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Docket Control
Arizona Corporation Commission
1200 W. Washington
Phoenix, Arizona 85007

RE: ARIZONA PUBLIC SERVICE COMPANY'S REBUTTAL TESTIMONY AND ASSOCIATED WORKPAPERS IN THE MATTER OF THE GENERIC PROCEEDING CONCERNING ELECTRIC RESTRUCTURING ISSUES.
DOCKET NO. E-00000A-02-0051, ET AL.

Dear Sir or Madam:

Pursuant to the Procedural Order dated October 9, 2002, Docket No. E-00000A-02-0051, et al., Arizona Public Service Company is hereby filing the rebuttal testimony of Mr. Steven W. Wheeler, Mr. Thomas Glock, Mr. Peter M. Ewen and Mr. Thomas J. Carlson .

Also attached are the associated workpapers.

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

Sincerely,

Jana Van Ness

Jana Van Ness
Manager
Regulatory Compliance

Attachment

JVN/vld

Cc: Docket Control (Original, plus 21 copies)
Service List

REBUTTAL TESTIMONY OF STEVEN M. WHEELER

On Behalf of Arizona Public Service Company

Docket No. E-00000A-02-0051, et al.

November 18, 2002

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REBUTTAL TESTIMONY OF STEVEN M. WHEELER
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-00000A-02-0051, et al.)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, ADDRESS AND OCCUPATION.

My name is Steven M. Wheeler. I am Senior Vice President, Regulation, System Planning and Operations for Arizona Public Service Company ("APS" or "Company").

Q. DID YOU FILE DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. My rebuttal testimony will respond to certain accusations by Panda/TECO witness Dr. Craig Roach concerning the Company's motives and past actions. I hope also to put the overall APS rebuttal case into some perspective. Finally, I address Reliant witness Curtis L. Kebler's comments regarding possible standards of affiliate conduct for the present Track B competitive solicitation, as well as certain of the recommendations of Residential Utility Consumer Office ("RUCO") witness Dr. Richard A. Rosen, Law and Water Fund ("LAW Fund") witness Dr. David Berry, and Wellton-Mohawk witness Robert W. Kendall.

II. SUMMARY

Q. WOULD YOU PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY?

APS is proud of its successful efforts to manage risk, control cost and reduce customers rates during perhaps the most difficult years in the electric utility industry since the late 1970s. And the Company does not apologize for any of the filings it has made with this Commission. Whether Dr. Roach's client agreed with them or not, APS has always tried to act in the interests of its customers and is doing so in this proceeding.

Second, although Mr. Carlson and Mr. Ewen will rebut specific criticisms of their pre-filed written testimony, I believe that once you get past the invective and the semantic debate over whether a particular need is more or less properly characterized as "reliability," "economy," "reliability must-run," etc., there are significant areas of agreement between APS and some of the merchant intervenors. We agree that APS should procure its needs for purchase power from the competitive market through a process that is reasonable and prudent.

Third, the specific recommendation of Reliant concerning standards of conduct for the upcoming Track B solicitation could, if interpreted literally, eliminate one of the largest of Reliant's (and the other merchant generators') competitors before the solicitation even started. I am, of course, speaking of Pinnacle West Capital Corporation ("Pinnacle West") and its Marketing and Trading division ("M&T"). This is hardly in the interests of APS and its consumers and is not needed to implement a reasonable, fair and open competitive power procurement in Track B.

Finally, although Dr. Rosen, Dr. Berry and Mr. Kendall's testimony on resource planning, demand-side management ("DSM") and the Environmental Portfolio Standard ("EPS") raise some important issues, I cannot support definitive Commission resolution of these matters in this Track B proceeding. There is simply insufficient time to properly consider and implement these proposals in a manner benefiting APS customers. Some aspects of their recommendations are better considered in separate proceedings already mandated by the Commission, or would be impacted by external events going on at the federal level, the outcome of which cannot be predicted at the present time.

III. PAST APS ACTIONS

Q. HAS APS "CONSISTENTLY MADE PROPOSALS THAT BENEFIT ITS SHAREHOLDERS AT THE EXPENSE OF ITS RATEPAYERS," AS ALLEGED BY DR. ROACH AT PAGE 7 OF HIS TESTIMONY?

A. Absolutely not. APS has provided its customers with rate decreases in 9 of the past 10 years, including the past 7 in a row. These decreases will amount to some 16% by next summer. APS has done so at a time when virtually every utility in the West, including those using the sort of structured procurement process being discussed in this proceeding, have been increasing rates, often significantly. APS and its affiliates have spent literally hundreds of millions of dollars just to keep the lights on in Phoenix and elsewhere in our service territory. APS has a proven track record of managing market volatility and risk that speaks loudest with results—lower costs to our customers.

APS also has benefited its Arizona customers by efficiently marketing the Company's surplus of generation to surrounding states during their time of need. It did so without bending, let alone breaking, the rules or compromising its long-held business ethics, as did so many others. And currently, APS is a leader in securing FERC approval of WestConnect, is a major player in this state's fight against El Paso Natural Gas, and is a partner with the Commission in attempting to modify FERC's Standard Market Design to reflect state and regional differences. APS has also been recently recognized by Innovest for its environmental leadership as one of the two most environmentally conscious electric utilities in the United States. All of these efforts were and are of significant value to our customers.

Q. WHAT ABOUT THE COMMISSION FILINGS REFERENCED IN DR. ROACH'S TESTIMONY?

A. None of those filings is relevant to Track B. Indeed, for all the claimed linkage between the Company's September 2002 financing application and Track B when they were seeking intervention in the former, no other merchant intervenor witness has even mentioned these other proceedings. In point of fact, APS believed, and continues to believe, that all three of the applications referenced in Dr. Roach's testimony <u>would have</u>, and in the case of the two matters still pending before the Commission, <u>will have</u> important benefits for our customers. And in each such instance, APS asked, and asks now, only an opportunity to make its case and have a decision from the Commission, which is the body APS has to convince.

IV. <u>OVERVIEW OF APS REBUTTAL CASE</u>

Q. WHY DO YOU BELIEVE APS IS IN FUNDAMENTAL AGREEMENT WITH MUCH OF WHAT THE MERCHANT INTERVENOR WITNESSES SAY?

With the exception of National Energy Group ("NEG") witness Thomas Broderick, we appear to agree that we should be determining the Company's unmet needs for Standard Offer retail customers. There are some important differences in how we calculate that need, but the fact that, for the most part, we are trying to determine the same need is encouraging. Second, APS agrees with Dr. Roach, Mr. Broderick and other merchant intervenor witnesses that the

Company should be attempting to acquire the least-cost mix of capacity and energy for its customers consistent with appropriate reliability and credit criteria. However, and as is to be expected between buyer and seller, there is significant disagreement as to what combination of products is best and which products should be acquired when, but at least we can agree on what we are trying to accomplish. Third, APS agrees with the merchant witnesses that ask for reasonable assurances to APS of full cost recovery for power contracts acquired through the Track B process. APS also supports the consensus positions, as reflected in the Staff Report, that the Environmental Portfolio Standard should be addressed in the 2003 proceeding set aside by Commission rule for its review, and that demand-side management ("DSM") should be incorporated into future procurements, but without a mandated set-aside.

V. OTHER SPECIFIC COMMENTS ON INTERVENOR TESTIMONY

Q. IN ADDITION TO DR. ROACH, ARE THERE OTHER INTERVENOR WITNESSES TO WHOM YOU WISH TO RESPOND?

A. Yes. Mr. Kebler suggests a specific and retroactive standard of affiliate knowledge and behavior that is both impractical and counterproductive to the interests of APS customers. Dr. Rosen has urged a return to traditional resource planning such as was briefly practiced in Arizona in the late 1980s and early 1990s. Dr. Berry proposes mandatory DSM procurements outside the Track B process, or at least outside the process used for power supply procurement, combined with a DSM "set aside" similar to that of the EPS. Mr. Kendall takes issue with what the Staff Report has characterized as a consensus position, i.e., that the EPS be addressed separately, although utilities remain free to seek EPS requirements in conjunction with the Track B procurement if they see fit to do so. While the issues raised by these latter three Intervenor witnesses are certainly important, I cannot support their resolution in this proceeding for a variety of practical and conceptual reasons.

Q. DOES APS OPPOSE STANDARDS OF CONDUCT FOR THE TRACK B PROCURMENT?

A. Not if the Commission believes them necessary. APS, and I specifically, posed no objections to the Staff's general recommendation for Standards of Conduct. But I noted in my direct testimony, APS cannot accept a Standard of Conduct that prevents the Company from effectively conducting the Track B solicitation in a manner that protects its customers. Nor can I support as being in the interests of our customers a Standard of Conduct that excludes automatically "out of the gate" a major potential bidder such as M&T. Taken literally, Mr. Kebler's recommended Standard of Conduct would do either or both of these things.

Mr. Kebler proposes a retroactive Standard of Conduct that requires APS to demonstrate that those APS employees (and Pinnacle West shared services employees) who have "worked on the [Track B] procurement, including its <u>development</u>, execution and review, did not have any improper contact with any utility affiliate that is participating in the competitive solicitation." (Testimony of Curtis L. Kebler at 14, emphasis added.) Mr. Kebler goes on to require that: "[M]embers of the [APS] procurement team should be required to certify that they have <u>no</u> knowledge of the <u>products</u> or offers of any affiliate participating in the competitive solicitation." (*Id.*) Aside from the lack of definition of "improper contact," which definition would be critical in implementing Mr. Kebler's suggestion, APS could not comply with either standard.

The simple facts are these:

- As a result of the 1999 APS Settlement and the Commission's Electric Competition Rules, M&T has performed power procurement, gas supply, scheduling, dispatch, financial and volume risk management and other contract management services required by APS.
- Until August 27, 2002, APS legitimately expected that both its generation and that of Pinnacle West Energy Corporation ("PWEC") would be owned by PWEC and jointly dispatched, operated, and used for APS customer needs, with any surplus marketed elsewhere in the region, also jointly, by M&T.
- APS began formulating its determination of unmet need and its procurement plan prior to August 27, 2002, which formulation of necessity involved M&T employees.
- After August 27, 2002, some M&T functions, specifically those involving APS procurement, began to be transferred back to APS.

