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BEFORE THE ARIZONA CORPORATION COMMISSION

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IN THE MATTER OF ARIZONA PUBLIC SERVICE COMPANY'S REQUEST FOR A VARIANCE OF CERTAIN REQUIREMENTS OF A.A.C. R14-2-1606 AND APPROVAL OF PURCHASE POWER AGREEMENT.	Docket No. E-00000A-02-0051 E-01345A-01-0822 E-00000A-01-0630 E-01933A-98-0471 E-01933A-02-0069

The Residential Utility Consumer Office ("RUCO") hereby provides notice of filing the Direct Testimony of Dr. Richard A. Rosen, in the above-referenced matter.

RESPECTFULLY SUBMITTED this 29th day of March, 2002.

Scott S. Wakefield
Chief Counsel

Arizona Corporation Commission
DOCKETED
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BEFORE THE ARIZONA CORPORATION COMMISSION

IN THE MATTER OF ARIZONA PUBLIC SERVICE COMPANY'S REQUEST FOR A VARIANCE OF CERTAIN REQUIREMENTS OF A.A.C. R14-2-1606 AND APPROVAL OF PURCHASE POWER AGREEMENT.	Docket No. E-01345A-01-0822

DIRECT TESTIMONY

OF

DR. RICHARD A. ROSEN

On Behalf of the Arizona
Residential Utility Consumer Office

Tellus Institute
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March 29, 2002

I. SUMMARY OF TESTIMONY

Q. WHAT IS YOUR NAME AND BUSINESS ADDRESS?

A. My name is Dr. Richard A. Rosen. My business address is Tellus Institute, 11 Arlington Street, Boston, MA 02116-3411.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. Appendix 1, which is attached to this testimony, describes my educational and professional background.

Q ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS CASE?

A. In this case, I am providing expert testimony on behalf of the Residential Utility Consumer Office ("RUCO").

Q. PLEASE SUMMARIZE YOUR TESTIMONY IN THIS DOCKET.

A. The main conclusions and recommendations that I have reached in this case are:

1. APS is correct in justifying the need for long-term protection for Standard Offer customers from potentially high and volatile wholesale market prices in Arizona. Thus, I agree with the underlying motivation for its proposed Purchased Power Agreement, even though I believe some important changes must be made in the APS proposal to more adequately protect its Standard Offer customers over the long run.

2. Because APS' Standard Offer rates are capped through July 1, 2004 based on the Settlement Agreement of 1999, consumers will be adequately protected without the proposed FPPA prior to July 2004. Thus, if the FPPA were to increase prior to July 1, 2004, that increase could not provide a basis for increasing retail rates anyway. In addition, the spirit of the Settlement Agreement implies that no underlying cost increases that might increase the FPPA charge that occur prior to July 1, 2004 should be allowed to impact retail rates after July 1, 2004. Therefore, I recommend that the FPPA which APS has proposed to begin on March 1, 2003 as part of the new PPA, not begin until July 1, 2004.
3. APS should continue with the two scheduled 1.5 percent rate reductions for small Standard Offer customers currently due for July 1, 2002, and July 1, 2003 as provided in the Settlement Agreement.
4. The ACC should re-set the rate of return on investment for the Dedicated Units during the 2003/2004 rate case for APS. The ACC should set this rate of return at that time as if these units were owned by a regulated utility, assuming the risk profile of a regulated utility and not that of an un-regulated generation subsidiary. Under the assumption that this PPA would also have to be approved by FERC, APS should agree to this process for allowing the ACC to set this rate of return by submitting the ACC recommended value to FERC for its approval.

5. In order to maintain the many benefits of the relatively low-cost power from these existing generating units for Standard Offer customers in the long run, the ACC should have the sole authority to decide whether or not the PPA is renewed after the first 15 years, and for each subsequent five-year period. Otherwise, it is very likely that APS would cancel the PPA after only 15 years, and Arizona ratepayers would lose the substantial economic benefits that these units would likely provide beyond that time.
6. In order to keep electricity prices and costs to consumers at the lowest reasonable levels for the next 15 years, the ACC should institute a new docket by October 1, 2002, in order to determine all demand-side management (DSM) investments that could be installed in APS' service territory that would reduce load at a cost less than the cost of the new PPA, in addition to the avoided costs of new transmission and distribution investments. This approach would further the goals of Commission Rule R14-2-213. Once all such cost-effective DSM programs are determined, the ACC should establish a schedule for their implementation in the fastest reasonable time such that the need for new generating units and transmission facilities is minimized.
7. Once APS' future load is reduced as much as is reasonable as a result of cost- effective DSM programs, APS should bid out its remaining generation needs above the level of peak demand covered by their existing generating units and the Dedicated Units in the PPA, as part of a least-cost planning process. APS should also be required to bid a

regulated generation cost into the auction process. This means that APS would remain the provider of last resort through new generation built under traditional regulation, if that option proves to be least cost to Standard Offer ratepayers. In contrast, third-party independent power producers, as well as PWEC, could be selected to provide these new power resources. If the bids from unregulated power producers can beat the regulated price that APS would need to charge on a traditional cost-of-service basis, then those unregulated price bids should be accepted. This process of setting up a competition between regulated and unregulated price bids for new generation would help to create an economically efficient and more competitive wholesale power market in Arizona. The amount of power needed from the competitive market may, then, be more or less than the 270 MW per year beginning in 2003, and continuing in each year through 2008, that APS has proposed to acquire. The amount of new capacity needed from the competitive generation market will depend on actual and projected load growth, and on the appropriate required reserve margins needed to maintain adequate system reliability in each year.

II: ANALYSIS OF THE PROPOSED PURCHASED POWER AGREEMENT

Q. WHAT REASONS DID APS GIVE FOR PROPOSING A NEW PURCHASED POWER AGREEMENT TO SERVE ITS STANDARD OFFER CUSTOMERS?

A. APS gave at least four major reasons for proposing a new purchased power contract for providing for most of the future load of its Standard Offer customers. The first reason was that APS has a continuing responsibility to provide reliable and reasonably priced service to its customers. Part of what APS means by reasonably priced service is prices that have fairly low volatility. APS is very concerned that wholesale market prices in the Arizona region may be quite volatile in the future, as they were in the recent past, and that customers would oppose direct exposure to those price swings. In addition, APS stresses the fact that if Standard Offer customers are forced to rely primarily on power supplies from the wholesale power market, then it is unclear who will have responsibility for maintaining system reliability. Furthermore, APS' witness, Mr. Jack Davis, claims that the wholesale market price for power in the region will likely exceed the cost of power to APS from the proposed PPA for each year 2002-2007, and probably beyond.

Second, beyond pricing and reliability issues, APS also believes that it is currently impractical, or impossible, to serve Standard Offer customers from as much third-party generation capacity as Rule 1606 seems to contemplate. APS claims that there is not enough new generating capacity under construction in Arizona to serve a large enough fraction of its generating requirements, and that some of the capacity that is under construction could not even transmit its output to APS' load centers.

Third, APS questions whether the wholesale market for power in Arizona will be sufficiently competitive to protect Standard Offer customers. APS points out that the prices of long-term purchased power in California last year were much higher than the cost of power had been under regulation in California. Thus, Arizona consumers would have to confront the possibility of high average market prices due to the exercise of market power in the region.

Finally, APS claims that it would be highly desirable for customers if APS was the power provider of last resort, whereby they would take responsibility for providing power under any eventuality.

Q. DO YOU AGREE OR DISAGREE WITH THESE CONCERNS PUT FORWARD BY APS?

A. I agree with APS that Standard Offer customers need much more direct and concrete protection from market-based wholesale prices than they will likely receive if the electric competition rules are implemented as-is. I agree that the mandate for APS to bid out 50 percent of its Standard Offer power requirements by January 1, 2003, and to acquire all additional power on a bilateral negotiated basis from third- party providers, is not a good idea under present and foreseeable conditions. APS correctly describes the many benefits that customers currently have from their access to the power from APS' mix of generating units; namely, a mix that includes coal, nuclear, and natural gas-based plants. Such a mix of fuel types will likely ensure lower and much more stable wholesale electric prices than relying on mostly new natural gas-fired generating units that are able to bid unregulated market prices. This is true, in part, because market prices are always likely to respond much more quickly and directly to volatility in the fuel costs of the new generating units, which are likely to be natural gas-fired units.

In fact, one consideration that APS did not mention in its testimony is that independent power producers typically have much higher costs of capital than regulated utilities, and the Enron crisis has only served to accentuate that problem. This implies that the price of deregulated power may rise substantially just to cover the new higher cost-of-capital requirements. This would likely result in bids from the IPP market that would be submitted to APS' auction at prices well above the price for which APS could provide power from the same type of new generating units on a regulated basis. For example, even before the Enron bankruptcy, IPP bid prices in Colorado's most recent integrated resource planning docket were higher than prices at which a regulated utility could provide power.

Q. WOULD YOU PLEASE SUMMARIZE HOW APS IS PROPOSING TO PROVIDE ADDITIONAL PRICE PROTECTIONS FOR THEIR STANDARD OFFER CUSTOMERS?

A. Yes. APS is proposing that it provide power to its Standard Offer customers for at least 15 years, from all its existing power plants as well as from several new units recently built or under construction by PWEC, on a basis that is close to a traditional cost-of-service basis. APS is proposing that the rate of return on the generating unit "ratebase" included in the PPA be 9.38 percent, based on a 50/50 debt/equity ratio, a 7.5 percent cost of debt and an 11.25 percent return on equity. I assume that the depreciation rates used to compute the Facilities Charge under the PPA would be the usual depreciation rates that APS has used under regulation in the past. (If this is not APS' proposed approach to depreciating these assets, the PPA should be modified to incorporate traditional depreciation rates.) APS also assumes that it will pay its full marginal income tax rates on all the income generated by the return on the contract "ratebase," and these income taxes are charged to Standard Offer customers.

APS has also proposed that the PPA would include three renewal options for a period of five years each, for a possible total contract duration of 30 years. Beginning after the fifteenth year, the PPA would automatically renew after each five-year period, unless one party cancelled the contract. Technically, the contract would be between APS and PWCC (Pinnacle West Capital Corporation).

The PPA would cover the output from APS' existing generating units, as well as from the West Phoenix combined-cycle units (#4 and #5), Redhawk #1 and #2, and Saguaro #3. These generating units are collectively referred to as the "Dedicated Units." APS is also proposing that it acquire 270 MW of additional generation capacity through a competitive bidding process in each year from 2003-2008, for a total of 1,620 MW in 2008. APS claims these additional power purchases would provide Standard Offer customers with quite enough exposure to the wholesale market through 2008, and I agree, since this would correspond to about 23 percent of the estimated APS peak load by 2008. Frankly, even 23 percent might be too much exposure to the deregulated wholesale market, given the risks inherent in that market.

Pursuant to the requirement of A.A.C. R14-2-1615, APS plans to transfer ownership of its existing generation assets to PWEC. PWCC is the holding company for both APS and PWEC. Under the terms of the PPA, APS would then pay PWCC a basic energy charge of $17.40 per MWH in

2003, and a facilities charge of $63.6 million per month, for the fixed charges for all the Dedicated Units. By 2004, the projected average charge under the proposed PPA would be about $48.00 per MWH. One advantage of the proposed PPA is that APS customers would only have to pay for as much power as they use. The PPA provides for a FPPA in order to adjust the base level energy charges under the contract for actual changes in PWEC's energy costs beginning in March 2003. APS will, then, commit to being the "provider of last resort," and will maintain all necessary generating reserves consistent with good utility practice. At the same time, APS proposes that almost all other aspects of the 1999 Settlement Agreement should go forward as planned.

Q. DO YOU HAVE ANY BASIC DISAGREEMENTS WITH APS' PROPOSED APPROACH FOR PROTECTING STANDARD OFFER CUSTOMERS UNDER THIS PROPOSED PPA?

A. Yes. I have some disagreements with APS' proposed approach under the PPA, because I do not believe that it will sufficiently protect Standard Offer customers. My main concern with this proposal is that APS might try to raise the required return on all of APS' existing generating capacity, either in its next ACC rate case, or in a case at FERC, above the level of return being requested here. I am concerned that, after this PPA is approved, APS (or PWCC) will argue that the appropriate rate of return for assets owned by an un-regulated affiliate of a utility is substantially higher than the regulated return that the ACC would find appropriate for APS if the assets were not divested to PWEC. If such a higher rate of return were approved by the appropriate regulatory body, the cost of power under this PPA to consumers could go up substantially. I do not think that the ACC should take this risk.

Q. WHAT DO YOU RECOMMEND TO PROTECT CONSUMERSFROM THIS RISK?

A. The ACC should insert language into the proposed PPA to make it very clear that the appropriate rate of return should reflect the risk profile of a regulated utility, and not an un-regulated subsidiary. APS' agreement with this provision would be especially relevant in this case because of the very long term (15-30 years) involved for this contract. With such a long-term contract, PWCC or PWEC would not face any significantly greater risk with regard to recovering these investments, plus a fair rate of return, than would APS, as a regulated utility. PWCC's risk will be very low because after 15 years the generating units will be highly depreciated, and, thus, very valuable in the un-regulated generation market at that time.

Q. IF THE EXISTING APS GENERATING UNITS ARE LIKELY TO BE VERY VALUABLE BY THE END OF THE INITIAL 15-YEAR PERIOD OF THE PROPOSED PPA, IS IT LIKELY THAT PWCC WILL AGREE TO AUTOMATICALLY RENEW THE PROPOSED CONTRACT FOR ANY ADDITIONAL TIME PERIOD?

A. No. The existing plants will be even more highly depreciated after 15 years than they are today. Therefore, it is extremely probable that PWCC will cancel this proposed PPA at that time (2015), because they will be able to sell the output of these plants at a deregulated market price that will be much higher than the cost-of-service based price inherent in the PPA. Thus, in order to prevent APS Standard Offer customers from losing these valuable resources at that time, I also urge the ACC to change the proposed contract so that the ACC, and only it, has the final authority to cancel the initial PPA after 15 years. Based on the ACC's current forecast of market prices, I believe that it is very likely that the ACC will want to extend the PPA to its full 30-year life, when contract renewal is at issue.

