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BEFORE THE

ARIZONA CORPORATION COMMISSION

REBUTTAL TESTIMONY OF JACK E. DAVIS

On Behalf of

Arizona Public Service Company

Docket No. E-01345A-98-0473
Docket No. E-01345A-97-0773
Docket No. RE-00000C-94-0165

July 12, 1999

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REBUTTAL TESTIMONY

OF

JACK E. DAVIS

I. INTRODUCTION

1.Q. WOULD YOU PLEASE STATE YOUR NAME AND BUSINESS ADDRESS?

1.A. My name is Jack E. Davis, and my business address is 400 North Fifth Street, Phoenix, Arizona 85004

2.Q. DID YOU PREVIOUSLY FILE DIRECT TESTIMONY IN THIS PROCEEDING?

2.A. Yes

3.Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

3.A. I will rebut certain of the statements and conclusions made in the testimony of the Enron witnesses Kingerski, Delany, Rosenberg and Frankena; Commonwealth Energy witness Bloom; and PG&E Energy Services witness Ogelsby. Collectively, these will be referred to as the "ESP Witnesses." To a somewhat lesser degree, I will also rebut Staff witness Williamson and Staff consultant Smith.

I will not directly respond to the non-evidentiary "Comments" submitted by Commonwealth Energy, the Arizona Consumers

Council, the Arizona Transmission Dependent Utility Group, and others. Many of these represent legal assertions concerning "fair value," rate case procedures, and certain technical provisions of the Settlement Agreement dated May 14, 1999 ("Agreement" or "Settlement Agreement"). Others are simply arguments about what the author believes the evidence shows or doesn't show, or whether the evidence is or will be "substantial." Arizona Public Service Company ("APS" or "Company"), the other signatories to the Agreement, and, I believe, the Commission's own counsel disagree with these legal assertions, and I find the "weight of the evidence" arguments curious at this point, since the Commission hasn't even held its hearing yet. In any event, APS will respond to legal issues in any such post-hearing briefs or memoranda as are believed necessary by the Chief Hearing Officer. Moreover, my rebuttal testimony as well as the rebuttal testimony of other witnesses, will, of necessity, address some of the same issues as contained in the various "Comments."

A second goal of my Rebuttal Testimony is to explain and hopefully clarify certain aspects of the Agreement. It is evident from my review of the ESP Witnesses' testimony that they may not fully understand the terms of this Agreement, and in some instances they have completely misstated those terms.

4.Q. WOULD YOU PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY?

4.A. Yes. The Agreement, as negotiated by the Company and all of its major customer group constituencies, allows Electric Service Providers ("ESPs") to compete on fair and equal terms to provide competitive electric services in the APS distribution service area. It does not and should not subsidize competitors and competition on the backs of Standard Offer customers. The Agreement is fully consistent with the proposed Electric Competition Rules, and in some respects goes further than such Rules in both promoting competitive opportunities for ESPs and limiting the actions of incumbent providers such as the Company.

The calculation of net mitigated stranded costs, which are only partially recoverable under the Agreement, uses one of the approved methodologies from Decision No. 61677 (April 27, 1999). It is, in every respect, a conservatively low calculation. Much of the criticism of the Agreement's calculation of net mitigated stranded costs comes from the parties' underlying disagreement with either the Electric Competition Rules themselves or Decision No. 61677. In other instances, witnesses engage in unsupported speculation to challenge this aspect of the Agreement.

The Agreement's provisions on the transfer of competitive assets are fully consistent with and even required by the pending Electric Competition Rules. Proposals to double-count either stranded costs or stranded benefits (negative stranded costs) or, worse yet, to double-count the latter and ignore the former will unfairly punish the Company, while at the same time providing no benefit to competitors.

Although transmission is largely a non-jurisdictional issue, falling under the exclusive authority of the Federal Energy Regulatory Commission ("FERC"), the Agreement does promote the concepts of fair and equal access to the Company's transmission system. It does so by its support for the Arizona Independent Scheduling Administrator ("AISA") and, eventually, a regional independent scheduling organization ("ISO") to be named "Desert Star."

Finally, the Agreement would grant APS and its competitive affiliates waivers of certain Commission rules and of statutory provisions, as well as make certain findings necessary for the APS generation affiliate contemplated by the Agreement to qualify as an "Exempt Wholesale Generator" ("EWG") under federal law. The waivers are, in part, necessary in order for APS to timely comply with other terms of the Agreement or with the Electric Competition Rules. The rules waivers are based on both the previous waivers agreed to by Commission Staff in the subsequently withdrawn 1998 settlement and on those granted to competitive telecommunications service providers. The statutory waivers are pursuant to specific legislation now embodied in A.R.S. § 40-202. EWG designation [which designation will be made by the Securities and Exchange Commission ("SEC") but which also requires this Commission to make certain specific findings as set forth in the Agreement] merely preserves the status quo for Pinnacle West Capital Corporation ("PinnWest") under the Public Utilities Holding Company Act of 1935 ("PUHCA").

II. COMPETITION ISSUES

5.Q. THE ESP WITNESSES HAVE ALLEGED THAT THERE WOULD BE NO COMPETITION UNDER THE TERMS OF THE AGREEMENT. DO YOU AGREE?

5.A. Of course not. These witnesses, and to some extent Staff witness Williamson and Staff consultant Smith, have expressed concern over the "spread" between the proposed unbundled distribution (direct access) rates and the Company's present tariffs (Standard Offer) rates. This differential is loosely referred to as the customer's "shopping credit" since it represents the "bogey" that a direct access customer generally must meet or beat if such customer is to procure electricity at a lower delivered cost than under the Company's Standard Offer. The ESP witnesses also point to what they would have the Commission believe are the insurmountable advantages of the incumbent (APS) – even though those advantages (to the extent they exist) are neither insurmountable nor a product of the Agreement.

6.Q. IS THE "SHOPPING CREDIT" THAT RESULTS FROM THE AGREEMENT INADEQUATE TO PERMIT COMPETITION?

6.A. No. During the long and sometimes heated discussions that led to the Settlement Agreement, Arizonans for Electric Choice and Competition ("AECC"), Enron, and APS were acutely aware of the need to create a reasonable opportunity for efficient ESPs to compete while at the same time providing tangible benefits to all Standard Offer customers. These are mutually inconsistent goals, and thus the issue engendered considerable thought and analysis. As is discussed by AECC witness Higgins in his direct testimony, the "shopping credit" resulting from the instant Agreement is larger than that previously agreed-to by Staff, including Staff consultant Smith, for virtually all customers in the 1998 settlement. It is also significantly larger than that allowed by SRP for over 99% of APS customers. Even at the lower SRP-determined level of "shopping credit", and despite the numerous other SRP- imposed impediments to competition – impediments that would not exist in the case of APS – direct access customers in the SRP distribution service area are already signing agreements and/or letters of intent with APS Energy Services Company, Inc. ("APSES"), an indirect affiliate of the Company and a competitive ESP.

In addition to Mr. Higgins' analysis and the real world experience of APSES in the SRP distribution service area, we have conducted our own analysis. We specifically looked at APS general service customers between 40 and 200 kW. Almost all of the load-serving ESPs certificated by the Commission (except APSES and Commonwealth) have expressed an exclusive interest in commercial customers, and this group (40 to 200 kW) comprises over 80% of those general service customers eligible to take direct access in the initial phase of retail competition. Their individual average load factor is 41%, producing a generation and transmission "shopping credit" of 4.59¢ per kWh. I could simply compare this with Ms. Smith's figure of 4.17¢ for market generation plus transmission and conclude that there is a considerable opportunity here for profitable sales, even before adding in the metering and billing credits overlooked in Ms. Smith's analysis. Additionally, an ESP would not be serving one or even a few isolated individual customers but would instead aggregate groups of such customers with load diversity. Thus, we believe a delivered market price alternative of 37.2¢ is more realistic. This creates 8.7 mils per kWh for ESP margins, or approximately 23% mark-up over cost. Attachment JED-1R provides more detail on this calculation.

All of these calculations, as well as those done by Enron and Staff consultant Smith, assume that an ESP can't beat the Palo Verde hub price for electricity. In reality, our own energy traders beat that price on bulk purchases. In fact, if an ESP doesn't use proper power portfolio acquisition techniques to secure power cheaper than just buying it at the relevant trading hub at the prevailing market price, a strong argument can be made that the ESP is not creating any new value. In other words, it ought to be difficult to make money in a competitive market. It is the struggle to do things cheaper, better, and more efficiently than the next guy that creates additional value for both the buyer and the seller and produces the long term benefits of competition.

7.Q. HAVEN'T OTHER REGULATORY COMMISSIONS REQUIRED HIGHER "SHOPPING CREDITS?"

7.A. Yes. Pennsylvania has required higher "shopping credits" for its high-cost electric utilities (e.g., Philadelphia Electric), with lower "shopping credits" for lower-cost Pennsylvania utilities (e.g., Allegheny Power). It is also my understanding that New Jersey presently contemplates higher "shopping credits." These higher "shopping credits" are either paid for by standard offer customers of those states' utilities in the form of no or reduced rate reductions for such customers, or by stretching out stranded cost recovery for direct access customers, or by effectively borrowing against a hoped-for windfall premium from divestiture of the incumbent's generating assets. If that windfall fails to materialize or greater numbers of customers than expected avail themselves of the inflated "shopping credits," the incumbent utility may have the right to obtain additional stranded cost recovery in the future.

8.Q. DOES APS SUPPORT SUBSIDIZING COMPETITORS AND COMPETITION BY ANY OF THE METHODS DESCRIBED ABOVE?

8.A. No. I agree with Dr. Alfred Kahn, perhaps this nation's leading expert on both regulation and deregulation, who recently referred to this as "bribing customers to leave." A copy of the complete text of Dr. Kahn's article in *The Electricity Journal* is set forth in Attachment JED-2R.

9.Q. WOULD A HIGHER SHOPPING CREDIT RESULT IN DIRECT ACCESS CUSTOMERS PAYING A LOWER SHARE OF STRANDED COSTS THAN A COMPARABLE STANDARD OFFER CUSTOMER?

9.A. That would necessarily be the result. I also agree with Dr. Kahn in the above-cited article that this would be both unfair and provide a subsidy to ESPs rather than a benefit to customers as a group. Moreover, my understanding is that all versions of the Commission's Electric Competition Rules, including those currently pending before the Commission, would not support this result. *See* A.A.C. R14-2-1607 (G).

10.A. WOULD A HIGHER "SHOPPING CREDIT" RESULT IN LOWER OVERALL ELECTRIC COSTS FOR AT LEAST THOSE APS CUSTOMERS CHOSING DIRECT ACCESS?

10.A. No. It may even result in higher bills. A higher "shopping credit" will not lower the market-clearing price of electricity. It will produce higher profits for ESPs. Indeed, if this larger "shopping credit" is created by keeping Standard Offer rates higher than would otherwise be the case, it could have the effect of artificially propping up the price of competitive electricity to direct access customers.

11.Q. SHOULD THE COMMISSION BE SURPRISED THAT THE ESP WITNESSES WANT HIGHER "SHOPPING CREDITS?"

11.A. Absolutely not. If I were in their position, I'd be arguing for as high a "shopping credit" as possible and for as many restrictions on the incumbent provider as I could conjure up. This would make my job as a competitor both easier and more profitable.

12.Q. AT PAGES 15 THROUGH 17 OF HER TESTIMONY, STAFF CONSULTANT SMITH HAS PROPOSED AN "INTERIM SHOPPING CREDIT" THAT IS SOMEWHAT LARGER THAN UNDER THE SETTLEMENT AGREEMENT WITH THE IDEA

THAT APS COULD COME BACK LATER IF THE HIGHER MARKET PRICES SUGGESTED BY MS. SMITH DID NOT MATERIALIZE. IS THIS ACCEPTABLE TO THE COMPANY?

12.A. No. This is just a variant on the Pennsylvania scheme except we are borrowing today against higher hoped-for market prices in the future instead of against higher sales prices for divested generation. Rather than end uncertainty for APS, its customers, and the ESPs, it creates new uncertainties. Ms. Smith's proposal also ignores that one of the bargained-for elements of the Agreement (for which APS agreed to forgo all CTC recovery in excess of $350 million regardless of future market prices or its ability to actually achieve the future cost mitigation inherent in the $533 million stranded costs figure) was the possibility (however remote) that actual stranded costs would be less than $533 million, thus making the $183 million present value "haircut" less punitive to our shareholders. In other words, it's the same type of asymmetrical and unfair proposal I discuss in Section III of my Rebuttal Testimony.

In addition, my accountants assure me that we would not be able to record the stranded cost recoveries deferred under Ms. Smith's scheme as regulatory assets because of the contingency surrounding their eventual recovery. Thus, rather than getting all the "pain" out of the way in 1999, there would be a downward drag on Company earnings throughout the transition period.

13.Q. WHAT ABOUT THE ESP WITNESSES' COMPLAINT ABOUT INCUMBENT MARKET POWER?

13.A. These ESP complaints are to be expected. They manifest themselves in several distinct assertions that I will paraphrase as follows:

a. the Agreement does not require divestiture of APS generation to a non-affiliated party;

b. the Agreement does not impose sufficient restrictions on the affiliate transactions between APS and the new competitive affiliates (i.e. code of conduct issues); and,

c. APS enjoys advantages over new entrants in the form of name recognition, superior knowledge of the APS distribution service areas and its customers, etc.

14.Q. DOES THE AGREEMENT REQUIRE APS TO DIVEST ITS GENERATION TO A NON-AFFILIATED PARTY?

14.A. No. Mandatory divestiture to a non-affiliated party has never been required by any of the several permutations of the Commission's Electric Competition Rules. Mandatory divestiture is neither required nor even authorized by H.B. 2663 ("The Retail Electric Competition Act"). Yet each of these ESPs, and many others for that matter, have still lined up to get CC&Ns to serve in the APS distribution service area. New Jersey and Pennsylvania, the two jurisdictions most often cited by the ESP Witnesses as "getting it right," have not mandated divestiture, although some utilities in those states have agreed to voluntarily divest. Simply put, these ESP Witnesses don't like the Commission's Electric Competition Rules.