APS cannot change history by somehow "undoing" their employees' relations with M&T. Nor could they "attest" they have "no knowledge" of the type of energy products M&T has and is capable of offering (any more than Reliant's energy traders could attest they have "no knowledge" of what M&T does, since Reliant routinely has conducted trades with M&T). What APS can do and is doing is to insulate its procurement team on a going-forward basis from those at M&T who would be involved in formulating or submitting any Track B bid. It will establish communications protocols concerning the solicitation as proposed by Staff and will not permit those personnel at M&T involved in bidding to have any role in substantive bid evaluation. In sum, we will do what we can without compromising the interests of our customers. But we should not be required to compromise those interests to satisfy every conceivable or speculative merchant "concern," nor can we agree to or promise the impossible.

Q. WHAT IS APS' POSITION ON INTEGRATED RESOURCE PLANNING?

A. I am supportive of the general concept of IRP, and in fact, it is part of my responsibilities at APS. However, the Commission's present integrated resource planning ("IRP") regulations were formulated in the late 1980s and, although only officially "suspended" in 1997, have not been actively utilized since the mid-1990s. Updating these rules to reflect today's electric market, with its myriad of new energy products (both physical and financial) and new players (IPPs, ESCOs, brokers, RTOs, etc.), and to accommodate the increasingly competitive nature of the type of information typically needed for a proper IRP, would require considerable time and effort. We also have the issues of retail access and federal wholesale market design that would need to be factored into any new state IRP process.

I might agree with Dr. Rosen that, <u>if</u> done properly and <u>if</u> reconcilable with continued retail competition and the new wholesale market design being hammered out on the federal level, this time and effort may be a worthwhile investment for both the Commission and utilities such as APS. But those are clearly some extremely important "ifs" that cannot be resolved in this proceeding. Moreover, there is simply no possible way of restarting such a cold and (as presently written) antiquated engine in time for a 2003 power solicitation.

Even doing so by 2004, as is suggested by Dr. Rosen, would appear ambitious to me. The last set of IRP regulations did not have to worry about either retail competition or federally-mandated regionalization of the planning process, and yet they still took many months to finalize and many more months for the necessary data to be gathered. Typical resource planning proceedings of the time were themselves over a year in length. At best, it would be mid-2004 before the results of Dr. Rosen's proposed IRP process could be implemented in any meaningful fashion.

Q. WHAT ABOUT DR. BERRY'S AND MR. KENDALL'S SUGGESTIONS ON DSM AND THE ESP?

A. I agree that DSM options are difficult to evaluate "head-to-head" with supply options for many of the same reasons as discussed by Dr. Berry. (See Testimony of Dr. David Berry at 4.) It was for that reason, plus the short time allowed under the Staff Report's timeline for bid evaluation, that APS proposed to exclude DSM resources from the first Track B procurement.

I further agree with Dr. Berry that developing a rational and effective DSM program will take time. (*Id.* at 5.) Moreover, since the Commission-directed redeployment of funds to the EPS, there is simply no existing funding source for DSM, nor a process in place for Staff evaluation and approval of DSM programs as existed during most of the 1990s.

Finally, Dr. Berry's "Environmental Risk Management" appears to be something that the Commission could, if it wished, address in any rejuvenated IRP process. I certainly would not support dealing with such an important issue on an *ad hoc* basis in this docket with this meager record.

As to Mr. Kendall's suggestion relative to the EPS, the Commission has already mandated a 2003 review of the entire EPS program. This would appear to be a perfect vehicle for vetting Mr. Kendall's concerns rather than asking the Commission to make a hasty decision in Track B based on the input of a single potential vendor of EPS products. As to the specific situation of Mr. Kendall's client, the Company has presently outstanding a renewables RFP, which RFP I am told remains open at the present time.

Q. ARE THERE OTHER REASONS WHY THE COMMISSION SHOULD DEFER ACTION ON THE RECOMMENDATIONS OF DR. BERRY, DR. ROSEN AND MR. KENDALL?

A. Yes. In Decision No. 65154, the Commission committed to a thorough review of all of the Electric Competition Rules. I can easily imagine that review impacting the practicality, necessity, or even the legality of some of these proposals. Overhanging any individual rule changes is the question of the long-term future of retail competition in this state.

Also, the federal government is considering a variety of initiatives that affect IRP and renewable energy, both central station and distributed. These include the SMD requirements for regional planning and resource adequacy requirements that may or may not consider DSM. There are the planning and transmission expansion roles envisioned for RTOs, such as WestConnect, and also federal legislation or proposed rulemakings on distributed generation, interconnection, and renewable energy requirements.

In short, there are too many unanswered questions regarding the nature, scope and even continued state role in resource planning to support deciding these and the related issues of DSM and EPS procurement at this time and in this proceeding.

VI. CONCLUSION

Q. DO YOU HAVE ANY CONCLUDING REMARKS?

A. Yes. To do its job of meeting customer demand reliably and at a reasonable price, APS must ask for what every buyer must have—the ability to determine what it needs, when it needs it, and what it is willing to pay—in other words, Mr. Carlson's ability to say "no" to proposals that hamstring the Company at our customers' expense.

Similarly, I urge the Commission to be cautious in adopting proposals that, although appearing to have some potential merit, have not been thoroughly addressed by Staff and the other parties, either during the Track B workshops or in their testimony. The "Law of Unintended Consequences" may not appear in any statute book, but it is well-founded in the human experience, as the still all too recent debacle in California reminds us.

Q. DOES THAT CONCLUDE YOUR PREFILED REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. Yes, it does.

REBUTTAL TESTIMONY OF THOMAS GLOCK

On Behalf of Arizona Public Service Company

Docket No. E-00000A-02-0051, et al.

November 18, 2002

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REBUTTAL TESTIMONY OF THOMAS GLOCK ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-00000A-02-0051, et al.)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, ADDRESS AND OCCUPATION.

A. My name is Thomas Glock. I am the Manager of Transmission Operations at Arizona Public Service Company ("APS" or "Company").

Q. PLEASE DESCRIBE YOUR PROFESSIONAL QUALIFICATIONS AND EXPERIENCE.

A. I have a Bachelor of Science degree from the University of Arizona. I began working for APS in 1983, and was an operator at the Yucca Power Plant in Yuma, Arizona until 1989. Subsequently, I have spent eleven years as a real-time generation dispatcher and/or managing the Company's Energy Control Center ("ECC"). From 1997 to 2000, I was the Chief Dispatcher and Transmission Section Leader for the ECC. I am a North American Electric Reliability Council ("NERC") and Western Systems Coordinating Council ("WSCC") Certified System Dispatcher. From 2000 until earlier this year, I was the Manager of Interconnections Development, and in that capacity was responsible for all interconnections to APS' transmission system.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. I will respond to the claims of some intervenors, including Mr. Thomas Broderick, Mr. Curtis L. Kebler and Mr. Robert W. Kendall that relate to Reliability Must Run ("RMR") issues and transmission import limitations in serving load-constrained areas such as the Valley and Yuma.

II. SUMMARY

Q. PLEASE PROVIDE A SUMMARY OF YOUR TESTIMONY.

A. Some of the merchant generator intervenors suggest that transmission deliverability and RMR should either be ignored or that the risk of any transmission limitations should be placed on APS rather than the seller. This is not the appropriate way to address RMR and deliverability. Instead, the RMR studies that were directed in the Track A order and discussed in the Biennial Transmission Assessment are the appropriate vehicles to quantify and resolve RMR issues.

Wellton-Mohawk goes further, and recommends that all load in the Valley and Yuma areas be contestable. This clearly exceeds the direction given in the Track A order and makes little sense given APS' existing transmission and rate-based generation resources. Wellton-Mohawk's criticisms of APS' resource planning for meeting load serving requirements in Yuma are likewise misplaced.

III. REBUTTAL TO NEG'S AND RELIANT'S RECOMMENDATIONS

Q. NEG'S WITNESS, MR. BRODERICK, RECOMMENDS ELIMINATING RMR FROM THE DETERMINATION OF UNMET NEEDS. DO YOU AGREE WITH HIS REASONING?

A. No. Mr. Broderick contends that there is "substantial uncertainty" about actual and future transmission import limits to serve APS customers. Apparently because of this uncertainty, he recommends that RMR and deliverability into transmission constrained areas such as the Valley simply be ignored in determining APS' unmet needs. This unfairly and inappropriately allocates <u>all risk</u>, including reliability risk, associated with present and future RMR requirements solely to APS. Under Mr. Broderick's logic, APS would have to buy power that it could not import into the Valley to serve its customers depending on present or future RMR conditions. NEG chose to locate their power plant outside the Valley where they could benefit from access to California and other markets through the Palo Verde hub, so it is inappropriate for them to now demand that APS ignore transmission deliverability issues into the Valley.

Q. DO YOU HAVE OTHER REBUTTAL COMMENTS ON MR. BRODERICK'S TESTIMONY?

A. Yes. Without providing any explanation, Mr. Broderick asserts that subjecting RMR to the main Track B procurement "can serve to demonstrate the validity of the calculated RMR." (Broderick Test. at p. 17.) As I discussed above, finding out that RMR is a real concern <u>after</u> the procurement is completed is hardly good policy or practice. However, APS has proposed that non-APS RMR requirements be separately bid in the procurement, which should provide the same "test" that Mr. Broderick appears to advocate.

Q. HOW WILL RMR REQUIREMENTS BE DETERMINED?

A. Consistent with both Decision No. 65154, the Track A order, and the current Staff Biennial Transmission Assessment, APS will complete an RMR study for both the Valley and Yuma by the end of January. The Valley study will be performed in conjunction with Salt River Project. These studies will determine and document RMR issues in APS' service area and will be completed prior to the competitive bidding commencing in 2003. There appeared to be consensus, or at least no opposition, at the Biennial Transmission Assessment workshops to using this approach for studying and quantifying RMR. Mr. Broderick's suggestion that the issue either be ignored, or be decided without benefit of the very study that Decision No. 65154 ordered, is certainly contrary to the ongoing work in the Biennial Transmission Assessment.

Q. MR. KEBLER OF RELIANT RESOURCES ALSO CRITICIZED DETERMINING RMR REQUIREMENTS IN THE RMR STUDY. ARE HIS CRITICISMS WARRANTED?

A. No. Throughout both the Track B workshops and in the Biennial Transmission Assessment, I believe it was understood that some details of the solicitation would be developed through January 31, 2003. Reliant was a participant in both proceedings. The RMR studies addressed in both the Track A order and the Biennial Transmission Assessment are simply not yet completed.

Further, the RMR figures are difficult to quantify in advance of the RMR study with the level of precision that Reliant demands. The actual import capability for any given hour, day, or year is dynamic, and thus the RMR requirements will vary based on final path ratings for new transmission lines and other system upgrades, anticipated generator loadings, the actual load and peak demand in the constrained area, and potential changes in system capability resulting from the loss of one electrical element, technically known as single contingency analyses, and the application of Western Electricity Coordinating Council ("WECC") operating requirements.

