Accumulated Depreciation and Amortization	$	(499,955)
3.	Net Utility Plant in Service	$	(764,635)
4.	Less: Total Deductions	$	(115,992)
5.	Total Additions	$	-
6.	Total Rate Base	$	(648,643)

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2
Total Company
(Thousands of Dollars)

PRO FORMA ADJUSTMENT: **EXCLUDE REGULATORY ASSESSMENTS AND FRANCHISE FEES**

Adjustment to Test Year operations to exclude regulatory assessments and franchise fees from both operating revenue and operating expense.

Line No.	Description		Amount
1.	**REVENUES:**		
2.	Operating Revenue		
3.	Regulatory Assessments	$ (3,431)	
4.	Franchise Fees	(28,276)	
5.	Total Pro Forma Adjustment to Revenues		$ (31,707)
6.	**EXPENSES:**		
7.	Other Operating Expenses		
	Operations Excluding Fuel Expenses		
8.	Regulatory Assessments	$ (3,431)	
9.	Franchise Fees	(28,276)	
10.	Total Pro Forma Adjustment to Expenses		(31,707)
11.	**OPERATING INCOME (before income tax)**		$ -
12.	Income Tax at 39.5%		-
13.	**OPERATING INCOME AFTER TAX**		$ -

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2
Total Company
(Thousands of Dollars)

PRO FORMA ADJUSTMENT: **ANNUALIZE JULY 1, 2003 ACC RATE LEVELS**
Adjustment to Test Year operations to reflect the annualization of ACC rate levels for the July 1, 2002 and July 1, 2003 rate decreases.

Line No.	Description		Amount
1.	**REVENUES:**		
2.	Operating Revenue		
3.	Residential (less Dusk-to-Dawn)	$ (19,106)	
4.	Small General Service (less Dusk-to-Dawn)	(7,160)	
5.	Medium General Service	(7,933)	
6.	Large General Service	(1,902)	
7.	Extra Large General Service	(462)	
8.	All Other	(442)	
9.	Total Pro Forma Adjustment to Revenues		$ (37,005)
10.	**OPERATING INCOME (before income tax)**		**$ (37,005)**
11.	Income Tax at 39.5%		(14,617)
12.	**OPERATING INCOME AFTER TAX**		**$ (22,388)**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2
Total Company
(Thousands of Dollars)

PRO FORMA ADJUSTMENT: **NORMALIZE WEATHER CONDITIONS**
Adjustment to Test Year operations to reflect normal weather conditions for the ten years ended December 31, 2002.

Line No.	Description			Amount
1.	**REVENUES:**			
2.	Operating Revenue			$ (5,204)
3.	Adjustment to sales (MWh) for the difference between normalized weather sales and actual sales		(45,880)	
4.	**EXPENSES:**			
5.	Fuel and Purchased Power Expenses			
6.	Adjustment to Sales (MWh)		(45,880)	
7.	Test Year Fuel and Purchased Power Costs (¢/kWh)	x	1.8033	
8.	Pro Forma Adjustment to Fuel and Purchased Power Expenses			(827)
9.	Operating Revenues Less Fuel and Purchased Power Expenses			$ (4,377)
10.	Other Operating Expenses			
11.	Adjustment to Sales (MWh)		(45,880)	
12.	Test Year Average OATT Expense (¢/kWh)	x	0.4760	
13.	Pro Forma Adjustment to OATT Expense			(218)
14.	**OPERATING INCOME (before income tax)**			**$ (4,159)**
15.	Income Tax at 39.5%			(1,643)
16.	**OPERATING INCOME AFTER TAX**			**$ (2,516)**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2
Total Company
(Thousands of Dollars)

PRO FORMA ADJUSTMENT: **ANNUALIZE CUSTOMER LEVELS TO YEAR-END 2002**
Adjustment to Test Year operations to reflect the annualization of customer levels at December 31, 2002.

Line No.	Description		Amount
1.	**REVENUES:**		
2.	Operating Revenue		$ 20,971
3.	Adjustment to sales (MWh) for the difference between customer annualized sales and actual sales	265,009	
4.	**EXPENSES:**		
5.	Fuel and Purchased Power Expenses:		
6.	Adjustment to Sales (MWh)	265,009	
7.	Test Year Fuel and Purchased Power Costs (¢/kWh)	x 1.8033	
8.	Pro Forma Adjustment to Fuel and Purchased Power Expenses		4,779
9.	Operating Revenues Less Fuel and Purchased Power Expenses		$ 16,192
10.	Other Operating Expenses		
11.	Adjustment to Sales (MWh)	265,009	
12.	Test Year Average OATT Expense (¢/kWh)	x 0.4760	
13.	Pro Forma Adjustment to OATT Expense		1,261
14.	Pro Forma Adjustment to Customer Accounts Expense		361
15.	**OPERATING INCOME (before income tax)**		**$ 14,570**
16.	Income Tax at 39.5%		5,755
17.	**OPERATING INCOME AFTER TAX**		**$ 8,815**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2
Total Company
(Thousands of Dollars)

PRO FORMA ADJUSTMENT: **SCHEDULE 1 CHANGES**
Adjustment to Test Year operations to reflect proposed revenue-related changes to Schedule 1.

Line No.	Description	Amount
1.	**REVENUES:**	
2.	Operating Revenue	$ 79
3.	**EXPENSES:**	
4.	Other Operating Expenses	
5.	Net Benefit - Online Bill Presentation	(3)
6.	**OPERATING INCOME (before income tax)**	**$ 82**
7.	Income Tax at 39.5%	32
8.	**OPERATING INCOME AFTER TAX**	**$ 50**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2
Total Company
(Thousands of Dollars)

PRO FORMA ADJUSTMENT: **BASE RATE COMPONENT FOR EPS**

Adjustment to Test Year operations related to the base rate component of the Company's System Benefits Charge which is used to fund the Environmental Portfolio Standard. Revenue is adjusted to reverse Test Year entries to contributions in aid of construction and to include the expenses allowed by the Commission.