15.Q. HAS ANY PARTY PROVIDED EVIDENCE OF APS MARKET POWER?

15.A. Not in my estimation. Although Dr. Hieronymus and Dr. Landon are the market power experts, I don't see where any party has provided any evidence of APS having significant market power outside of a few load pocket situations.

16.Q. HOW DOES THE SETTLEMENT AGREEMENT RESOLVE THE LOAD POCKET SITUATIONS DESCRIBED BY ENRON WITNESSES FRANKENA AND DELANEY?

16.A. The Agreement did not cause, exacerbate, and cannot directly resolve this situation. Load pockets represent transmission-constrained areas. As such, they are largely FERC issues. I discuss this more thoroughly in Section V of my Rebuttal Testimony.

17.Q. WHAT DO THE PROPOSED COMMISSION ELECTRIC COMPETITION RULES REQUIRE AS REGARDS A CODE OF CONDUCT?

17.A. The pending Electric Competition Rules require APS to propose a code of conduct within 90 days of the effective date of such Rules. It says nothing about an interim code of conduct. By mandating APS to submit an interim code of conduct within 30 days of the approval of the Agreement, the Settlement Agreement goes beyond what is being considered in the pending Electric Competition Rules. When and if the Electric Competition Rules are finally adopted, APS would submit a "permanent" code of conduct for Commission approval.

18.Q. WHAT IF THE ELECTRIC COMPETITION RULES REQUIRE A MORE RESTRICTIVE OR PRESCRIPTIVE CODE OF CONDUCT THAN THE INTERIM CODE OF CONDUCT FILED BY APS UNDER TERMS OF THE AGREEMENT?

18.A. APS would have to comply with the more stringent requirements. The same is true should the Commission decide to reinstate all or part of the particular provisions of "old" Rule 1617, which prescribed and prohibited specific affiliate relationships and transactions. The interim code of conduct under the Agreement supplements whatever provision the Commission adopts by rule – it does not replace it.

19.Q. WHAT IF THE FINAL ELECTRIC COMPETITION RULES DO NOT REQUIRE A CODE OF CONDUCT OF ANY SORT?

19.A. I judge such a result to be an extremely unlikely outcome, but in that event, APS would continue to abide by the interim code of conduct filed pursuant to the Agreement.

20.Q. WHAT WOULD BE THE ELEMENTS OF THE INTERIM CODE OF CONDUCT?

20.A. The Agreement requires APS to consult with the other signatories on this interim code of conduct. However, it is probably safe to say that the interim code of conduct will be designed to prevent subsidization of competitive services by non-competitive services. Second, there will be no unlawful discrimination in the provision by APS of non-competitive services to an ESP or its customers. Third, it will assure equal access by all ESPs to customer-specific information (with, of course, the customer's permission) upon reasonable terms and conditions. This necessarily means no preferential access to such information by any competitive affiliate of APS. Fourth, it will address Commission access to affiliate books and records necessary to assure compliance by APS with the interim code of conduct.

21.Q. WILL APSES AND THE COMPETITIVE GENERATION AFFILIATE REFERENCED IN THE AGREEMENT BE SUBJECT TO THIS INTERIM CODE OF CONDUCT?

21.A. The contemplated generation affiliate, which is to be a direct PinnWest subsidiary, will not offer retail services in Arizona, and thus would be regulated by FERC and subject to the stringent FERC code of conduct on affiliated transactions as regards its relations with both APS and APSES. APSES is not a signatory to the Agreement and, as a direct PinnWest subsidiary, is no longer controlled by APS. Nevertheless, it will be effectively subject to the interim code of conduct because virtually all the restrictions inherent in such a code of conduct are imposed on APS. For example, if APS is expressly prohibited by the code of conduct from giving subsidies to APSES, obviously APSES is effectively prohibited from receiving such subsidies. Also APSES may be reselling excess purchases of power into the wholesale market, and thus would likewise become subject to FERC jurisdiction (as well as that of the Commission) and the FERC code of conduct.

22.Q. DO APS AND APSES HAVE ANY ADVANTAGES IN THE FORM OF NAME RECOGNITION, GOOD WILL, SUPERIOR

KNOWLEDGE OF THE ARIZONA MARKET AND ITS CUSTOMERS, ETC.?

22.A. APS may have these advantages, but APS will not be engaging in competitive electric services for the most part, so whatever incumbent advantages it possesses are pretty much irrelevant. APSES may also enjoy some of these advantages in areas served by APS or close to areas served by APS. However, these are advantages enjoyed by all successful incumbents, whether its Anheuser Busch (Budweiser beer) or AT&T (long-distance telecommunications).

III. STRANDED COSTS

23.Q. DOES THE AGREEMENT CREATE THE POSSIBILITY THAT APS WILL COLLECT MORE THAN THE AGREED UPON $350 MILLION DOLLARS THROUGH THE CTC?

23.A. No. All APS customers must fall into either of two categories: direct access or Standard Offer. The same CTCs, by class, are imputed to both sets. Thus, whether all eligible APS customers chose direct access, or none chose direct access, or any combination of direct access and Standard Offer customers in between those two extremes, recovery of the CTC is capped at $350 million. If the agreed-upon CTCs produce more revenue than anticipated due to higher than expected sales or deliveries of electricity between January 1, 1999 (the beginning of the recovery measurement period) and the end of 2004 (the end of the recovery period), the Agreement provides for a reconciliation procedure that first offsets any such over collection against amounts otherwise recoverable under the agreement.

24.Q. WOULD ANY SUCH OVERCOLLECTION CONSTITUTE AN INTEREST-FREE LOAN TO THE COMPANY?

24.A. No. By reducing the amounts deferred under the Agreement, these hypothetical over collections of the $350 million would similarly reduce APS' allowed returns on these deferrals. In the unlikely event that the CTC over collection of the $350 million was greater than the additional costs deferrable under the Agreement, there would be a negative balance that should accrue a return similar to that of a positive balance. However, this is the sort of structural detail that the Commission and affected parties would work out in the proceeding contemplated by the last paragraph of Section 2.6

25.Q. WOULD APS COLLECT STRANDED COSTS BOTH FROM THE MARKET RATES CHARGED BY ITS GENERATING AFFILIATE AND THROUGH THE CTC?

25.A. No. The generation affiliate would recover market rates while the CTC is, by definition, the difference between book value and market rates. There is no overlap between the two.

26.Q. WHAT IF MARKET ELECTRICITY PRICES TURN OUT TO BE LOWER OR HIGHER THAN ANTICIPATED?

26.A That's a different question. If that turns out to be true and all else remains equal, itself an unlikely event, APS' stranded costs would be higher or lower than $533 million (although not necessarily or even likely less than the $350 million cap).

27.Q. WHAT IF THE ACTUAL STRANDED COSTS DO TURN OUT TO BE LESS THAN $350 MILLION?

27.A. That is extremely unlikely. However, such a hypothetical result is inherent with choosing a fixed number for CTC recovery. APS bears all of the risk that stranded costs will exceed expectations. Customers bear only part of the risk that they will be less than expected. Proposals such as that of Staff consultant Smith, which place none of the risk for overestimation on customers but all of the risk for underestimation on shareholders, are both asymmetrical and, to put it more simply, unfair. As such, they are similar to the asymmetrical "risk sharing" schemes denounced by the Commission more than a decade ago:

> It would take many pages for us to discuss the numerous arguments for and against "value-based pricing,' "risk sharing," and "market-based pricing," . . . Fortunately, it is not necessary for us to examine in minute detail the many assumptions which form the foundation of the otherwise objective-looking calculations of present worth and opportunity cost. After reviewing the various proposals presented, we find ourselves in agreement with APS witness [Dr. Alfred] Kahn that, as formulated, **these proposals are simply unfair.** In Decision No. 55118, the Commission indicated that if one wishes to chose an absolute (per se) standard for utility performance, one must be prepared to give [shareholders] credit for performance above the standard as for below. Although we are intrigued with these concepts, as formulated and offered, they ignore this fundamental principle [of reciprocity] and will, therefore, be rejected at this time.
> [Emphasis supplied.]

Decision No. 55228 (October 9, 1986).

28.Q. WHY DO YOU BELIEVE IT SO UNLIKELY THAT APS' ACTUAL STRANDED COSTS WOULD BE LESS THAN $350 MILLION?

28.A. It is unlikely that APS' stranded costs will be less than the $533 million figure cited in the Agreement, let alone $350 million. This is true for the following reasons:

a. APS estimates of market price are at the high end of reasonableness, and higher market prices mean lower stranded costs;

b. APS has already significantly improved its generation cost efficiency and has factored even more significant cost mitigation into its calculation of stranded costs;

c. Other utilities in the region are likely making similar efforts to reduce generation costs, but this factor suppressing market prices was ignored in APS' study;

d. APS has assumed that operating margins from "must-run" units will not be constrained by regulation, thus decreasing stranded costs;

29.Q. HOW DO APS' MARKET PRICE PROJECTIONS COMPARE TO THOSE OF OTHER EXPERTS?

29.A. We are clearly more "bullish" about future market prices than SRP. A comparison of the market prices used in the APS stranded cost calculation and those adopted by SRP are shown in my Attachment JED-3R. APS has also compared its projections with those of EPIS and CERA, both established consulting firms that do this sort of analyses. APS is higher than either of these consultants' price forecasts using either unified or Balkanized market assumptions. Those comparisons are also shown on Attachment JED-3R.

30.Q. DIDN'T STAFF CONSULTANT SMITH COME UP WITH SOME HIGHER MARKET PRICES IN MAKING HER RECOMMENDATION?

30.A. Yes. These prices are based on just a few months experience in 1999, which she then extrapolates out through the year 2004. I found Staff consultant Smith's use of these prices particularly puzzling because during the course of negotiating the 1998 settlement agreement, we had shared the detail of all our market pricing assumptions with Staff's stranded cost expert, Dr. Kenneth Rose. Dr. Rose did not express disagreement with our overall results. In fact, Dr. Rose shared his own market price analysis with the Company. Dr. Rose relied heavily on a study by the United States Energy Information Administration ("USEIA"). A comparison of those projections with those of APS shows that USEIA's prices are lower than the Company's. *See* Attachment JED-3R. Therefore, Staff consultant Rose's figures would have produced higher stranded cost estimates than those proposed by APS.

31.Q. IS THERE A FURTHER REASON TO BELIEVE THAT THE COMPANY'S MARKET PRICE ESTIMATES ARE ON THE HIGH SIDE?

31.A. Yes. Additional capacity in the form of efficient gas-powered generation will have a suppressing effect on market price. It's the old law of supply and demand. APS has assumed far less in the way of new generation supply market entry than the announced plans of both incumbent utilities and merchant builders. APS' stranded cost calculation is, in effect, counting on some two-thirds of these projects being cancelled or delayed significantly. As noted earlier, APS has also ignored the likely improvements in plant operating efficiencies from existing plants other than its own.

32.Q. PLEASE DISCUSS APS' ASSUMPTIONS ABOUT COST MITIGATION?

32.A. The combination of past and future reduced O&M for generation have reduced APS' stranded generating costs (ACC jurisdiction) by $137 million (present value) during the period 1999-2004. APS has assumed that even greater capacity factors can be achieved in the future. I should note that some of the APS units being considered in the stranded cost calculation will be over 50 years old by the time of their retirement, and yet APS has assumed that they will operate more efficiently than they did some 20 years earlier.

33.Q. AT PAGE 13 OF HER TESTIMONY, STAFF CONSULTANT SMITH HAS CRITICIZED THE COMPANY'S CLAIM OF HIGHER CAPACITY FACTORS AS EXAGGERATED AND IGNORING THE IMPACT OF LOWER APS CAPACITY FACTORS ON MARKET PRICE. ARE SUCH CRITICISMS VALID?

33.A. No. As can be seen by Attachment JED-4R, which was previously provided to Staff, APS has not compared its prospective capacity factors with a single aberrant year or even a few years, but against the entire prior decade's historical operating experience of each unit. APS also acknowledges that industry capacity factors have improved slightly in recent years, but they are still well below those projected by APS in its stranded cost calculation. Ms. Smith also fails to note that if other utilities increase their capacity factors, that will have a depressing impact on future market prices.

Ms. Smith also claims that had APS used lower capacity factors for its own generating units, it may have increased the market price. APS has made analyses of precisely that impact and has found the trade-off between lower assumed output (i.e., lower capacity factors) and higher market prices leaves APS a big loser. The impact of lower output totally dominates that of higher prices causing significantly higher stranded costs. APS has also shared these analyses with Staff during the course of the last settlement.

34.Q. PLEASE EXPLAIN HOW THE INCLUSION OF "MUST-RUN" UNITS IN APS' STRANDED COST CALCULATION REDUCED THE $533 MILLION ESTIMATE.

34.A Virtually everyone, including APS, is proposing that "must-run" units must be rate-regulated because of the micro-market power they possess in certain load pockets within the state within a limited number of hours in the year. The $533 million stranded cost estimate did not impose such a constraint and assumed that these units could sell their output at market prices whenever their operating costs put them "in the money" (market price above variable O&M). Since, in general, market prices exceed the embedded cost-of-service for these older, largely or fully-depreciated units, this produced higher revenues (and lower stranded costs) than had we constrained prices to cost-of-service levels.

35.Q. HAVE YOU SUMMARIZED THE IMPACT ON THE COMPANY'S ESTIMATE OF STRANDED COSTS OF THESE VARIOUS ASSUMPTIONS?

35.A. Yes. As can be seen on Attachment JED-5R, APS' stranded cost estimate would increase to $774 million simply if the SRP market price assumptions were substituted for the Company's. The other market price assumptions previously discussed would produce stranded cost estimates of between $546 million and $845 million. Adding in the impact of aggressive O&M mitigation, higher APS capacity factors, and increased market entry would have increased this figure by at least another $300 million.