Q. DID STAFF WITNESS JERRY SMITH RAISE THE ISSUE OF CHANGES TO THE IMPORT LIMITATION AS WELL?

A. Yes. Mr. Smith commented at the final APS Track B Workshop that the figure provided for Valley Import Capability and which is used in APS' needs assessment could be increased in certain years to reflect planned transmission projects. These include the Southeast Valley Project in 2006 and Table Mesa in is served from remote generation imported over transmission lines. Local generating capacity is used when the import limits are exceeded, but APS' plants in Yuma meet or exceed all applicable environmental permitting requirements. Also, there is significant operational flexibility in meeting Yuma loads given the location of non-APS power plants in the area and the North Gila transmission line, which allows for energy purchases from the California markets. APS is also making transformer upgrades at substations in the area that will increase transmission import capability.

APS is not in the critical position that Wellton-Mohawk suggests, and I certainly do not think it is necessary for APS to pay any sort of "RMR premium" at this time. As was recognized in the Biennial Transmission Assessment, the as yet still proposed Wellton-Mohawk project is by no means the only option APS has to address future load serving capability at Yuma, and I would not want to foreclose those other options by committing now to a project that does not have either a Certificate of Environmental Compatibility or any financing, particularly given today's difficult credit environment. APS does, however, view the Wellton-Mohawk project as one of several possible future resources for meeting load serving obligations in Yuma.

Q. DOES THAT CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

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REBUTTAL TESTIMONY OF PETER M. EWEN

On Behalf of Arizona Public Service Company

Docket No. E-00000A-02-0051, et al.

November 18, 2002

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REBUTTAL TESTIMONY OF PETER M. EWEN ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-00000A-02-0051, et al.)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, ADDRESS AND OCCUPATION.

A. My name is Pete Ewen. I am the Manager of the Forecasts Department at Arizona Public Service Company ("APS" or "Company").

Q. DID YOU FILE DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. My rebuttal testimony will respond to certain assertions made in this proceeding by Panda/TECO witness Dr. Craig Roach and National Energy Group ("NEG") witness Mr. Thomas Broderick. Specifically, I will provide additional explanation of my calculation of unmet needs, address the accuracy of the October 2002 APS load forecast, and provide additional clarification regarding the determination and treatment of reliability must-run ("RMR") requirements, as well as reserve margin calculations.

II. SUMMARY

Q. WOULD YOU PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY?

A. As I explained in my direct testimony, I derived APS's unmet needs for capacity and energy from a comparison of APS's expected energy and peak demand requirements with the availability of APS resources to meet those needs. I calculated this amount by following the definition set out by the Commission in Track A and adopted in the October 25, 2002 Staff Report ("Staff Report").

See Decision No. 65154 (September 10, 2002); see also Staff Report at 4. In essence, this calculation simply affirms that APS's procurement of power from the wholesale market will be done under two separate processes – a formal solicitation process for our reliability needs and an economy energy procurement process. My rebuttal testimony further demonstrates both how accurate APS's forecasts have been and that the estimate of unmet needs provided and explained to the merchant Intervenors at the November 6 workshop is the appropriate estimate to use.

III. CALCULATION OF UNMET NEED

Q. WOULD YOU PLEASE SUMMARIZE AGAIN HOW YOU ESTIMATED APS'S UNMET ENERGY NEEDS?

A. Briefly, I derived APS's unmet needs for capacity and energy from a comparison of the expected energy and peak demand requirements over the next ten years with the availability of APS resources to meet those needs. The specific analysis is discussed in great detail in my direct testimony so I will not repeat those details here.

Q. DO YOU BELIEVE THAT YOU HAVE UNDERSTATED APS'S UNMET ENERGY NEEDS AS ASSERTED BY DR. ROACH AND MR. BRODERICK?

A. Not in the least. I calculated APS's unmet needs by following the definition set out by the Commission in Track A (see Decision No. 65154) and in the Staff Report. This prescribed methodology is an accurate depiction of APS's reliability needs.

Q. DO YOU BELIEVE THAT YOU MISUNDERSTOOD THE COMMISSION'S OR STAFF'S INTENT?

A. No, I do not. In Decision No. 65154, the Commission ordered APS to "acquire, at a minimum, any required power <u>that cannot be produced</u> from its own existing assets, through the competitive procurement process as developed in the Track B proceeding." (Decision No. 65154 at 23, 33, emphasis added.) Staff provided further guidance in the Staff Report when it explained:

> The Staff believes the solicitation in 2003 should be for the energy and capacity the utility <u>cannot supply from generation assets that are included in the utility's rate base, from contracts in effect, as of September 1, 2002, and from generation sources it must take as a result of law or regulation</u> (QF's and Environmental Portfolio sources). [Emphasis added.]

(Staff Report at 35, lines 4-8.) Not coincidentally, I believe Tucson Electric Power ("TEP") has used precisely the same method as I did for calculating its unmet needs and has not been criticized by <u>any</u> witness in these proceedings.

Q. WHAT ABOUT THE REFERENCE TO "AT A MINIMUM" IN THE DECISION?

A. The Commission explained that APS "may decide to retire or displace inefficient, uneconomic, environmentally undesirable plants," an action that might result in an increase in unmet needs. (Decision No. 65154, fn. 8 at 23.) APS has already accounted for such factors in its forecast. As a result, my direct testimony addressed our retirement plans and discussed economic displacement through a separate process. See Testimony of Peter M. Ewen at 18, 22.

Q. HOW WOULD YOU RESPOND TO DR. ROACH'S AND MR. BRODERICK'S ASSERTIONS THAT THEIR REVISED CALCULATIONS OF APS'S UNMET NEEDS BETTER COMPARE TO "STAFF'S CALCULATION"?

A. It is important to note that Staff did not prepare an independent calculation of APS's unmet needs. Instead, as noted in the Staff Report, Staff portrayed APS's unmet needs based on information provided by APS at a workshop in August. As I explained at the November 6 workshop, those numbers were merely "estimates" based on then available information and assumptions. They were never intended to be definitive forecasts that would precisely define or limit the power to be procured in a process that would start deliveries almost a year later.

Q. DO YOU BELIEVE THAT YOUR ESTIMATE OF UNMET NEEDS APPROPRIATELY ADDRESSES THE ECONOMIC VALUE OF APS'S EXISTING PLANTS?

A. Yes, I do. Contrary to the assertion by Mr. Broderick, this calculation of unmet needs does not at all "overstat[e] the economic level of output of its exiting [sic] units." (Testimony of Thomas Broderick at 3.) In fact, it does not even attempt to portray the economic value of the existing units. My direct testimony, in concert with Mr. Carlson's direct testimony, clearly distinguished the procurement of power from the wholesale market into two separate processes – a formal solicitation for our reliability needs (unmet capacity and energy needs as defined by the Staff report), and an economy energy procurement process that allows APS to make periodic smaller-scale purchases on an on-going basis to displace its own generation when it is economic to do so.

As Mr. Carlson describes in his rebuttal testimony, purchasing from the market in this manner is the best way to acquire sufficient quantities of economic energy without "moving the market" to the disadvantage of APS customers. Although this procurement strategy, which will be conducted in a fair, unbiased and equitable manner, may not result in the one time, large volume contracts that the merchant generators desire, it provides for the greatest amount of competition by not foreclosing the selective participation of other regional generators who may have excess capacity only at certain times of each year. Allowing APS to maximize its possible pool of suppliers at times of its choosing will be the most effective way of maintaining downward pressure on prices throughout the procurement process, thereby providing the greatest benefits to APS and its customers. Because the benefits of separating these two types of needs is so clear, I will focus the remainder of my rebuttal testimony on the issues relating to the accuracy of our load forecast and on the mischaracterizations of our unmet needs assessment.

IV. LOAD FORECAST ACCURACY

Q. HOW DID APS USE ITS MOST RECENT FORECAST OF DEMAND AND ENERGY TO DETERMINE ITS ASSESSMENT OF UNMET NEED?

A. As I explained in my direct testimony, I determined APS's unmet needs using our most recent forecast of demand and energy completed in October of this year. In calculating those unmet needs, I used methods that are consistent with the industry and that are similar to the methods documented in each of the Company's most recent IRP filings (in 1992 and 1995). Furthermore, the accuracy of these methods (particularly in the near-term) is very good, with an average error rate of less than two percent when projecting the next year's energy demand.

Q. GIVEN THEIR GENERALIZED CRITICISMS, DID EITHER DR. ROACH OR MR. BRODERICK CRITICIZE ANY SPECIFIC ELEMENT OF YOUR LOAD FORECASTING METHODOLOGY?

A. No.

Q. DID EITHER WITNESS PROPOSE <u>ANY</u> ALTERNATIVE ASSUMPTIONS OR METHODOLOGIES BE ADOPTED FOR THE RETAIL CUSTOMER LOAD FORECAST?

A. No.

Q. WOULD YOU RESPOND TO DR. ROACH'S ASSERTION THAT APS'S LOAD FORECAST REFLECTS A PERSISTENT UNDERESTIMATION OF PEAK LOAD?

A. Yes. I explained in great detail in my direct testimony the steps that APS applies in preparing its load forecast. As I indicated there, APS has every incentive to be as accurate as possible in its forecasting efforts. I also described some of the unique circumstances that led to faster than projected growth during the time in question. It also is clear that the merchant generators would prefer as high a forecast as possible, because a higher forecast naturally leads to a higher projected unmet need. As a practical matter, the forecasting process at APS is one that considers the range of possible outcomes in the future and selects the outcome that has the greatest probability of being right. Hindsight review may reveal that the projected value we selected was too low or too high for a period of time, but that does not help much in selecting the next expected case forecast. A flipped coin can turn up heads three or four times in a row, but the chances of the next flip being heads is still just 50/50. As a case in point, we have projected growth in Arizona population for the next two years to average 2.8%. We know, however, that depending on how the economy rebounds from this latest recession, we reasonably could see population growth anywhere between 2.4% and 3.2%. The amount of demand uncertainty related to this one variable alone is about 130 Mw. Obviously, other factors also will affect the actual growth in peak demand. While we all hope that economic growth will recover stronger than we have predicted, there is no guarantee that it will. If it does, though, one can not conclude that our current forecast is "poor."