Q. WHAT IS YOUR SECOND DISAGREEMENT WITH APS' PROPOSAL?

A. My second disagreement with APS' proposal is that I do not understand the need to implement the new proposed FPPA prior to July 1, 2004, given the constraints imposed on retail rates under the 1999 Settlement Agreement. Since, APS' next retail rate case will occur between 2003 and 2004, and since retail rates are capped by the Settlement Agreement prior to July 1, 2004, I do not believe it would be appropriate to begin implementation of the proposed wholesale FPPA on March 1, 2003. I do not understand what purpose it would serve. Certainly, if the new FPPA is implemented before July 1, 2004, then no accumulated increase in FPPA charges should be allowed to impact the new retail rates that would come into affect as an outcome of the next rate case. Thus, if the FPPA charges accumulated prior to July 1, 2004 are not allowed to impact rates either before or after July 1, 2004, as I recommend, I do not see the purpose of establishing a FPPA prior to July 1, 2004.

Q. IS THERE ANY OTHER IMPLICATION OF THE FACT THAT APS' RETAIL RATES FOR STANDARD OFFER SERVICE ARE FIXED BY THE SETTLEMENT AGREEMENT UNTIL JULY 1, 2004?

A. Yes. There is another clear implication of the fact that APS' Standard Offer retail rates are fixed by the 1999 Settlement Agreement until July 1, 2004. Because of this fact, the magnitude of the price for wholesale power under the proposed PPA from whenever its start-date is until July 1, 2004 appears to be irrelevant. No matter what those wholesale power costs to APS are for Standard Offer service, APS' retail rates will remain the same. Thus, for example, the exact rate of return assumed for the Dedicated Units from now until the 2003/2004 rate case is completed would seem to be irrelevant to any future retail rates, as long as the wholesale rates charged under the PPA from its start-date until July 2004 are not allowed to impact retail rates after July 1, 2004. However, it is still very important to establish a reasonable set of initial input parameters for the pricing equation contained within the original PPA in order to make sure that no bad precedents are established.

Q. IS THERE ANY OTHER PROVISION OF THE 1999 SETTLEMENT AGREEMENT WITH APS THAT IS CRUCIAL FOR THE PROTECTION OF RATEPAYERS?

A. Yes, there is. Pursuant to the 1999 Settlement Agreement APS has committed to two additional scheduled retail rate reductions for Standard Offer customers. These two 1.5 percent rate reductions are scheduled for July 1, 2002 and July 1, 2003. These two rate reductions should, of course, be implemented.

Q. WHAT IS YOUR THIRD DISAGREEMENT WITH APS' PROPOSED APPROACH FOR PROTECTING STANDARD OFFER CUSTOMERS?

A. My third basic disagreement with APS' proposal for protecting Standard Offer customers is that I do not believe it is appropriate to commit ahead of time to acquiring any specific fixed amount of new generating capacity from a competitive bidding process, until it is more precisely determined how much total generating capacity APS needs in each future year. Obviously, depending on the actual and forecasted demand growth rate from 2002-2008, APS might need more or less than the additional 270 MW per year from 2003-2008 proposed by the PPA. Since new generation can only be acquired with a lead time of about 3-4 years, depending on the type of new capacity required, additional planning information should be utilized to fine-tune the amount of additional generation resources for which competitive bids will be sought in each year. Thus, I do not see a need to fix the amount of capacity to be acquired from a competitive bidding process now.

Closely related to this disagreement is my concern that APS' filing in this docket does not provide a suggested framework for the least-cost provision of providing the new generation resources to APS' Standard Offer customers. This is clearly desirable to help minimize electric rates, as well as to maximize the economic efficiency of the Arizona economy. As part of a new resource acquisition process at least cost, APS should first agree to develop and implement all reasonable demand-side management (DSM) programs which could be implemented in its service territory, and which would be lower in cost than the cost of power under the proposed PPA, or than the cost under my modified PPA, if my proposal is adopted by the ACC. By demand-side management programs I mean energy conservation and load management programs that both APS and customers could implement. Thus, I propose that once some form of a new PPA is approved by the ACC, but no later than October 1, 2002, the ACC should begin a docket to evaluate and determine all the cost-effective DSM programs that could be implemented over the next five years in order to reduce load growth for APS in a cost-effective manner.

Q. ONCE THE DSM PROGRAMS ARE EVALUATED AND A SCHEDULE FOR THEIR IMPLEMENTATION IS ESTABLISHED, WHAT SHOULD HAPPEN NEXT?

A. Once the likely load growth rate for APS net of DSM implementation is determined, then APS should proceed to determine that amount of new generation capacity that it is likely to require in each year between 2004 and 2008. (Note, this least-cost planning process should be repeated about every two or three years, depending on circumstances.) If it is clear that some additional new generating capacity is needed during the period 2002-2004, then given time constraints, that capacity will need to be acquired prior to making the full DSM impact determination. After the DSM assessment is completed, a schedule can then be determined for how much generating capacity needs to be acquired by APS in each year from 2004-2008 through a competitive bidding process. Again, the answer may differ from APS' current suggestion of 270 MW per year, on average.

Q. ONCE IT IS DETERMINED HOW MUCH ADDITIONAL GENERATION CAPACITY APS NEEDS TO ACQUIRE IN EACH YEAR, SHOULD THAT AMOUNT OF GENERATION BE ACQUIRED SOLELY FROM THIRD-PARTY IPP PROVIDERS?

A. No. A least-cost approach would require that APS's new generation capacity requirements should be acquired via a three-way competitive process. Third-party IPPs should be allowed to bid against PWEC, if APS' subsidiary desires to bid. But, in addition, APS itself, as a regulated utility, should be required to "bid" what its regulated cost would be to provide the same type of power supplies over the same duration as bid by others. However, since the ACC sets the rate of return and depreciation rates, etc., for regulated assets, all APS would have to do would be to bid a specific level of initial capital investment, and operation and maintenance costs. The ACC would, then, be able to translate this bid into the equivalent of an annual cash flow requirement (revenue requirement) that could be compared to the deregulated bids. APS would, then, be limited in charging ratepayers only what it bid and no more. Of course, APS might try to exaggerate the amount of the initial capital investment required for a particular type of generating unit, but this figure could be litigated as part of the bid evaluation docket.

This process would, then, allow APS to determine, on a least-cost basis, the best way to provide power for its Standard Offer customers. If the non-regulated wholesale power market can provide power at lower cost than APS can on a regulated basis, then that will demonstrate the better economies available in the de-regulated wholesale market. However, if APS can provide incremental power supplies at a lower cost to customers than the deregulated market can provide, perhaps because APS' cost of capital is lower than that of IPPs, then this will also provide an important lesson for Arizona regulators and electric utility planners. Either way, APS' Standard Offer customers will win because they will obtain new power supplies at the lowest possible price. Of course, if PWEC/PWCC bids into the competitive bidding process, then, as APS states, a third party will need to oversee the auction process.

A least-cost planning process also means that different kinds of bids need to be solicited each time incremental amounts of capacity are needed. For example, baseload, cycling and peaking capacity should always be solicited with a range of contract durations. This is necessary because a generation planner cannot tell ahead of receiving the bids how many megawatts of peaking vs. cycling vs. baseload capacity might be a least cost mix of generation supplies in any particular year, since the fuel price forecasts as well as the bid prices for each different kind of new capacity interact with the dispatch of the existing generation system in complex ways. Thus, since least cost planning requires that the lowest present value of revenue requirements over the duration of the planning period be used to select the bids, a wide-range of types of bids should be solicited. In addition, the planning period used should be at least 20 years. This methodology is a standard approach to least-cost planning.

Q. DO YOU HAVE ANY OTHER OBSERVATIONS TO MAKE ABOUT APS' PROPOSED APPROACH FOR PROTECTING STANDARD OFFER CUSTOMERS OVER THE LONG RUN?

A. Yes. I think it is very important to note that the basic thrust and spirit of the APS proposal is very constructive as a way of providing Standard

Offer customers with rate protection while a competitive wholesale and retail market tries to develop. It is clear from recent experience that this is likely to take a long time, if it ever happens. In the meantime, I agree with APS that if Standard Offer customers find a better deal in the competitive retail market, then they should still be free to avail themselves of that better deal, and leave Standard Offer service. However, since, as of now, not a single customer of APS' is currently off Standard Offer service, including industrial customers, it is likely that it will be very difficult to develop a viable retail market for electricity in Arizona for many years. While a competitive retail market develops in parallel with a competitive wholesale market, it is very important to provide Standard Offer customers with the best set of regulatory and rate protections available to the ACC. This is why I have proposed to strengthen APS' plan by the recommendations that I have made.

Q. DO YOU ACCEPT APS' ARGUMENT IN FAVOR OF ITS PROPOSED PPA THAT THE PRICES UNDER THAT CONTRACT WILL LIKELY BE LESS THAN WHOLESALE MARKET PRICES FOR THE SAME AMOUNT AND TYPE OF POWER OVER THE NEXT 15 YEARS?

A. Yes. I agree with APS that it is very likely that the average price for power to Standard Offer customers under the proposed PPA (and, therefore, under my proposed alternative) will be significantly less than market prices over the 15-year initial period for that contract, and beyond. Dr. Hieronymous' testimony presents a fairly convincing case that this is likely to be the case even for the first five years of the PPA; namely, from 2002-2007. After 2007 it is even more likely that wholesale market prices will be higher than the PPA prices, because the generating unit assets covered by the PPA will continue to depreciate, while market prices will tend to rise in current dollars as the cost of generating equipment and the cost of operating new power plants tends to rise with inflation, and with the price of natural gas.

In addition, it is extremely likely that prices under the PPA will be far less volatile than wholesale market prices. Under the PPA, natural gas will only provide a modest fraction (25-30 percent) of the fuel inputs for the relevant group of power plants, namely all the "Dedicated Units" proposed by APS. Since the cost of natural gas will likely be the most volatile cost component of the PPA contract, its volatility will be highly damped by the other relatively stable fixed cost components, and by other less volatile fuel costs. In contrast, as was seen in Western wholesale market prices for electricity during 2000 and 2001, the deregulated wholesale market price for electricity will tend to track the volatility of natural gas prices rather closely.

Q. IN SUMMARY, IF THE ACC DOES NOT APPROVE SOME OR ALL OF THE CHANGES THAT YOU HAVE RECOMMENDED TO APS' PROPOSED PLAN IN ORDER TO PROTECT STANDARD OFFER CUSTOMERS, DO YOU BELIEVE THAT APS' PLAN IS STILL PREFERABLE TO THE CURRENT SITUATION WHICH CONTEMPLATES A MUCH GREATER RELIANCE ON THE DEREGULATED WHOLESALE POWER MARKET THAN APS' PLAN WOULD?

A. Yes. If some or all of my proposed modifications to APS' proposed plan are either not adopted by the ACC, or for some reason can not be implemented as part of a revised plan, I still believe that the original APS proposal would be better for Standard Offer customers than the present interpretation of the Competition Rules would likely be.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

APPENDIX 1

QUALIFICATIONS

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I hold a B.S. in Physics and Philosophy from MIT, a M.S. in Physics from Columbia University, and a Ph.D. in physics from Columbia University. Currently I am a senior research director at Tellus Institute, as well as executive vice-president and secretary/treasurer of the Institute. I am also the manager of the Institute's Electricity Program.

Q. PLEASE PROVIDE A BRIEF DESCRIPTION OF TELLUS INSTITUTE.

A. Tellus Institute is a non-profit organization specializing in energy, natural resources, and environmental research. Within Tellus Institute, the Electricity Program focuses on energy and utility research areas which include demand forecasting, conservation program analysis, electric utility dispatch and reliability modeling, least-cost utility planning and integrated resource planning, avoided cost analysis, financial analysis, cost of service and rate design, non-utility generation issues, bidding systems, incentive regulation, cost of capital analysis, and utility industry restructuring.

Q. PLEASE ELABORATE ON YOUR EXPERIENCE WITH ELECTRIC UTILITY SYSTEM SUPPLY PLANNING.

A. As past director of the Energy Group and manager of the Electricity Program, I have had wide experience assessing utility system supply options on both a service area and a regional basis. These assessments have encompassed all types of generation plant, transmission plant, purchases of capacity and energy, fuel purchases and contracting, central station district heating and decentralized cogeneration plants, and alternative sources of energy such as wind, biomass, and solar energy connected to electricity grids. These assessments have dealt with the technical, economic, environmental, regulatory, and financial aspects of supply planning, including the relationships between supply planning, load forecasting, rate design, and revenue requirements. I have also reviewed the prudence of many past supply planning decisions by utilities.

Q. PLEASE PROVIDE A FEW ADDITIONAL DETAILS OF YOUR EXPERIENCE IN THE AREA OF UTILITY PLANNING.

A. Power supply system modeling and integrated resource planning has been a major focus of my activities for the past 22 years. My research and testimony in this area began in 1980, and I have testified in numerous cases involving generation planning and the integration of demand and supply technologies on a least-cost basis. For example, I submitted extensive generation planning testimony in the 1980 CAPCO Investigation in Pennsylvania in Case No. I-79070315, and in the 1981 Limerick

Investigation as well (Case No. I-80100341). In early 1982, I prepared a major report for the Alabama Attorney General's Office entitled "Long-Range Capacity Expansion Analysis for Alabama Power Company and the Southern Company System," and I filed testimony in Docket No. 18337 before the Alabama Public Service Commission. In addition, I testified on the excess capacity issue regarding Susquehanna Unit 1 in the 1983 Pennsylvania Power and Light Co. Rate Case (No. R-822169). In 1987, I testified before the Federal Energy Regulatory Commission ("FERC") on NEPOOL's Performance Incentive Program on behalf of the Maine Public Utilities Commission in Docket No. ER-86-694-001. In 1989, I testified before the Pennsylvania Public Utility Commission on excess capacity and ratemaking treatment regarding Philadelphia Electric Co.'s Limerick 2 nuclear unit. This work was performed on behalf of the Pennsylvania Office of Consumer Advocate in Docket No. R-891364. I also testified in Vermont in Docket No. 5330 on the cost-effectiveness of the proposed purchased power contract between the Vermont utilities and Hydro-Quebec. In the 1980s, I testified in several cases involving the planning and construction of the Palo Verde nuclear units, before the Arizona Corporation Commission ("Commission" or ACC), as well as before FERC.