36.Q. MS. SMITH ALSO CONTENDED THAT APS' TRUNCATION OF THE STRANDED COST CALCULATION AT YEAR 2004 LIKELY CAUSED AN OVERSTATEMENT OF STRANDED COSTS. IS THAT ACCRUATE?

36.A. No. Although Decision No. 61677 adopts truncation of the stranded cost calculation at the end of the five year transition period in its Option No. 1, APS has carried out the calculation to 2016, which is when APS predicts very significant unit retirements. Jurisdictional stranded costs would increase to $574 million. This information was likewise provided Staff, and thus I can not understand why anyone would attempt to give the Commission the false impression that APS had somehow "gamed" its calculation of the $533 million stranded cost figure cited in the Agreement.

IV. TRANSFER OF COMPETITIVE ASSETS

37.Q. WHY IS IT REASONABLE TO TRANSFER APS' GENERATING ASSETS TO THE CONTEMPLATED PINNWEST SUBSIDIARY AT BOOK VALUE?

37.A. Stranded costs are, by definition, the difference between book value and market value. That's not just my definition, but the definition of stranded costs used in the Commission's Electric Competition Rules. That difference is either a positive number (stranded costs) or negative (stranded benefits). Reflecting market price in the transfer would double-count either the losses (stranded costs) or the profits (stranded benefits). It's just that simple. I realize that not every party agrees with the Company's calculation of stranded costs, but that is a different issue from that of whether the same figure should be counted twice. I would hope that all of us could agree that such double-counting is wrong.

38.Q. IS THERE SOME GENERALLY-ACCEPTED ACCOUNTING RULE THAT SUCH A TRANSFER OF GENERATING PLANTS SHOULD BE AT THE LOWER OF MARKET OR BOOK VALUE AS WAS SUGGESTED BY ESP WITNESS OGLESBY AT PAGE 5 OF HIS TESTIMONY?

38.A. Not that I ever heard of. In fact, generally accepted accounting rules specifically mandate the transfer of assets between entities under common control (in this case, PinnWest) at book value. Mr. Ogelsby's proposal of transferring the above-book generating assets at that higher price while transferring below-book assets such as Palo

Verde at book value not only double-counts the above-book assets (which have already been considered in reducing APS' estimate of stranded costs to the $533 million figure cited both in the Agreement and in the Company's 1998 stranded cost filing with the Commission), it ignores the below-book losses attributable to the other individual generating supply assets. This is not only blatantly "unfair" (to again quote the Commission's own words), it does not meet the Commission's requirement in the Electric Competition Rules for measuring "net stranded costs" [emphasis supplied] because there would be no netting of above and below-market assets.

39.Q. HAS MR. OGELSBY PREVIOUSLY PROPOSED THIS TREATMENT OF GENERATING ASSETS IN ARIZONA?

39.A. No. Mr. Ogelsby made no mention of this in his previous testimony during the generic stranded cost proceeding. Similarly, although Mr. Ogelsby did not file testimony in either the SRP stranded cost proceeding or on the prior 1998 APS/Staff settlement agreement, PG&E Energy Services did submit testimony of other witnesses in the latter proceeding. Not surprisingly, the market generation or "shopping credit" was not high enough in that settlement to suit PG&E Energy Services, but it took no issue with the transfer of APS generating units to an affiliate at book value nor with any of the regulatory waivers sought by the Company.

40.Q. WAS SUCH A TRANSFER AT BOOK VALUE AN EXPRESS PART OF THE EARLIER 1998 SETTLEMENT?

40.A. Yes.

41.Q. DOES THE VALUE AT WHICH THE GENERATING ASSETS ARE TRANSFERRED TO AN APS AFFILIATE AFFECT THE PRICE IT CAN CHARGE FOR ELECTRICITY?

41.A. Of course not. This idea is a hold-over from cost-of-service regulation. Market price is determined by the law of supply and demand. Demand is independent of the individual supplier's costs. Only variable costs affect supply. In the short-run, only some portions of O&M are variable. In the long-run, marginal capital costs are also variable. However, sunk costs such as the fixed costs of existing generating units play no part in determining market price. If they did, the fact that the market value of APS generating units is less than book value would give the transferee a marketing advantage as compared to a transfer at book value, as called for in the Agreement.

42.Q. HAS COMMISSION STAFF SUPPORTED THIS TRANSFER AT BOOK VALUE?

42.A. Yes. Both in the withdrawn 1998 settlement agreement and in the current proceeding, this has not been as issue with Commission Staff.

43.Q. SEVERAL WITNESSES HAVE CRITICIZED THE COMPANY FOR NOT MORE CLEARLY INDICATING WHAT ASSETS WILL BE TRANSFERRED TO THE GENERATING AFFILIATE. CAN YOU BE MORE SPECIFIC?

43.A. The Company can not come up with the definitive list of assets to be transferred until both this Agreement is approved and the Electric Competition Rules are finalized. But with those caveats, I have attached as Attachment JED-6R a list and description of the assets APS presently intends to transfer to one or more new affiliates.

APS has already been authorized to transfer some limited assets to APSES per Commission Decision No. 61668 (April 21, 1999). It does not presently anticipate any further transfers to APSES. Similarly, APS has no present plans to engage in competitive metering for non-residential customers, meter reading, or billing. Thus, APS would not be transferring any assets related to these services to an affiliate. It will instead retain them for Standard Offer service (which by Commission rule is not a competitive service) and for the metering of direct access residential customers (which APS is permitted to do without divestiture under the proposed Electric Competition Rules).

44.Q. WILL APS BE PROVIDING "COMPETITIVE ELECTRIC SERVICES," AS DEFINED BY THE COMMISSION, PRIOR TO DIVESTITURE OF THE ABOVE-DESCRIBED ASSETS?

44.A. No, excepting the residential metering discussed in response to the previous question. The Electric Competition Rules would prohibit such competitive activities by APS, and the Agreement does not change that fact.

45.Q. WHY NOT SIMPLY DIVEST YOUR GENERATING PLANTS TO A THIRD PARTY?

45.A. Having never persuaded either the Commission or the legislature that mandatory divestiture was appropriate, I would have thought this "dead horse" ESP issue had long since been put to rest. As with code of conduct and other issues, the ESP Witnesses have injected old arguments over the Electric Competition Rules into this proceeding. Suffice it to say that none of these witnesses have addressed the very issues that led the Commission to reject their previous pleas for divestiture:

a. lack of authority to mandate or coerce divestiture;

b. cost of third-party divestiture;

c. the inability to sell the Company's interest in Palo Verde at any price (the NRC has never approved the transfer of the operator's interest in a nuclear power plant to a non-affiliated entity); and,

d. concerns related to jointly-owned units such as Palo Verde, Four Corners, Navajo or jointly-owned plant facilities such as Cholla (participant rights to extended prior notice, rights of first refusal, etc.).

One new suggestion that did surface in this proceeding is Mr. Ogelsby's proposal to sell-off everything but Palo Verde. The thought of a utility distribution company with a nuclear power plant as its sole generation asset is almost too horrible to imagine. When they did this in Great Britain, they realized that only the government could afford such an undiversified portfolio of generation.

V. AISA/ISO TRANSMISSION ISSUES

46.Q. IS THE AISA ADDRESSING ALL OF THE TRANSMISSION ISSUES RAISED BY ENRON AND THE OTHER PARTIES?

46.A. Yes. Through the AISA, of which Enron is not only a member, but also part of its governing body, "must-run" and other protocols are being developed. Enron was a very active participant in formulating and even drafting these AISA protocols. One of the 10 completed protocols specifically addresses "must-run" by requiring "must-run" generators to sell to the AISA at a pre-determined price based on incremental cost. In addition, all schedules will be posted on both the control area operators' and the AISA OASIS. Two days prior to schedule implementation, Scheduling Coordinator schedules will be similarly posted. If any Scheduling Coordinator for an ESP (or for a UDC, for that matter) believes that the control area operator is acting improperly, it can challenge the operator through the AISA Director, who must resolve the dispute prior to schedule implementation.

47.Q. ARE MR. DELANEY'S STATEMENTS ABOUT OASIS, THE TOTAL TRANSFER CALCULATION, AND AVAILABLE TRANSFER CAPABILITY, AS SET FORTH AT PAGES 11-16 OF HIS TESTIMONY, ACCURATE?

47.A. Absolutely not. Mr. Delaney's allegations and insinuations are completely false and inaccurate. I realize that the AISA is basically a FERC issue, with FERC having to approve the operating protocols and "must-run" pricing provisions, but Mr. Delaney does not help the Commission's understanding of the AISA process by these kinds of misrepresentations.

48.Q. WHAT ABOUT MR. DELANEY'S EXPRESSED CONCERNS ABOUT ENERGY IMBALANCE SERVICE?

48.A. I could not believe my eyes when I read his comments. The AISA energy imbalance protocol was developed by a sub-group of AISA members chaired by Enron! The bottom line as to this and the other

AISA issues raised by Enron is simple. The AISA is made up of a large number of highly diverse groups - power marketers and other load-serving ESPs such as Enron, transmission-owning utilities (both investor-owned and public power), transmission-dependent utilities, distribution cooperatives, G&T cooperatives, municipalities, etc. Not surprisingly given the multitude of represented interests, no one got everything they wanted in the development of the operating protocols. Just as obviously, the perceived "losers" in the "give and take" process of devising such protocols at AISA will, no doubt, try to get a second "bite at the apple" when the protocols are filed with FERC. However, to at this time interject this Commission and, even worse, this Settlement Agreement into that process is, quite frankly, irresponsible and only seeks to confuse the Commission with hyper-technical "red herrings."

VI. REQUESTED WAIVERS AND EWG STATUS

49.Q. WHY DID APS SEEK VARIOUS WAIVERS OF THE COMMISSION'S GENERAL AFFILIATE RULES (A.A.C. R14-2-801, *ET SEQ.*), AN EXTENSION OF THE TIME TO DIVEST UNDER RULE 1615, AND THE WHOLE OR PARTIAL RESCISSION OF CERTAIN OLD COMMISSION ORDERS?

49.A. The delay in divesting APS generation to an affiliate was, to begin with, strictly a matter of cost. Provisions in the Palo Verde and West Phoenix sale/leaseback agreements and in our first mortgage bond indenture would have made divestiture in 2000 or even 2001 much more expensive. As I look at the situation today, I very much doubt we could physically accomplish a divestiture by year-end 2000, as was originally contemplated by the Electric Competition Rules. For example, over 60 agreements are involved in the transfer of these assets. Most require some manor of formal consent by the other party. For facilities located on Indian land, both tribal and Interior Department consents are necessary. NRC approval for the Palo Verde license transfer alone is expected to take 6 months. Air, water, and waste permits must also be transferred. Our "best case" estimate is 9-12 months for that. I could go on and on, but I think I've made my point. Thus, the delay takes on certain pragmatic considerations in addition to cost.

The affiliate rule waivers would largely impact only the Company's competitive affiliates, electric and otherwise. (APS has affiliates such as SunCor Development Company that have nothing to do with the electric business and never have.) These, along with the whole or partial recision of certain previous Commission orders are described in Exhibit D to the Settlement Agreement. As can be readily seen by just reading Exhibit D, these regulations would impede the competitive electric market as well as other competitive lines of business that PinnWest may seek to develop. The rescinded or amended orders, to which I do not believe any witness has taken issue, are equally relics of the past.

50.Q. WOULD YOU EXPLAIN EACH OF REQUESTED WAIVERS OF THE AFFILIATE RULES?

50.A. Rule 806 specifically authorizes the Commission to grant these waivers. It is also my understanding that such waivers are routinely granted competitive telecommunications entities such as MCI, AT&T, etc. The requested waivers or modifications include:

a. Rule 803 excepting as a proposed reorganization would involve APS. Absent this waiver, PinnWest's decision to sell SunCor or to buy a chain of pizza shops would arguably fall under this provision, which requires extensive Commission notice and review of such a "reorganization."

b. Rule 801(5), which embodies the definition of reorganization discussed above.

c. Rule 804 (A), which deals with access by the Commission to an affiliate's books and records – a subject that will be addressed in the interim and final code of conduct to which I have previously testified.

d. Rule 805 (A)(2) deals only with the business activities of APS' affiliates other than with APS. It is clearly not consistent with these affiliate's non-jurisdictional status to require this information, which has been waived for any competitive telecommunications provider that has requested it.

e. Rule 805 (A) (6) governs allocations of cost from PinnWest to affiliates. To the extent this applies to APS, it is covered by the code of conduct. PinnWest allocations to non-regulated enterprises is of no legitimate concern of the Commission.

f. Rule 805 (A) (9) – (11) refer to certain documents (contracts. leases, etc.) relating to transactions between APS and affiliates. This provision also overlaps with code of conduct issues. APS certainly does not object to providing such documents if and when it is seeking to include these costs in or exclude revenues from the determination of regulated rates, but does not believe they should be routinely filed with the Commission.

51.Q. WHAT ABOUT THE STATUTORY WAIVERS REQUESTED IN THE AGREEMENT?

51.A. A.R.S. § 40-202 specifically authorizes the Commission to waive the statutes cited in Section 4.3 of the Agreement. A.R.S. § 40-374 was omitted because of an oversight. No witness has argued that these provisions should apply to competitive services. In fact, at least one ESP (Phaser) has also sought exemption from at least some of these provisions. Staff witness Williamson says that there should be a generic investigation of this issue as regards all ESPs rather than a "piecemeal" approach. I have no particular objection to this as long as at least interim waivers are granted to APS and its affiliates pending completion of such a generic investigation. Unfortunately, generic dockets have a way of dragging on and on, and the uncertainty concerning these statutes' application in the meantime is not an acceptable situation.