Q. WOULD YOU PLEASE RESPOND TO DR. ROACH'S ALLEGATIONS THAT APS HAS ENGAGED IN UNSPECIFIED FORECASTING "GIMMICKS"?

A. It seems particularly notable that Dr. Roach reaches his "conclusion" based only on a reference to supposed prior underforecasting. Dr. Roach never identifies any such specific "gimmicks," nor can he, because none were used. Moreover, as I explain in more detail below, APS's forecasting has been remarkably accurate, particularly in the last few years.

Q. DOES AN EXAMINATION OF APS'S HISTORICAL FORECAST ACCURACY PRESENT A COMPLETE PICTURE JUSTIFYING THE ASSERTIONS BY DR. ROACH AND MR. BRODERICK THAT APS FORECASTS ARE UNREASONABLE?

A. No, it does not. Unfortunately, and based only on a superficial examination of our historical forecast accuracy, Dr. Roach and Mr. Broderick conclude that APS has conducted "poor forecasting." That is simply not true. A better way to assess how "good" a forecast was may be to compare that forecast against others trying to forecast the same thing. Put another way, the *ex post* identification of forecast "error" using the lens of perfect hindsight does not "prove" that the forecast was unreasonable when made.

Schedule PME-1R shows APS's forecasting performance as compared to other contemporaneous energy demand forecasts prepared by Western U.S. utilities for the Western Electric Coordinating Council's ("WECC's") 10-Year Coordinated Plan. The schedule presents average peak demand and energy forecast errors in recent years for APS side by side with the forecast errors of all utilities within each of the four regions of the WECC. It is notable that such a presentation should be statistically biased against APS because the aggregate forecast errors for a region will always be lower than the average of the forecast errors from the individual companies contributing to the forecast. That is, the accuracy of the aggregated forecasts benefits from some companies overforecasting and some companies underforecasting. The very best that the average of the individual forecasts can do is to match the aggregated forecast accuracy; the average of the individual forecasts can never do better than the aggregated forecast.

What can be observed from the schedule is that APS's forecast accuracy is remarkable when stacked up against other regional utilities. No single region has forecasted peak demand more accurately 1-year ahead or 2-years ahead than has APS since 1998. On a 3-year ahead basis, only one region achieved accuracy results even comparable to APS. The accuracy results for energy forecasts show that APS had more accurate forecasts than any region for 1-year ahead forecasts, was comparable to two regions and far better than the other two regions for 2-year ahead forecasts, and was vastly better than three of the four regions for 3-year ahead forecasts. Again, this comparison is naturally biased against APS.

Q. WHAT DO THE ABOVE COMPARISONS DEMONSTRATE?

A. It should be clear from the above comparisons that APS's load forecasts are strikingly accurate, particularly in the last few years, when compared to the industry. When you consider that accuracy in this situation (*i.e.,* where APS has every incentive for an accurate forecast while the merchant Intervenors' preference would be for as high a forecast as possible, regardless of support), APS's load forecasts are precisely the forecasts that should be relied upon for the procurement process.

Q. HOW DO YOU RESPOND TO MR. BRODERICK'S PROPOSED ADDITIONS OF NON-APS LOAD TO YOUR FORECAST?

A. I reject Mr. Broderick's adjustments to the forecast to add in non-APS load. He includes in the APS retail and wholesale standard offer load forecast amounts for wholesale customers who are no longer APS customers. For example, the largest of these customers, Citizens Telecommunications Corporation ("Citizens"), asked to cancel its agreement with APS and negotiated a new contract with Pinnacle West Marketing and Trading ("M&T") in June 2001, long before Track B was established. APS has no responsibility or obligation to meet this contract load with APS generation nor does M&T serve it using any APS resources.

Q. WOULD YOU EXPLAIN THEN WHY SUCH NON-APS LOAD IS INCLUDED IN CERTAIN PEAK DEMAND INFORMATION AND EXCLUDED FROM OTHER INFORMATION?

A. Yes. Mr. Broderick is correct that these M&T customers are included in the presentation of certain peak demand information and excluded from other information, and I can certainly see how that might be superficially confusing. In one case (the higher peak demand number), the presentation of peak demand represents the Company's <u>delivery</u> obligation, or the maximum demand that our transmission and distribution system was required to carry in that year. In the other case (the lower peak demand number), the presentation of peak demand represents the APS <u>generation</u> obligation, or the maximum demand that APS was required serve from its own generation resources. With respect to Citizens, M&T owns the generation obligation via the June 2001 contract. APS, of course, retains the delivery obligation because Citizens' load is in the APS control area. Although not the ideal way to do it, we provided these separate representations of peak demand in the discovery process only because in our historical data we do not have the weather-normalized system peak excluding Citizens and TOUA prior to 2001.

Q. WHAT ABOUT THE FOUR CONTRACTS THAT MR. BRODERICK ARGUES SHOULD BE TREATED AS PINNACLE WEST CONTRACTS?

A. Mr. Broderick's assertion is wrong. Schedule PME-2R attached to this testimony shows six contracts and the dates they were signed. One can see from the schedule that four contracts for the summer of 2003 were transacted between March 28, 2000 and March 30, 2000 by APS. The counterparties on these contracts were Williams, Morgan Stanley, Constellation and Enron. These purchases were made for the purpose of serving our retail customer load. The last two contracts in the schedule were both transacted on November 29, 2001. One is a sale from APS back to Enron to close out the purchase from Enron as a result of Enron's bankruptcy. The other contract, also entered into on November 29, 2001, was with Morgan Stanley and was the replacement contract for the closed out Enron position. APS's net purchase position did not change as a result of these last two transactions.

Notably, for each of those original four contracts, the purchaser was APS and not Pinnacle West as alleged by Mr. Broderick. (See Testimony of Thomas Broderick at 15.) Because these contracts were provided in discovery, it is difficult for me to understand why or how Mr. Broderick could possibly have concluded that these were Pinnacle West contracts that were somehow "assigned" to APS. (See Testimony of Thomas Broderick at 15.) There is no legitimate justification for removing these contracts from APS's pre-existing resources.

Q. ARE DR. ROACH'S AND MR. BRODERICK'S CRITICISMS OF OUR RMR CALCULATIONS VALID?

A. No. As one can see in Schedule PME-1 attached to my direct testimony, the amounts of capacity and energy for RMR service are quite small. Because they are so small and clearly could be met by <u>any</u> non-APS unit within metro-Phoenix, I find it difficult to comprehend Dr. Roach's position that these tiny amounts represent a shield for in-Valley Pinnacle West Energy Corporation ("PWEC") units. Nothing in my testimony or in Mr. Carlson's testimony could be construed as remotely suggesting such an attempt. I find the accusation even more remarkable in light of Mr. Carlson's direct testimony to the effect that APS will entertain any bids for such non-APS RMR service and could select a winning bidder other than PWEC if the price were more favorable and deliverability was assured. To restate my direct testimony, APS desires to keep the procurement of non-APS RMR service separate (but concurrent) because of the unique nature of the service required.

V. <u>NOVEMBER ESTIMATE OF UNMET NEEDS</u>

Q. WHAT WERE THE DIFFERENCES BETWEEN THE ESTIMATES OF UNMET NEEDS APS PROVIDED IN AUGUST AND THOSE PROVIDED AT THE NOVEMBER WORKSHOP?

A. At the November 6 workshop, I provided a handout to all of the participants, including Mr. Broderick and Dr. Roach, that explained and reconciled the differences between the calculation of estimated unmet needs provided in August and the calculation provided in November, and that handout is attached here as Schedule PME-3R. From the schedule, one can see that the APS estimate of unmet capacity need was lowered by 549 Mw in 2003, 655 Mw in

2004, and 904 Mw in 2005. One can also see that the estimate of unmet energy need was reduced by 5,095 gwh in 2003, 5,370 gwh in 2004 and 6,027 gwh in 2005.

Q. WHY DO YOU KEEP REFERRING TO THESE CALCULATIONS AS "ESTIMATES"?

A. Because they are. As I described in my direct testimony, they are based on a variety of critical forecast assumptions such as: the rate of economic growth; the relative intensity of electric usage; the rate of adoption of new electricity using devices; hotter or cooler weather; and power plant and transmission system performance. The actual unmet need can only be determined in real time and totaled after the fact. Thus, I caution everyone not to impart a degree of precision and finality to these estimates that is unrealistic.

Q. WOULD YOU PLEASE EXPLAIN THE ADJUSTMENTS MADE BETWEEN AUGUST AND NOVEMBER?

A. Yes. Several adjustments were included in the November estimates that make that estimate more accurate.

First, the load forecast was revised in late September (released in October), as it typically is, as a result of completing the summer and being able to assess the actual as compared to expected growth in peak demand. The new load forecast lowered the peak demand for 2003 by 212 Mw, but raised the energy forecast by 89 gwh. While the revisions to forecasted peak demand and energy amounts usually go in the same direction, in this instance they did not because the previous forecast had added too much demand for the amount of energy in the forecast. The result was a projected load factor that was far lower than what had historically been experienced. The October 2002 forecast corrected this anomaly. Schedule PME-4R shows the system load factors that resulted from each forecast and compares them with the historical experience. One can clearly see that the current forecast has an appropriately balanced peak demand and energy forecast.

The second adjustment relates to the portrayal of reserve margin. In my direct testimony, I described quite clearly how and why I calculated the reserve margin the way I did. Specifically, our historical practice has been to purchase firm capacity and energy products where the seller provides reserves, and this is a standard procurement practice across the industry. The two long-term contracts described in discovery – the SRP Territorial purchase and the Pacificorp diversity exchange – both are examples of firm purchases where the sellers (SRP and Pacificorp) provide the reserves. In contrast, the contingent portion of the SRP purchase is not firm, so APS does carry reserves for this portion of the contract.

Although Dr. Roach takes great exception to this method, it should be clear that his portrayal of a higher reserve requirement is only a matter of presentation that does <u>not</u> affect the calculation of unmet needs. That is, there is a total reserve margin associated with APS's load that must be provided, and the assignment of reserves to one party or another comes down to whether a purchase is firm or contingent. As Mr. Carlson describes in his testimony, a firm purchase (where the seller provides reserves) normally will be more valuable and command a higher price than a contingent purchase (where the buyer takes on the reserve risk). Traditionally, when APS has evaluated its capacity reliability needs, we have concluded that we must have firm capacity to cover our peak needs. This is precisely why Mr. Carlson included firm capacity as one of the products APS would be soliciting. While I believe it is slightly misleading to portray the APS unmet need as including <u>all</u> of the required reserves (because our reliability needs must be met with <u>firm</u> capacity) just to produce a higher number, it does not have <u>any</u> effect on the ultimate solicitation. Firm capacity offers naturally will be worth more than contingent offers, and the change in reserve margin presentation has absolutely <u>no</u> effect on the amount of energy APS needs for reliability purposes. In other words, I could accept Dr. Roach's method of <u>presenting</u> reserve requirements, but that would not increase the amount of our solicitation for firm power to meet our reliability needs.