Line No.	Description		Amount
1.	**REVENUES:**		
2.	Operating Revenue	$	5,263
3.	**EXPENSES:**		
4.	Other Operating Expense		
5.	Renewables		6,000
6.	**OPERATING INCOME (before income tax)**	**$**	**(737)**
7.	Income Tax at 39.5%		(291)
8.	**OPERATING INCOME AFTER TAX**	**$**	**(446)**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2
Total Company
(Thousands of Dollars)

PRO FORMA ADJUSTMENT: **BASE FUEL AND PURCHASED POWER**
Adjustment to Test Year operations to include 2003 base fuel and purchased power ¢/kWh costs at adjusted 2002 consumption.

Line No.	Description		Amount
1.	**EXPENSES:**		
2.	Fuel and Purchased Power Expenses		
3.	Normalized 2003 Fuel and Purchased Power Costs (¢/kWh)	2.3170	
4.	Test Year Fuel and Purchased Power Costs (¢/kWh)	1.8033	
5.	Adjustment to Fuel and Purchased Power Costs (¢/kWh)	0.5137	
6.	Test Year Sales (MWh)	23,254,517	
7.	Pro Forma Adjustments to Test Year Billed Retail Sales (MWh)		
8.	To Adjust to Normal Weather	(45,880)	
9.	To Annualized to December 31, 2002 Customer Level	265,009	
10.	Adjusted 2002 Sales (MWh)	23,473,646	
11.	Pro Forma Adjustment to Fuel and Purchased Power Expenses (Line 5 X Line 10)		$ 120,584
12.	**OPERATING INCOME (before income tax)**		**$ (120,584)**
13.	Income Tax at 39.5%		(47,631)
14.	**OPERATING INCOME AFTER TAX**		**$ (72,953)**

Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2
Total Company
(Thousands of Dollars)

PRO FORMA ADJUSTMENT: **NORMALIZE OFF-SYSTEM SALES**
Adjustment to Test Year operations to include off-system revenues consistent with the Base Fuel and Purchased Power pro forma adjustment.

Line No.	Description		Amount
1.	**REVENUES:**		
2.	Normalized Off-System Revenue - 2003	$ 63,079	
3.	Test Year Off-System Revenue - 2002	$ 191,279	
4.	Pro Forma Adjustment to Revenues		$ (128,200)
5.	**EXPENSES:**		
6.	Fuel and Purchased Power Expenses		
7.	Normalized Off-System Fuel and Purchased Power Expenses - 2003	$ 48,330	
8.	Test Year Off-System Fuel and Purchased Power Expenses - 2002	$ 200,198	
9.	Total Pro Forma Adjustment to Fuel and Purchased Power Expenses		(151,868)
10.	**OPERATING INCOME (before income tax)**		**$ 23,668**
11.	Income Tax at 39.5%		9,349
12.	**OPERATING INCOME AFTER TAX**		**$ 14,319**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2
Total Company
(Thousands of Dollars)

PRO FORMA ADJUSTMENT: **PWEC UNITS**

Adjustment to Test Year operations to include the Pinnacle West Energy Units including West Phoenix Combined Cycle No. 4, West Phoenix Combined Cycle No. 5, Redhawk Combined Cycle No. 1, Redhawk Combined Cycle No. 2 and Saguaro Combustion Turbine No. 3.

Line No.	Description	Amount
1.	**REVENUES:**	
2.	Operating Revenue	$ 56,779
3.	Fuel and Purchased Power Expenses	(34,970)
4.	Operating Revenues Less Fuel and Purchased Power Expenses	$ 91,749
5.	**EXPENSES:**	
6.	Other Operating Expenses	
7.	Operations Excluding Fuel Expenses	14,110
8.	Maintenance	18,549
9.	Sub-total O&M Expenses	$ 32,659
10.	Depreciation and Amortization	41,541
11.	Administrative and General	8,797
12.	Other Taxes	11,256
13.	Total Other Operating Expenses	$ 94,253
14.	**OPERATING INCOME (before income tax)**	**$ (2,504)**
15.	Interest Expense	36,179
16.	Taxable Income	$ (38,683)
17.	Income Tax at 39.5%	(15,280)
18.	**OPERATING INCOME AFTER TAX [Line 14 - Line 17]**	**$ 12,776**

ARIZONA PUBLIC SERVICE COMPANY

Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2

Total Company

(Thousands of Dollars)

PRO FORMA ADJUSTMENT: **ANNUALIZE PAYROLL**

Adjustment to Test Year operations to reflect the annualization of payroll and payroll taxes to employee levels at December 31, 2002 and salary levels at March 2003.

Line No.	Description		Amount
1.	**EXPENSES:**		
2.	Fuel Expenses	$ 7	
3.	Other Operating Expenses		
4.	Operations Excluding Fuel Expenses	851	
5.	Maintenance	173	
6.	Total Pro Forma Adjustment to Expenses		$ 1,031
7.	**OPERATING INCOME (before income tax)**		**$ (1,031)**
8.	Income Tax at 39.5%		(406)
9.	**OPERATING INCOME AFTER TAX**		**$ (625)**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2
Total Company
(Thousands of Dollars)

PRO FORMA ADJUSTMENT: **EMPLOYEE SEVERANCE**
Adjustment to Test Year operations to reflect a three-year levelization of expenses incurred during the Test Year related to a voluntary severance and early retirement program offered by the Company.

Line No.	Description	Amount
1.	**EXPENSES:**	
2.	Other Operating Expenses	
3.	Operations Excluding Fuel Expenses	$ (23,155)
4.	Total Pro Forma Adjustment to Expenses	$ (23,155)
5.	**OPERATING INCOME (before income tax)**	**$ 23,155**
6.	Income Tax at 39.5%	9,146
7.	**OPERATING INCOME AFTER TAX**	**$ 14,009**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2
Total Company
(Thousands of Dollars)

PRO FORMA ADJUSTMENT: **EMPLOYEE BENEFITS ADJUSTMENT**
Adjustment to Test Year operations to reflect increased employee benefits expenses.