Finally, in January 1998 I testified before this Commission on behalf of the Residential Utility Consumer Office ("RUCO") in Docket No. U-0000-94-165 regarding public policy recommendations on key issues related to calculation, sharing, and recovery of stranded costs; and presentation of the "retail generation service" methodology for computing stranded costs. In September 1998, in Docket No. E-01933A-98-0471, I was the author of comments to the Commission entitled "Analysis and Recommendations of Residential Utility Consumer Office Regarding the Tucson Electric Power Company's Stranded Cost Filing." In November 1998 I filed testimony before the Commission in Docket Nos. E-01933A-98-0471; E-01933A-97-0772; E-01345A-98-0473; E-01345A-97-0773; and U-00000C-94-165 on various filings related to the unbundled service tariffs, stranded cost recovery proposal for Arizona Public Service and Tucson Electric Power Company, and various other aspects of their restructuring proposals. I filed testimony before the Commission in Docket No. RE-00000C-94-0165 in July 1999 on the status of settlement discussions between RUCO and Citizens Utilities Company-Arizona Electric Division ("CUC-AED"), and summary concerns about CUC-AED's stranded cost recovery plans. In February 2002, I filed testimony before the Commission in Docket No. E-01032C-00-0751 on Citizens Communications Company's Purchased Power and Fuel Adjustment Clause and its wholesale power supply contract with Arizona Public Service.

Due to my extensive regulatory experience supporting the public interest, as outlined above, in 1988 I was chosen to serve a three-year term on the Research Advisory Committee of the National Regulatory Research Institute, an appointment made by the public utility commissioners serving on the NRRI Board of Directors. In addition, I have been the project manager on contract research that the Tellus Institute has performed for the U.S. Department of Energy, the U.S. Environmental Protection Agency, the U.S. Department of Justice, the National Association of Regulatory Utility Commissioners (NARUC), the New England Conference of Public Utility Commissioners, the New England Governors Conference, and the National Council on Competition in the Electric Industry.

In the last six years, I have spent most of my time analyzing electric utility restructuring issues. As early as 1996, I testified before the New Hampshire Public Utilities Commission on issues affecting the design of the state's pilot programs (Docket No. 96-150), and I testified before the New York Public Service Commission on stranded costs, market structures, and other issues related to ConEd's, NYSEG's, and RG&E's restructuring plans. I also have worked on or testified on other restructuring issues in Nevada, New Mexico, New Jersey, Illinois, Missouri, Colorado, Pennsylvania, Maryland, Maine, Rhode Island, and Michigan.

BEFORE THE
ARIZONA CORPORATION COMMISSION

DOCKET NO. E-01345A-01-0822

DIRECT TESTIMONY
OF
LARRY E. RUFF

ON BEHALF OF
SEMPRA ENERGY RESOURCES

March 27, 2002

Table of Questions

BEFORE THE
ARIZONA CORPORATION COMMISSION

DOCKET NO. E-01345A-01-0822

DIRECT TESTIMONY OF LARRY E. RUFF

March 27, 2002

1. INTRODUCTION

1.1 BACKGROUND AND SUMMARY

Q. Please state your name, occupation and business address.

A. My name is Larry E. Ruff. I am currently an independent consultant. My business address is 8017 Oak Way, Windsor, California, 95492.

Q. What is your educational and professional background?

A. My professional résumé is attached. In summary, I have a BS degree in physics from the California Institute of Technology and a PhD in economics from Stanford University. I have thirty-three years experience in academia, government, industry and consulting as an energy and environmental economist, policy advisor and consultant. For the fourteen years prior to May 2000, when I became an independent consultant, I was a Senior Vice President with National Economic Research Associates (NERA) and a Managing Director (and other titles) at Putnam, Hayes & Bartlett Inc. (PHB). Since the late 1980s I have specialized in the design and implementation of competitive electricity and gas markets in the United States and abroad.

A. I lived and worked in London during, and played a major role in, the development of the initial competitive electricity market in England and Wales. I subsequently led market design projects in Victoria and New South Wales (Australia), India, Thailand and Ontario (Canada) and was closely involved in the design and/or implementation of competitive electricity markets in New Zealand, Argentina, Peru, Alberta (Canada), and Spain. In the United States, I have testified before the Federal Energy Regulatory Commission and numerous state regulatory commissions on gas and electricity transmission pricing and market design issues, demand-side management programs and other matters, and have advised parties in many states regarding competitive electricity markets. I speak and write widely on these issues.

Q. What is the purpose of your testimony in this proceeding?

A. Counsel for Sempra Energy Resources has asked me to analyze and comment on the economic and competitive issues raised by the request of the Arizona Public Service Company (APS) to the Arizona Corporation Commission (Commission) for a variance to the Commission's Rule R14-2-1606(B). This Rule 1606(B) requires that, beginning in 2003, "the power purchased by [APS] for Standard Offer Service [SOS] shall be acquired from the competitive market through prudent, arm's length transactions, and with at least 50% through a competitive bid process." APS is requesting that the Commission waive this requirement for prudent, arms long, competitive purchasing, and instead allow APS to enter into a long-term – i.e., 13-to-28 year – full-requirements Purchase Power Agreement (PPA) with APS' own parent company Pinnacle West Capital Corporation (PWCC), under which PWCC's generating subsidiary Pinnacle West Energy Corporation (PWEC) would be guaranteed full-cost-plus-ROR on all the generating assets transferred to PWEC by APS plus more than $1,000,000,000 of additional assets to which PWEC committed after wholesale competition became Commission policy.

Q. Please summarize your overall conclusions and recommendations.

A. The Commission's Rule 1606(B), fairly interpreted, was and still is a prudent and practical way to phase in wholesale competition in Arizona for the benefit of Arizona consumers and the economy; it does not, as APS suggests, require that APS scrap its previous generation assets and meet all its needs by buying from unreliable merchant plants burning spot-priced gas. In contrast, the APS request for a variance, and in particular the proposed long-term, full-requirements, cost-plus-guaranteed-profit PPA, are not in the public interest or in the interest of APS' SOS customers for many reasons, including: the inherent conflicts of interest and lack of incentives for efficiency in the PPA arrangements; the likelihood that the PPA will require SOS customers to pay new stranded costs; and the chilling and distorting effect on wholesale and retail competition. Instead of approving the APS request, the Commission should require APS to implement Rule 1606(B) in a prudent, phased process, such as using competitive negotiation and/or bidding processes to define new, five-year contracts for approximately 20 percent of its SOS load requirements each year beginning in 2003.

1.2 OUTLINE AND CONCLUSIONS

Q. How is your testimony organized?

A. My testimony consists of the following four sections in addition to this introductory Section 1:

Section 2: Electricity Competition in General

Section 3: The APS-Proposed PPA and Its Effects

Section 4: APS' Arguments for the Variance and PPA

Section 5: An Alternative Approach

Q. Please summarize your conclusions regarding electricity competition in general.

A. On the value of and experience with competition in electricity, I conclude that:

- Well-designed and well-implemented competitive wholesale electricity markets can deliver and – with a few notable and understandable exceptions – have delivered real benefits to consumers and the economy generally;
- Retail competition for small consumers, while potentially valuable, is difficult in the short run and is not strictly necessary for effective wholesale competition – provided that the utility distribution companies (UDCs) that serve SOS customers actively compete in the wholesale market for their SOS supplies; and
- The California and Enron debacles demonstrate that big mistakes can be made, but also provide valuable lessons about how to avoid these mistakes; these events

are not reasons to avoid competition itself and are not slowing efforts at the Federal level to create efficient, competitive wholesale markets.

Q. Why do you think the proposed PPA arrangements are not in the public interest or in the interests of APS' SOS customers?

A. The proposed PPA arrangements – which include both the PPA between APS and its parent PWCC and the contract between PWCC and its generation affiliate PWEC – are not in the public interest or in the best interest of APS' customers for many reasons, the most important of which include:

- The PPA arrangements involve inherent conflicts of interest that are inappropriate in principle and that create identifiable problems in this specific case;
- The PPA would reverse the most important steps the Commission has taken to move toward competitive wholesale and retail markets in Arizona, including undoing parts of the 1999 APS Settlement on stranded costs that were designed to protect consumers and probably even requiring SOS customers to pay new stranded costs;
- The PPA contains few incentives for PWCC and/or PWEC to operate efficiently, many inherent conflicts of interest, and some incentives for PWCC and/or PWEC to operate inefficiently at the expense of APS' SOS customers;
- The pricing provisions in the PPA may create a "death spiral" effect if retail competition becomes effective within the next ten years or so, creating strong pressure on APS and the Commission to keep retail competition ineffective; and
- The PPA gives PWCC a unilateral option to extend or terminate the PPA in the future, which PWCC will presumably exercise based on expected market conditions at the time, in effect creating a heads-PWCC-wins, tails-PWCC-wins-more arrangement.

Q. Please summarize your evaluation of arguments made by APS and its witnesses in support of the requested variance and proposed PPA.

A. The APS case does not demonstrate any real problems with Rule 1606(B) or compare the APS request for variance and proposed PPA to reasonable alternatives, and the arguments made in support of the PPA are at best weak. More specifically:

- APS creates a bogeyman version of Rule 1606(B) and then puts forward its PPA as though it were the only viable alternative to this bogeyman, when in fact there are many, better alternatives to the APS bogeyman and to the proposed full-cost-plus-guaranteed-profit PPA;
- The claims made by APS and its witnesses concerning the reliability and economic advantages of the PPA over Rule 1606(B) have little basis, particularly when the PPA is compared to interpretations or slightly modified versions of Rule 1606(B) that are more reasonable than the APS bogeyman; and
- The claims that the PPA will not impede the development of wholesale competition are based implicitly on simplistic theories that are not valid for complex electricity markets in the early stages of development, and on factual assertions that are incorrect, irrelevant or (in at least one case) inconsistent with APS' own testimony.

Q. What does your testimony conclude and recommend regarding alternatives to the APS requested variance and proposed PPA?

A. My testimony concludes that there are alternatives to the APS request that would be more prudent, more consistent with the public and consumers' interests, and more consistent with the Commission's competition objectives. In particular, I recommend that Rule 1606(B) be modified or – more accurately – clarified to allow/require APS to use arms-length negotiations and/or an open bidding process to acquire the resources it needs for SOS supply from a prudent combination of affiliated and unaffiliated generators. As an example, I outline a process in which APS would eventually be meeting its SOS needs with a portfolio of five-year contracts, approximately 20 percent of which (measured by energy) would be replaced each year.

2. ELECTRICITY COMPETITION IN GENERAL

2.1 THE OBJECTIVES OF WHOLESALE AND RETAIL COMPETITION

Q. What is the ultimate objective of competition in electricity markets?

A. The ultimate objective of public policy in electricity and elsewhere is to reduce the total costs of meeting consumer's needs, not just for electricity or even for energy, but for all the things they desire. Competition in electricity can help achieve this ultimate objective by motivating suppliers to produce electricity at lower costs – subject to policies that reasonably internalize environmental and other social costs – and by producing more cost-reflective consumer prices.

Q. How does wholesale competition help accomplish the objective of meeting consumer needs reliably and efficiently?

A. Wholesale competition motivates generators to reduce the costs of each power plant, to offer wholesale buyers contracts with good risk-management terms, and – the most important effect in such a capital-intensive industry – to invest in cost-effective amounts and types of generating capacity. In particular, wholesale competition largely eliminates the possibility that consumers will be stuck with stranded generation costs, because those who make generation investment decisions know that they, not the consumers who have no control over such decisions, will face the economic consequences of these decisions, good or bad.

Q. How does retail competition or "choice" help accomplish the objective of meeting consumer needs reliably and efficiently?

A. Retail choice can have some effect on retailing costs and services themselves, but its most important effect is to motivate generators to reduce their costs – which are by far the largest costs that can be affected by competition – and to offer better risk management arrangements. With retail choice, each competitive generator knows that if it tries to raise its prices to cover too-high costs, or if it does not offer contracts that reduce market risks for the buyer, consumers or the retailers who serve them will buy from other generators.

Q. Can retail competition be effective and efficient without a liquid and competitive wholesale market?

A. No. Competitive retailers must have access to an open and efficient wholesale market so that they can contract for the supplies they need to serve final consumers and sell any contracted amounts their customer do not need. Until there is such a wholesale market – including a real-time spot market that prices imbalances on a market basis – retail competition will be difficult and its results disappointing.

Q. Can wholesale competition be effective and efficient without active retail competition, and if so how?

A. Retail competition can help maintain effective and efficient wholesale competition but is not strictly necessary for it, at least not in the initial years of market development. But the only effective substitute for retail competition as a way to keep pressure on the wholesale market is to require the UDCs who supply SOS customers to buy their SOS supplies in the competitive wholesale market with strong incentives to keep their purchase costs down. If the UDCs who supply SOS customers do not buy in the wholesale market, but instead enter into long-term, full requirements, cost-based contracts – particularly contracts with their own affiliates – wholesale competition will suffer badly. There will be fewer generators competing to sell in the market, fewer UDCs competing to buy in the market, less activity by innovative traders and marketers, and fewer market transactions to provide liquidity and price transparency. The few generators favored with the UDC contracts will have both short-run and long-run advantages over other generators, for no reason except that they somehow got the initial contracts.

2.2 Experience with Competition in Electricity

Q. Has competition in electricity been successful in delivering its promised benefits, in most cases?

A. Yes. There have been teething problems in all competitive markets, but these have usually been less serious than the problems in the monopoly systems they replaced and have been the predictable/predicted results of bad market designs that can be avoided elsewhere. Successful competitive markets in New Zealand, Australia, Spain and elsewhere have reduced the historical tendency toward over-capacity, over-staffing and inefficient operations in these systems. Competitive markets in Argentina, Chile, Peru and elsewhere have solved the historical tendency toward underinvestment and unreliability in these systems. Competitive markets in systems where there was no apparent crisis, such as the UK and PJM, have increased diversity, flexibility, innovation and efficiency in the wholesale market, and ultimately choice in the retail market, while maintaining reliability.

Q. How do you explain the problems in the California electricity market, and why will Arizona not have similar problems?

A. California is the universal poster child for those who do not want competitive electricity markets for whatever reason. But California made many serious policy mistakes, including:

- A decade or more of bad policy and uncertainty prior to competition, such as the "Standard Offer 4" requirement that utilities contract long-term for large quantities of high-cost power from qualifying facilities (QFs), and stringent and inflexible air pollution and plant siting regulations that discouraged new power plant construction;
- Creation of an idiosyncratic and badly flawed wholesale market that independent market design experts saw as such and warned about in advance; and
- Last-minute, poorly-analyzed, even imprudent political decisions, particularly the decision that UDCs would provide SOS at capped rates but would not own or contract for generation resources.