Q. DID YOU TREAT RMR SERVICE DIFFERENTLY BETWEEN THE AUGUST AND NOVEMBER ESTIMATES OF UNMET NEEDS?

A. Yes. Another factor that contributed to the differences in unmet needs was the preliminary "placeholder" estimate of the amount of RMR service that may be required in the metro-Phoenix load pocket included in the estimate of unmet needs provided at the November workshop. That estimate was not available at the time the August estimate of unmet needs was prepared, and APS clearly indicated so at the time.

Q. WHAT ABOUT THE IMPACT OF ENERGY PRODUCED BY APS OWNED GENERATION ON THE ESTIMATES OF UNMET NEEDS?

A. Perhaps the single largest adjustment between the August and November estimates of unmet needs relates to the amount of energy produced by APS owned generation and firm purchases (or, conversely, the amount of unmet <u>energy</u> need). Although the appropriate recognition of the March 2000 contract purchases lowered the unmet energy need by 215 gwh, the remainder of the adjustment largely came from the exclusion of the PWEC units in the modeling process. Prior to the Commission's Track A order, APS had assumed that the new PWEC combined cycle units would be dedicated to native load and, as a result, all of the resource projections until that time dispatched those units alongside the APS units at marginal running costs rather than market value. As more efficient units, these new units understandably were dispatched ahead of the older gas-fired generation, leaving the older gas-fired generation with many hours where they were idle or running at lower capacity factors.

When the Commission defined how to calculate unmet needs in the Track A order, and Staff provided its further guidance in the Staff Report, the new PWEC units were appropriately excluded from the dispatch model and the system was redispatched. In the absence of these new units, the older gas-fired generation was forced to make up the slack, and the idle and low capacity factor hours evaporated. Note that <u>neither</u> the August nor November dispatch runs included economy energy. This explains why the economy energy figures shown on Schedule PME-13 of my direct testimony do not match the PWEC energy amounts provided in the August 2002 workshop handout. Once you introduce economy energy and remove the PWEC units, the PWEC energy from the August handout is replaced by a <u>combination</u> of both increased output from APS units and energy.

Q. DO YOU BELIEVE THAT THIS METHOD UNDERESTIMATES APS'S RELIABILITY NEEDS?

A. No. This method provides the current best estimate of APS's reliability needs. The estimates will continue to be refined, however, in future years, just as in past years. As explained in more detail in Mr. Carlson's testimony, APS will procure additional energy as it is economic to do so.

Q. WOULD YOU PLEASE SUMMARIZE THE DIFFERENCES BETWEEN THE AUGUST AND NOVEMBER ESTIMATES OF UNMET NEEDS?

A. Yes. To summarize the above discussion, the August estimate of unmet needs differed from my November presentation because it (i) was computed using a different methodology for dedicated merchant unit energy, (ii) omitted roughly 185 Mw and 215 gwh of legitimate preexisting purchase contracts, (iii) portrayed reserve margin differently, (iv) did not include the special conditions of metro Phoenix RMR service, and (v) used a load forecast that was subsequently updated. These adjustments are reflected in the estimate included in my direct testimony and provided at the November workshop and more accurately reflect APS's unmet needs for reliability purposes.

VI. <u>CONCLUSION</u>

Q. DO YOU HAVE ANY CONCLUDING REMARKS?

A. Yes. I have responded to the comments made by Dr. Roach and Mr. Broderick regarding the calculation of APS's unmet needs and the accuracy of our forecast. I have again explained the adjustments made to develop the more accurate calculation of unmet needs provided at the November 6 workshop. I also have attempted to make clear that APS has every incentive to prepare an accurate forecast and has a good track record in preparing those forecasts. The fact that I may not have addressed any specific witnesses' argument does not imply agreement with such argument.

Q. DOES THAT CONCLUDE YOUR PREFILED REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. Yes, it does.

Schedule PME-1R
Comparison of Recent Forecast Accuracy
APS vs. Other WECC Regions

	Mean Absolute Percent Error				
	APS	Northwest Power Pool Area	Rocky Mountain Power Area	Arizona, New Mexico, S. Nevada Power Area	California, Mexico Power Area
Summer Peak Demand					
1-Year Ahead					
1998 forecast for 1999	2.3%	16.8%	1.6%	0.4%	1.3%
1999 forecast for 2000	2.8%	16.5%	9.8%	3.7%	0.7%
2000 forecast for 2001	1.5%	9.3%	11.1%	3.4%	11.4%
Average	2.2%	14.2%	7.5%	2.5%	4.5%
2-Years Ahead					
1998 forecast for 2000	5.1%	14.3%	7.9%	6.9%	3.6%
1999 forecast for 2001	2.6%	7.5%	15.9%	8.1%	7.0%
Average	3.9%	10.9%	11.9%	7.5%	5.3%
3-Years Ahead					
1998 forecast for 2001	5.6%	5.4%	14.2%	11.9%	10.3%
Energy Load					
1-Year Ahead					
1998 forecast for 1999	0.2%	4.1%	5.7%	2.1%	1.1%
1999 forecast for 2000	5.9%	1.7%	7.7%	2.7%	1.5%
2000 forecast for 2001	0.1%	10.4%	7.5%	2.6%	5.9%
Average	2.1%	5.4%	7.0%	2.5%	2.8%
2-Years Ahead					
1998 forecast for 2000	3.2%	3.7%	2.4%	2.1%	5.3%
1999 forecast for 2001	5.6%	11.4%	10.6%	5.8%	2.8%
Average	4.4%	7.6%	6.5%	4.0%	4.1%
3-Years Ahead					
1998 forecast for 2001	3.5%	13.2%	5.8%	7.2%	1.9%

SCHEDULE PME-2R

APS CONTRACT NO. 59894

APS CONTRACT NO. 59895
APS CONTRACT NO. 59896

Williams Energy Marketing & Trading Company

Physical Confirmation

To: Arizona Public Service Company
Attn: Don Stoneberger
Date: March 31, 2000
Fax: (602) 250-2325
Ref.: 84236

Pursuant and subject to the terms and conditions of the Western Systems Power Pool Agreement, this confirms the following Transaction negotiated between Steve Culliton of Williams and Don Stoneberger of Arizona Public Service Company.

Transaction Date: March 30, 2000

Buyer: Arizona Public Service Company

Seller: Williams Energy Marketing & Trading Company

Product: Electricity Firm On-Peak Power Pacific Prevailing Time

Term	Quantity	Fixed price	Differential
July 1-31,2001	10,000 MWh's (25 MW's)	per MWh	N/A
August 1-31,2001	10,800 MWh's (25 MW's)	per MWh	N/A
September 1-30,2001	9,600 MWh's (25 MW's)	per MWh	N/A
July 1-31,2002	10,400 MWh's (25 MW's)	per MWh	N/A
August 1-31,2002	10,800 MWh's (25 MW's)	per MWh	N/A
September 1-30,2002	9,600 MWh's (25 MW's)	per MWh	N/A
July 1-31,2003	10,400 MWh's (25 MW's)	per MWh	N/A
August 1-31,2003	10,400 MWh's (25 MW's)	per MWh	N/A
September 1-30,2003	10,000 MWh's (25 MW's)	per MWh	N/A

Schedule:
Mon-Sat HE PPT 07:00 thru 22:00, excl holidays
Mon-Sat HE PPT 07:00 thru 22:00, excl holidays
Mon-Sat HE PPT 07:00 thru 22:00, excl holidays

Holiday Calendar: NERC

Contract Quantity: 92,000 MWh's

Delivery Point(s): Palo Verde Switchyard

Types of Service: Service Schedule C2 X

Performance Obligation: X FIRM ____ NON-FIRM

Special Provisions:

These specific terms and conditions together with the Western Systems Power Pool Agreement shall constitute the entirety of the agreement between Buyer and Seller unless Company furnishes to Williams notice of alleged errors by facsimile, other electronic transmission, or first class mail by the earlier of the fifth (5th) Business Day following the Business Day of receipt of this Confirmation from Williams or six (6) hours prior to the Period of Delivery, this Confirmation shall be conclusive evidence of the Transaction that is the subject matter thereof, and shall, along with the terms herein, be the final expression of all its terms, notwithstanding any failure of Company to execute such Confirmation.

WILLIAMS ENERGY MARKETING & TRADING COMPANY

By: Greg Hickl

Greg Hickl
Director of Power Trading

Prepared by: Angela Perry , Risk Control Management
Phone No: (918) 573-2000
Fax No: (918) 573-8233

Ref: 84236

ARIZONA PUBLIC SERVICE COMPANY

Signature: For David Hansen

Print Name: David A. Hansen

Title: Director, Bulk Power Marketing & Resource Operations

Date: 4.5.00

4/4/00

(b)(2)

MORGAN STANLEY CAPITAL GROUP INC.
1585 BROADWAY
NEW YORK, NEW YORK

Revised Confirmation
May 15, 2000

Arizona Public Service Company
Attn: Frank Moreno
Fax 602-250-3199

APS CONTRACT NO. 59890
59891
59892

MS Reference: e76373
Trade Date: March 30, 2000

This is to confirm Morgan Stanley Capital Group Inc.'s (MSCGI) sale of firm energy to Arizona Public Service Company (APS). This transaction has been concluded under the Western System Power Pool (WSPP) Master Agreement as revised February 1, 2000, and as may be amended from time to time. With additional terms as stated below:

Buyer:	APS
Seller	MSCG
Term:	July 1, 2001 through September 30, 2001 July 1, 2002 through September 30, 2002 July 1, 2003 through September 30, 2003
Delivery:	Monday through Saturday, Hours Ending 0700 through 2200 Pacific Prevailing Time (PPT), excluding NERC Holidays.
Quantity:	Fifty (50) MW of firm energy per hour.
Delivery Location:	Palo Verde
Energy Price:	$ per MWH
Scheduling:	All scheduling will be completed by the Business Day prior to the day of delivery.

Morgan Stanley Real-Time Communications and Scheduling:

212-761-8748 Office
212-761-0292 Fax

Please confirm that the terms stated herein accurately reflect the agreement reached between APS and MSCG by returning an executed copy of this Confirmation Letter. (Fax: 212-761-0292.)