Line No.	Description	Amount
1.	**EXPENSES:**	
2.	Fuel and Purchased Power Expenses	
3.	Fuel Expenses	$ 253
4.	Other Operating Expenses	
5.	Operations Excluding Fuel Expenses	18,623
6.	Maintenance	5,942
7.	Total Pro Forma Adjustment to Expenses	$ 24,818
8.	**OPERATING INCOME (before income tax)**	**$ (24,818)**
9.	Income Tax at 39.5%	(9,803)
10.	**OPERATING INCOME AFTER TAX**	**$ (15,015)**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2
Total Company
(Thousands of Dollars)

PRO FORMA ADJUSTMENT: **ON-GOING DIRECT ACCESS EXPENSE**

Adjustment to Test Year operations to include on-going costs of compliance with the Electric Competition Rules. Such costs were previously deferred and therefore were not included in Test Year operating expenses.

Line No.	Description		Amount
1.	**EXPENSES:**		
2.	Other Operating Expenses		
3.	Operations Excluding Fuel Expenses	$	1,477
4.	Total Pro Forma Adjustment to Expenses	$	1,477
5.	**OPERATING INCOME (before income tax)**	**$**	**(1,477)**
6.	Income Tax at 39.5%		(583)
7.	**OPERATING INCOME AFTER TAX**	**$**	**(894)**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2
Total Company
(Thousands of Dollars)

PRO FORMA ADJUSTMENT: **ON-GOING INDEPENDENT SPENT FUEL STORAGE INSTALLATION ("ISFSI") EXPENSE**
Adjustment to Test Year operations to reflect the on-going costs of ISFSI. Such System Benefits related costs were previously deferred and therefore were not included in Test Year operating expenses.

Line No.	Description		Amount
1.	**EXPENSES:**		
2.	Fuel Expenses		
3.	For Current Operations	$	2,129
4.	For Post-Shutdown (Placed in Decommissioning Fund)		752
5.	Total ISFSI Fuel Expenses	$	2,881
6.	**OPERATING INCOME (before income tax)**	**$**	**(2,881)**
7.	Income Tax at 39.5%		(1,138)
8.	**OPERATING INCOME AFTER TAX**	**$**	**(1,743)**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2
Total Company
(Thousands of Dollars)

PRO FORMA ADJUSTMENT: **TRANSMISSION EXPENSES**

Adjustment to Test Year operations to remove transmission and ancillary services-related expenses from base rates and include OATT costs as an expense consistent with FERC rules requiring APS to take transmission and related ancillary services for the APS Standard Offer customers under the APS OATT.

Line No.	Description	Amount
1.	**REVENUES:**	
2.	Operating Revenue	$ (2,310)
3.	**EXPENSES:**	
4.	Other Operating Expenses	
5.	Operations Excluding Fuel Expense	112,362
6.	Maintenance	(610)
7.	Depreciation and Amortization	(29,163)
8.	Administrative and General	(5,814)
9.	Other Taxes	(19,236)
10.	Total Pro Forma Adjustment to Expenses	$ 57,539
11.	**OPERATING INCOME (before income tax)**	**$ (59,849)**
12.	Interest Expense	(18,756)
13.	Taxable Income	$ (41,093)
14.	Income Tax at 39.5%	(16,232)
15.	**OPERATING INCOME AFTER TAX [Line 11 - Line 14]**	**$ (43,617)**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2
Total Company
(Thousands of Dollars)

PRO FORMA ADJUSTMENT: **INTEREST ON CUSTOMER DEPOSITS**
Adjustment to Test Year operations to reflect the operating income impact of interest on customer deposits.

Line No.	Description	Amount
1.	**EXPENSES:**	
2.	Other Operating Expenses	$ 875
3.	Operations Excluding Fuel Expenses	$ 875
4.	Total Pro Forma Adjustment to Expenses	
5.	**OPERATING INCOME (before income tax)**	**$ (875)**
6.	Income Tax at 39.5%	(345)
7.	**OPERATING INCOME AFTER TAX**	**$ (530)**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2
Total Company
(Thousands of Dollars)

PRO FORMA ADJUSTMENT: **NORMALIZE NON-NUCLEAR MAINTENANCE EXPENSE**
Adjustment to Test Year operations to reflect the normalization of fossil production maintenance expense and to include the O&M costs of generators acquired for compliance with the Environmental Portfolio Standard.

Line No.	Description	Amount
1.	**EXPENSES:**	
2.	Other Operating Expenses	
3.	Environmental Portfolio Standard	$ 868
4.	Fossil Generation Maintenance Normalization	(6,882)
5.	Total Pro Forma Adjustment to Expenses	$ (6,014)
6.	**OPERATING INCOME (before income tax)**	**$ 6,014**
7.	Income Tax at 39.5%	2,376
8.	**OPERATING INCOME AFTER TAX**	**$ 3,638**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2
Total Company
(Thousands of Dollars)

PRO FORMA ADJUSTMENT: **NORMALIZE NUCLEAR MAINTENANCE EXPENSE**
Adjustment to Test Year operations to reflect the normalization of nuclear production maintenance expense.

Line No.	Description	Amount
1.	**EXPENSES:**	
2.	Other Operating Expenses	
3.	Maintenance	$ (945)
4.	Total Pro Forma Adjustment to Expenses	$ (945)
5.	**OPERATING INCOME (before income tax)**	**$ 945**
6.	Income Tax at 39.5%	373
7.	**OPERATING INCOME AFTER TAX**	**$ 572**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2
Total Company
(Thousands of Dollars)

PRO FORMA ADJUSTMENT: **ANNUALIZE DEPRECIATION AND AMORTIZATION**
Adjustment to Test Year operations to reflect the requested changes to depreciation rates.