52.Q. DOES APS OBJECT TO AN ESP SUCH AS ENRON, COMMONWEALTH OR PG&E ENERGY SERVICES RECEIVING SIMILAR WAIVERS?

52.A. Absolutely not. But APS should not be punished simply because it was the first to ask the Commission to use this provision of H.B. 2663.

53.Q. WHY SHOULD THE COMMISSION MAKE THE REQUISITE FINDINGS FOR THE COMPANY'S FUTURE GENERATING AFFILIATE TO QUALIFY AS AN EWG?

53.A. First of all, let's be clear that the "exempt" part of EWG means exempt from PUHCA – not that the generator is exempt from FERC regulation. An EWG may also apply to FERC for "market-based" rate authority, but that is a different issue. Second, the party that is actually "exempt" from PUHCA is PinnWest.

PinnWest is presently an exempt holding company under PUHCA. That exemption is based on the fact that PinnWest operates a single utility operating in a single state and subject to state regulation. Exemption from PUHCA is important because it frees PinnWest from onerous filing, reporting, and prior (SEC) approval provisions in PUHCA. Most public utility holding companies are exempt and strive mightily to preserve their exempt status.

If APS is split into retail functions regulated by the Commission and wholesale functions regulated by FERC, as is required in the proposed Electric Competition Rules, this addition of Genco as a new PinnWest subsidiary will threaten PinnWest's exempt status unless the generating company is determined to be an EWG. PUHCA requires the relevant state regulatory commission to make specific findings, much as A.R.S. § 40-301, *et seq.*, requires the Commission to make specific findings in approving an issuance of securities by APS. It is the Commission's Electric Competition Rules that have created this situation, and therefore the Commission needs to help preserve the *status quo*. It will also speed along the process of divestiture itself since this will be one additional thing that will not have to be done by year-end 2002.

VII. CONCLUSION

54.Q. IN CONCLUSION, WOULD YOU SUMMARIZE YOUR MAJOR POINTS ON REBUTTAL?

54.A. In my Direct Testimony, I warned the Commission against those who would kill this Agreement through the "death by a thousand cuts." Not only have we seen this, but several parties have tried to cut the very heart out of a settlement approved by representatives of virtually all our customers. Some look eagerly back to the days of two-year rate proceedings costing millions of dollars. Others would have you promote their business interests by punishing either the Company or its Standard Offer customers or both. I ask the Commission to reject their arguments and approve this Settlement Agreement. Is the Agreement perfect from my perspective – no. But it is fair. It is comprehensive. It has widespread support from the people the Commission is sworn to protect – the average utility customer of APS.

56.Q. DOES THIS CONCLUDE YOUR DIRECT WRITTEN REBUTTAL TESTIMONY?

56.A. Yes.

ESP MARGIN ANALYSIS

ESP Costs:	**Market Estimate: (mils/kwh)**
Load Weighted Wholesale Energy	25.7[1]
Transmission	3.4
Losses	1.8
Ancillary Services	1.1
Marketing	3.0
Risk Premia	2.2
Total ESP Costs	**37.2**[2]
"Shopping Credit":	**45.9**[3]
Margin:	**8.7**

[1] Uses Class (40-200kw) load factor
[2] Does not include cancellation credit, which should approximate 4.5 times the Risk Premia. Inclusion would decrease ESP costs (increase margins) by another 10 mils per kWh.
[3] Calculated as difference between Standard Offer billing and Direct Access billing for 40-200 kw customers at 41% individual load factors under Settlement Proposed Rates.

GUEST EDITORIAL *Alfred E. Kahn*

Bribing Customers to Leave and Calling It "Competition"

The large number of states that have decided to open their retail electricity markets to competition are now grappling with the task of ensuring that challengers of the franchised local utility company monopolies have a fair opportunity to compete.

The transition is complicated by the recognition by most of them of an obligation to offer the utility companies an opportunity to recover most or all of their "stranded" costs—investment costs historically incurred that competition might make it impossible for them to recover. I will not discuss here the merits of that commitment (See, however, my *Who Should Pay for Power Plant Duds?* WALL ST. J., Aug. 15, 1985.)

but it necessarily implies that customers not be able to escape their share of those costs by deserting their historical suppliers.

An additional complication is created by the understandable unwillingness of regulatory commissions to expose consumers to the risks of a possibly quite volatile unregulated wholesale price, to which the retail margin (still regulated because local distribution remains a monopoly) would be added. They have therefore insisted also on the utility companies freezing their retail prices (rather than just the retail margins).

This arrangement has therefore confronted regulators, in state after state, with the question of what credit or discount retail customers should receive from that frozen price of their utility supplier when they shift their patronage to a competitor—obviously an important determinant of the ability of those competitors to induce them to do so.

It is an elementary economic proposition that the way to ensure that production is carried out efficiently—i.e., with the minimum expenditure of society's scarce resources—is to distribute responsibility for production among suppliers on the basis of their incremental or avoidable costs. That is what competition tends to do. Following this reasoning, the efficient "shopping credit" for customers who desert their utility company suppliers should therefore clearly be whatever (incremental) costs each supplier would save or avoid because of their departure—the wholesale price of the power itself along with some, probably small, costs of retailing. That would be the margin within which the competing retail marketer would have to operate if it

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Some of the views expressed in this article were previously presented in regulatory proceedings in testimony by Mr. Kahn on behalf of two electric utility companies.

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were to compete effectively, so long as it offered the same services as the utility company. Clearly, any competitors with incremental costs higher than those of the incumbent would be unable to offer buyers a price sufficiently low to induce them to shift. Nor should they be, since their taking over the function of serving consumers would impose costs on society greater than the costs it would save by consumers shifting to them.

It may well be—indeed, consumer inertia makes it highly likely—that an inducement to customers to shift equal only to the costs that their historical suppliers would save would not create much of an opportunity for competitors, so even one with incremental costs no higher than those of the utility would probably still be unable to entice many customers away. If so, however, that would be because the mere resale of electric power, purchasable by incumbents and challengers alike from regional power pools at a competitive wholesale price, offers comparatively few opportunities for creative or socially useful competition, so long as the retail prices of the incumbent are frozen. The real opportunities for aggressive and innovative competitors selling electric power alone will emerge when the utility price caps come off. Consumers will be looking for protection from the risks of what could be highly volatile wholesale markets and, until then, in bundling sales of electric power with other energy-related services—audits, conservation, climate control, load management and the supply and servicing of energy-using equipment.

To the extent that a competitor can offer additional services of this kind, which customers value sufficiently to pay the additional cost of providing them, it can of course charge them more than the credit they would receive from the utility company upon their departure and thereby compete effectively. In either case, it would be consumers

who would be making the unbiased choices, depending upon whether those additional services were or were not worth the additional cost.

Unfortunately, regulators are always under strong political pressures to produce visible results. Confronted with a public demand for "competition," they are strongly tempted to produce some live competitors, regardless of their relative efficiency or the relative attractiveness of the bundled services they offer. The "shopping credit" given to departing customers presents an easy opportunity to succumb to that temptation.

The Pennsylvania Commission, for example, has intentionally required electric utility companies to offer a credit much greater than the costs they avoid when they lose a customer—some 50 percent higher than the California and Massachusetts commissions have prescribed. One of its commissioners has boasted that as a result more customers in Pennsylvania will have shifted to a new supplier than in the entire remainder of the country. He obviously believes he has stumbled upon the secret of perpetual motion: "Bigger shopping credits create greater consumer savings," he says, vacuously. The clear lesson for other states is to prescribe shopping credits twice as large as Pennsylvania's and in this way seize the leadership in the race to stimulate competition and generate such "consumer benefits."

The economist has the unpleasant job of reminding people that somebody has to pay for apparently free lunches. The Pennsylvania commissioner clearly believes that it will be the utility company: The more it pays the customers it loses than the costs it saves by their leaving, the less it will have left over to recover its stranded costs. That is in fact the case when the shopping credit is determined after the utility rates have been frozen.

That reasoning is nevertheless either naïve or disingenuous. If a state decides to permit a utility company recovery of something less than 100 percent of its stranded costs, the obvious and logical way—the only fair way—to do so is to order it to reduce rates to all its customers. If, having frozen rates at a level it considers sufficient to permit recovery of that predetermined proportion of the costs likely to be stranded, a commission then introduces a shopping credit with a built-in subsidy, it is clearly altering the terms of the stranded cost bargain with the utility company. In fact the Pennsylvania decision contemplates the possibility of the utility company being permitted to raise its rates to all customers in the future, if the inflated shopping credit results in stranded cost recovery less than the amounts previously agreed upon. In any event, to deny the company full recovery not in the form of an overall rate reduction, but by ordering a shopping credit greater than its avoided costs, is to benefit the customers who leave their historical supplier at the expense of the ones who remain. The bigger the benefit to the one group, the greater the sacrifice by the other. That's what we call economics. A system under which the only way to qualify for the saving is to shift patronage subsidizes competitors, not consumers as a group.

Of course, there is always the "infant industry" case for such special protection or subsidization of would-be entrants who would not otherwise be able to compete. The consensus view of economists about this possible biasing of competition would place a very heavy burden of proof on its proponents—a convincing demonstration that the asserted advantages of the incumbent are likely to be so overwhelming as to make competitive challenge impossible; and that the cost to consumers of such preferences are outweighed by the prospective benefits of the additional competition that they protect.

My own assessment has two parts. First, I am highly skeptical that the potential benefits of competition in the mere retailing of electric power as such are sufficiently attractive to justify deliberately subsidizing it by imposing a tax on the customers who remain with their historical supplier—and especially while the utility's rates are frozen. It is competition among *generators* in the wholesale market that promises the largest benefits by wringing inefficiencies and monopoly elements out of the price of the power itself, and forcing suppliers to bear the costs of investments that turn out badly, rather than passing them on to captive customers.

Second, as I have already pointed out, the real opportunity for aggressive and innovative competition at the retail level is in the offering of energy services generally, not just power alone. Here, however, there simply is no case for special protection or subsidy of competitors. In the offer of many of these services, it is the electric utility company that is the entrant. In the market for energy conservation services, it would have to compete with local builders and contractors in heating, ventilating, and air conditioning, with companies like Sears Roebuck, Montgomery Ward, General Electric, and Honeywell, which already provide such equipment and services in hundreds of localities and enjoy the advantages of incumbency and brand recognition.

Playing with artificial competitive handicapping is playing with a tar baby. Once commissions decide to provide subsidies to competitors they will have to revisit them perennially, trying to decide how much is enough and when they should end—an intensely political process and a very odd kind of deregulation indeed. ■

Of course, there is always the "infant industry" case for special protection.