These California-specific factors created a tinderbox waiting for a spark. And then a regional drought, high natural gas prices and surging demand hit all at once, setting off the California explosion and meltdown.

None of the factors that created the California disaster-in-waiting is or is likely to be present in Arizona. New power plants are being developed in the region faster than the market can absorb them, and hence many are in the wings just waiting for demand to grow. The wholesale market is not efficient and liquid enough to support effective retail competition, but has well-tested mechanisms for supporting bilateral wholesale contract trading among UDCs and generators. The SOS procedures, including Rule 1606(B) properly interpreted, not only allow but require UDCs to enter into contracts to serve their SOS loads. Nobody can guarantee good rainfall, low gas prices or modest demand growth for long, but the controllable factors in Arizona give the system enough resilience to withstand any plausible surprises here.

Q. Enron was a principal advocate of competition in electricity and the use of risk-management paper as substitutes for hard assets. What does the collapse of Enron say about these policies?

A. The Enron collapse primarily reinforces old and well-understood principles, such as the imprudence of making large bets and then doubling-up to try to recover losses, and the ultimate futility of trying to hide bad results with false or perhaps even fraudulent reporting. The fact that Enron tried to fool the world, and perhaps itself, by calling its gambling "hedging" says nothing about the wisdom or viability of true hedging strategies. The most important lesson of the Enron collapse for the issues in this proceeding is that something this large could be absorbed with barely a ripple in competitive power markets.

Q. How do you think events such as California and Enron should or will affect the future of electricity competition in the US and in the Southwest?

A. Due caution is always in order, and everybody in this business should take time to identify the right lessons to draw from the California and Enron disasters. But this has already largely been done, and FERC is now moving forward to adopt a Standard Market Design and RTO rules that will continue the development of wholesale competition across the US without making the California mistakes. The fact that it is possible to make big mistakes that create large costs should not be allowed to overshadow the fact that we know how to do it right and that when it is done right there can be significant benefits.

3. THE APS-PROPOSED PPA AND ITS EFFECTS

3.1 THE KEY FEATURES OF THE PPA

Q. What are the principal features of the proposed PPA that affect the public interest and the interests of APS' SOS customers?

A. The principal features of that PPA that affect APS customers and the public interest include the following:

- **Affiliate Relationships:** The PPA arrangements consist of the PPA between APS and its parent company PWCC, and an underlying contract between PWCC and its unregulated and supposedly competitive generating affiliate PWEC. The PWCC/APS/PWEC family of companies has "formulated," "negotiated" and "assessed" these arrangements internally and is now asking the Commission to approve its handiwork.

- **Exclusive, Full Requirements Contract:** Under the PPA, "PWCC shall be the exclusive provider of APS' Full Load Requirements," [PPA, Article 1.1(A)] i.e., of all the "Energy Products" (including reserves) that APS needs to supply its SOS customers. PWCC must meet APS' Full Load Requirements either from its contract with PWEC or by buying in the market, and has full discretion in deciding what combination of such actions to use and in determining the adequacy of reserves. [PPA, Article 1.2(B)]

- **28-Year PPA, with Unilateral PWCC Option To Terminate at 13, 18 or 23 Years:** The PPA is expected to become effective on January 1, 2003 and will remain in force at least until December 31, 2015, which is a 13 year term. In addition, the PPA "shall automatically be renewed for up to three additional 5-year terms unless either Party" decides not to renew, [PPA, Article 11.2(B)] which – given that both Parties are both within the PWCC family and currently even share presidents – effectively gives PWCC a unilateral option to terminate or extend the PPA after 13, 18 or 23 years.

- **Limited Market Purchases of Energy Products by PWCC:** If APS' Full Load Requirements exceed what PWEC is required to provide under the PPA, or if contract entities fail to deliver, PWCC will purchase Supplemental or Replacement Energy Products in the market. Furthermore, commencing on January 1, 2003, PWCC will use a Competitive Bidding Process to buy for APS, at APS' cost, Energy Products equivalent to 270 MW of capacity (at 51% load factor), with the amount purchased through this process increasing to 1,620 MW in 2008 and staying there for the remaining term of the PPA. The 1,620 MW of competitively purchased Energy Products is estimated by APS to be 23% of peak load in 2008. This is less than half as much competitive purchasing, five years later, than currently required by Rule 1606(B).[1]

- **Fixed Payments To Cover All Recoverable Fixed Costs and ROR:** The monthly Facilities Charge (FC) guarantees that PWEC will recover depreciation plus a 9.38%/year ROR on the full, undepreciated capital costs (less amounts written off as part of the 1999 APS Settlement on stranded costs) plus all actual short-run-fixed costs such as plant payrolls and maintenance, of all Dedicated Units. The amount of the FC does not depend in any way on whether or how much the Dedicated Units are used to supply APS' Full Load Requirements or are cost-effective in doing so, or on the amount or value of output from the Dedicated Units that is sold to third parties.

- **Energy Payments To Cover All Actual Fuel Costs but Only Fuel Costs:** The Base Fuel Charge (BFC) and a Fuel & Purchased Power Adjustment (FPPA) guarantee that PWEC will (perhaps with a lag due to the annual true-up mechanism) recover the full costs of all the fuel used in the Dedicated Units, including the costs (or benefits) associated with hedging fuel costs, emission

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[1] If 270 MW is 23% of peak SOS load in 2008, peak SOS load in 2008 is 7,043 MW (1,620/0.23 MW). Dedicated Units are to provide at least 4,720 MW of peak capacity in 2008, [PPA Service Schedule, pp. SS 2-3] which is two-thirds (4,720/7,043 = 0.67) of the expected peak load. Thus, in 2008 about two-thirds of peak load will come from Dedicated Units, about one-fourth from the Competitive Bidding Process and about one-tenth from other contracts.

allowances, etc. The variable energy charge does not include any short-run-fixed costs such as payroll and maintenance, all of which are in the FC.

- **Retention by PWEC of 75% of Any Net Margin from Off-System Sales:** The net margin from any sales to third parties of Energy Products from Dedicated Units is shared between PWEC and APS, but with PWEC getting 75 percent – even though APS is paying all fixed and variable costs of all Dedicated Units.

- **Inclusion of New PWEC Units in Dedicated Units:** The Dedicated Units include not only all the previously-regulated units transferred from APS to PWEC, but also new PWEC units such as West Phoenix and Redhawk with a capital cost of over one billion dollars. PWEC committed to these units after the Commission's competition policy was in place, presumably at its own risk in the emerging competitive wholesale market, but under the PPA will be guarantee full recovery of all capital costs plus a ROR of 9.38 percent/year.

3.2 EFFECTS OF THE PPA ON COMPETITION

Q. Please explain your statement that the PPA arrangements involve affiliate arrangements that are inappropriate in principle and that create identifiable problems in this specific case.

A. The potential for conflicts of interest is obvious in this situation, where PWCC, APS and PWEC have "negotiated" and will administer complex agreements among themselves, and will then expect the Commission to approve passing all the resulting costs on to APS' SOS customers. Such affiliate relationships destroy the usual presumption that a regulated utility such as APS, while it may not have strong incentives to reduce costs or be innovative, will at least try to get the best possible deal for its captive customers in its dealings with suppliers and others. When APS is buying from unregulated, for-profit affiliates, the most realistic assumption for the Commission to make is that APS will negotiate and administer the PPA with at least one eye on the bottom line of its affiliates. There are very good reasons why such conflicts of interest are regarded as inherently undesirable.

It is impossible in complex situations to identify all the specific problems caused by conflicts of interest, which is why such conflicts of interest are usually rejected on principle. Most of the problems with the PPA discussed later in this testimony are traceable to or at least exacerbated by the fact that the contract counterparties are affiliated. One example is the possibility, discussed further later in my testimony, that PWCC could sell output from Dedicated Units in the market and keep 75 percent of the net margin at the same time it is buying Supplemental or Replacement Energy Products at APS' cost to meet APS' load. This would be unlikely to happen if PWCC had incentives to get maximum performance from PWEC and/or to minimize costs to APS, or if APS were an independent company acting as prudent purchasing agent for its captive customers.

Q. Please explain why you think this PPA would reverse the most important steps the Commission has taken to move toward a competitive wholesale market.

A. The Commission has taken two principal steps to create wholesale competition in Arizona: (1) APS and other utilities are required to transfer their generation assets to unregulated and presumably independent, entities – PWEC in the case of APS; and (2) the separated UDCs are required to meet their SOS needs with prudent, arms-length, market transactions with some combination of affiliated and unaffiliated generation companies. The proposed variance to Rule 1606(B) would eliminate the market purchasing requirement, while the proposed long-term, full-requirements, full-cost-pass-through PPA would effectively undo the separation of generation from the UDCs, leaving little or nothing of the Commission's wholesale competition policy.

Q. Please explain why you think this PPA would delay the development of retail competition in Arizona.

A. On paper there is full retail competition or choice in Arizona now, but in fact there is virtually none – and there will be little or none until the wholesale market is efficient and liquid. The implementation of Rule 1606(B) would not by itself make much difference to retail competition, because real retail competition will be limited until there is an efficient wholesale spot market and Arizona is far from having (or wanting) that. But the PPA, by reversing the movement toward efficient wholesale competition, would also eliminate one of the necessary (if not sufficient) conditions for retail competition.

3.3 EFFECTS OF THE PPA ON STRANDED COSTS

Q. Please explain why you say that the PPA would undo parts of the 1999 APS Settlement on stranded costs that were designed to protect consumers.

A. The APS stranded cost settlement required APS to write down the recoverable value of its generation assets and allowed APS to charge prices above expected market prices through 2004 in order to recover as much of its remaining book asset value as it could, with no guarantees. After 2004 and the transfer of APS generating assets to PWEC, APS was to buy its SOS supplies at market (contract and spot) prices and pass the costs through to SOS customers, while PWEC would sell its output at market (contract and spot) prices. But the PPA guarantees PWEC a ROR of 9.38 %/year on the full book value of all the transferred APS assets at least until 2013 and far beyond if extensions are in the interest of PWCC as a whole. This arrangement appears to be very different from what was agreed in the 1999 APS Settlement, and will probably result in the PWCC family recovering more of its original stranded costs than it otherwise would.

Q. Please explain why you say that the PPA creates the potential for new stranded costs.

A. The PPA guarantees full cost recovery plus a 9.38 %/year ROR, not just for the units previously owned by APS and previously regulated by the Commission, but also for units such as West Phoenix and Redhawk that were built by PWEC on an unregulated basis presumably in anticipation of selling output at unregulated market prices for many years. But market conditions have softened considerably since these PWEC plants were committed, and most price forecasts no longer justify building such new plants. As Mr. Jack E. Davis of APS said: "Even as this testimony is being written [on December 12, 2001], we are seeing the impact of today's lower market prices for power in the form of cancelled or delayed power plant projects." [Direct Testimony of Jack E. Davis, December 12, 2001, p. 24] Unfortunately for PWEC and its parent PWCC, it is too late to cancel or delay the West Phoenix and Redhawk plants; if the market does not firm up enough to make these plants profitable, ratepayers or shareholders will be stuck with new stranded costs.

The PPA proposed by APS would require APS – i.e., ultimately APS' SOS customers – to pay the full capital costs including ROR of the new PWEC units even if these costs exceed the market value of the services provided by these units. But generation costs in excess of the market value of the product are, by definition, stranded generation costs. Thus, as long as market conditions remain as described by APS' witness Mr. Davis, APS' SOS customers will probably be paying otherwise-stranded costs of generating units built by APS in a competitive environment.

Q. Will the possibility of new stranded costs be eliminated if market prices increase in the future?

A. If market prices increase well before 2015, APS' SOS customers may get fair value from the PPA over its initial term. As discussed below, however, the PPA gives PWCC a unilateral option to terminate the PPA in 2015, 2020 or 2025, so if market prices increase in the long run PWCC will presumably exercise its option to terminate the PPA. APS' *SOS customers may cover losses* incurred by the new PWEC units in the early years of their life, and then see PWEC reap the profits later.

Q. Could the Commission prevent the PPA from creating new stranded costs by determining that some of the PPA costs were not prudent?

A. Presumably the Commission will have to approve APS' SOS rates from time to time and hence could disallow some of the PPA's costs as imprudent, leaving these costs with the PWCC family of companies. But if the Commission approves the PPA now, it may have difficulty disallowing APS' PPA costs later unless it specifically reserves the right to do so; and reserving such a right could have serious financial consequences for APS' parent PWCC. The Commission should not approve the PPA now with the expectation that it can easily disallow later any PPA costs that are stranded by market developments.

3.4 EFFECTS OF THE PPA ON INCENTIVES

Q. Please explain your conclusion that the PPA contains few incentives for PWCC and/or PWEC to operate efficiently for the benefit of consumers?

A. The PPA between APS and its parent PWCC, and (as far as can be determined from the PPA) the underlying contract between PWCC and its generation subsidiary PWEC, are both full-cost-plus-profit contracts that create no obligation or incentives to be efficient in purchasing, staffing or operations for the benefit of SOS consumers. In particular:

- Under the PPA, PWCC is required to meet APS' Full Load Requirement but has full discretion in deciding how "to select or acquire the resources" needed to do so (including the right "under economic dispatch ... to purchase power rather than schedule the Dedicated Units," [PPA Section 1.2(B)]) and the right to pass all resulting costs straight through (with a lag due to the true-up mechanism) to APS, with no obligation or contractual incentive to minimize such costs;
- Under the contract between PWCC and PWEC, PWEC is paid the full costs of all fuel, payrolls, operations and maintenance of the Dedicated Units, with no obligation or contractual incentive to minimize such costs; and
- The PPA says that, "at a minimum, PWCC shall" make specified amounts of capacity and energy available from the Dedicated Units [PPA Service Schedule Section 3.2.3], but provides no penalties for failure to do so, even if failure to do so requires PWCC to meet APS' load by purchasing Replacement Energy Products in the market at additional cost to APS.[2]

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[2] Failure to make available the contractual minimum amounts from the Dedicated Units could be a Failure to Perform Agreement, which could become an event of default under the PPA if PWCC did not fix the problem within 5 days after receiving written notice from APS.

Q. Does the PPA give PWEC and/or PWCC incentives to improve the energy and capacity available from the Dedicated Units, and if so would APS or its SOS customers share in the benefits?