Line No.	Description	Amount
1.	**EXPENSES:**	
2.	Other Operating Expenses	$ 3,027
3.	Depreciation and Amortization	$ 3,027
4.	Total Pro Forma Adjustment to Expenses	
5.	**OPERATING INCOME (before income tax)**	**$ (3,027)**
6.	Income Tax at 39.5%	(1,196)
7.	**OPERATING INCOME AFTER TAX**	**$ (1,831)**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2
Total Company
(Thousands of Dollars)

PRO FORMA ADJUSTMENT: **REGULATORY ASSETS**

Adjustment to Test Year operations to remove the amortization of regulatory assets which will be fully amortized by June 30, 2004 and to include amortization of continuing regulatory assets.

Line No.	Description	Amount
1.	**EXPENSES:**	
2.	Other Operating Expenses	
3.	Depreciation and Amortization	$ (111,754)
4.	Total Pro Forma Adjustment to Expenses	$ (111,754)
5.	**OPERATING INCOME (before income tax)**	**$ 111,754**
6.	Interest Expense	(1,819)
7.	Taxable Income	$ 113,573
8.	Income Tax at 39.5%	44,861
9.	**OPERATING INCOME AFTER TAX [Line 5 - Line 8]**	**$ 66,893**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2
Total Company
(Thousands of Dollars)

PRO FORMA ADJUSTMENT: **ISFSI ASSET**
Adjustment to Test Year operations to reflect the amortization of the System Benefits related ISFSI regulatory asset.

Line No.	Description		Amount
1.	**EXPENSES:**		
2.	Other Operating Expenses		
3.	Depreciation and Amortization		
4.	For Current Operations	$	7,459
5.	For Post-Shutdown (Placed in Decommissioning Fund)		792
6.	Total Pro Forma Adjustment to Expenses	$	8,251
7.	**OPERATING INCOME (before income tax)**	**$**	**(8,251)**
8.	Interest Expense		76
9.	Taxable Income	$	(8,327)
10.	Income Tax at 39.5%		(3,288)
11.	**OPERATING INCOME AFTER TAX [Line 7 - Line 10]**	**$**	**(4,963)**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2
Total Company
(Thousands of Dollars)

PRO FORMA ADJUSTMENT: **REVERSAL OF SETTLEMENT WRITE-OFF**
Adjustment to Test Year operations to include a 15-year amortization restoring the $234 million disallowance taken by the Company in consideration of certain benefits previously agreed to under the 1999 Settlement.

Line No.	Description	Amount
1.	**EXPENSES:**	
2.	Other Operating Expenses	
3.	Depreciation and Amortization	$ 15,600
4.	Total Pro Forma Adjustment to Expenses	$ 15,600
5.	**OPERATING INCOME (before income tax)**	**$ (15,600)**
6.	Interest Expense	4,094
7.	Taxable Income	$ (19,694)
8.	Income Tax at 39.5%	(7,779)
9.	**OPERATING INCOME AFTER TAX [Line 5 - Line 8]**	**$ (7,821)**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2
Total Company
(Thousands of Dollars)

PRO FORMA ADJUSTMENT: **NUCLEAR DECOMMISSIONING FUNDS**
Adjustment to Test Year operations to increase contributions to the nuclear decommission trust funds.

Line No.	Description	Amount
1.	**EXPENSES:**	
2.	Other Operating Expenses	$ 7,766
3.	Depreciation and Amortization	$ 7,766
4.	Total Pro Forma Adjustment to Expenses	
5.	**OPERATING INCOME (before income tax)**	**$ (7,766)**
6.	Income Tax at 39.5%	(3,068)
7.	**OPERATING INCOME AFTER TAX**	**$ (4,698)**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2
Total Company
(Thousands of Dollars)

PRO FORMA ADJUSTMENT: **ANNUALIZE PROPERTY TAX TO YEAR ENDING DECEMBER 31, 2002**
Adjustment to Test Year operations to reflect property taxes calculated using December 31, 2002 plant balances.

Line No.	Description		Amount
1.	**EXPENSES:**		
2.	Other Operating Expenses	$	10,199
3.	Other Taxes	$	10,199
4.	Total Pro Forma Adjustment to Expenses		
5.	**OPERATING INCOME (before income tax)**	**$**	**(10,199)**
6.	Income Tax at 39.5%		(4,029)
7.	**OPERATING INCOME AFTER TAX**	**$**	**(6,170)**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2
Total Company
(Thousands of Dollars)

PRO FORMA ADJUSTMENT: **FINANCING APPLICATION**
Adjustment to Test Year operations to reflect 264 basis point differential specified in Commission Decision No. 65796.

Line No.	Description		Amount
1.	**EXPENSES:**		
2.	Other Operating Expenses		
3.	Amortization of Gain	$	(3,416)
4.	Total Pro Forma Adjustment to Expenses	$	(3,416)
5.	**OPERATING INCOME (before income tax)**	**$**	**3,416**
6.	Income Tax at 39.5%		1,349
7.	**OPERATING INCOME AFTER TAX**	**$**	**2,067**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2
Total Company
(Thousands of Dollars)

PRO FORMA ADJUSTMENT: **INCOME TAX/SYNCHRONIZED INTEREST ON TEST YEAR RATE BASE**
Adjustment to Test Year operations to reflect the synchronization of interest expense using the adjusted year-end 2002 capital structure and cost of long-term debt, as well as the use of the statutory income tax rate.

Line No.	Description	Amount
1.	Interest Expense	$ (12,783)
2.	Taxable Income	$ 12,783
3.	Income Tax at 39.5%	5,049
4.	**OPERATING INCOME AFTER TAX**	**$ (5,049)**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2
Total Company
(Thousands of Dollars)

PRO FORMA ADJUSTMENT: **MISCELLANEOUS ADJUSTMENTS**
Adjustment to Test Year operations to eliminate non-recurring and out-of-period expenses.