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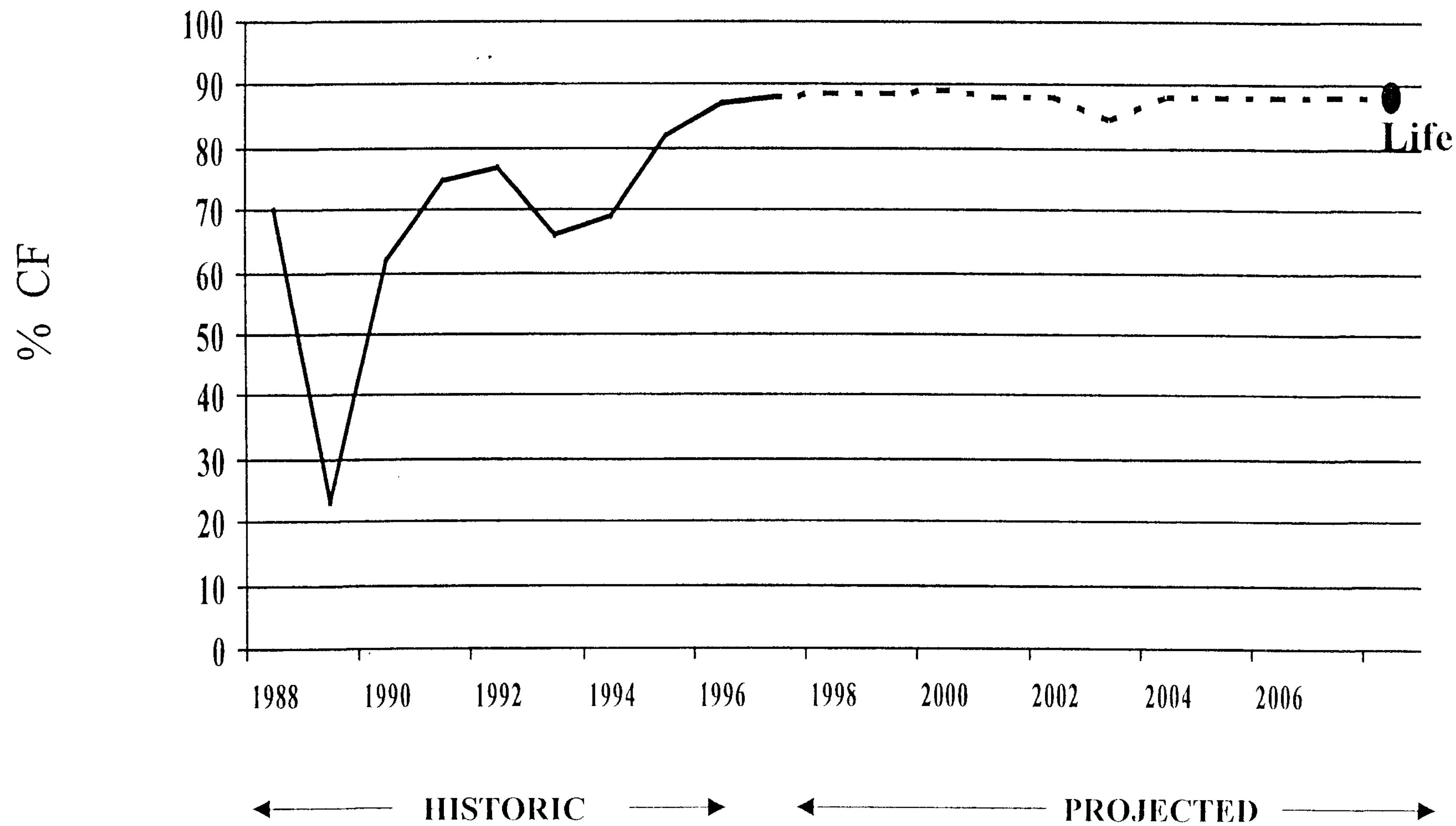
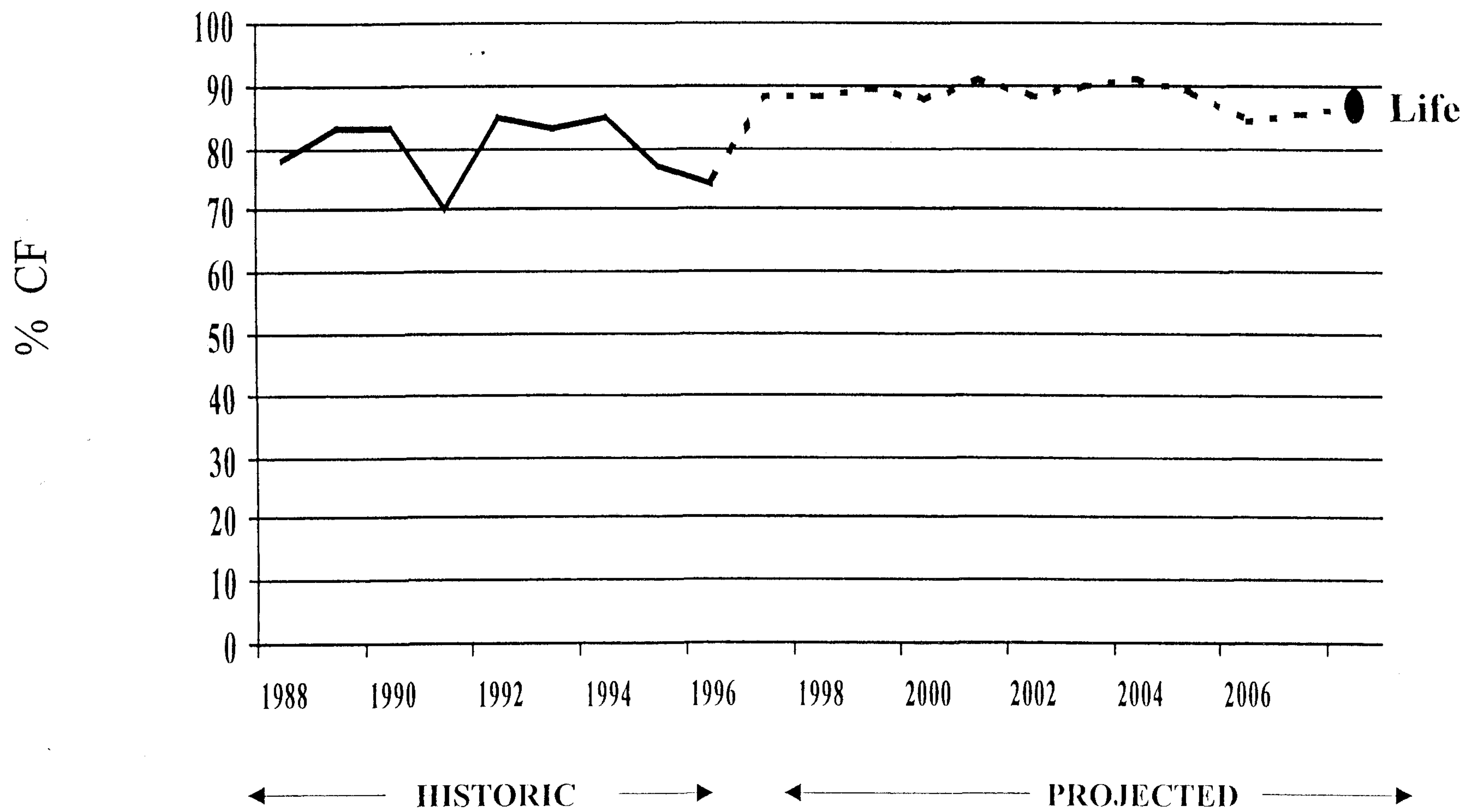
Market Price Forecast Comparison
($/MWH)

Year	APS	SRP	EPIS	EIA	CERA Unif.	CERA Balk.
1999	26.3	24.4		23.4	21.5	23.6
2000	25.7	24.6	20.1	25.0	24.3	26.2
2001	27.0	24.9	22.4	26.3	26.6	29.6
2002	28.3	25.3	24.2	27.6	29.3	28.9
2003	30.4	25.7	25.5	29.5	29.4	29.0
2004	32.2	26.3	28.4	31.4	29.9	29.1
2005	34.7	26.9	30.1	32.8	30.3	30.0
2006	35.4	27.6	32.0	33.1	31.4	30.0
2007	38.0	28.3	33.5	34.8	32.3	30.9
2008	39.5	28.9	34.6	35.5	34.4	32.2
2009	40.4	29.6	35.2	35.8	34.6	33.4
2010	40.8	30.3	37.9	36.2	34.9	34.8
2011	42.0	31.1	38.2	36.9	35.3	35.9
2012	43.2	31.8	39.0	38.4	36.0	36.6
2013	43.2	32.6	41.1	39.2	36.3	37.3
2014	43.9	33.4	41.9	39.6	36.5	37.8
2015	43.0	34.2	42.5	39.6	36.8	39.5

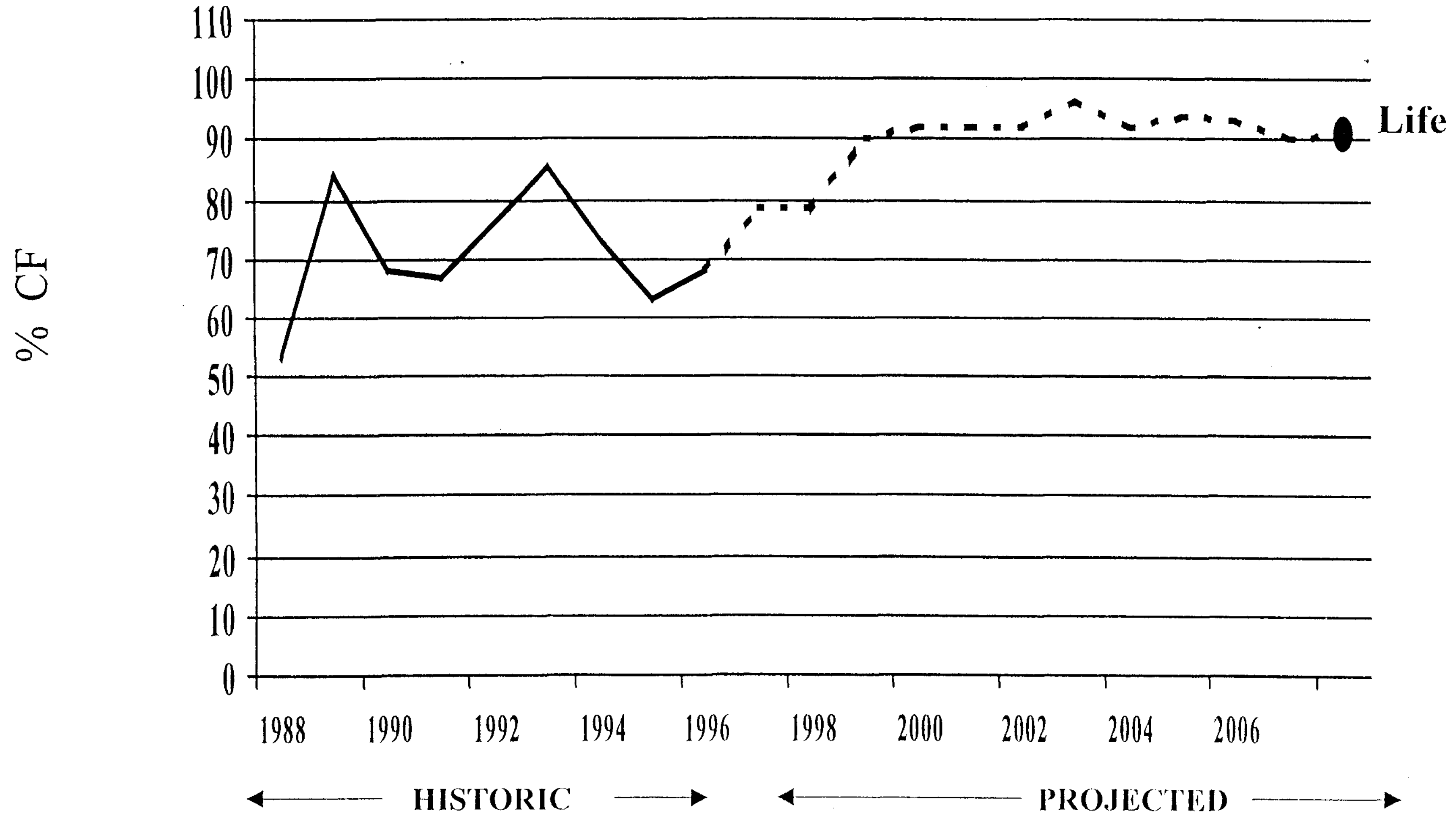
HISTORIC AND PROJECTED CAPACITY FACTORS (PALO VERDE)



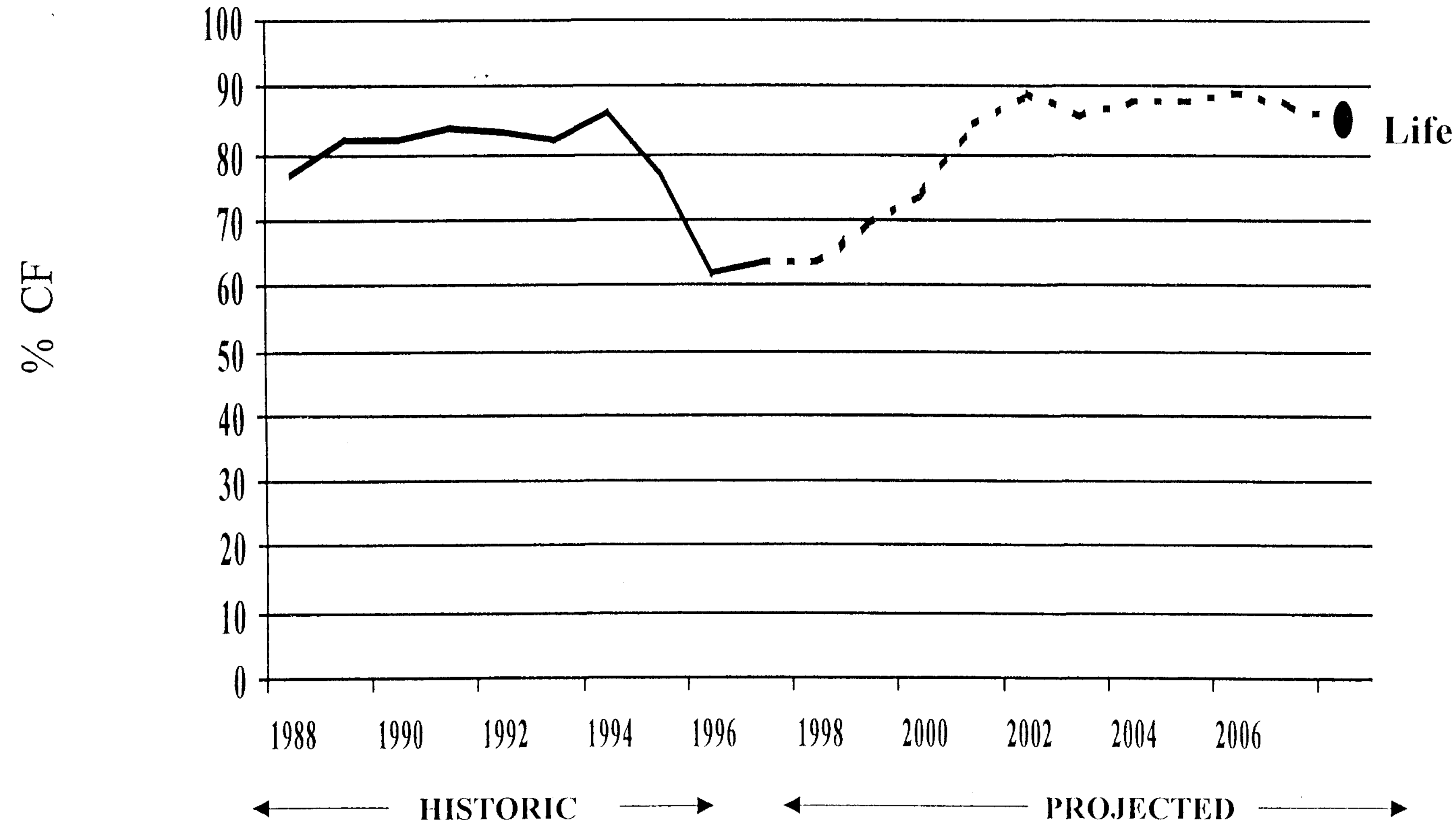
HISTORIC AND PROJECTED CAPACITY FACTORS (FOUR CORNERS)



HISTORIC AND PROJECTED CAPACITY FACTORS (CHOLLA)



HISTORIC AND PROJECTED CAPACITY FACTORS (NAVAJO)



Calculated Stranded Cost Based on Industry Market Price Forecast
1999-2004 CPW in Millions of Dollars

	APS	SRP	EPIS	EIA	CERA Unif.	CERA Balk.
1999-2004	533	774	845	593	594	546

Description of assets to transfer to New Generation Company

Four Corners Generating Station

Steam Generating Units 1, 2 and 3

Boilers, turbines, generators, coal pulverizers, flue gas scrubbers, flue gas chimneys, lime silos, coal belts, natural gas lines, land leases, ash ponds, evaporation ponds, emergency coal pile, circulating water pumps, maintenance buildings, materials and supplies inventory and other related facilities.