A. There is no incentive for PWEC and/or PWCC to increase the output of Dedicated Units if this output displaces Supplemental or Replacement Energy in meeting SOS load, because all Dedicated Unit costs and all Supplemental and Replacement Energy costs are passed straight through to APS. However, if increased output from the Dedicated Units is sold to third parties, PWCC keeps 75 percent of the net sales margin – even if this increases costs for APS and its SOS customers. For example, if PWEC spends $1 million on increased maintenance in order to increase off-system sales margins by $2 million, PWEC nets $1,500,000 (75% of $2 million) but APS/SOS customers lose $500,000 ($1 million minus 25% of $2 million).

Q. Please explain your conclusion that the PPA contains some incentives for PWCC and/or PWEC to operate inefficiently at the expense of APS' SOS customers.

A. It is hard to identify all such possibilities in a complex situation, but there are several created by the provision allowing PWCC to keep 75 percent of the net margin from any off-system sales from Dedicated Units.[3] As long as the Dedicated Units "make available" the contract minimum MW of capacity at system peak and minimum MWh of annual energy, PWCC could (for example) buy Replacement Energy at APS' cost to meet APS' SOS load during scheduled maintenance of a Dedicated Unit and then use the newly-refurbished unit to sell Energy Products to third parties later and keep 75 percent of the net margin from those sales. Or PWEC could spend $1 million of APS' money to upgrade a process that increases off-system sales margins by $800,000 – a non-cost-effective investment that would net PWCC $600,000 (75% of $800,000) and cost APS' SOS customers $800,000 ($1 million minus 25% of $800,000).

[3] Sharing of the margin from off-system sales is common in power purchase contracts and can be a good way to encourage the seller to find profitable off-system sales opportunities. The problems referred to here are created by the full-cost-pass-through nature of the PPA and particularly the affiliate relationships.

3.5 EFFECTS OF THE PPA ON RETAIL COMPETITION – AND *VICE VERSA*

Q. Please explain your conclusion that the PPA may create a "death spiral" effect if retail competition becomes effective before 2015.

A. The PPA requires APS to pay the full costs of all of PWEC's Dedicated Units, plus the full costs of the Energy Products supplied through the Competitive Bidding Process, independent of what APS' SOS load is at any time. APS expects that, in 2008, the 1,620 MW (at 51 percent load factor) to be purchased through the Competitive Bidding Process will be 23 percent of APS' peak SOS load, implying a peak SOS load of 7,043 MW (1,620/0.23 MW) in 2008. Combined with the requirement that Dedicated Units make available 4,720 MW in 2008, these numbers imply that APS expects PWCC to be buying about 1,700 MW of Supplemental Energy Products in 2008 to serve APS' SOS load.

APS does not explicitly say so, but its projections of SOS load appear to assume that retail competition will not be effective by 2008, i.e., that APS' SOS load will grow at about the same rate as electricity demand generally. But if retail competition becomes effective by 2008 – or 2012 – APS could lose a significant amount of SOS load to competitive retailers, particularly if market prices are low relative to APS' average costs under the PPA. If competitive retailers capture, say, 2,000 MW of APS load by 2008, PWCC will not be buying any Supplemental Energy Products and in fact will have more capacity and energy from the Dedicated Units and the Competitive Bidding Process than APS needs. As more SOS load is lost to competitive retailers, the average costs in \$/MWh of the PPA – and presumably APS' SOS rates – will become even higher, driving away more SOS load and increasing prices further, etc. This is what is commonly called a "death spiral."

Q. Why do you assume that APS' SOS rates will be based on the total PPA cost per unit of SOS load, and are there alternatives that might eliminate the death spiral effect?

A. I do not know how the Commission will determine SOS rates in the future, but I presume APS is assuming it will be able to pass through all PPA costs to SOS customers, and if so the average SOS rate in any (say) year will be approximately the total annual PPA cost (plus non-energy APS costs) divided by total SOS sales. Of course, if the death spiral scenario actually materialized, many expectations would be disappointed, and both APS and the Commission would have some difficult choices to make. For example, the Commission might disallow some PPA costs as imprudent and/or PWCC might offer to absorb some costs in order to stop the spiral.

Q. Could APS avoid the death spiral effect by selling output from Dedicated Units into the market or to the retailers serving the previously-SOS customers?

A. It might. But remember, 75 percent of any margin from off-system sales from Dedicated Units goes to PWCC, not to reduce PPA costs to APS or prices to SOS customers. PWCC might be able to sell enough of the Energy Products purchased in the Competitive Bidding Process to keep average PPA costs from increasing, but could also sell Energy Products from the Dedicated Units and keep 75 percent of the net margin for itself.

Q. Could the death spiral effect be avoided by assuring that retail competition does not become effective during the term of the PPA?

A. Yes, and that is one reason why I say the PPA would delay retail competition. (The lack of an efficient wholesale spot market is the other principal reason.) If the PPA is approved, APS will have strong incentives to assure that retail competition does not become effective, and even the Commission – or future Commissions – may prefer to delay effective retail competition than to deal with the problems created by a death spiral and new stranded costs.

3.6 PWCC's Unilateral Renewal Option and Its Effects

Q. Please explain your conclusion that PWCC has a unilateral option to extend or terminate the PPA, thereby creating "a heads-PWCC-wins, tails-PWCC-wins-more arrangement."

A. The PPA is in force at least through 2015, and is automatically renewed for up to three additional 5-year terms unless either of the Parties to the PPA decides not to renew it.

But the Parties to the PPA are APS and its parent company PWCC, who are currently so closely integrated that Mr. Jack E. Davis is president of both. It is reasonable to assume, therefore, that the PWCC family and its then current president(s?) will decide to terminate the PPA or not in 2015, 2020 or 2025 depending on what is good for PWCC as a whole, largely independent of the effects on APS' customers.

It is impossible to say now with any certainty whether termination or continuation of the PPA will be in the interest of PWCC in 2015, 2020 or 2025, but the one-sided nature of PWCC's unilateral option can be illustrated by considering the following two possible scenarios:

- If in 2015 market prices are projected to be higher than average PPA costs over the next five years or more, PWCC will exercise its option to terminate the deal so that it can sell PWEC's product at the high market prices, leaving any SOS customers and/or their SOS suppliers exposed to those high market prices.
- If in 2015 market prices are projected to be lower than average PPA costs over the next five years or more, termination would be in the interests of SOS customers (if there are any by then) but not in the interests of PWCC. If APS were an unconflicted agent of its SOS customers, it would exercise its option to terminate on their behalf. But as a subsidiary of PWCC, APS would probably not exercise its termination option, so that its affiliate PWEC could continue receiving above-market prices.[4]

[4] The Commission might be able to "persuade" APS to exercise its termination option in the best interest of its SOS customers, by determining that failure to do so would be imprudent. But it might not be easy for the Commission to determine what is prudent at the time, and any significant risk that the Commission will deem PPA costs imprudent later would create serious problems for both APS and the Commission. Before approving this or any other long-term PPA, the Commission should carefully consider what this means for its ability to protect consumers in the future.

Q. What do you think is the most likely long-run economic outcome under the PPA?

A. The PPA front-loads capital costs much as traditional utility rate-making does, and perhaps more if PWEC uses accelerated rather than traditional straight-line utility depreciation. And current wholesale market conditions are weak, as APS' own witnesses have acknowledged. Thus, in the early years the average PPA cost is likely to be above market prices, which will be sustainable because retail competition will not be a realistic option. In the later years of the initial term of PPA, the average PPA cost will probably be more-or-less the same as average market prices, provided that retail competition remains ineffective. Then in 2015, when the depreciated value of the Dedicated Units is small enough that average PPA costs will probably be significantly below average market prices, the PPA will be terminated, SOS customers (if there are any) will be exposed to market prices, and PWEC/PWCC will get the full market value of the Dedicated Units that SOS customers have paid for with above-market SOS prices for much of the previous 12 years.

4. APS' ARGUMENTS FOR THE VARIANCE AND PPA

4.1 THE APS BOGEYMAN VERSION OF RULE 1606(B)

Q. Why do you say that APS sets up a misleading bogeyman version of Rule 1606(B)?

A. APS does not really explain why its proposed variance and PPA are the best solution to any specific problem, but instead cites a range of scary events and possibilities as though Rule 1606(B) would necessarily increase the risks of these. For example, in its Request for a variance and PPA, APS:

- Cites repeatedly the recent volatility of spot wholesale prices, thereby suggesting that Rule 1606(B) requires APS to buy in spot markets;
- Refers to "merchant plant owners [who have no] responsibility for APS system reliability," thereby suggesting that merchant plants are necessarily less reliable than utility plants;

- Cites the alleged "over-reliance by many western energy suppliers on volatile natural gas supplies," as though Rule 1606(B) requires APS to "over-rely" on unhedged gas supplies and as though no western energy suppliers used other fuels or hedged gas prices;
- Says that "few if any non-affiliated generators" would be able to supply a 3,000 MW "block of power in 2003 or for several years after that," suggesting that Rule 1606(B) requires APS to buy only from non-affiliated generators or even to buy 3,000 MW in a single block from a single supplier; and
- Refers to APS "scrambling" for supplies if transmission paths from merchant plants to APS become constrained, as though all merchant plants and no PWEC plants used potentially constrained transmission paths.

If Rule 1606(B) required APS to buy in the short-term market 3,000 MW of unhedged gas-fired capacity from a single, unaffiliated, merchant supplier who could deliver only over unreliable transmission lines, then Rule 1606(B) would indeed be a foolish Rule. But there is nothing in Rule 1606(B) to prevent APS from defining the characteristics of the portfolio of supply resources it wants, including specifying the length of contracts, the types of fuel or (better) price indexing formulas, and the transmission firmness it wants. There is nothing in Rule 1606(B) to prevent APS from contracting with its own affiliates when they are the most cost-effective suppliers of what APS needs. In fact, for APS not to define carefully what it needs or not to contract with an affiliated generator that is the most cost-effective supplier would be imprudent, in direct violation of Rule 1606(B).

All Rule 1606(B) requires is that, once APS has decided what resources it needs to meet its load reliably, it select the suppliers of those resources and define the contract prices and terms in "the competitive market through prudent, arm's length transactions, and with at least 50% through a competitive bid process" in which unaffiliated as well as affiliated generators can participate. This, unlike APS' bogeyman version of Rule 1606(B), would be a perfectly reasonable and prudent way for APS to acquire the SOS supplies it needs.

Q. Why do you say that APS puts forth its own PPA as though it were the only possible alternative to Rule 1606(B), and that there are many, possibly better, alternatives?

A. Even if APS' bogeyman version of Rule 1606(B) were accurate, the appropriate response would be to propose changes in Rule 1606(B) that might solve identified problems. But APS takes a different course, proposing to scrap Rule 1606(B) entirely and replace it with a very specific, long-term, full-requirements, full-cost-plus-guaranteed-profit contract with APS' affiliated companies.

There are many possible alternatives to APS' interpretation of Rule 1606(B), including what the Commission probably had in mind all along: A prudent phase-in of competitive contracting over time. Even if market purchases are to be replaced with long-term contracts, and even if PWCC is to provide all of APS' requirements, there are many variations on the theme that are more consistent with the Commission's competitive objectives, more prudent and better for APS' SOS customers that the specific PPA proposed by APS. For example, the single, 13-to-28-year contract between PWCC and PWEC for all of PWEC's capacity at full-cost-plus-guaranteed-profit could be replaced with a portfolio of contracts, and then unaffiliated generators could be allowed to compete for pieces of the portfolio initially or increasingly over time. The contract quantities could vary to reflect changes in APS' SOS load. There could be cost-sharing arrangements to provide more incentives for efficiency. So there are many options even within the long-term contract framework; but APS does not suggest or acknowledge the existence of such variations on the PPA that it and its affiliates have formulated by and for themselves.

4.2 ALLEGED RELIABILITY ADVANTAGES OF THE PPA

Q. Please explain why you say there is little basis for the reliability advantages that APS alleges for the PPA.

A. Under the PPA, the APS system would be operated by PWCC as a vertically integrated monopoly, much as it has been operated for decades. There is no doubt that such a system can be operated reliably or that APS has done so and PWCC could continue to do so. But competitive systems, and the independent generating units within them, can and do operate just as reliably as the APS system and its generating units, elsewhere in the United States and abroad. APS has not demonstrated or even made a plausible case that a reasonable interpretation of Rule 1606(B) could not be consistent with reliable operations, but has simply sketched a bogeyman version of Rule 1606(B) and implied that it would be unreliable.

Q. How would the reliability advantages of central dispatch be maintained if APS were to contract with many unaffiliated generators rather than with PWCC as a single, full-requirements seller?

A. It is unclear to me whether APS or PWCC would operate the central dispatch process under the PPA, but either way the same central dispatch process could be used to coordinate the activities of many independent generators. Most of the contracts between APS (or PWCC) and (large) unaffiliated generators would have to be dispatchable, and those that were not would have to be cheaper to reflect the lower value of nondispatchable generation. The dispatchable contracts would have to be written to assure unaffiliated generators that they would not be discriminated against in the APS/PWCC dispatch or would be compensated if they were. Contracting would be easier and more efficient if APS were to establish an independent system operator (ISO) and a central spot market, but some independent generation could be accommodated reliably within a dispatch process operated by APS or PWCC.

4.3 ALLEGED ECONOMIC ADVANTAGES OF THE PPA

Q. Why, according to APS and its witnesses, is the PPA in the economic interest of APS' SOS customers, and what is your summary evaluation of these arguments?

A. APS and its witness make the following three principal arguments to support the view that the PPA is in the economic interest of SOS customers:

- The PPA would protect SOS customers from price volatility because the Dedicated Units are largely coal and nuclear with fixed fuel costs;

- Average PPA costs are likely to be less than average market prices over the term of the PPA; and
- Market-determined prices may not be "reasonable" because there is not enough unaffiliated generation in the APS market region to create effective competition.

My summary evaluations of these argument are, respectively:

- A reasonable interpretation and implementation of Rule 1606(B) would protect consumers from price volatility as well as, and at less risk than, the PPA;
- The alleged price advantage of the PPA is based on inappropriate comparisons and inherently unreliable forecasts; and
- PWEC market power is an argument for revoking PWEC's market-based rate authority and breaking up PWEC, not for a 13-28 year contract.

Q. Please explain why a reasonable interpretation and implementation of Rule 1606(B) would protect APS' SOS customers from price volatility as well as, and at less risk than, the proposed PPA.