Line No.	Description		Amount
1.	**REVENUES:**		
2.	Operating Revenue	$	6,117
3.	**EXPENSES:**		
4.	Other Operating Expenses		
5.	Operations Excluding Fuel Expenses		(699)
6.	Total Pro Forma Adjustment to Expenses	$	(699)
7.	**OPERATING INCOME (before income tax)**	**$**	**6,816**
8.	Income Tax at 39.5%	$	2,692
9.	**OPERATING INCOME AFTER TAX**	**$**	**4,124**

ARIZONA PUBLIC SERVICE COMPANY
SCHEDULE OF AMOUNTS TO BE DEPOSITED IN THE
DECOMMISSIONING TRUSTS INCLUDED IN COST-OF-SERVICE
PALO VERDE UNIT I
(Thousands of Dollars)
(APS Share)

Line	Year	Post Shutdown On-Going ISFSI Annual Contribution Required	Post Shutdown ISFSI Regulatory Asset Amortization Annual Contribution Required	Decommissioning Annual Contribution Required	Total Annual Contribution Required	ACC Jurisdictional Amount /1/
1	2004	$ 125	$ 107	$ 4,077	$ 4,309	$ 4,246
2	2005	251	214	5,122	5,587	5,505
3	2006	251	214	5,122	5,587	5,505
4	2007	251	214	5,122	5,587	5,505
5	2008	251	214	5,122	5,587	5,505
6	2009	605	214	5,122	5,941	5,854
7	2010	960	214	5,122	6,296	6,204
8	2011	960	214	5,122	6,296	6,204
9	2012	960	214	5,122	6,296	6,204
10	2013	960	214	5,122	6,296	6,204
11	2014	960	214	5,122	6,296	6,204
12	2015	960	214	5,122	6,296	6,204
13	2016	960	214	5,122	6,296	6,204
14	2017	960	214	5,122	6,296	6,204
15	2018	960	214	5,122	6,296	6,204
16	2019	960	214	5,122	6,296	6,204
17	2020	960	214	5,122	6,296	6,204
18	2021	960	214	5,122	6,296	6,204
19	2022	960	214	5,122	6,296	6,204
20	2023	960	214	5,122	6,296	6,204
21	2024	960	214	5,122	6,296	6,204
22	2025	-	-	-	-	-
23	2026	-	-	-	-	-
		$ 16,134	$ 4,387	$ 106,517	$ 127,038	$ 125,183

/1/ ACC Jurisdictional share is approximately 98.54%.

ARIZONA PUBLIC SERVICE COMPANY
SCHEDULE OF AMOUNTS TO BE DEPOSITED IN THE DECOMMISSIONING TRUSTS INCLUDED IN COST-OF-SERVICE
PALO VERDE UNIT II
(Thousands of Dollars)
(APS Share)

Line	Year	Post Shutdown On-Going ISFSI Annual Contribution Required	Post Shutdown ISFSI Regulatory Asset Amortization Annual Contribution Required	Decommissioning Annual Contribution Required	Total Annual Contribution Required	ACC Jurisdictional Amount /1/
1	2004	$ 126	$ 194	$ 6,153	$ 6,473	$ 6,378
2	2005	250	388	8,072	8,710	8,583
3	2006	250	388	8,072	8,710	8,583
4	2007	250	388	8,072	8,710	8,583
5	2008	250	388	8,072	8,710	8,583
6	2009	606	388	8,072	9,066	8,934
7	2010	2,561	388	8,072	11,021	10,860
8	2011	2,561	388	8,072	11,021	10,860
9	2012	2,561	388	8,072	11,021	10,860
10	2013	2,561	388	8,072	11,021	10,860
11	2014	2,561	388	8,072	11,021	10,860
12	2015	2,561	388	8,072	11,021	10,860
13	2016	-	-	-	-	-
14	2017	-	-	-	-	-
15	2018	-	-	-	-	-
16	2019	-	-	-	-	-
17	2020	-	-	-	-	-
18	2021	-	-	-	-	-
19	2022	-	-	-	-	-
20	2023	-	-	-	-	-
21	2024	-	-	-	-	-
22	2025	-	-	-	-	-
23	2026	-	-	-	-	-
		$ 17,098	$ 4,462	$ 94,945	$ 116,505	$ 114,804

/1/ ACC Jurisdictional share is approximately 98.54%.

ARIZONA PUBLIC SERVICE COMPANY
SCHEDULE OF AMOUNTS TO BE DEPOSITED IN THE DECOMMISSIONING TRUSTS INCLUDED IN COST-OF-SERVICE
PALO VERDE UNIT III
(Thousands of Dollars)
(APS Share)

Line	Year	Post Shutdown On-Going ISFSI Annual Contribution Required	Post Shutdown ISFSI Regulatory Asset Amortization Annual Contribution Required	Decommissioning Annual Contribution Required	Total Annual Contribution Required	ACC Jurisdictional Amount /1/
1	2004	$ 125	$ 95	$ 5,098	$ 5,318	$ 5,240
2	2005	251	190	6,017	6,458	6,364
3	2006	251	190	6,017	6,458	6,364
4	2007	251	190	6,017	6,458	6,364
5	2008	251	190	6,017	6,458	6,364
6	2009	605	190	6,017	6,812	6,713
7	2010	960	190	6,017	7,167	7,062
8	2011	960	190	6,017	7,167	7,062
9	2012	960	190	6,017	7,167	7,062
10	2013	960	190	6,017	7,167	7,062
11	2014	960	190	6,017	7,167	7,062
12	2015	960	190	6,017	7,167	7,062
13	2016	960	190	6,017	7,167	7,062
14	2017	960	190	6,017	7,167	7,062
15	2018	960	190	6,017	7,167	7,062
16	2019	960	190	6,017	7,167	7,062
17	2020	960	190	6,017	7,167	7,062
18	2021	960	190	6,017	7,167	7,062
19	2022	960	190	6,017	7,167	7,062
20	2023	960	190	6,017	7,167	7,062
21	2024	960	190	6,017	7,167	7,062
22	2025	960	190	6,017	7,167	7,062
23	2026	1,004	238	6,017	7,259	7,153
		$ 18,098	$ 4,323	$ 137,472	$ 159,893	$ 157,559

/1/ ACC Jurisdictional share is approximately 98.54%.