APS share of Steam Generating Units 4 and 5

Boilers, turbines, generators, coal pulverizers, bag houses, SO2 absorber towers, flue gas chimneys, lime silos, ash loading silos, circulating water pumps, land leases, maintenance buildings, auxiliary boiler, natural gas lines, coal belts, materials and supplies inventory and other related facilities.

APS share of Common Facilities

Coal sampler, water rights, materials and supplies inventory, administration building, warehouse buildings and yards, brine concentrator, condensate water demineralizer, cafeteria building, river pump station, potable water building, vehicle maintenance garage, vehicles, roads, land leases, parking lots, scales, fencing and other related facilities.

Rights and agreements

Coal purchase agreements, land leases, water rights, lime purchase agreements, SO2 allowances, natural gas agreements and all other rights and agreements required to operate the plant.

Cholla Generating Station

Steam Generating Units 1, 2, and 3

Boilers, turbines, generators, coal pulverizers, coal silos, flue gas scrubbers, flue gas chimneys, natural gas lines, land and land leases, circulating water pumps, maintenance building, cooling tower, lake and other related facilities.

APS share of common facilities

Coal inventory, materials and supplies inventory, well fields, warehouse, gas and oil lines, oil storage tank, coal belts, coal crusher towers, railroad, ash ponds, lime silos, evaporation ponds, planning and maintenance buildings, administration buildings, roads, parking lots, land and land rights, locomotives, vehicles, vehicle maintenance garage, fencing and other related facilities

Rights and agreements

Coal purchase agreements, railroad freight agreements, water rights, lime purchase agreements, SO2 allowances, natural gas agreements and all other rights and agreements required to operate the plant.

Navajo Generating Station

APS share of Steam Generating Units 1, 2 and 3 and other facilities

Boilers, turbines, generators, coal pulverizers, coal silos, flue gas scrubbers, flue gas chimneys, materials and supplies inventory, railroad, locomotives and rail cars, coal inventory, roads, fencing, warehouses, administration buildings, maintenance buildings, cooling towers, water rights, land leases, fencing, vehicles and power operated equipment and other related facilities.

Rights and agreements

Coal purchase agreements, land leases, water rights, lime purchase agreements, SO2 allowances, natural gas agreements and all other rights and agreements required to operate the plant.

Ocotillo Generating Station

Steam Generating Units 1 and 2

Boilers, turbines, generators, cooling towers, water wells and other related facilities.

Combustion Turbines 1 and 2

Combustion engine, generator and other related facilities.

Common Facilities

Land and land rights, fuel lines, maintenance buildings, administration buildings, roads, fences, vehicles and power operated equipment, storage tanks, warehouse and other related facilities.

Saguaro Generating Station

Steam Generating Units 1 and 2

Boilers, turbines, generators, cooling towers, water wells and other related facilities.

Combustion Turbines 1 and 2

Combustion engine, generator and other related facilities.

Common Facilities

Land and land rights, fuel lines, maintenance buildings, administration buildings, roads, fences, vehicles and power operated equipment, storage tanks, warehouse and other related facilities.

Yucca Combustion Turbines 1, 2, 3 and 4

Combustion engine, generator, administration building, storage and maintenance buildings, land and land rights including excess land, vehicles and power operated equipment, storage tanks, fuel lines, storage buildings, roads, fences and other related facilities.

Douglas Combustion Turbine

Combustion engine, generator, land, fencing, fuel lines and storage facilities, and other related facilities.

West Phoenix Generating Station

Steam Generating Units 4, 5 and 6

Boilers, turbines, generators, buildings and other related facilities

Combustion Turbines 1 and 2

Combustion engine, generator and other related facilities

Combined Cycle Units 1, 2 and 3

Combustion engine, generator, steam boiler and other related facilities.

Common facilities

Land and land rights, fencing, oil tanks, administration building, maintenance buildings, gas and oil lines, roads, wells, vehicles and power operated equipment and other related facilities.

Palo Verde Generating Station

Steam Generating Units 1, 2 and 3

Nuclear reactor, steam generator, turbine, generator, cooling towers, water reclamation facility, effluent water line, cooling ponds, evaporation ponds, maintenance buildings, warehouse, administration buildings, fire protection building, low level radiological waste building, vehicle maintenance garage, containment building, emergency warning systems, fences, roads, parking lots, land, auxiliary generators, spent fuel pool, fuel and chemical tanks, vehicles and power operated equipment, security buildings, visitor information center, fuel building, railroad, technical support center and other related facilities.

Rights and agreements

Effluent water agreement, pipeline rights of way, fuel agreements, NRC operating license, DOE spent fuel disposal agreement, emergency evacuation agreements and all other rights and agreements to operate the plant.

Common to all generating stations

Employees, employee salaries and benefits, tools and equipment, vehicles and power operated equipment, miscellaneous storage facilities and tanks, office equipment and furniture, computer equipment, communication equipment, meters, piping, wiring, lighting, HVAC, land owned and leased relating to the generation business, etc.

Current assets and current liabilities as well as any other long-term assets related to the generation business will be determined as of the date of the transfers.

Arizona Public Service Company
Docket Nos. E-01345A-98-0473,
E-010345A-97-0773, RE-00000C-94-0165

Summary of Settlement Provisions That Differ from the Proposed Competition Rules

The following list identifies those provisions that differ from the proposed Electric Competition Rules, as adopted in Decision No. 61634 (April 23, 1999). Of course, the proposed Electric Competition Rules are still evolving. Thus, while Arizona Public Service Company ("APS") believes that the following list is complete as of today, there may be additional differences resulting from either amendments to the proposed Electric Competition Rules or construction and interpretation of the adopted rules by the Commission in the future. Moreover, Rule R14-2-1614(C) expressly allows variances and waivers when in the public interest, such that even the differences identified below are not in conflict with the Electric Competition Rules.

1. APS will open 140 MW of additional capacity ahead of the minimum phase-in requirements under the rules, as well as increase the number of residential customers eligible for Direct Access under the residential phase-in. (Section 1.1)

2. Although not required by the rules, APS may provide Standard Offer service to customers with loads over 3 MW that seek to return to such service so long as these customers give at least one-year's advance notice. (Section 2.3)

3. Rule R14-2-1607(B) states that the Commission "shall allow" APS a reasonable opportunity to recover stranded costs, but under the Settlement APS will not recover $183 million (NPV) of Stranded Costs. (Section 3.3)

4. Because the Settlement provides for a present determination of stranded costs, revised estimates of stranded costs under R14-2-1607(I) could not be filed.

5. The Commission will grant a two-year extension to separate competitive assets under R14-2-1615(A). (Section 4.1)

6. Due to the extension of time to divest generating assets to an affiliate, the Commission will grant a corresponding two-year extension to the requirement in R14-2-1606(B) that all Standard Offer service be procured from the competitive market. (Section 4.1)

7. Rule R14-2-1616 requires a code of conduct to be filed within 90 days of after adoption of the rules. Under the terms of the Settlement, APS will file an interim code of conduct within 30 days of approval of the Settlement. (Section 7.7)

EXHIBIT
APS-10
Admitted

BEFORE THE

ARIZONA CORPORATION COMMISSION

REBUTTAL TESTIMONY OF ALAN PROPPER

On Behalf of

Arizona Public Service Company

Docket No. E-01345A-98-0473
Docket No. E-01345A-97-0773
Docket No. RE-00000C-94-0165

July 12, 1999

EXHIBIT
APS-11
admitted

REBUTTAL TESTIMONY OF ALAN PROPPER

Q. WHAT IS YOUR NAME?

A. My name is Alan Propper.

Q. ARE YOU THE SAME ALAN PROPPER WHO PRESENTED DIRECT TESTIMONY ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY (APS OR COMPANY) IN THIS PROCEEDING?

A. Yes, I am.

Q. WHAT IS THE PURPOSE OF THIS REBUTTAL TESTIMONY?

A. The purpose of this testimony is to provide comments and rebuttal on certain pricing related aspects of the testimonies of Staff Witness Williamson and Staff Consultant Smith, Enron Corporation's Witness Kingerski, PG&E Energy Services Corporation's Witness Oglesby, and Commonwealth Energy Corporation's Witness Bloom.

Q. ARE YOU SPONSORING ANY ATTACHMENTS IN CONJUNCTION WITH THIS TESTIMONY?

A. Yes. Attachment AP-1R is APS's proposed format for the second page of a Standard Offer Service customer's bill.

Q. WHAT COMMENTS DO YOU WISH TO MAKE REGARDING STAFF WITNESS WILLIAMSON'S TESTIMONY?

A. Mr. Williamson proffers the view that the pricing provisions in the Settlement Agreement could be readily altered to accommodate Staff Consultant Smith's after-the-fact inputs. He seems to miss or ignore the point that these provisions have been the result of months of negotiations among the parties, and that the resulting rate provisions of the Settlement Agreement satisfy a set of guidelines and parameters that were agreed to by the parties. These guidelines and parameters encompassed overall revenue requirements, relative Standard Offer and Direct Access class rate levels and rate designs, cost allocation and functionalization, annual rate reductions, Stranded Cost recovery through explicitly negotiated annual and class Competitive Transition Charges (CTC), patterning for the recovery of costs associated with Regulatory Assets, credits and charges for certain Electric Service Provider (ESP) provided services, etc. The result of these complex and lengthy negotiations are pricing provisions that fit together like a puzzle and are not conducive to basic conceptual changes and general after-the-fact tweaking and tinkering of the type Mr. Williamson recommends to the Arizona Corporation Commission (ACC).

Q. WOULD YOU DISCUSS THE SPECIFIC AREAS IN WHICH YOU DISAGREE WITH MR. WILLIAMSON'S RECOMMENDED CHANGES?

A. Mr. Williamson's summary of recommendations were detailed in the testimony of Staff Consultant Smith. Ms. Smith's first proposed change to the Settlement Agreement concerns APS's use of avoided or decremental costs in the calculation of credits for those customers using the services of an ESP for their Metering, Meter Reading, and Billing requirements. Avoided costs were used in these calculations because most embedded costs are not eliminated for APS when a customer chooses an ESP for these services. This fact was discussed in some length in my Direct Testimony. Ms. Smith prefers the use of the higher embedded cost based credits. The use of embedded costs would unfairly penalize APS unless the $350 million Stranded Cost provision is correspondingly increased and/or the level of Standard Offer Service rate decreases are reduced to reflect Ms. Smith's preference.

Ms. Smith seems to have two bases for her recommendation to revise the Settlement Agreement to incorporate embedded cost credits. The first is that the previously withdrawn "1998 Settlement" used embedded credits for revenue cycle services. The "1998 Settlement", for those of us who were not part of the APS deregulation history, also included different Stranded Cost provisions, lower Standard Offer Service rate reductions, a swap of Tucson Electric Power Generation assets with APS Transmission assets, and other provisions unique to that historical and never to be implemented settlement. As her second basis, Ms. Smith states that using avoided costs in developing the credits is anti-competitive since customers choosing an ESP to provide these services will end up continuing to pay APS for some portion of these costs. This belief appears to be shared by Enron Witness Kingerski. What seems to have been forgotten by Ms. Smith and Mr. Kingerski is that a customer choosing to have an ESP provide these services is still responsible for the costs he caused and continues to cause APS to incur. To ignore the difference between embedded and avoided costs would create a revenue shortfall for APS and a shift of revenue requirements to other customers that I believe would be unfair. In addition, Ms. Smith's observation that the use of avoided cost will make it more difficult for an ESP to provide these services at a competitive rate is not a reason for APS or its Standard Offer Service customers to subsidize an ESP's business development costs. At any rate, such a change would cause a reduction to APS's projected revenues and therefore would require altering the tariff as agreed to by the parties and proposed in the Settlement Agreement. It should be noted that in California the issue of avoided cost versus embedded cost for Metering, Meter Reading, and Billing credits was thoroughly reviewed and resulted in that state's decision to use an avoided cost approach as presented in this Settlement Agreement. California Public Utilities Commission ("CPUC") rejected the assertions of Enron, Cellnet, and other metering providers for an embedded cost treatment of metering, meter reading and billing services, provided by competitors. The CPUC described its policy objective: "Here, as in previous cases, we must balance competing objectives to promote competition, provided the utilities with a reasonable opportunity to recover costs and protect customers from unfair pricing", Decision 98-09-070 (California P.U.C. September 17, 1998), at 10. Then, in rejecting Enron's analysis for embedded cost treatment, the CPUC wrote: "For example, Enron proposes that revenue cycle services credits reflect depreciation and other capital costs that are "sunk". These costs do not fall when the utility stops offering service to a customer; the utility must still recover them or assume an associated loss.

We agree with Edison's observation that a fully-allocated cost method assumes inappropriately that all costs are variable, even at low levels of penetration", Decision 98-09-070 (California P.U.C. September 17, 1998) at 11. The same policy justification – not shifting costs upon Standard Offer Customers – is appropriate in Arizona.