Morgan Stanley Capital Group Inc.
Joseph F. Delaney, III
Principal

ARIZONA PUBLIC SERVICE COMPANY

Signature: for David Hansen DS

Print Name: David A. Hansen

Title: Director, Bulk Power Marketing & Resource Operations

Date: 5.23.00

5/19/00

FILE

APS CONTRACT NO. 59853, 59854, 59855

Constellation Power Source

111 Market Place • Suite 500 • Baltimore, Maryland 21202 • Fax 410-468-3540

FROM: CONSTELLATION POWER SOURCE
TO: ARIZONA PUBLIC SERVICE
ATTN: DON STONEBERGER
FAX: 16022503719
PH: 602-250-2809
CC: NATSOURCE, INC.
ATTN: FEIERSTEIN MITCH

Tue 28Mar00 06:55:38 pm

CONFIRMATION AGREEMENT

This will confirm the verbal agreement reached on 28 MARCH 2000 between ARIZONA PUBLIC SERVICE ("Counterparty") and Constellation Power Source, Inc. ("CPS") (each individually a "Party" and collectively the "Parties") regarding a power purchase and sale transaction (the "Agreement") on the following terms and conditions:

1. Commercial Terms. The "Commercial Terms" of this transaction are as follows:

REF:	ELS2JUP,ELS2JUQ,ELS2JUR
Trade Date :	28 MARCH 2000
Buyer:	ARIZONA PUBLIC SERVICE P.O. BOX 53999 PHOENIX, AZ 85072-3999 U.S.
Seller:	CONSTELLATION POWER SOURCE,INC. 111 MARKET PLACE SUITE 500 BALTIMORE, MARYLAND 21202
Delivery Point:	DELIVERED AT PALO VERDE
Type of Transaction:	Firm energy sale pursuant to Service Schedule C-2 to the Western Systems Power Pool Agreement as revised effective as of February 1, 2000 (the "WSPP Agreement").

Goldman Sachs Power L.L.C. is the exclusive advisor to Constellation Power Source.

Delivery Period:	July 1, 2001 - September 30, 2001 July 1, 2002 - September 30, 2002 July 1, 2003 - September 30, 2003
Hourly Quantity:	25 MWH
Daily Quantity:	400 MWH per business day
Total Quantity:	92,000 MWH for the delivery period
Price :	USD PER MEGAWATT HOUR
Other Terms :	6X16 (HE 07:00 TO HE 22:00 PPT MONDAY-SATURDAY EXCLUDING NERC HOLIDAYS) Scheduling to be completed with CPS in accordance with WSCC Guidelines.

2. Governing Law.
This Agreement and the rights and duties of the Parties hereunder shall be governed by and construed, enforced and performed in accordance with the laws of the state of New York, without regard to principles of conflicts of law. Each Party herein waives its respective right to any jury trial with respect to any litigation arising under or in connection with this Agreement.

3. Advisor.
Goldman Sachs Power LLC ("GSP") is the exclusive advisor to CPS and not a principal of CPS. From time to time, CPS may designate one or more employees of GSP as CPS's agent for purposes of performing its obligations under this Agreement. CPS shall be solely responsible for any and all obligations and liabilities associated with this Agreement and for any and all actions or inactions of such employees. Neither GSP, Goldman, Sachs & Co. nor J. Aron & Company, nor any of their affiliates, has any responsibility for, or liability with respect to this Agreement.

All provisions contained or incorporated by reference in the Western Systems Power Pool Agreement effective as of February 1, 2000, and as amended from time to time between the Parties, will govern this Confirmation except as expressly modified herein.

Please execute below as indicated and return to us by fax.

Regards,

Constellation Power Source, Inc.

ERIC PLATEIS
TRADER
CONSTELLATION POWER SOURCE, INC.
BALTIMORE OFFICE

PHONE : 410-468-3530
FAX : 410-468-3540

Agreed by Counterparty:

[signature] DS

By: DAVID A. HANSEN

Title: DIRECTOR. BULK POWER MARKETING + RESOURCE OPERATIONS

.ARON. T.FAX. C.ELS2JUP,ELS2JUQ,ELS2JUR. .ENDARON.

ml 3/31/00

59886; 59887; 59888

Deal No. 315589.1

Enron Power Marketing, Inc.
P.O. Box 4428
Houston, Texas 77210-4428
(FAX) (713) 646-2491

ENRON

April 24, 2000

Mark Wiesinger
Arizona Public Service Company
400 N 5th St
Phoenix, AZ 85004

Fax No. (602) 250-3719

REVISED CONFIRMATION LETTER

This Revised Confirmation Letter supersedes the prior Confirmation Letter dated March 31, 2000, and shall confirm the agreement reached on March 30, 2000 between Arizona Public Service Company and Enron Power Marketing, Inc. ("EPMI") regarding the sale of Firm Energy under the terms and conditions that follow:

Seller: Enron Power Marketing, Inc.

Buyer: Arizona Public Service Company

Type of Commodity: WSPP Schedule C Firm Energy in effect as of February 1, 2000, as periodically amended.

Term: Sunday, July 1, 2001 through Sunday, September 30, 2001.
Hour Ending (HE) 0700 through HE 2200 (16 Hours each day), Monday through Saturday only, excluding NERC Holidays;

Monday, July 1, 2002 through Monday, September 30, 2002.
Hour Ending (HE) 0700 through HE 2200 (16 Hours each day), Monday through Saturday only, excluding NERC Holidays;

Tuesday, July 1, 2003 through Tuesday, September 30, 2003.
Hour Ending (HE) 0700 through HE 2200 (16 Hours each day), Monday through Saturday only, excluding NERC Holidays;
Pacific Prevailing Time.

Type of Commodity: Firm Energy

Price: US Dollars $[redacted]/MWh.

Quantity: 25 Mws of Firm Energy per hour.

Delivery Point(s): PALO VERDE

Scheduling: EPMI Real Time Operations: 1-800-684-1336

04-24-00 16:22

Deal No. 315589.1

This confirmation letter is being provided pursuant to and in accordance with Western Systems Power Pool Agreement ("WSPP Agreement"), as amended periodically with FERC approval, to which Arizona Public Service Company and EPMI are parties. Terms used but not defined herein shall have the meanings ascribed to them in the WSPP Agreement.

Please confirm that the terms stated herein accurately reflect the agreement reached on March 30, 2000 between you and EPMI by returning an executed copy of this letter by facsimile to EPMI at (713) 646-2491. Your response should reflect the appropriate party in your organization who has the authority to enter into this transaction. If you have any questions please call (713) 853-1886.

Arizona Public Service Company

By: [signature]

Name: DAVID A. HANSEN

Title: DIRECTOR, BULK POWER MARKETING & RESOURCE OPS

Enron Power Marketing, Inc.

By: [signature]

Name: Tim Belden

Title: Vice President

APS

THE POWER TO MAKE IT HAPPEN™

APS Contract No. 63860
Cathy Pocock
Bulk Power Marketing & Resource Operations
P. O. Box 53999, M/S 9831
Phoenix, Arizona 85072-3999
Telephone: (602) 250-3622
Facsimile: (602) 250-3199
November 30, 2001

CONFIDENTIAL

To: Enron Power Marketing, Inc.

The following terms and conditions shall govern the transaction of November 29, 2001 between Matt Motley on behalf of Enron Power Marketing, Inc. ("EPMI") and Cathy Pocock on behalf of Arizona Public Service Company ("APS") whereby EPMI agreed to purchase and receive and APS agreed to sell and deliver energy as follows:

Seller:	Arizona Public Service Company 400 N. 5th Street, M/S 9842 Phoenix, Arizona 85004	**Buyer:**	Enron Power Marketing, Inc. P.O Box 4428 Houston, Texas 77210-4428
Confirm Administrator:	Margie Logan (602) 250-2809 (phone) (602) 250-3719 (fax)	**Confirm Administrator:**	Melissa Murphy (713) 853-1886 (phone) (713) 646-2443 (fax)
Preschedule:	(602) 250-4371	**Preschedule:**	(800) 684-1336
Real Time:	(602) 250-4470	**Real Time:**	(800) 684-1336
Quantity (MW/hr.):	25 Megawatts	**Quantity (MWh):**	30,800 MWh
Price ($/MWh):		**Type of energy:**	Firm
Start date:	July 1, 2003	**End date:**	September 30, 2003
Day(s) of week:	Monday through Saturday excluding Sundays and NERC holidays	**Hours:**	H. E. 0700-2000, Pacific Prevailing Time ("PPT").
Delivery Point:	Palo Verde		
Transmission Contingencies:	None	**Generation Contingencies:**	None

Enabling Agreement: APS and EPMI enter into this transaction pursuant to and in accordance with Service Schedule C (SSC) of the WSPP Agreement, to which APS and EPMI are parties. Terms used but not defined herein shall have the meanings ascribed to them in the WSPP Agreement.

Additional Terms: Per attached.

If the above accurately reflects the terms and conditions of the agreement between APS and EPMI on November 29, 2001, please sign a copy of this Agreement and return it via fax to the APS Confirm Administrator listed above.

Arizona Public Service Company

Signature: D. F. David Hansen

Print Name: David A. Hansen

Title: Director, Bulk Power Marketing & Resource Operations

Date: 12-5-01

Enron Power Marketing, Inc.

Signature: Considered Accepted

Print Name: Final Since Response

Was Not Received Within

Title: Business Days Of Receipt

Date:

2/1/02

ck 12/31/01

E:\common\CONTRACT\PWRSALES\ENRON\Sell\63860 aps cp sale.doc

Scheduling: Preschedules shall be exchanged for all deliveries of energy, including identifications of receiving and generating control areas under this Agreement by 11:00 a.m. Pacific Prevailing Time on the last work day observed by both Parties prior to the scheduled date of delivery. Interchange scheduling shall be conducted in accordance with Western Systems Power Pool (WSPP) Operating Procedure No. 1.

Special Provisions: *Deliveries will be made except during interruptions or reductions which are due to uncontrollable forces as defined in Section 10 of the Western Systems Power Pool Agreement, dated* July 1, 2001, as it may be amended ("WSPP Agreement"), in which case the obligations of both Parties will be reduced for the duration of the interruption or reduction.

APS shall supply firm energy in accordance with WSPP Service Schedule C utilizing available generation or purchased power resources at the point of delivery. If, in order to maintain firm energy deliveries, APS is required to obtain additional generation or transmission resources, APS shall absorb all additional costs incurred, including any charges for generation, transmission or ancillary services.

NERC Holidays: *The following shall be deemed holidays for purposes of this Agreement:* New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving, and Christmas Day.