EXHIBIT
APS-4
admitted

DIRECT TESTIMONY OF CHRIS N. FROGGATT

On Behalf of Arizona Public Service Company

Docket No. E-01345A-03-___

June 27, 2003

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DIRECT TESTIMONY OF CHRIS N. FROGGATT
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-03-____)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Chris N. Froggatt. My business address is 400 North Fifth Street, Phoenix, Arizona, 85072-3999.

Q. WHAT IS YOUR POSITION WITH ARIZONA PUBLIC SERVICE COMPANY?

A. I am Vice President and Controller for Arizona Public Service Company ("APS" or "Company"). My educational background and professional qualifications, as well as my professional experience, are set forth in Appendix A, which is attached to this testimony.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. My testimony will primarily focus on the historical accounting data, including unadjusted test-year data, in the Company's filing. I will also testify regarding the capital structure used to calculate the Company's cost of capital.

II. SUMMARY OF TESTIMONY

Q. PLEASE PROVIDE A SUMMARY OF YOUR TESTIMONY.

A. My testimony addresses historical accounting data that is required by the various Standard Filing Requirements ("SFR") Schedules of the Arizona Corporation

Commission ("Commission") supporting the Company's rate case filing. Thus, I discuss information from the test year and prior years relating to the Summary Schedules, SFR Schedules A-2, A-3 and A-4; certain components of the Company's historical original cost rate base in SFR Schedule B-1; the working capital allowance component of rate base in SFR Schedule B-5; and income statements relating to the test year and prior years in SFR Schedule C-1. I will also discuss the factor used to gross up operating income to account for taxes in SFR Schedule C-3. I also discuss the capital structure of the Company and, using the information on cost of equity provided by Dr. Olson and the Company's cost of debt, provide APS' overall cost of capital in SFR Schedules D-1, D-2 and D-3. Finally, I sponsor the various schedules relating to the Company's financial statements and certain statistical data required by the schedules, which are includes in SFR Schedules E-1 through E-9 (excepting SFR Schedule E-6 which is not applicable to APS).

III. HISTORICAL AND TEST YEAR ACCOUNTING DATA

Q. COULD YOU PLEASE DESCRIBE THE ACCOUNTING INFORMATION CONTAINED WITHIN THE SFR SCHEDULES THAT YOU ARE SPONSORING?

A. As the Controller of APS, I am responsible for accounting and financial reporting by the Company. Thus, my testimony covers historical accounting data, including the actual year-end figures as of December 31, 2002 ("Test Year"). The majority of this information is either directly or indirectly contained in both the APS and consolidated Pinnacle West Capital Corporation ("PWCC") audited financial statements included in filings made with the Securities and Exchange Commission ("SEC") for the relevant years.

Additionally, all of the accounting information provided in my testimony complies with Generally Accepted Accounting Principles ("GAAP"). These are the principles that accounting professionals use to prepare financial statements. One major goal of GAAP is to make financial statements comparable from year to year, from industry to industry, and from jurisdiction to jurisdiction. APS' accounting practices also comply with accepted utility accounting standards, such as the Federal Energy Regulatory Commission ("FERC") Uniform System of Accounts, which has also been adopted by the Commission.

In large part, my testimony supports the testimony of other APS witnesses. The direct testimony of APS witness Donald G. Robinson addresses the adjusted test year data that results when certain pro forma adjustments are applied to actual test year data. Mr. Robinson's testimony also addresses projections to actual test year data. The direct testimony of APS witness Laura L. Rockenberger addresses, among other things, Reconstructed Cost New Less Depreciation ("RCND"), working capital requirements, and depreciation. APS witness Alan Propper's direct testimony focuses on the jurisdictional allocation of APS revenues, costs, and rate base items. And Dr. Charles Olson's testimony addresses the Company's cost of equity.

A. Summary Schedules

Q. **DID YOU PREPARE SFR SCHEDULES A-2, A-3 AND A-4?**

A. Yes, in part. The information related to actual 2000 and 2001 results, and the unadjusted or actual test year information in each of these schedules was prepared by me and my staff.

Q. PLEASE DESCRIBE THE HISTORICAL INFORMATION IN SFR SCHEDULE A-2.

A. SFR Schedule A-2 provides the "Summary Results of Operations" for the Test Year and the prior two years. It also includes projected information for two years after the test year. I am sponsoring the data contained in the first three columns of SFR Schedule A-2, which is historical data for the prior years and the Test Year. The projected information is being sponsored by Mr. Robinson.

Q. PLEASE DISCUSS SFR SCHEDULE A-3.

A. SFR Schedule A-3 is the "Summary of Capital Structure" for APS, also broken down into the test year, two prior years, and a projected period. As with SFR Schedule A-2, I am sponsoring the historical prior year and Test Year data. This Schedule shows that the Company's actual capital structure has remained relatively stable over the last three years, with debt-to-total capitalization ratios ranging between 49.8% (year-end 2002) and 51.1% (year-end 2001).

Q. ARE YOU SPONSORING ANY INFORMATION ON SFR SCHEDULE A-4?

A. Yes. SFR Schedule A-4 contains information on construction expenditures and gross utility plant in service. I am sponsoring the information on lines 1, 2 and 3 of this schedule, which is the actual construction expenditures and gross utility plant in service for 2000, 2001 and the Test Year, respectively.

Q. PLEASE DISCUSS THE HISTORICAL INFORMATION ON SFR SCHEDULE A-5.

A. SFR Schedule A-5 shows summary changes in financial position for the two prior years, Test Year and projected year periods. This schedule illustrates APS change in financial position over these various periods, by showing funds obtained from operations and financing and netting these against funds spent on construction or other expenditures. As with the other historical accounting information, I am sponsoring the data in the first three columns of SFR Schedule A-5, relating to sources and application of funds.