Q. WHAT WAS THE NEXT AREA OF MS. SMITH'S PROPOSED CHANGES TO THE PRICING COMPONET OF THE SETTLEMENT AGREEMENT?

A. Ms. Smith has a concern that Standard Offer Service customers will not be able to determine the dollars they would have available to shop for an ESP to provide them with Generation, Transmission, and Ancillary Services. APS understands this concern, but does not believe that Standard Offer Service unbundling as suggested by Ms. Smith will in any way resolve this perceived problem. It probably would make it worse. In order to provide the necessary information for Standard Offer Service customers to make informed choices concerning switching to Direct Access Service, APS has designed a "Page 2" to the format of the bill that will be sent to all Standard Offer Service customers. This additional page would contain the Standard Offer Service customer's alternative billing amount under Direct Access Service. In addition, the bill would contain the amount APS would have billed the customer's Scheduling Coordinator for Transmission and Ancillary Services. The difference between the Standard Offer Service bill and the sum of the Direct Access Service bill plus the charge for Transmission and Ancillary Service would give the customer or a potential ESP the total dollar amount, as well as cents per kilowatthour, of what could be paid by the customer for Generation without exceeding the Standard Offer Service bundled rate. This amount, which is the amount available to pay a supplier other than APS for Generation, would be clearly indicated on the Standard Offer Service bill. The proposed "Page 2" information is what Standard Offer Service customers actually require to make knowledgeable decisions as to whether they should convert to Direct Access Service. The unbundling approach is not just impractical to implement for APS's Standard Offer Service rates, it simply does not provide useful information to our customers, and deprives them of the information really needed for decision making. Attachment AP-1R illustrates the billing information that would be made available on all Standard Offer Service bills.

Q. WAS THERE A THIRD AREA OF MS. SMITH'S PROPOSED PRICING RELATED CHANGES TO THE SETTLEMENT AGREEMENT THAT YOU WISH TO REBUT?

A. Ms. Smith is of the opinion that the difference between the Standard Offer Service bill and the Direct Access Service bill, or "shopping credit" as I call it, or "market generation credit" (MGC) as she calls it, is not sufficient in most instances to create competition in the generation market. Mr. Kingerski also makes this claim. I do not agree, and believe that there is a sufficient difference between Standard Offer and Direct Access pricing to allow for fairly widespread competition amongst the ESPs and APS Standard Offer Service. It should be noted that the objectives for the transition to a fully competitive electric energy market should not include a guaranteed profit for ESPs, and that the effective shopping credits must not be somehow artificially increased to meet such an objective. It should also be noted that the APS "shopping credit" is generally greater than that available to customers of the Salt River Project. Relative "shopping credits" are discussed further in Mr. Davis' testimony. I would like to make it very clear that Ms. Smith's remedies to increase competition are far from "minor" and would lead to a quick unraveling of the carefully pieced together Settlement Agreement.

Q. AT PAGE 21 OF HER TESTIMONY, MS. SMITH STATED THAT THERE IS A PROBLEM WITH THE PROPOSED CTC FOR GENERAL SERVICE CUSTOMERS BECAUSE IT IS A DEMAND CHARGE AND CERTAIN GENERAL SERVICE CUSTOMERS DO NOT HAVE DEMAND METERS. DO YOU AGREE THAT THIS IS A PROBLEM AT THIS TIME?

A. No. Under the phase-in of the proposed Competition Rules, only General Service customers of 40 kW or greater are eligible for Direct Access Service prior to January 1, 2001. Thus, every customer that may take Direct Access Service until that time must have an hourly consumption measuring meter and customers must have such a meter to comply with the Company's Direct Access Service rates. The only General Service customers that are not subject to a demand rate are those with unmetered service less than 5 kW. The Direct Access issues associated with customers receiving unmetered service have yet to be fully resolved, but the Company will file a Direct Access Service rate schedule for such customers for approval by the Commission prior to January 1, 2001.

Q. DO YOU WISH TO REBUT THE TESTIMONY OF MR. KINGERSKI IN ANY ADDITIONAL AREAS?

A. Yes. Mr. Kingerski is of the opinion that the Standard Offer Service rates should not be APS's current rates, but instead be fully unbundled and cost based in a manner that he finds acceptable. Perhaps this opinion would be realistic at some future time if, at that time, APS's individual rate schedules were each totally based on costs. Although APS's overall tariff is currently cost based, APS has over 50 individual rate schedules whose origins had numerous bases. Even at their inception, the rates did not truly reflect the functionalization and classification of costs inherent in the cost-of-service study, as a result of ACC actions. In addition, rate designs, as well as the rates of return by class and even by rate schedule, varied widely. Over the years, the rates moved further from their original cost relationships as a result of across-the-board price reductions and other ACC approved changes. It should be noted that the original rates and subsequent changes were reasonable at the time they were implemented and consistent with the pricing regime under which APS and the electric utility industry were operating. These circumstances, together with the fact that today's costs may vary from those inherent in an old cost-of-service study, make APS's current rates unsuited for the type of unbundling advocated by Staff and the ESPs. Any attempt to unbundle the rates based on functionalized costs would end up with the total of the unbundled pieces not adding up equal to actual individual bills. In many instances the differences would be substantial, and in all instances confusing and even misleading to our customers. There would have to be some type of line item to indicate the overcollection or undercollection from true and current costs. I do not believe that this is a realistic option. Another option would be to discontinue our current tariff, and develop a completely new set of cost based unbundled rates for Standard Offer Service. However, such an action would cause extreme dislocations in class revenues and individual customer bills. I presume that such imposed increases to so many customers' bills would force the requirement for a full rate case and thereby destroy any possibility for an expeditious settlement and implementation of competition.

Q. WHERE ELSE DO YOU DISAGREE WITH MR. KINGERSKI'S TESTIMONY?

A. Mr. Kingerski seems to believe that a whole new set of cost based unbundled Direct Access Service rates should have been developed instead of the using the apportionment process to relate the functionalized revenue requirements of the current bundled Standard Offer Service rates to the Direct Access Service rates. Once again, this might be a realistic opinion if the individual Standard Offer Service rates were totally cost based. However, since they are not, it was necessary to have a paralleling relationship between the two sets of rates so that the transition to a Direct Access Service option would be rational as well as orderly. Once the transition period is complete, consideration could be given to Direct Access and Standard Offer rates that are totally cost based, though this philosophy could also prove to have its own drawbacks.

Q. ON PAGES 14 AND 15 OF HIS TESTIMONY, MR. KINGERSKI'S IMPLIES THAT APS WILL BILL ESPS FOR DISTRIBUTION

SERVICE AND THAT THERE WILL THEN BE A DOUBLE RECOVERY OF BILLING COSTS. IS THIS A TRUE ASSESSMENT OF THE FACTS?

A. No. Mr. Kingerski is mistaken on how APS will bill and recover payment for Distribution service. Any retail customer electing to secure power and energy from an ESP will be billed directly by APS for Distribution service. Therefore, even though a retail customer elects Direct Access Service, APS still must render a bill to that customer for the Distribution service APS provides.

Q. **MR. KINGERSKI STATES THAT APS'S ONLY MOTIVATION FOR USING AN APPORTIONMENT PROCESS TO DERIVE DIRECT ACCESS SERVICE RATES WAS TO PRESERVE APS'S REVENUE AND THAT THERE WAS NO INTENTION TO HAVE UNBUNDLED RATES REFLECT THE COST OF THE UNBUNDLED SERVICE. IS THIS A CORRECT CONCLUSION?**

A. No, it is not. By apportioning current rates, which through the ACC approved 1996 rate reduction mechanism are assured of being cost based in the aggregate, and using the appropriate functional cost ratios from the APS's latest cost-of-service study, the Direct Access Service rates are assured of being cost based in the aggregate to the extent approved by the ACC. This process also fulfills the ACC's stated objective that the introduction of competition should not increase customers' rates. Mr. Kingerski's proposal to completely redesign all of APS's rates so that each will be cost based would create major rate dislocations for most of APS's customers.

Q. MR. KINGERSKI MADE VARIOUS STATEMENTS REGARDING THE RECOVERY OF ENERGY IMBALANCE COSTS. DO YOU HAVE A GENERAL COMMENT TO MAKE ON THIS SUBJECT?

A. Yes. Mr. Kingerski correctly noted that Energy Imbalance issues relate to the Arizona Independent Scheduling Administrator (AISA) and to the Federal Energy Regulatory Commission (FERC). The AISA has not completed its protocols at this time, much less filed them with FERC. In addition, it is not known whether FERC will accept whatever AISA files, whether a full hearing will be required before FERC, or whether it will be necessary for APS to make its own separate FERC filing.

Q. MR. KINGERSKI CONTENDS THAT APS SHOULD UNBUNDLE ENERGY IMBALANCE IN ITS STANDARD OFFER SERVICE PRICE. IN ADDITION, HE CONTENDS THAT IF THIS SERVICE COMPONENT IS NOT UNBUNDLED, A DIRECT ACCESS SERVICE CUSTOMER WILL PAY FOR IT TWICE—ONCE THROUGH APS'S DIRECT ACCESS RATE AND AGAIN THROUGH THE ESP'S CHARGES TO THE CUSTOMER. DO YOU AGREE?

A. No. Energy Imbalance costs are one of FERC's wholesale related Ancillary Services. Scheduling Coordinators providing services for ESPs would be the entities subject to this charge under APS' Open Access Transmission Tariff (OATT). The Scheduling Coordinator would pass this cost on to the ESPs, who presumably would again pass this cost on to its aggregated retail customers. Service to a public utility's Standard Offer Service customers is considered retail native load and, as prescribed under FERC's Order No. 888, is not taken under an OATT. It should be understood that the very nature of bundled retail service precludes Energy Imbalances. APS's loads within its own control area (which are predominantly retail native loads) are dynamically linked to certain generation units which automatically ramp up or down as needed. As such, these loads never are out of balance. Furthermore, since APS's Standard Offer Service rates include the costs associated with purchased power and all of APS's generation resources, Standard Offer Service customers are already paying for the resources used to preclude Energy Imbalance. At such time when APS must secure energy through competitive bid on the open market, APS would consider revising its Standard Offer Service rates to provide for recovery of Energy Imbalance costs, or alternatively, propose an adjustment clause for the effective recovery of such costs.

Q. **DO YOU AGREE WITH MR. KINGERSKI'S CONTENTION THAT ESPs SHOULD HAVE THE RIGHT TO PURCHASE ENERGY FROM APS AT THE SAME BELOW MARKET PRICE RATES AS HE BELIEVES IS INHERENT IN CERTAIN COMPONENTS IN THE STANDARD OFFER SERVICE RATE AT CERTAIN TIMES OF THE YEAR?**

A. Absolutely not. The generation component of APS's Standard Offer Service rates is not based on the market price, nor should it be until such time as APS is required to secure energy for Standard Offer Service customers through competitive bidding. APS planned and constructed an integrated system consisting of diverse generation resources and transmission facilities in order to supply power and energy to its customers at the lowest cost possible. To the extent that APS generation resources produce power and energy cheaper than the "market price", APS's Standard Offer Service customers, who have and are presently paying for these facilities, are entitled to be served at costs recognizing these facilities. APS's system was not built to provide below market priced power to Enron or other ESPs.

Q. MR. KINGERSKI ALSO SUGGESTS THAT APS'S STANDARD OFFER SERVICE RATES SHOULD BE INCREASED, SO THAT THESE RATES WILL BE COMPETITIVE WITH THOSE OF ESPS. DO YOU AGREE WITH THIS PHILOSOPHY?

A. No. I do not believe that competition should be fostered by artificially increasing or decreasing the price of one of the potential supplying parties.

Q. DO YOU HAVE ANY PRICING RELATED COMMENTS ON MR. OGLESBY'S TESTIMONY?

A. Yes. Mr. Oglesby believes that the one year's advance notice requirement that will be placed on Direct Access Service customers over 3MW desiring to return to Standard Offer Service is anti-competitive. The purpose of the one year notice policy is to recognize that APS's planning process, cost incurrence, and cost recovery are on a minimum one-year cycle, and APS does not want its larger customers shifting back and forth between Direct Access Service and Standard Offer Service with the possibility of creating costs that others will have to pay. Also, it should be noted that the currently proposed Competition

Rules would allow APS to refuse service to returning Standard Offer Service customers whose annual electric consumption exceeds 100,000 kWh, which would include all customers over 3 mW.

Q. DO YOU HAVE ANY COMMENTS ON MR. BLOOM'S TESTIMONY?

A. Yes. Mr. Bloom states that the Basic Service Charge should be eliminated, since with unbundled rates there is no need for non-cost based charges. Mr. Bloom does not seem to realize that Basic Service Charges are in effect to cover certain non-variable customer related costs. These charges cannot be eliminated unless the costs they are designed to collect were artificially transferred or tilted to the demand or energy component of the rate. Such a move would only exacerbate the problems many electric utilities are now experiencing by having rates that do not follow costs. In addition, Mr. Bloom's comments on the Direct Access Service rates not showing a "shopping credit" seem to miss the point. It is the Standard Offer Service customer that needs to know his potential shopping credit should such customer opt for Direct Access Service. A Direct Access Service customer has no "shopping credit". The ESP will be buying Generation, Transmission, and Ancillary Services on the marketplace for that customer.

Q. DOES THIS COMPLETE YOUR REBUTTAL TESTIMONY?

A. Yes. It does.

ARIZONA PUBLIC SERVICE COMPANY

Informational Unbundling for Standard Offer
Proposed Standard Offer Bill

Typical Summer Bill on Rate E-12 at 7/1/99 Rate Levels
The following information is proposed to be shown on the customer's monthly bill:

Standard Offer Bill Calculation:

Your total kWh usage is	991
Basic Service Charge	$ 7.50
Charge for kWh used	101.80
Regulatory Assessment	0.20
Sales Tax	7.17
TOTAL	$ 116.67

Informational Unbundling:

Your total usage for this month was:	991 kWh	
You Standard Offer Bill was (see page 1):		$ 116.67
If you had chosen direct access to an ESP, your APS bill for delivery service would have been:		
Basic Delivery Service:	$ 10.00	
Distribution Service:	$ 41.20	
System Benefits:	$ 1.14	
Competition Transition Charge:	$ 9.22	
Regulatory Assessment:	$ 0.12	
Sales Tax:	$ 4.04	
Total Amount for **APS Delivery Service Only**:	$ 65.72	$ 65.72
Residual Transmission & Generation Amount:		$ 50.95
Transmission and Ancillary Services billed to your ESP:		$ 5.09
Residual Generation Amount:		$ 45.86
Transmission & Generation Shopping Credit		**5.14** ¢/kWh

If you are provided Metering, Meter Reading and Consolidated Billing by a competitive supplier of these services, your monthly bill from APS would be reduced by $1.90. You may then be charged for these services by your ESP.