A. Any reasonable interpretation and implementation of Rule 1606(B) would result in APS holding a portfolio of contracts that would protect APS' SOS customers almost entirely from short run – i.e., day-to-day and month-to-month – price volatility and would significantly dampen year-to-year and even longer-term variations. For example, my suggestion that APS cover essentially its entire SOS load with a portfolio of five-year, market-priced contracts, with 20 percent of these contracts expiring and being renewed in the market each year, would accomplish this.

If the PPA insulates SOS consumers from the market more than a portfolio of market-priced, medium-term contracts would do, it is going too far. Trying to insulate consumers totally from market prices necessarily creates large risks and inefficiencies, because market prices will almost surely diverge from the contract prices over time. If average PPA costs turn out higher than market prices, the death spiral effect may emerge if retail competition becomes effective or retail competition may be blocked in order to prevent this. If PPA costs turn out below market prices, efficient energy conservation and competitive retailing will be discouraged and consumers will experience serious price-shock when the PPA expires. Even consumers taking SOS should be exposed to market prices to some extent, because it is undesirably and ultimately impossible to protect them entirely and forever from market realities.

Q. Please explain why APS witness Jack Davis' comparison of PPA costs to long-run marginal cost is inappropriate.

A. Mr. Davis says that the PPA would save APS over $1 billion by 2007, on the assumption that market prices equal the long-run marginal cost (LRMC) of a new gas-fired combined cycle plant, which he estimates to be between $52/MWh and $60/MWh. [Direct Testimony of Jack E. Davis, p. 24] But he also says on the same page that, "as this testimony is being written, we are seeing the impact of today's lower market prices for power in the form of cancelled or delayed power plant projects," which implies that market prices are now significantly below LRMC and must be expected by project developers to remain below LRMC for at least several years. Thus, Mr. Davis' comparison of PPA prices to LRMC over the next five years is irrelevant, and his estimate of cumulative savings over that period is at best misleading. Even if he is correct about the relationship between the PPA costs and LRMC, and even if these do not change over the contract term, the most he can say is that *someday* the PPA may start providing positive benefits to SOS customers.

Q. Please explain why APS witness William Hieronymus' comparison of average PPA costs to the prices of long-term contracts in California is inappropriate.

A. Dr. Hieronymus compares the estimated average costs of the PPA to the prices in long-term contracts signed by the Department of Water Resources (DWR) in California in late 2001, and concludes that the DWR contracts are significantly more expensive than the PPA after correcting for estimated differences in fuel costs, transmission costs, etc., between California and Arizona. He acknowledges that the wholesale electricity market in California was extremely tight and chaotic prior to the summer of 2001, that "some critics" regard the DWR contracts as overpriced because of generator market power, and that short-term electricity contracts signed even later in 2001 were "not economic" for the buyers, but says that the later, longer-term DWR contracts are comparable to the PPA.

It seems obvious to me that market conditions and perceptions in California even in late 2001 were still heavily influenced by the turmoil, shortages, political pressure and extremely high prices that were then only a few months in the past. Prices in contracts negotiated by a government agency during this period in California should not be regarded as good estimates of the prices APS could get in a well-managed negotiation and competitive bidding process in 2003. In any case, it is neither wise nor necessary to guess about such things; the only reliable way to determine what the market can do is to try it.

Q. Please comment on the argument that natural gas prices are likely to be more volatile and to increase more than the costs of coal and nuclear fuels.

A. Short-term or spot natural gas prices are inherently more volatile than coal and nuclear fuel costs but – as recent market developments demonstrate – go down as well as up, and can easily be hedged at some cost. Projections that long-run gas prices must start going up soon because there is only so much gas in the world have been made for decades, but somehow the "temporary gas bubble" refuses to burst or even to deflate for long. Nobody should bet too much on anybody's projection of future gas prices.

A more fundamental response to this argument is that, like most of the others made by APS and its witnesses, it is irrelevant to the relative merits of the PPA and a reasonable interpretation of Rule 1606(B). Rule 1606(B) does not require that APS scrap its coal and nuclear plants and bet its future or its customers' welfare on stable or low gas prices, but only that APS use arms-length negotiations and competitive bidding to determine whether and the extent to which unaffiliated generators might be cost-effective alternatives to some APS affiliates in providing what APS needs to serve its SOS load. If APS wants supply contracts with price terms comparable to what it can get from PWEC coal and nuclear plants, it should ask for these and see what the market can produce.

Q. Do you think the uncertainties about the economics of the PPA relative to implementation of Rule 1606(B) can or should be resolved by debates among experts, or by some other means?

The only reliable way to determine the extent to which generators unaffiliated with APS can meet APS' needs more cost-effectively than affiliated generators is to implement the kind of prudent, contestable process the Commission had in mind with Rule 1606(B). If APS defines the mix of fixed and variable energy cost resources it wants to serve its SOS customers and then implements arms-length negotiation and competitive bidding processes to get that mix, gas-fired generators will factor the cost of any needed hedges into their offers and compete with PWEC's coal and nuclear plants. The PWEC plants that can provide what APS needs in the most cost-effective way will win the competition and get contracts. But some non-PWEC plants – plants that would be excluded from the game under the PPA – might also win APS contracts in a fair competition. This latter possibility may be just what APS and its affiliates fear, but is what the Commission and APS' SOS customers should be encouraging.

Q. Please explain why ineffective competition within the APS market region would suggest denying or revoking PWEC's market rate authority and moving to break up PWEC rather than approving the PPA.

A. APS witness Hieronymus says "it is far from certain that the competition to serve the approximately 3,000 MW of APS load beginning in January 2003 would lead to reasonable prices" because there will then be only three non-PWEC generating units with a total of less than 1,500 MW uncontracted capacity in the APS market region. [Direct Testimony of William H. Hieronymus, p. 3] He acknowledges that PWEC itself could bid to supply part of the APS load, but says it "would do so with the knowledge that it faced limited competition and that some of its capacity likely would be needed." [Direct Testimony of William H. Hieronymus, p. 3]

Dr. Hieronymus is saying, in effect, that APS' generation affiliate PWEC has and will exercise substantial market power in a competitive bidding process to serve half of APS' 2003 SOS load. In fact, the implication of Dr. Hieronymus' position is that PWEC would have and would presumably exercise market power in any negotiation with APS to serve the other half of APS' SOS load. I do not know whether Dr. Hieronymus is correct about this or not, but if he is there would appear (to this non-lawyer) to be serious implications for this proceeding and beyond. The most obvious implication is that the PWEC units in the APS market should not have market-based rate authority, but instead should remain under cost-of-service regulation until its market power is significantly reduced, which would presumably require PWEC to spin off some of its units to competitive generating companies.

Q. Are you aware that FERC has granted market-based rate authority to PWEC, and what are the implications of this?

A. Yes, I know that FERC, in September, 2000, approved market-based rate authority for PWEC, pursuant to its policy of granting such authority to a power seller "if the seller and its affiliates do not have, or have adequately mitigated, market power in generation and transmission and cannot erect other barriers to entry." [92 F.E.R.C. P61,248] I have not reviewed the factual basis for this FERC decision or the current factual situation, and I would not presume to judge the legal issues here. But as an economist it certainly seems to me that either:

- PWEC and its affiliates (still) do not have or have adequately mitigated market power, in which case there is no reason that APS should not be able to get "reasonable" prices in a competitive solicitation for its SOS needs; or
- PWEC and its affiliates (now) have so much market power that they should not have market-based rate authority, and should not be allowed to negotiate a "market" PPA among themselves.

Q. If Dr. Hieronymus is correct that PWEC has significant market power within the APS market region, what are the implications for the Rule 1606(B) process?

A. If PWEC has as much market power as Dr. Hieronumus suggests, the wholesale market in the region cannot be competitive until PWEC spins off enough of its capacity within the region to create a competitive structure – or until enough new generation enters, which would probably take longer. If the Commission is still committed to creating wholesale competition – or retail competition, which is not possible without wholesale competition – it should do what it can to induce PWEC to spin off generation capacity and, in the meantime, should do what it can to encourage non-PWEC generation in the region. This argues for moving ahead aggressively to implement Rule 1606(B) rather than approving the PPA proposed by APS. Indeed, approving that 12-28 year, full-requirement, cost-plus-guaranteed-profit PPA between PPA and its affiliates would make it more difficult to restructure PWEC and would discourage new entrants, delaying by many years the date when wholesale (and then retail) competition could become effective.

4.4 THE ALLEGED "NON-EFFECTS" OF THE PPA ON COMPETITION

Q. Is there a theoretical basis for the assertion by APS and its witnesses that long-term contracts will not affect market competition, and if so what is its applicability to this situation?

A. The claim that long-term contracts will not affect outcomes in short-term markets has its theoretical basis in the principle that a (well-designed) contract does nothing except create property rights that are perfect substitutes for and just as tradable as the underlying assets, and hence in a perfect market in a perfect world the existence of a long-term contract would have no effect on the physical outcomes or the prices in short-term markets. For example, if APS contracts (through PWCC) to buy Energy Products from PWEC, PWEC should be willing to buy those Energy Products in the spot market from anybody else who can produce them more cheaply than PWEC itself can. If there is some advantage to trading under a contract rather than trading only in the spot market and somebody other than PWEC could satisfy the contract more cheaply than PWEC can, PWEC should be willing to sell the contract to or write a back-to-back contract with the more efficient producer. If PWEC had no commercial, institutional or political reason not to let other, more efficient generators produce the services PWEC was contracted to deliver under the PPA, and if it were cheap, easy and riskless to do the deals necessary to let this happen, the long-term PPA between APS and PWEC would affect the distribution of money but would not affect who produces what or at what price in the short run markets.

Q. Why does this simple theory of contracting not apply well to real electricity markets?

A. No market is "perfect" in the strict sense of that term, but electricity markets are more complex and imperfect than most, particularly where, as in Arizona, there is not (yet) an efficient spot market integrated with system operations. If PWEC has a contract to deliver Energy Products to APS, PWEC cannot easily identify and do a deal with other generators who can provide the Energy Products more cheaply at any time, and cannot easily sell the contract to or write a back-to-back contract with another generator that is better situated to perform the contract. Even if PWEC could easily buy the services it needs to meet its contract, it has commercial, institutional and political reasons to avoid doing so; for example, it will not want to make life easier for its competitors, pass up a chance to favor its affiliates, or explain to regulators why other generators are producing the products when PWEC is collecting fully fixed-costs-plus-guaranteed-profit under the PPA.

Such practical, commercial and political realities mean that, once PWEC has a long-term PPA with APS, PWEC will perform the contract itself even if others could provide some services more cheaply. If some other generator has large enough advantages over PWEC to overcome the high search, negotiation and contracting costs, and to offset the commercial and political risks of giving business to competitors or inviting criticism of the PPA arrangements, PWEC might do some subcontracting and spot buying. But the existence of the exclusive, long-term contract makes it very difficult for other generators to compete for spot or shorter-term contract sales even if they are significantly more efficient than PWEC; unlike in the simple theory, the initial long-term contracts have a strong effect on who actually produces the product and on prices in the shorter-term markets.

Q. Given that high transaction costs are a reality, how can these inefficiencies of long-term contracting be reduced?

A. The ultimate solution is to create efficient short-term and spot markets, so that the party with the long-term contract can easily buy physical services from others and so that parties without contracts can easily sell physical services when they really are the low-cost supplier. But until such efficient short-term markets exist, the only way to reduce the efficiency and competitive obstacles created by long-term contracts is to diversify and open the competition for the contracts themselves. Instead of long-term, full-requirement, cost-based contracts with a single seller, buyers should enter into multiple, shorter-term contracts with different entities. The lack of an efficient spot market will mean that operations will be inefficient to some extent no matter who wins these contracts, but if there is an open competition for the contracts themselves the generators who can perform the contracts with the least inefficiency will presumably win in the short run, and the prospect of getting such contracts in the future will encourage others to get into and stay in the game.

Q. What role does the APS (or PWCC) economic dispatch process play in the kind of contract market you are describing?

A. A well-designed economic dispatch process is a form of spot market that can reduce the operational inefficiencies that are otherwise created by long-term contracts. If APS were to contract with PWCC – or, better, an ISO unaffiliated with any generators – to operate its economic dispatch process on a market basis, all generators could have equal access to that dispatch process and its payments, thereby maintaining short-term operational efficiency as well as reliability. Short of creating a market-based ISO, APS could contract with PWCC on a full-requirements basis but then PWCC could contract with and dispatch both affiliated and unaffiliated generation on a nondiscriminatory basis. There would be no reason for PWCC to contract to pay all of PWEC's costs plus a guaranteed profit on all of PWEC's old and new capacity for 13 to 28 years.

Q. Does the PPA affect competition only in the short-run dispatch, or does it have long-run effects on competition as well?

A. The PPA's long-run effects on competition will ultimately be more important than its short-run effects. If APS buys exclusively from PWEC/PWCC under the long-term PPA, other generators will have trouble competing in the short run markets for the reasons outlined above, and hence will sell less product at lower prices than they would in the absence of the PPA. Obviously, this will mean that fewer existing unaffiliated generators will be able to stay open and fewer new unaffiliated generators will be built while the PPA is in effect. Meanwhile, PWEC/PWCC will have a strong cash-flow from the PPA and hence will be in a good position to invest in new capacity. Then, when PWCC goes into the market to buy Supplemental or Replacement Energy Products, it will "discover" that its affiliate PWEC is in the best position to supply these. And when the PPA is eventually terminated, PWEC will have more capacity, including more new capacity, in the region than it would have had in the absence of the PPA. Not only will competition be chilled while the PPA is in effect, but in the long run competition will be distorted in favor of PWEC.

Q. How can the PPA affect competition if, as APS says, there are no realistic alternatives to most of the PWEC generation units, which were designed and located specifically to serve APS load?

A. I can neither confirm nor refute the APS claim that there are no realistic alternatives to most of the PWEC generation units, although it seems logical that many of the PWEC assets have locational and operational advantages in serving APS load and hence would "win" in any fair competition to serve that load. But I doubt that ***all*** of the Dedicated Units specified in the PPA would win such a competition even in the short run, much less over the entire 13-to-28 year term of the PPA. The only reliable way to determine when it is cost-effective to displace any of the PWEC Dedicated Units and with what is to keep continual competitive pressure on all of those units, not to ask PWEC's parent PWCC to decide when to discard some of her children in favor of the neighbors' brats.