Additional Terms and Conditions: Neither Party shall transfer or assign all or any part of this Agreement or its rights or obligations hereunder or otherwise dispose of any right, title or interest herein without the prior written consent of the other Party, which consent shall not be unreasonably withheld or delayed. Notwithstanding the foregoing, either Party may, without the need for consent from the other Party, (a) transfer, pledge, or assign this Agreement as security for any financing; (b) transfer, assign or delegate this Agreement or its rights or obligations hereunder to an Affiliate of such party; or (c) *transfer, assign* or delegate this Agreement to any person or entity succeeding to all or substantially all of the assets of such party; ***provided, however***, **that any such assignee shall agree to be bound by the terms and conditions hereof and,** ***provided, further***, **that any transfer, assignment or delegation that does not require consent hereunder shall not, in any way, release the assignor from liability for full performance of any obligations (and only those obligations) arising under this Agreement prior to the effective date of the transfer, assignment or delegation.** To the extent a transfer does not require consent, the transferring Party shall provide prompt notice to the other party of the transfer and the effective date thereof. Any transfer in violation of this section shall be deemed null and void.

The definition of Affiliate: **"Affiliate"** means, with respect to any person, any entity controlled, directly or indirectly, by such person, any entity that controls, directly or indirectly, such person, or any entity directly or indirectly under common control with such person. For this purpose, "control" of any entity or person means ownership of a majority of the voting power of the entity or person.

Billing and Payment: Monthly billings and payment shall be in accordance with Section 9 of the WSPP Agreement. Billings and payment shall be sent to:

Arizona Public Service Company
Attention: Cash Management, Station 8104
P. O. Box 53920
Phoenix, AZ 85072-3920

Enron Power Marketing, Inc.
Attention: Client Services Manager
P.O. Box 4428
Houston, TX 77210-4428

APS Contract No. 63860 shall be included on all correspondence or invoices in reference to this agreement.

Attachment TANGH-BC-1 2-16(b)(3)(5)

PINNACLE WEST
CAPITAL CORPORATION

PWMT Confirmation No. 63863

Cathy Pocock
Pinnacle West Marketing & Trading
P. O. Box 53999, M/S 9831
Phoenix, Arizona 85072-3999
Telephone: (602) 250-3622
Facsimile: (602) 250-3199

November 30, 2001

TRANSACTION CONFIRMATION
CONFIDENTIAL

To: Morgan Stanley Capital Group, Inc.

This Transaction Confirmation ("Confirmation") confirms the verbal agreement reached November 29, 2001 between Tom Funk, on behalf of Morgan Stanley Capital Group, Inc. ("MSCG"), and Cathy Pocock, on behalf of Pinnacle West Marketing & Trading, a division of Pinnacle West Capital Corporation ("PWMT"), whereby MSCG agreed to sell and deliver and PWMT agreed to purchase and receive energy pursuant to WSPP Service Schedule C (SSC) as follows:

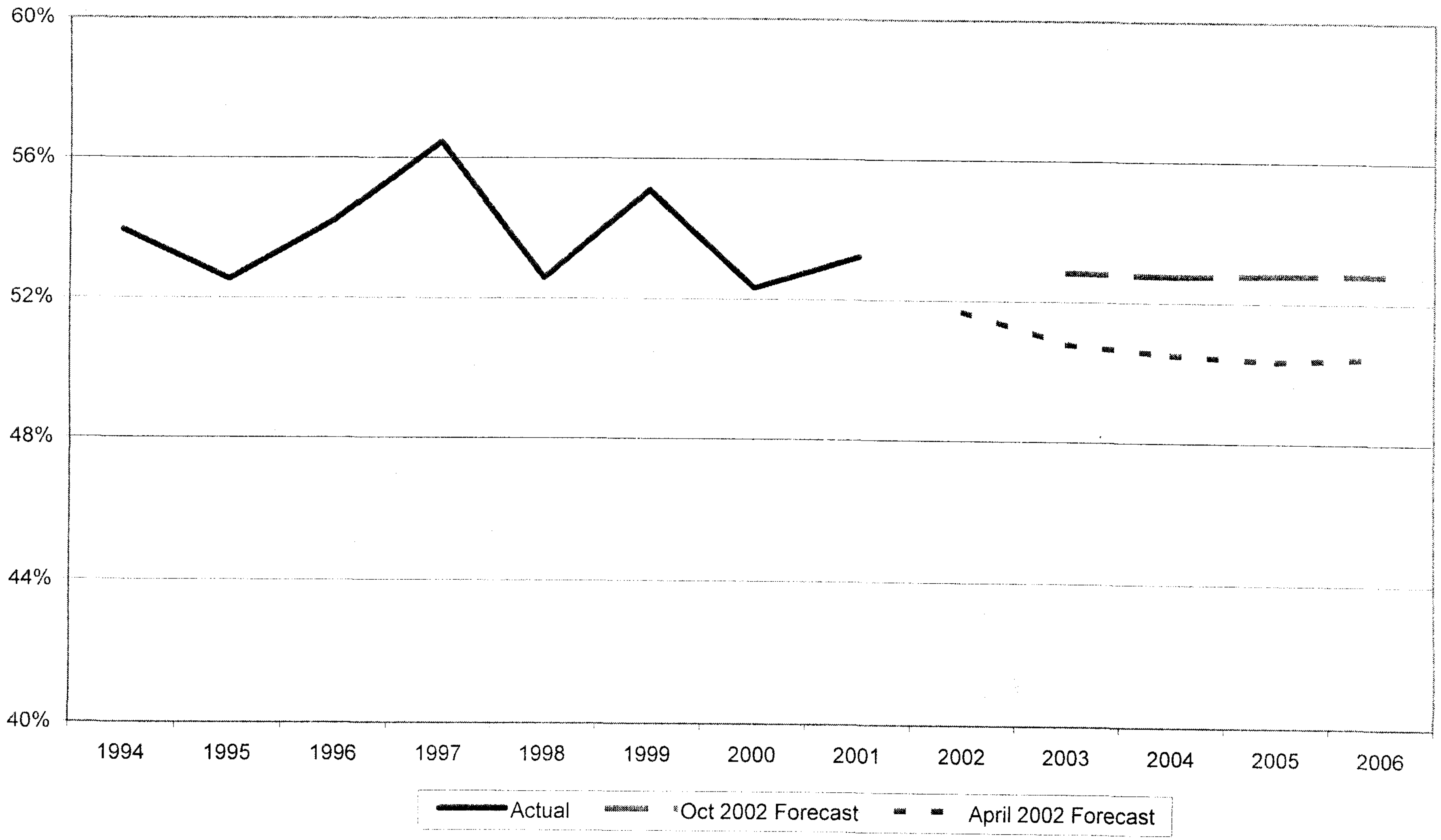
Quantity (MW/hr.):	25 Megawatts	**Product:**	30,800 MWh
Price ($/MWh):		**Delivery Point:**	Palo Verde
Start date:	July 1, 2003	**End date:**	September 30, 2003
Type of Energy:	Firm		
Schedule:	H. E. 0700-2200 Pacific Prevailing Time ("PPT") Monday through Saturday excluding Sunday & NERC holidays.		
Special Provision:	WSPP Schedule C with liquidated damages.		

If you are in disagreement over any of the provisions stated above, please contact Cathy Pocock upon receipt of this Confirmation.

SCHEDULE PME-3R
APS ESTIMATE OF UNMET CAPACITY AND ENERGY NEEDS
COMPARISON OF CURRENT (11/04/02) ESTIMATE TO PREVIOUS ESTIMATE
2003-2005

	2003			2004			2005		
	11/4/2002 Estimate	Workshop Estimate	Change	11/4/2002 Estimate	Workshop Estimate	Change	11/4/2002 Estimate	Workshop Estimate	Change
Peak Demand and Capacity (MW)									
Peak Demand	5,723	5,935	(212)	6,023	6,267	(244)	6,269	6,570	(301)
Planned Reserves	598	712	(114)	602	752	(150)	602	788	(186)
APS Units and Long Term Contracts	4,757	4,697	60	4,790	4,730	60	4,793	4,737	56
Forward Hedges	125	-	125	-	-	-	-	-	-
Non-APS RMR	29	-	29	184	-	184	338	-	338
Renewables	9	-	9	17	-	17	23	-	23
Net Unmet Needs	1,401	1,950	(549)	1,634	2,289	(655)	1,717	2,621	(904)
Energy (GWH)									
Energy Sales + Losses	26,494	26,405	89	27,841	27,733	108	28,999	28,979	20
APS Nuclear Generation	8,333	8,333	-	8,901	8,901	-	8,513	8,513	-
APS Coal Generation	12,498	11,726	772	12,762	11,852	910	12,936	12,079	857
APS Gas/Hydro Generation	3,184	254	2,930	3,600	363	3,237	4,214	548	3,666
Long Term Contracts	1,583	295	1,288	1,672	345	1,327	1,986	479	1,507
Forward Hedges	215	-	215	-	-	-	-	-	-
Non-APS RMR	-	-	-	2	-	2	8	-	8
Renewables	41	62	(21)	85	83	2	114	105	9
Net Unmet Needs	640	5,735	(5,095)	819	6,189	(5,370)	1,228	7,255	(6,027)
PWEC Unit Energy Displacement	-	5,728	(5,728)	-	6,170	(6,170)	-	7,217	(7,217)
Unmet Needs Net of Displaced Energy	640	7	633	819	19	800	1,228	38	1,190

Schedule PME-4R
APS System Load Factor



REBUTTAL TESTIMONY OF THOMAS J. CARLSON

On Behalf of Arizona Public Service Company

Docket No. E-00000A-02-0051, et al.

November 18, 2002

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REBUTTAL TESTIMONY OF THOMAS J. CARLSON
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-00000A-02-0051, et al.)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, ADDRESS AND OCCUPATION.

My name is Thomas J. Carlson. I am the Head of Trading for Arizona Public Service Company ("APS" or "Company").

Q. DID YOU PREVIOUSLY SUBMIT DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. My rebuttal testimony will respond to criticisms of the proposed APS power procurement program, and of APS itself, by Panda/TECO witness Dr. Craig R. Roach, National Energy Group ("NEG") witness Thomas Broderick, Wellton/Mohawk witness Robert W. Kendall, and to a lesser extent Sempra witness E. Douglas Mitchell and Reliant witness Curtis L. Kebler. These witnesses have either misunderstood that program or are attempting to mischaracterize that program to the Commission. They are attempting to both increase the size of the procurement and focus the scope of the procurement on what these sellers would like to sell rather than what APS and its customers need to buy. They have also drawn precisely the wrong conclusions from the California experience in 2000-2001, and not surprisingly, therefore, have proposed a "solution" that is more likely to replicate that experience in Arizona than prevent it.