ARIZONA PUBLIC SERVICE COMPANY

Informational Unbundling for Standard Offer
Proposed Standard Offer Bill

Typical Summer Bill on Rate E-32 at Proposed 7/1/99 Rate Levels
The following information is proposed to be shown on the customer's monthly bill:

Standard Offer Bill Calculation:

Your total kWh usage is	36,500
Your total kW usage is	100

Basic Service Charge	$ 12.50
Charge for kWh used	3,171.91
Charge for kW Demand	175.75
Regulatory Assessment	4.71
Sales Tax	220.25
TOTAL	$3,585.12

Informational Unbundling:

Your total usage for this month was: 36,500 kWh
You Standard Offer Bill was (see page 1): $ 3,585.12

If you had chosen direct access to an ESP,
your APS bill for delivery service would have been:

Basic Delivery Service:	$ 12.50	
Distribution Service:	$ 1,289.85	
System Benefits:	$ 41.98	
Competition Transition Charge:	$ 243.00	
Regulatory Assessment:	$ 2.22	
Sales Tax:	$ 104.04	
Total Amount for **APS Delivery Service Only**:	$ 1,693.59	$ 1,693.59
Residual Transmission & Generation Amount:		$ 1,891.53
Transmission and Ancillary Services billed to your ESP:		$ 156.40
Residual Generation Amount:		$ 1,735.13
Transmission & Generation Shopping Credit		**5.18** ¢/kWh

If you are provided Metering, Meter Reading and Consolidated Billing by a competitive supplier of these services, your monthly bill from APS would be reduced by $4.60. You may then be charged for these services by your ESP.

BEFORE THE

ARIZONA CORPORATION COMMISSION

REBUTTAL TESTIMONY OF DONALD G. ROBINSON

On Behalf of

Arizona Public Service Company

Docket No. E-01345A-98-0473
Docket No. E-01345A-97-0773
Docket No. RE-00000C-94-0165

July 12, 1999

EXHIBIT
APS-12
admitted

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Donald G. Robinson, and my business address is 400 North Fifth Street, Phoenix, Arizona 85004.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am Director of Strategic Financial Planning for Arizona Public Service Company. My qualifications are set forth in Attachment DGR-1.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. To address certain issues related to post-divestiture capital structure and the magnitude of proposed APS rate reductions.

Q. ENRON WITNESS ROSENBERG (P.8) RECOMMENDS "AN AFFIRMATIVE SHOWING BY APS THAT ITS DECISIONS ON CAPITALIZATION OF ITS AFFILIATES DO NOT DISADVANTAGE CUSTOMERS OR UNDULY ADVANTAGE ITS UNREGULATED AFFILIATE". IS THIS A REASONABLE PROPOSAL?

A. No. Dr. Rosenberg seems to be suggesting that the Commission should be concerned about the capital structure of both the Commission-regulated utility (APS) and the FERC-regulated 'Genco". The regulated utility will receive consideration from Genco for its generation assets equal to the book value of the transferred property. This consideration will necessarily include the assumption of some APS debt (for pollution control bonds and debt associated with the sale/leaseback)-debt which must remain with the generation assets. The form of the remainder of the purchase price will be determined at the time of the transfer and could include cash or other compensation. The actual capital structure of Genco will be determined by its board.

APS itself has every incentive to maintain a reasonable capital structure because it will continue to need access to the capital markets on reasonable terms. In addition, because the Commission retains the power to review its capital structure in the next rate case and to make any justifiable rate adjustments it finds are supported by the evidence (in the form of a "hypothetical" capital structure), APS cannot impose the higher cost of an unreasonable capital structure on customers. Furthermore, during the term of the Settlement, the Company's rates are decreasing, which is inconsistent with increasing the percentage of equity in its capital structure, as is apparently feared by Mr. Rosenberg.

Q. WHY SHOULD THE COMMISSION BE INDIFFERENT TO THE CAPITAL STRUCTURE OF GENCO?

A. The capital structure of Genco should be no more the concern of this Commission than the capital structure of other wholesale generators who sell into the Arizona wholesale market. An individual generator's capital structure does not determine or even influence market prices in the fully competitive wholesale market.

Q. ON PAGE 8, LINES 11 THROUGH 13, DR. ROSENBERG STATES THE FOLLOWING: "IF THE MARKET VALUE IS ALSO LESS THAN THE BOOK VALUE IT IS POSSIBLE THAT SOME OF THESE PLANTS COULD BE SOLD AT A LOSS, GIVING RISE TO A TAX LOSS." DO YOU AGREE WITH DR. ROSENBERG'S ASSERTION?

A. No. A sale of APS' generating plants (even if feasible) will almost certainly produce the opposite effect. Even though the auction could result in a "loss" for financial reporting purposes, it will most likely result in a "gain" for income tax reporting purposes. A taxable gain will, in turn, result in an additional cash tax liability. The reason for the difference between the financial statement result (i.e., big loss) and the income tax result (i.e., gain) is the accelerated depreciation methods and shorter depreciable lives allowed pursuant to the Internal Revenue Code for income tax reporting purposes. The adjusted tax basis of the Company's generating assets is far less than the net book value of the generating assets. For example, the tax life of Palo Verde is 10 years compared to a book life of approximately 35 years. Therefore, the current tax basis for the majority of Palo Verde is zero. It is unlikely that the generating plants would be sold for an amount less than their adjusted tax basis and, therefore, a tax loss simply would not occur.

Q. SEVERAL PARTIES (E.G., STAFF WITNESS SMITH AND THE ARIZONA CONSUMERS COUNCIL) HAVE SUGGESTED THAT THE PROPOSED RATE REDUCTIONS MIGHT, IN SOME SENSE, BE "INADEQUATE". DO YOU AGREE?

A. No, and I would note that no party has presented any evidence whatsoever that a greater rate reduction is warranted or would be fair to the Company. In their comments, the Arizona Consumers Council speculate that rates may be too high post-divestiture because rate base has not been reduced to reflect the generation assets transferred to an affiliate. This suggestion fails to consider three significant facts that should alleviate any such concern. First, the assets will not be transferred until December 31, 2002, by which time APS will have reduced rates to standard offer customers by 6%. Second, once the assets are sold, any "reduction" in revenue requirements associated with the transferred assets may be more than offset by: (1) the significant increase in operating expenses of the regulated utility caused by the need to acquire replacement power from the market; and (2) higher costs associated with new distribution plant investment. Thirdly, the general rate case <u>required</u> by Section 2.6 to the Agreement would, under present Commission rules, use a test period that reflected the net impact (if any) of the asset divestiture on APS' revenue requirements and would represent the first opportunity for the Commission to consider such impact <u>even in the absence of the Agreement.</u>

Q. STAFF WITNESS SMITH (PP. 18-20) APPEARS TO BE SOMEWHAT DISMISSIVE OF THE MAGNITUDE OF THE RATE DECREASES IN HER TESTIMONY. DO YOU HAVE ANY COMMENTS?

A. Yes. I am somewhat surprised that Ms. Smith questions the adequacy of the proposed rate reductions, because she supported smaller reductions in our previous settlement with Staff. She attempts to base her belated reservations about the level of rate decreases on a comment that the "Company's Form 10-K notes that its 1998 revenues were lower than normal by $33 million because of milder than normal weather". This is a rather cursory "analysis" upon which to question the adequacy of the Agreement's rate reduction. It also suffers the deficiencies of being: 1) a factually incorrect statement; and 2) a distortion of the actual situation. The Company's Form 10-K (p. 20) does discuss the effects of "milder weather", but that "milder weather" is compared to the hotter than normal 1997 weather, not "normal" weather as Ms. Smith asserts. In fact, 1998 had virtually 100% "normal" weather, therefore, there would be no impact of weather in a traditional rate case.

The Company provided the calculation of the 1999 rate decrease as part of Mr. Propper's direct testimony. It showed a rate decrease of .68%, which is considerably less than the Company's proposed decreases of 1.5%. Even if one added back the APS share of unit cost savings (described at page 20 of Ms. Smith's testimony), one could not produce a 1.5% rate reduction.

Q. **DO YOU BELIEVE THAT MS. SMITH'S DISCUSSION OF RATE REDUCTIONS IN OTHER JURISDICTIONS IS HELPFUL?**

A. No. Her comments regarding rate reductions in other jurisdictions are irrelevant - they ignore both the specific cost structure of APS and the previous reductions APS already made in anticipation of competition. These total 8.4% and should be added to the 7.5% reductions in the Agreement before making any such comparison.

Q. **DO YOU SHARE MS. SMITH'S CONCERNS ABOUT THE ADJUSTMENT CLAUSES CONTAINED IN THE PROPOSED SETTLEMENT?**

A. No. First, Ms. Smith refers to them as "automatic" adjustment clauses. The Agreement nowhere uses such a term. Parties will be able to review the prudence of these costs. The form of the clauses and the mechanics of their operation would have to be approved by the Commission. I further anticipate that no collection of any deferred costs would happen until there had been a Commission finding that the deferred costs were reasonable, prudent, and within the categories described in the Agreement. Second, adjustment clauses only allow recovery of costs. Third, adjustment clauses are a widely used method of efficiently tracking and recovering costs largely beyond a utility's control, such as purchased power.

Q. THE ARIZONA CONSUMERS COUNCIL CLAIMS IN ITS COMMENTS (P.2) THAT: "NO FINANCIAL INFORMATION OF ANY KIND" HAS BEEN PRESENTED TO JUSTIFY THE RATE PROVISIONS OF THE SETTLEMENT. IS THIS AN ACCURATE CRITICISM?

A. Not at all. Leaving aside the fact that this is not a rate increase proceeding (and thus the traditional Commission rate case filing requirements are not applicable), APS has presented financial information from which the Commission can conclude that the Settlement's rate provision are just and reasonable. This information includes:

(1) APS financial performance information for 1998 (Schedule AP-3); and

(2) Adjusted test year financial data, including return on rate base (Schedule AP-4).

I have also provided Attachment DGR-2, which shows our projected 1999 earnings to be $114.8 million with a return on equity of 5.8%, far below the Company's "allowed" return of 11.25%. Even after adding back the effects of the write-off, the return would be 10.9%, still below the level last found reasonable by the Commission.

Q. WOULD THE TYPE OF FULL RATE CASE NORMALLY REQUIRED FOR A PROPOSED RATE INCREASE, AS SUGGESTED BY THE CONSUMERS COUNCIL, PROMOTE THE START OF COMPETITION?

A. No. A full rate case would result in a very significant delay in competition. APS' last two litigated rate cases took 23 months and 29 months to complete. While both of these cases included the contentious issue of Palo Verde, neither contained any significant rate design issues. A full rate case now would include the equally contentious issue of stranded costs and the even more difficult issue of rate design. It is safe to assume that a rate proceeding addressing these issues would last at least the 12-13 months contemplated by the Commission's rules (A.A.C. R14-2-103 B.11) and probably many more. Because customers will logically need to know the final determination of these issues before they would be able to make an informed decision on electric service, competition would be delayed many more months if not years.

Q. IS THE 11.25% RETURN ON EQUITY APPROVED BY THE COMMISSION IN THE 1996 SETTLEMENT AGREEMENT STILL REASONABLE?

A. Yes, and in fact it may be somewhat low.

Q. WHY DO YOU THINK 11.25% IS REASONABLE?

A. The average return on equity granted by the state commissions for electric utilities throughout the country has increased in the last two years; in 1997 it was 11.4% and 11.7% in 1998, both above the 11.25% currently authorized. Additionally, since the end of 1998, the Treasury bill yield has increased by approximately 43 basis points, which would indicate that the appropriate return on equity could be above 11.7%.

Q. HOW CAN THE COMMISSION DETERMINE A RETURN ON FAIR VALUE SHOULD IT BELIEVE SUCH A DETERMINATION APPROPRIATE?

A. The Commission has always, at least as long as I can remember, set a return on fair value that would allow APS to recover its embedded cost of capital, which is merely the cost of equity weighted with the embedded cost of the Company's debt and preferred stock (if applicable). I have provided a weighted cost of capital calculation in Attachment DGR-3.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

Statement of Witness Qualifications

Donald G. Robinson is Director of Strategic Financial Planning for Arizona Public Service Company. Mr. Robinson is responsible for the Company's financial planning, budgeting, forecasting and strategic analysis areas as well as certain regulatory areas.

Mr. Robinson was previously Director of Pricing, Regulation and Planning for Arizona Public Service Company. In this position I've had responsibility for the Company's regulatory activities before the Arizona Corporation Commission and the Federal Energy Regulatory Commission, as well as the Company's pricing and planning functions.

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
Projected 1999 Income Statement - $ in Millions

Line #		1999
1	Revenues	$ 1,791
2	Operating Expenses	733
3	Depreciation and Amortization	387
4	Income Taxes:	
5	Income Taxes excluding ITC Amortization	307
6	ITC Amortization	(27)
7	Total Income Taxes	280
8	Interest Expense	135
9	Regulatory Disallowance Write-Off	234
10	Deferred Income Taxes - Regulatory Disallowance Write-Off	(94)
11	Net Income	$ 116
12	Return on Average Common Equity	5.9%
13	Return on Average Common Equity (Excluding ITC Amortization per ACC)	4.5%
14	Return on Average Common Equity (Excluding ITC Amortization, $234m write-off and its associated regulatory asset amortization)	10.9%

ARIZONA PUBLIC SERVICE COMPANY
Summary Cost of Capital
December 31, 1998
(Thousands of Dollars)

Description	Amount	Capital Ratio	Cost Rate	Weighted Cost
Long Term Debt	$1,890,802	47.72%	6.75%	3.22%
Preferred Stock	95,241	2.40%	6.08%	0.15%
Common Equity	1,976,368	49.88%	11.25%	5.61%
Total	$3,962,411	100.00%		8.98%