More fundamentally, competition in a market does not determine only which units supply the physical product in the short run; it also determines the prices and other terms in short-term transactions and creates incentives for all prospective players to operate and invest more efficiently in the long run. Even if a fair competition to serve APS' SOS load resulted in all of the PWEC Dedicated Units "winning" in the short run, the winning prices and other terms of the deal, such as who bears what technical and economic risks, would almost surely be different from those in the PPA.

More importantly, all actual and prospective generators in the region would begin planning for future competitions, knowing that they have a shot at winning future contracts if, but only if, they are able to offer better terms than their competitors. Using a competitive process to determine who supplies what and at what prices might not change physical operations much in the short run, but would immediately change prices and long-run incentives for all generators – including PWEC.

Q. Why would competition to provide Supplemental and Replacement Energy Products to PWCC, and the Competitive Bidding Process, not be enough to allow wholesale competition to develop?

A. Competition for short-term, marginal sales may be better than no competition at all, but it is not at all the same as competition for longer-term, large volume contracts. In fact, given the difficulty other generators will have competing once PWEC has a long-term contract for its entire existing capacity, PWEC may end up getting much of the marginal business and building or buying from others much of the capacity needed to meet growth over the contract term – particularly given that its parent PWCC will be the most significant buyer in the region. Throwing some crumbs to competitors is not the same as creating real competition.

Q. APS emphasizes that it is not asking the Commission to slow retail competition, and says that competitive generators can supply the competitive retail market. What is your reaction to these statements?

A. It is easy – perhaps even cynical – for APS to endorse retail competition and tell their competitors to sell directly to consumers or to competitive retailers, because APS must know that retail competition will not be effective until there is an efficient and liquid wholesale market in the APS region, and this will not happen while the PPA is in force. In fact, APS must not be expecting retail competition to amount to anything over the term of the PPA, or else they would not confidently be predicting that their SOS load will continue growing at about the same rate as electricity demand generally. If APS thought they might lose any significant SOS load by 2008 or 2012, they would be more worried than they seem to be about how to avoid the death spiral effect I described earlier in this testimony.

Q. Is APS correct that the PPA cannot have a significant effect on competition because APS' load and PWEC generation are small parts of regional totals?

A. Again, APS is being inconsistent here, arguing first that transmission constraints make it impossible or difficult for many or most nonaffiliated generators to serve APS load, and then comparing APS load and PWEC generation to regional totals as though there were no transmission constraints. As a general matter, electricity markets are effectively limited by transmission constraints, and APS and its witnesses themselves say that APS load and PWEC generation are large parts of the totals in the relevant transmission-constrained markets. The PPA will strongly affect competition in these markets even if the total quantities are small compared to the total WSCC.

Fundamentally, every utility and every generation company is small compared to some regional, national or international market. If enough submarkets are carved off from the rest and made noncompetitive, on the grounds that each one is only a small part of some larger total, there will soon be little effective competition anywhere. If there were good reasons to approve APS' request for a variance and PPA, there would be good reasons to approve similar retreats from competition almost everywhere. But competition in electricity is in the public and consumer interests generally, and hence it is desirable in the APS market – eve if APS is small compared to some global totals.

Q. Does it matter that much or most of the independent generation in Arizona has been or is being built to serve other markets?

A. Not much. All markets are interrelated, so a reduction in demand for independent generation to serve APS will affect all generation to some extent. Generation that was built to serve, say, California and cannot serve APS because of transmission constraints will not win any APS contracts in a well-designed competitive process. But generation that was built primarily to serve California but can serve APS should have an opportunity to compete fairly with APS affiliates to do so.

5. AN ALTERNATIVE APPROACH

Q. What is your recommendation to the Commission with regard to the APS requested variance and proposed PPA?

A. The Commission should not approve the variance to Rule 1606(B) and should certainly not approve the PPA in its present form. Rule 1606(B) should be modified or – more accurately – clarified to make it explicit that it is not the bogeyman APS makes it out to be, but is only a requirement that Arizona utilities begin buying their SOS supplies in arms-length negotiations and competitive bidding process in which unaffiliated generators have an opportunity to compete with APS' affiliates to supply some the SOS load.

Q. Can you outline the kind of clarification to Rule 1606(B) you would recommend to the Commission?

A. The details of any modified Rule 1606(B) must, of course, be determined by the Commission through its procedures, but the following illustrates of the kind of process I have in mind:

- APS (and other Arizona utilities) should define the characteristics of the contract portfolio needed to meet SOS loads reliably, including the desired mix of short-term and long-term (e.g., one-to-five year) contracts, energy price terms (i.e., fixed, gas-indexed, etc.), firm and interruptible transmission capability, etc.;
- As soon thereafter as practical, APS should: (1) conduct an open competitive process in which PWEC and non-affiliated generators compete to supply 50 percent[5] of the APS-defined portfolio; and (2) negotiate arms-length, market-

[5] As discussed above, some PWEC units may have so much market power that they must be kept under cost-of-service regulation or cost-based contracts until the structure of the generation sector becomes more competitive. Any such regulated/contracted PWEC generation should be considered part of the "negotiated" half of the APS portfolio, and the contracts should be short-term – e.g., two years – so that competition to replace them can occur as soon as the market structure becomes competitive enough.

priced contracts with PWEC or other generators for any SOS load not contracted in the competitive process or supplied by still-regulated generators;

- The initial contracts should be divided into tranches of one year, two year, three year, four year and five-year contracts, with approximately 20 percent of SOS energy covered by contracts in each tranche
- Each year after 2003, APS should conduct a competitive process and/or arms length negotiations to replace with new five-year contracts the 20 percent of contracts expiring in that year, plus or minus any changes in SOS load; and
- The Commission should, to the extent its procedures allow, commit to approving SOS rates that will allow APS to recover each year the average costs of its SOS contract portfolio procured as outlined above.

A process such as the one described above will protect SOS customers from short-term price volatility, moderate any long-term price trends, adjust the size of the portfolio for any changes in SOS load due to retail competition, take advantage of well-located and low-cost PWEC units, allow some efficient competitors to get into the market in the short run and put all generators on notice that they have a shot at business in the long run if, but only if, they offer real value compared to competitors.

Q. Do you think it is realistic that APS could, by January 2003, design and implement the kind of arm's length negotiations and competitive process you describe?

A. Perhaps not now, given that APS' request for variance and the PPA has diverted so many APS and other resources from the implementation of Rule 1606(B). Even so, however, the PPA itself requires APS to use a competitive bidding process to buy 270 MW of Energy Products[6] beginning on January 1, 2003, demonstrating the feasibility of implementing a competitive process even at this late date. But even if it is now too late to implement Rule 1606(B) fully by 2003, the obvious solution is to

[6] The 270 MW is to provide Energy Products at a 51% load factor, meaning that it will provide 270 MW x 8,760 hours/year x 0.51 = 1,206,252 MWh/year of Energy Products.

modify the schedule to make it more realistic, not to scrap the whole concept of phasing in competition in favor of a long-term, full-requirements, full-cost-plus-guaranteed-profit PPA among affiliates.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE
ARIZONA CORPORATION COMMISSION

DOCKET NO. E-01345A-01-0822

**DIRECT TESTIMONY OF WILLIAM R. ENGELBRECHT
ON BEHALF OF
ARIZONA PUBLIC SERVICE COMPANY**

MARCH 29, 2002

TESTIMONY OF WILLIAM R. ENGELBRECHT
ON BEHALF OF
SEMPRA ENERGY RESOURCES

Q. Please state your name, business address, and title.

A. My name is William R. Engelbrecht, and my business address is 101 Ash Street, San Diego, California 92101. I am employed by Sempra Energy Resources (SER) and hold the position of Managing Director - Energy Supply. I am responsible for the marketing of the electric off-take from SER's generation portfolio and am also responsible for the fuel supply requirements of that portfolio. I am also responsible for managing power sales agreements and for hedging activities that SER engages in to manage its risk.

Q. What is the purpose of your testimony?

A. My testimony will address four primary areas relating to how APS' Request for Variance and proposed Power Purchase Agreement (PPA) would place additional burdens on APS customers by forcing upon those customers PWCC resources that have neither been properly chosen based on sound Resource Planning practices nor chosen based on a head-to-head competitive solicitation. The first area I will discuss are the principles of sound Resource Planning. The second area is SER's willingness to sell power to APS under competitive and attractive prices, terms and conditions. The third area is whether APS customers will likely pay more than necessary under the proposed PPA. The fourth area examines the depiction in Figure 5 on pages 24-25 of Mr. Davis' testimony.

Q. Would you please describe the principles of sound Resource Planning?

A. As APS/PWCC witness Mr. Davis discusses in his testimony, sound Resource Planning involves a prudent mix of types of energy products and services along with a sound mix of contract terms, lengths, and so forth. The risk to consumers, and when I speak of risk, I refer to price risk and volatility risk, is affected by a number of factors including the length of the contract, the size of the contract and the ability of the parties to perform their respective obligations.

APS/PWCC inexplicably failed to follow their own recipe in "negotiating" the PPA. Instead of structuring a procurement portfolio that provided price stability, reliable resources and sound risk management, APS/PWCC simply put all of their eggs into one basket and tried to present it as a balanced and reasonable solution to a problem that probably does not even exist. A contract with a single party for 100% of Standard Offer Service (SOS) requirements and a potential term of nearly thirty years is altogether unreasonable on its face. Since APS is wholly owned by PWCC, and since Mr. Davis is the head of both organizations, he in essence negotiated the PPA with himself – resulting in all of the counterparty risk being contained within a single entity. In this setting, there can be absolutely no business objectivity nor a healthy balancing of risks such as would be associated with an arms length transaction, and the PPA is structured in such a way that consumers eventually will pay for any risks that materialize. However, there is one positive aspect (unfortunately, not from the perspective of the APS customer) to this type of incestual relationship - there are likely to be very few disputes under the PPA.

Along with counterparty risk, the PPA exposes SOS customers to considerable price risk, as the price they will pay for power is locked in for a number of years without sufficient regard to the evolution of the competitive wholesale market. The PPA contemplates only the status quo and whatever generation APS/PWCC may construct (including the Red Hawk plant, which is nearly completed with no apparent locked-in market for its output) without regard to power plants currently approved and under construction. Exhibit 1 to my testimony shows that there is currently over 7,200 MW of new generation under construction and scheduled to be online in Arizona by the end of 2003, with a total of over 22,000 MW of new generation by the end of 2007.

Prudent Resource Planning would call for a layering of contracts in such a way as to take advantage of these added resources as they become available. In general, the resource planner would look at the load shape, the resources currently committed (whether through existing agreements, must-run or must-take status, etc.) and then look at the total capacity and energy of baseload, intermediate load and peaking capacity and ancillary services that would be required to meet that load, and develop an analysis of how to meet those needs at the lowest possible cost, lowest risk, greatest flexibility and greatest reliability of supply. Resources should be selected based on the lowest risk-adjusted cost to customers.

In a market where so much new supply is in development, there would likely be a great number of contracts executed for varying products and of varying duration. If the planning horizon indicated, for example, that 5,000 MW of new peaking capacity would be available in say, the next five years, then it would be prudent Resource Planning to create an opportunity to take advantage of that new supply, provided it is cost-competitive. The means to achieve that would be to structure the layers of contracts in such a way that some percentage of the power requirements based on projected load would be available for bidding during the period when the new supply was available. By "testing the market" in this way, the resource planner can mitigate price risk by taking advantage of abundant, and therefore cost-competitive, supply.

At the same time, price volatility is mitigated by having long-term contracts in place. Locking up virtually the entire market for an extended period of time almost guarantees that consumers will pay higher prices in the long run. It also provides disincentives for newer, less expensive, cleaner and more efficient generation to be built since there will be no local market available. A structured Resource Planning portfolio is layered with short-term, intermediate-term and long-term contracts to maximize the benefits to consumers by providing low prices and price stability.

Exhibit 1 focuses only on generation resources that are built within Arizona. In reality, there are thousands of MW of capacity available from resources outside of Arizona that should also be considered when doing Resource Planning. The existence of competition in this fashion helps ensure that supply and demand will equilibrate, that sound economics will be used in planning and siting generation resources, and that consumers will enjoy the full benefits of increased competition. In a fully competitive environment such as I have described, the generators assume the market risk that there will be an oversupply or that their plants are too old or inefficient to compete successfully. Under the PPA, APS/PWCC pass all of the risk onto consumers and are guaranteed recovery of all their costs plus a rate of return. For consumers, this is the worst possible outcome.

Another interrelated key attribute of any Resource Planning process worth its salt is the existence of a competitive solicitation of resources. Failure to pursue the opportunities that exist out in the competitive marketplace is analogous to burying one's head in the sand and pretending to be an ostrich. Given the potential self-dealing inherent in the proposed PPA, any such competitive solicitation looking out into the marketplace would necessarily need to be conducted and evaluated by a commission-assigned independent third party. This would be the only way to ensure that APS customers were receiving the most prudent and least expensive Resource Planning mix of resources.

Q. Is SER willing to sell power to APS under competitive and attractive prices, terms and conditions?

A. Yes, SER is both willing and able to sell short-term, intermediate-term or long-term power to APS under competitive and attractive prices, terms and conditions to help meet their resource requirements. In Arizona, specifically adjacent to (within 1,800 ft. of) the new Hassayampa Switchyard, our Mesquite Power gas-fired combined cycle project is under construction. Mesquite will have 625 MW of capacity come on-line by June 1, 2003, with another 625 MW by December 31, 2003. This creates a total of 1,250 MW of new SER generation in the "local[1]" area, the primary portion of the APS load. This new SER generation has the exact same interconnection point (i.e., Hassayampa 500-kV) as the PWCC Redhawk Project; therefore it is exactly just as accessible to APS customers as is Redhawk. The new combined cycle projects proposed by Duke, PG&E, and Gila Bend Power Partners, which will also connect directly to Hassayampa, fall into this same category. APS, for the sole use and benefit of its customers, has transmission capacity available today from the Palo Verde/Hassayampa common bus to its load centers, and will have additional capacity as its Southwest Valley 500-kV line addition (owned jointly with SRP) is placed in service by June 2003. That transmission capacity can be used by APS on behalf of its customers (who pay the annual revenue requirement of that

[1] In the greater Phoenix Region.

transmission capacity) in order to tap into a large quantity of competitive resource supply available at the Palo Verde/Hassayampa common bus hub. There is nothing unique about the PWCC Redhawk plant that makes it a more likely and more attractively priced candidate for APS customers versus other generating plants and resource opportunities in the area.