B. Rate Base Schedules

Q. ARE YOU SPONSORING HISTORICAL ACCOUNTING DATA RELATING TO THE RATE BASE SCHEDULES?

A. Yes. I am sponsoring the historical data in SFR Schedule B-1 and SFR Schedule B-5.

Q. PLEASE DISCUSS THE HISTORICAL DATA IN SFR SCHEDULE B-1.

A. I am sponsoring the information provided in the first column of SFR Schedule B-1, which are the various components of the total company original cost rate base. As of the end of 2002 and prior to any pro forma adjustments, the total Company unadjusted original cost rate base was approximately $3.9 billion. This total figure was comprised of approximately $4.9 billion of net plant in service, $1.6 billion of deductions such as deferred taxes or customer advances, and $600 million of additions such as regulatory assets, allowance for working capital, and nuclear decommissioning funds.

Q. WHICH PORTIONS OF THE HISTORICAL INFORMATION IN SFR SCHEDULE B-5 ARE YOU SPONSORING?

A. This SFR Schedule outlines the allowance for working capital to be applied to the Company's rate base. Working capital represents the amount of cash, materials and supplies, fuel, and prepayments needed to meet current expenses and contingencies that might ordinarily develop. Working capital is an investment just like other capital requirements such as power plants and transmission and distribution infrastructure, and it is thus part of APS' rate base. I am sponsoring all of the data in SFR Schedule B-5, with the exception of the Cash Working Capital calculation on line 1 of page 1. The Cash Working Capital amount resulted from the Lead-Lag Study performed under the direction of Ms. Rockenberger, which is described in her testimony. The resulting working capital allowance is approximately $176 million, which includes $54 million of Cash Working Capital. The total working capital allowance is reflected in the total Test Year rate base at line 15 of SFR Schedule B-1.

C. Test Year Income Statements

Q. WERE YOU RESPONSIBLE FOR PREPARING THE ACTUAL TEST YEAR INFORMATION IN SFR SCHEDULE C-1?

A. Yes.

Q. PLEASE DISCUSS THE INFORMATION THAT YOU ARE SPONSORING IN SFR SCHEDULE C-1.

A. SFR Schedule C-1 is the summary of the Company's adjusted test year income statement. I am sponsoring the historical Test Year data in the first column of SFR Schedule C-1. This information is the baseline from which pro forma adjustments are made and shows operating income and net income for the test year. As shown on the schedule, APS' operating income and net income during the Test Year period were $329 million and $199 million, respectively, on sales of nearly $2.1 billion.

Q. ARE YOU SPONSORING ANY OTHER RELATED SFR SCHEDULES?

A. Yes, I am sponsoring SFR Schedule C-3, which is the computation of the gross revenue conversion factor.

Q. PLEASE DESCRIBE SFR SCHEDULE C-3.

A. SFR Schedule C-3 calculates the factor applied to "gross up" income to account for income taxes and, when applicable, other expenses such as franchise fees so that taxes that must be paid by APS are reflected in the revenue requirement that APS is requesting. Because there are no other expenses to include in APS' case, the Gross Revenue Conversion factor of 1.6529 shown on Line 5 is simply an algebraic transformation of APS' total, or composite state and federal, tax rate of 39.5 percent. This factor is used on Schedule A-1 at Line 7 to arrive at the increase or decrease in Gross Revenue Requirements necessary to account for income taxes.

D. Capital Structure and Cost of Capital

Q. WERE YOU RESPONSIBLE FOR PREPARING SCHEDULES D-1, D-2 AND D-3?

A. Yes.

Q. PLEASE DISCUSS THE COST OF CAPITAL INFORMATION THAT YOU ARE SPONSORING.

A. SFR Schedule D-1 is the summary of the Company's historical and projected cost of capital and I am sponsoring the Test Year data in this schedule. SFR Schedule D-2 presents supporting detail for the long-term debt that is summarized on SFR Schedule D-1. SFR Schedule D-3, which addresses preferred stock, is included in the Company's schedules for completeness but is irrelevant because APS has no outstanding preferred stock at the end of 2002.

Q. PLEASE DISCUSS IN MORE DETAIL THE COMPANY'S OUTSTANDING LONG-TERM DEBT AS OF THE END OF THE TEST YEAR.

A. Approximately one-half of APS' outstanding long-term debt consisted of unsecured notes with a weighted average interest rate of around 6.8 percent ($88.486 million in annualized interest divided by $1.3 billion). The remainder of the long-term debt consisted of first mortgage bonds, senior notes, and pollution control indebtedness with weighted average interest rates of about 6.1 percent, 5.9 percent, and 2.2 percent, respectively. APS also has a small amount of interest related to capital lease obligations which is classified as interest expense and thus reflected on the schedule.

Q. HAVE YOU MADE ANY ADJUSTMENTS TO THE END OF TEST YEAR DEBT?

A. Yes. During the first two quarters of 2003, there were some adjustments to the amount of long-term debt outstanding due to call provisions in first mortgage bonds relating to maintenance and repair redemptions ("M&R calls"). Also, there were adjustments to interest rates due to rate resets on outstanding pollution control bonds. These adjustments decreased the Company's embedded cost of debt and overall leverage from the end of Test Year actual figures. A summary of the impacts to actual end of Test Year data from the adjustments for the M&R calls and pollution control bond rate resets is provided in Attachment CNF-1 to this testimony.

Q. WHAT WAS APS' CAPITAL STRUCTURE AT THE END OF THE TEST YEAR?

A. After adjusting for the M&R calls and pollution control bond rate resets, APS' total long-term debt and common equity was approximately $4.3 billion. This was comprised of just over $2.1 billion in long-term debt (including current maturities) and just under $2.2 billion in common equity. Thus, APS' capital structure at the end of the test year was approximately 50 percent debt and 50 percent equity.

Q. WHAT COST OF CAPITAL HAVE YOU CALCULATED TO INCLUDE IN SFR SCHEDULE D-1?

A. Given an 11.5 percent cost of equity discussed in Dr. Olson's testimony, the embedded cost of debt of 5.81 percent, and the actual Test Year debt-equity ratio discussed above, APS' weighted average cost of capital is 8.67%, which is reflected on Line 6 of SFR Schedule D-1.

Q. HOW DOES RATEBASING THE PWEC DEDICATED UNITS AFFECT APS' DEBT AND EQUITY RATIOS?

A. In this proceeding APS is proposing that Pinnacle West Energy's ("PWEC") Redhawk Units 1 and 2, West Phoenix Combined Cycle Units 4 and 5 and the Saguaro Combustion Turbine (collectively the "PWEC Units") be transferred to APS and included in rate base. If the PWEC-related debt is incorporated into APS' existing capital structure, leverage is increased to approximately 55% debt and 45% common equity. Both APS witnesses Steven M. Wheeler and Ajit Bhatti address the proposed ratebasing of the PWEC Dedicated Units in more detail in their testimony, while Mr. Robinson discussed the impact of this increased leverage on the Company's overall cost of capital.

E. Financial Statements and Statistical Schedules

Q. ARE YOU SPONSORING SFR SCHEDULES E-1 THROUGH E-9?

A. Yes. These schedules relate primarily to historical financial and accounting information, as well as the notes to the financial statements. SFR Schedule E-6 is required only for combination utilities and therefore is not included.

Q. PLEASE DISCUSS SFR SCHEDULES E-1, E-2 AND E-3.

A. These three schedules contain information found on the balance sheet, the income statement and the cash flow statement for the Test Year period and the two prior years. SFR Schedule E-1 provides comparative balance sheets for these periods, while SFR Schedules E-2 and E-3 provide comparative statements of income and comparative statements of cash flows, respectively. All of these financial statements were included in APS' Form 10-K filings with the SEC for the relevant years, as restated in 2002.

Q. PLEASE DISCUSS SFR SCHEDULE E-4.

A. SFR Schedule E-4 shows changes in stockholders' equity for the Test Year and two prior years. This schedule shows that stockholders' equity changed by net income, dividends paid and other comprehensive loss. APS' other comprehensive loss includes minimum pension liability adjustments and unrealized losses on derivative instruments used to hedge gas and power costs. GAAP require these items to be reported in stockholders' equity through other comprehensive income or loss, rather than be reflected in net income.

Q. WHAT IS PROVIDED IN SFR SCHEDULE E-5?

A. SFR Schedule E-5 is the detailed statement of utility plant that makes up the Company's rate base, broken down by account number under the Uniform

Systems of Accounts. The first page of SFR Schedule E-5 is a summary, which includes balances for gross plant in service, accumulated depreciation, nuclear fuel, work in progress and plant held for future use. The remainder of the schedule presents supporting detail by account.

Q. WHAT INFORMATION IS PROVIDED IN SFR SCHEDULE E-7?

A. SFR Schedule E-7 provides detailed information concerning APS' sales (in kWh), number of customers and average usage per customer over the last three years, including the test year. This information is contained in or derived from APS' FERC Form 1 filings for the applicable periods and is separated by customer classes to show residential, commercial, industrial, irrigation, public street and highway lighting, other sales to public authorities and sales for resale. Additionally, SFR Schedule E-7 shows average revenue per residential customer, which in 2002 was approximately $1,140. SFR Schedule E-7 also shows that the direct production expense per kWh sold and direct transmission expense per kWh sold was 2.9 cents and 0.09 cents in 2002, respectively.

Q. PLEASE DISCUSS SFR SCHEDULE E-8.

A. SFR Schedule E-8 provides a breakdown of the taxes paid by APS during 2002 and the two prior years, showing federal, state and local taxes paid. This tax figure is used to derive the gross-up factor used in SFR Schedule C-3.

Q. PLEASE DISCUSS SFR SCHEDULE E-9?

A. SFR Schedule E-9 sets forth the notes to the financial statements. These notes include, but are not limited to, the Company's accounting policies for depreciation, capitalized interest and income taxes. The notes also provide additional detailed information related to the income statement, balance sheet and cash flow statement.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

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Appendix A
Statement of Qualifications
Chris N. Froggatt

Chris N. Froggatt is Vice President and Controller for Arizona Public Service Company. Mr. Froggatt has responsibility for Accounting Services, Tax Services, Financial Services (budgets and forecasts), Insurance and Energy Risk Management, Supply Chain, Transportation and Public Safety. These services are provided as needed across all of the Pinnacle West companies.

Mr. Froggatt graduated from Michigan State University in 1980 with a Bachelor's Degree in Accounting. He is a Certified Public Accountant and a member of both the American Institute of Certified Public Accountants and the Arizona Society of Certified Public Accountants.

Mr. Froggatt spent six and one-half years in public accounting upon graduation from college. He joined APS in December 1986 as Manager of Financial Reporting and became Director of Accounting Services in 1992. In July of 1997, Mr. Froggatt was named Controller for APS and had effectively the same responsibilities for Pinnacle West. He was promoted to Vice-President and Controller of Pinnacle West in July 1999.

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ADJUSTMENTS FOR MAINTENANCE AND REPLACEMENT CALLS AND POLLUTION CONTROL BOND RATE RESETS
(dollars in thousands)

DESCRIPTION	LONG-TERM DEBT AMOUNT	COST OF LONG-TERM DEBT
12/31/02 UNADJUSTED	$ 2,227,180	6.02%
Impact of Calls:		
FIRST MORTGAGE BOND - 8%	(33,075)	(0.03)%
FIRST MORTGAGE BOND - 7.25%	(54,150)	(0.04)%
Subtotal	2,139,955	5.95%
Reset PC Bond Interest Rates	-	(0.14)%
12/31/02 ADJUSTED	$ 2,139,955	5.81%