In addition to Mesquite, SER has in operation or under construction an additional 1,105 MW of combined cycle generation available in the Southwest that could provide APS additional power purchase potential from the SER generation portfolio, independent of the 1,250 MW that Mesquite brings to the market. That SER generation portfolio can also supply back-up to any APS purchase from Mesquite. The 2,355 MW SER portfolio alone could in theory provide the majority of the APS 3,000 MW SOS requirement. When the SER portfolio is combined with the many thousands of MW of additional capacity represented by other new Palo Verde area generators as well as other sources of power purchasing opportunities at the Palo Verde hub, there is far more capacity than necessary available to APS and its customers to form what any energy-coherent person would call a liquid, competitive marketplace.

To date, SER has no forward sales commitments from the Mesquite Power project. It is fully available to serve Arizona load. In fact, I stated in my ACC Siting Committee testimony for Mesquite that Mesquite's primary market region focus was Arizona. And, the ACC, in granting such License, added a requirement that at least a portion of Mesquite's power be made available for local purchase. SER has fulfilled that requirement by offering to sell power to PWCC, as discussed below.

In addition to the SER generation portfolio and the other generators physically interconnected at the Palo Verde/Hassayampa common bus, APS also has the ability to purchase other sources of power at the Palo Verde hub. The Palo Verde hub has been a major trading hub in the Western U.S. for some time. Physical and financial trades occur there daily. APS' claim that enough of a competitive market does not and WILL NOT exist as to have justified exploring the marketplace to "search" for the lowest cost power proposals for their customers is simply absurd.

It should be noted that SER has within the last year had discussions with PWCC representatives regarding a SER sale of power to PWCC and its various customers. PWCC was not only not interested in purchasing a share of its customer requirement from SER, but asked us whether we had interest in a power purchase from them.

Q. Will APS customers likely pay more than necessary under the proposed PPA?

A. Most definitely. The purpose of this area of my testimony is to demonstrate that the PPA between APS and its affiliate PWCC is self-serving and denies Arizona consumers access to the major benefit of wholesale electric competition, namely, low priced, reliable electricity. By negotiating this lopsided agreement with its affiliated generation company under terms that assure APS/PWCC a practically risk free lockup of the electricity market, APS/PWCC virtually assure consumers of higher prices over the long run than they would expect to pay in a fully competitive market with APS following prudent Resource Planning and acquisition strategies.

This specific PPA harms APS customers by not following prudent Resource Planning practices. In summary, the PPA is not a competitive solicitation and therefore will not result in the lowest possible cost to APS customers. It is much too large a block of power for a single counterparty (who for all intents and purposes is the same entity as the buyer) and a single deal. The PPA is for much too long a term (i.e., 13 years) – it locks in a big mistake for a long period of time. The PPA also prevents APS customers from receiving the price benefit of an oversupplied market.

The PPA calls for older, less efficient, higher polluting power plants to become "Dedicated Units," that are assured of recovering their variable costs, plus an energy price, plus a dedicated rate of return without regard to whether or not it makes economic sense for those units to be operated. In fact, the guaranteed recovery of expenses and return of capital offer a disincentive for APS to exercise prudent decision making in the dispatch of generation. Under a worst case scenario, when market prices are high, APS would have the best of all possible worlds – namely, the ability to sell its output from its generating plants into the market at market prices while continuing to earn a rate of return from its captive SOS customers, who will also reimburse APS for the higher power costs it incurs buying in the market. This is an unacceptable outcome that both harms consumers and squelches competition in the wholesale market. It enables APS/PWCC to reap the benefits normally accruing to an integrated monopoly while maintaining a façade of competition. In periods of oversupply when market prices are driven down and competition becomes difficult, APS/PWCC is more likely to survive because it has a guaranteed price for its power, along with a guaranteed return.

The PPA and Variance Request at the heart of this proceeding do not present a Resource Planning strategy that is beneficial to consumers by providing a reliable source of power at the lowest obtainable price. To the contrary, the benefits of this arrangement fall largely on PWCC, as discussed in the testimony of Dr. Ruff. In addition, many of the assumptions upon which the APS/PWCC's pleadings and testimony are based appear to be faulty, leading to incorrect conclusions and imprudent stewardship of available generation resources. For instance, fuel diversity is an issue raised in the testimony of Mr. Davis. That testimony emphasizes the fact that 40% of the Dedicated Units are either coal or nuclear fueled, providing some measure of protection from capacity shortages or price spikes in the short-term natural gas markets. While these assertions are true on the surface, the APS/PWCC position fails to acknowledge that both nuclear and coal units have extremely high fixed costs compared to gas-fired generators, and are less efficient, even though they do have lower variable costs. Therefore, coal and nuclear plants are only economical to operate when they are running at a capacity factor of at least 80-90%. Otherwise, the $/mmBtu values for coal versus natural gas depicted in Exhibit WHH-2 of the testimony of Dr. Hieronymus change drastically and the coal units, with higher fixed and environmental costs, cannot compete with newer, more efficient and less polluting gas units. Thus, the value alleged by APS/PWCC in having fuel diversity as a hedge against gas curtailments or price spikes during the summer peak is a myth. Coal and nuclear plants are not intended for use as peaking plants or to provide capacity or ancillary services – they are uneconomical to operate in that fashion. Instead, coal and nuclear plants are most suited to providing baseload power, which means that they will normally be operating year round at a high capacity factor and would largely be unavailable to provide additional power if the gas supply in the state became constrained.

Moreover, given the fact that coal and nuclear plants have lower variable costs and are also, as APS/PWCC point out, strategically placed in strategic locations where they are the generation most available to meet APS SOS load. Many of these units are also designated as Reliability Must Run units and/or provide their output on a "must-take" basis. Consequently, these units exercise considerable market power and have the ability to set the market price for power at a level significantly higher than what would be set by newer, cleaner and more efficient units but for the difference in location. All of these cost factors work in favor of APS/PWCC and against consumers, who ultimately pay the higher costs associated with this market power.

Q. In your opinion, is the comparison between the projected long run marginal costs of the new, gas-fired generating units under construction by merchant generators and the long run marginal cost of the "dedicated units" at pages 24-25 (Figure 5) of the testimony of Mr. Davis, a fair and accurate comparison?

A. Probably not. Mr. Davis does not indicate what any of the assumptions used by APS in calculating the \$52-\$60 per MWh in long run marginal costs (LRMC) ascribed to the merchant generation were, nor does he give an actual projected figure for the LRMC of the dedicated units. Absent those assumptions, it is difficult to assess the fairness and accuracy of the alleged savings depicted in Figure 5. I would observe, however, that merchant generators recover their capital costs through their power sales into the market, so that the price required for the power <u>includes</u> the recovery of capital investment. By contrast, APS is proposing to recover the capital costs of the dedicated units through a <u>separate charge</u> to APS customers including a 9.38% return that appears to have been left out of the comparison illustrated in Figure 5. Such an omission would be misleading because, if a merchant generator's power is not purchased, that merchant earns no return on its investment; by contrast, APS will earn a 9.38% return even if no power is purchased from the dedicated units. In fact, under the proposed PPA, APS would earn that return even if the dedicated units were not operating.

It is unclear from Mr. Davis' testimony (1) what, if any, assumptions were made regarding return on capital investment in the projected LRMC of the new merchant units, and (2) what figure Mr. Davis was using as the LRMC of the dedicated units. If one were to assume that, as it appears, Mr. Davis' "comparison" included both power prices and return on capital in the projected LRMC of the merchant units, and only power costs and no return on capital for the dedicated units, then the comparison is an unfair "apples to oranges" comparison. To make an apples-to-apples comparison, the LRMC of the merchant units, including a return on capital investment, would have to be compared to the rates paid by APS customers for both energy purchases and the 9.38% facilities charge over the period from 2002 to 2007. That comparison may differ dramatically from what is depicted in Figure 5.

Q. Does this conclude your testimony?

A. Yes.

ATTACHMENT 1

STATEMENT OF QUALIFICATIONS
WILLIAM R. ENGELBRECHT

STATEMENT OF QUALIFICATIONS
WILLIAM R. ENGELBRECHT

My name is William R. Engelbrecht, and my business address is 101 Ash Street, San Diego, California 92101. As Managing Director - Energy Supply, I am responsible for the marketing of the electric off-take from SER's generation portfolio and am also responsible for the fuel supply requirements of that portfolio. I also am responsible for managing power sales agreements and for hedging activities that SER engages in to manage its risk.

Previously, I was Director of Portfolio Asset Management for SER from 1998 to 2001. Prior to the merger between Enova Corporation and Pacific Enterprises that formed Sempra Energy, I worked for San Diego Gas & Electric Co., the principal subsidiary of Enova Energy, Inc., from 1981 to 1998. As a 17-year veteran of the utility industry, I previously held various engineering and leadership positions in the areas of Transmission Planning, Resource Planning, Strategic Planning and California Industry Restructuring.

I hold a bachelor's degree in Electrical Engineering, with a specialty in Power, from the University of Illinois, where I was also a member of Triangle Fraternity. During my career, I have spoken at a number of national conferences and have provided expert testimony numerous times on electricity-related matters before the California Energy Commission and the California Public Utilities Commission, as well as also testifying before the Connecticut Siting Council and the Arizona Commerce Commission.

As a member of the Institute of Electrical and Electronic Engineers, I am a registered Electrical Engineer in California. I have served in a number of leadership positions, including President, Vice-President and Treasurer, in my local alumni club - the Illini Club of San Diego County. I have also held alumni Board positions for my Fraternity.

EXHIBIT 1

ARIZONA PROPOSED POWER PLANTS

ARIZONA PROPOSED POWER PLANTS

STATUS	FACILITY	ESTIMATED ONLINE DATE	OUTPUT (MW)	# OF UNITS	TECHNOLOGY	FUEL TYPE
0	West Phoenix (Phase 1)	08/01/2001	120	1-1-1	Combined	Gas
	Desert Basin	06/01/2001	520	1-2-1	Combined	Gas
	Griffith Energy Project	07/01/2001	650	1-2-1	Combined	Gas
	South Point	06/01/2001	540	1-2-1	Combined	Gas
	Yearly Subtotal:		1,830			
	Status Total:		1,830			
1	Kyrene	06/01/2002	250	1-2-1	Combined	Gas
	West Phoenix (Phase 2)	09/01/2002	500	1-2-1	Combined	Gas
	Gila River 2	08/01/2002	520	1-2-1	Combined	Gas
	Arlington Valley 1	08/01/2002	580	1-2-1	Combined	Gas
	Sundance Energy Project # 1	06/01/2002	450	10	Comb Turb	Gas
	Redhawk 2	06/01/2002	530	1-2-1	Combined	Gas
	Redhawk 1	06/01/2002	530	1-2-1	Combined	Gas
	Gila River 1	06/01/2002	520	1-2-1	Combined	Gas
	Yearly Subtotal:		3,880			
	Harquahala	06/15/2003	1,040	3-1-1	Combined	Gas
	Gila River 4	01/01/2003	520	1-2-1	Combined	Gas
	Gila River 3	01/01/2003	520	1-2-1	Combined	Gas
	Mesquite Power Plant	03/01/2003	1,250	2-2-1	Combined	Gas
	Yearly Subtotal:		3,330			
	Status Total:		7,210			
2	Arlington Valley 2	06/30/2003	600	1-2-1	Combined	Gas
	Yearly Subtotal:		600			
	Bowie 1	06/30/2004	500	1-2-1	Combined	Gas
	Springerville Unit 4	06/01/2004	380	1	Fossil	Coal
	Gila Bend	06/01/2004	845	1-3-1	Combined	Gas
	Springerville Units # 3	06/01/2004	380	1	Fossil	Coal
	Yearly Subtotal:		2,105			

STATUS	FACILITY	ESTIMATED ONLINE DATE	OUTPUT (MW)	# OF UNITS	TECHNOLOGY	FUEL TYPE
	Bowie 2	12/31/2005	500	1-2-1	Combined	Gas
	Santan	12/01/2005	825	3-2-1	Combined	Gas
	Yearly Subtotal:		1,325			
	Redhawk 3	06/01/2006	530	1-2-1	Combined	Gas
	Sundance Energy Project # 2	06/12/2006	90	2	Comb Turb	Gas
	Yearly Subtotal:		620			
	Redhawk 4	12/01/2007	530	1-2-1	Combined	Gas
	Yearly Subtotal:		530			
	Status Total:		5,180			
3	Welton-Mohawk	06/01/2003	520	1-2-1	Combined	Gas
	Yearly Subtotal:		520			
	La Paz 1	10/30/2004	540	1-2-1	Combined	Gas
	Yearly Subtotal:		540			
	La Paz 2	03/30/2005	540	1-2-1	Combined	Gas
	Yearly Subtotal:		540			
	Status Total:		1,600			
4	Littlefield (Beaver Dam)	06/01/2003	520	1-2-1	Combined	Gas
	Yearly Subtotal:		520			
	Signal Peak (Desert Basin 2)	06/01/2004	580		Combined	Gas
	Yearly Subtotal:		580			
	Maestros Group Nogales Project	01/01/2007	500			Gas
	Winchester	06/01/2007	750	1-2-1	Combined	Gas
	White Tank Mountain	01/01/2007	1,250	5	Pump Storage	Hydro
	Yearly Subtotal:		2,500			
	Status Total:		3,600			
5	Big Sandy (Phase 1)	08/01/2002	500	1-2-1	Combined	Gas
	Yearly Subtotal:		500			

STATUS	FACILITY	ESTIMATED ONLINE DATE	OUTPUT (MW)	# OF UNITS	TECHNOLOGY	FUEL TYPE
	Toltec 1	09/30/2003	1,200	2-2-1	Combined	Gas
	Big Sandy (Phase II)	12/01/2003	220	1-1-1	Combined	Gas
	Yearly Subtotal:		1,420			
	Toltec 2	03/31/2005	600	1-2-1	Combined	Gas
	Yearly Subtotal:		600			
	Safford	01/01/2007	220			Gas
	Montezuma (520 MW)	01/01/2007	0		Combined	Gas
	Yearly Subtotal:		220			
	Status Total:		2,740			

Total for Arizona Proposed Power Plants: 22,160

Status Key:
0 - Commercial Operation
1 - Under Construction
2 - Regulatory Approval Received
3 - Application Under Review
4 – Announced
5 - Suspended or Denied Approval