Second, I will describe a specific proposal for the procurement of short-term economy energy needs that brings some of the thoughts expressed in my direct testimony into more focus. Although I am still opposed to using the same formal Track B process as is contemplated for securing our reliability needs, APS is willing to consider a compromise to satisfy the concerns expressed by some parties. Specifically, a system of quarterly "mini-Track B" procurements could be implemented for a significant portions of our estimated economic energy needs.

II. SUMMARY

Q. WOULD YOU PLEASE SUMMARIZE YOUR TESTIMONY?

A. APS today benefits from one of most sophisticated and innovative power procurement programs in the United States. It has allowed the Company to successfully manage risk and control costs during extremely turbulent and volatile market conditions. The proof is in seven straight years of rate reductions. To criticize APS for not having experience in formal power auctions or RFPs for "asset-backed" unit contingent products is like criticizing a New Yorker for not knowing how to milk a cow or a modern PC-owner for not using a main frame or understanding Fortran. In the case of the former, it is a skill-set of little value given the New Yorker's circumstances and needs. For the latter, you have a somewhat antiquated method of computing that has been superceded from both a hardware and software perspective.

The "APS economy energy proposal" (Testimony of Dr. Craig R. Roach at 5) is not just an APS proposal. It is the same approach to economy energy and other short-term purchases apparently used by Tucson Electric Power Company

("TEP"), which Dr. Roach uncritically accepts, and embraced by TEP witness David Hutchens. It flows directly from the language used in the Staff Report, which in turn comes directly from the Commission's language in the Track A order, Decision No. 65154 (September 10, 2002).

Our (and I presume TEP's) short-term procurement program is the polar opposite of the mandatory real-time purchase scheme used in California. Indeed, it is the Panda/TECO proposal for an RFP process seeking largely unit-backed contingent power that is eerily reminiscent of Gray Davis' California. It could lock APS and its customers into 365 days a year capacity <u>costs</u> during the next couple years to meet a less than 90 days a year capacity <u>need.</u>

There may be a significant risk to our customers in entering into 10 or 20-year agreements (except under special circumstances, which I discuss in my rebuttal testimony), as is recommended by some of the witnesses in this proceeding. Regional Transmission Organizations ("RTOs") and some manner of FERC-mandated Standard Market Design ("SMD") are coming and could significantly affect the relative economics of differing generators. Retail access may be down, but it would be foolish to assume it is dead. Credit problems plague the electric power industry, and it is difficult to know who will be in business 10 or 20 months from now, let alone 10 or 20 years. Power markets will remain soft for at least the next year or two, and may well get softer before they firm up. Although APS will consider any serious offer from a credit-worthy supplier, there is simply no need for APS and its customers to be forced into accepting long-term contracts today.

APS does use least cost evaluative criteria, including dispatch simulation and forward pricing models, over the period for which it is primarily soliciting bids, which is the period 2003 through 2006. Although it is important to simultaneously evaluate the impact of <u>major</u> transmission additions on longer-term proposals, this can be done, as proposed by Dr. Richard Rosen in this proceeding, through a less-software driven iterative process. Moreover, no such transmission additions are planned until after 2006, and the Company is leery of most long-term purchase power commitments for the reasons set forth above.

III. <u>APS POWER PURCHASING EXPERIENCE</u>

Q. BOTH IN DATA REQUESTS AND IN THEIR TESTIMONY, SOME OF THE MERCHANT INTERVENORS HAVE QUESTIONED THE COMPANY'S EXPERIENCE IN RFP SOLICITATIONS, FORMAL AUCTION PROCESSES, AND EVEN IN SECURING THE ENERGY PRODUCTS DESCRIBED IN YOUR DIRECT TESTIMONY. ARE ANY OF THOSE CONCERNS VALID?

A. Not in the least. For example, Dr. Roach accuses APS of not having "much experience in these products." (See Testimony of Dr. Craig R. Roach at 13.) In fact, APS utilizes one of the most innovative and advanced utility power procurement programs in the country. We have a proven track record of managing price, volume and reliability risks through a sophisticated combination of physical and financial derivatives, physical and financial hedges, swaps and other trading devices. APS has long hedged both long and short positions in both power and fuel through various call and put options, costless collars, butterfly options, etc., to reduce and manage costs without exposing customers to large capital investment risks. It is a program that has been in place for years, and since 1998, a period of incredibly unstable and volatile markets for both power and natural gas, it has allowed APS to meet or beat the market, not just at the time of purchase but also at the time of delivery.

None of these savings were the result of issuing RFPs. I have personally conducted many RFPs in my former role as APS Director of Generation Fuel Procurement, and they have almost universally resulted in above-market bids. This will nearly always be the case when there is an established and viable trading market for the good or service being procured. If the RFP bidders were satisfied just to receive the going market price for their good or service, they would simply sell into the market today and avoid the cost and uncertainty of the RFP process. It is because they <u>expect</u> to receive above-market prices, either due to some manner of product differentiation (my megawatts are better than their megawatts) or the lack of equivalent market alternatives for the buyer (e.g., Colorado, which has no liquid trading hubs, or where the buyer is not permitted by circumstances or the regulator to say "no"), that they generally wish to participate in an RFP process in the first instance.

Now, RFPs do serve a valuable role when soliciting "designer" or specialty energy products such as reliability must-run ("RMR"), DSM or renewable energy, or even when evaluating the design and construction of a new power plant (just like the mainframe computer in the example from my Summary is still useful in analyzing problems requiring vast amounts of computer memory). And, as suggested by my direct testimony proposal, they can be used when a structured procurement is required for regulatory purposes and there is insufficient time and/or consensus about products and results to use a more sophisticated auction process. Although somewhat cheaper than some forms of auction, the costs of an RFP do not fare well compared to an average $12 cost of conducting a power transaction through the Intercontinental Exchange ("ICE"), a web-based power market procurement site (whose original founders included, incidentally, Reliant and Duke, among others). It's not so much that the RFP process does not work, but that the market has worked and will work better and less expensively for most of the products we need.

For the highly structured procurement of large quantities of standard power products through a wholly transparent process, I agree with Mr. Kebler that there are advantages to an auction. I do not share his confidence that one could be assembled on such an *ad hoc* basis with no agreement on process and no apparent acceptance by Staff of the results for purposes of assured full cost recovery. I would also note that this is a process that APS historically has never needed, and APS customers would not have benefited from the Company's incurring the considerable cost of developing any particular experience in such procurements. But if and when the need for and regulatory acceptance of this form of procurement is more apparent, APS will be ready to acquire the expertise necessary to successfully utilize this procurement tool.

IV. <u>THE "APS ECONOMY ENERGY PROPOSAL"</u>

Q. DID APS PROPOSE "ITS" ECONOMY ENERGY PROCUREMENT PROGRAM JUST TO AVOID MAKING PURCHASES FROM PANDA/TECO, NEG AND THE OTHER MERCHANT INTERVENORS?

A. Of course not. APS has proposed to acquire economy energy and other short-term needs using precisely the methodology endorsed by the Staff Report and precisely the methodology used by TEP and supported by Mr. Hutchens, whom I will simply quote:

> Q. What is TEP's position on Staff's recommendation [p. 4:25] that "short term power, and daily, weekly or monthly power acquired to meet unplanned needs, would however continue to be purchased in the normal course of business as it is today"?
>
> A. <u>TEP strongly agrees with this position</u>. <u>It is an obvious necessity that the utility be afforded discretion to enter into short-term transactions</u>. <u>As Staff recognizes</u>, this gives the utility the opportunity to <u>economically displace plant or contract energy with cheaper market power</u> or purchase to cover unplanned needs arising from temperature extremes and unplanned generation or transmission outages <u>without jeopardizing system reliability by being unnecessarily burdened with a cumbersome procurement process</u>.

(Testimony of David Hutchens at 8, emphasis added.) I can't help but note that Dr. Roach takes absolutely no exception to either TEP's calculation of unmet need or its suggested procurement of that need, including economy energy.

Q. DID "APS PROPOSE THIS [THE 'APS ECONOMY ENERGY PROPOSAL'] <u>NOW</u>" IN ORDER TO "SUBVERT THE [TRACK B] SOLICITATION" AND IN THE HOPE OF BUYING "FROM ITS AFFILIATE'S REDHAWK PLANT AT SPOT MARKET PRICES?"

A. No. Dr. Roach's inflammatory statements (Testimony of Dr. Craig R. Roach at 15) are neither historically correct as to the origin and timing of this proposal, nor are they prospectively accurate as to APS' intent or ability to favor Pinnacle West Energy Corporation ("PWEC") generation in making economy purchases.

During the first Track B workshops, APS fully anticipated divestiture of all its existing generation (with the exception of renewables), and under such circumstances, the distinction between reliability needs and economic needs was meaningless, and so it probably comes as no surprise that neither APS or TEP made much effort to distinguish them. However, by the time APS actually distributed its first rough "guesstimate" of unmet needs in the late August Track B workshop, it was evident that divestiture was not going to happen, and the

Company's representative went to great lengths to state that the numbers given for both APS and non-APS generation should be reduced to reflect economy purchases, which the Company did not propose to procure through the formal Track B process. Thus, neither the "APS economy energy proposal" or, for that matter, the "TEP economy energy proposal" should have been a surprise to anyone and were certainly not unveiled on November 4th as some sort of plot to "subvert" Track B.

As to Dr. Roach's second allegation, APS very much wishes to buy economy energy at or below spot prices from anyone willing to sell it, including affiliates. That is why, in part, the vast majority of APS' needs for economy energy and short-term capacity are procured today through "blind" mechanisms, that is, the identity of the underlying seller is unknown to the buyer at the time of purchase. Sellers of economy energy come from a group of pre-screened (by a third party such as ICE or Bloomberg) entities that simply sign up with either or both of these trading platforms or work through an unaffiliated (to APS) energy broker. As indicated in my direct testimony, APS should reserve the right to do what is necessary, including buying directly from an affiliate, to maintain reliable service to our customers. But this Panda/TECO and NEG rhetoric about there being some sort of vast inter-affiliate conspiracy to purchase economy energy from Redhawk or West Phoenix rather than through the formal Track B process is not just overblown, it is just plain wrong.

Q. ASIDE FROM THE AFFILIATE ISSUE OR WHOSE "ECONOMY ENERGY PROPOSAL" IT WAS, DOES APS INTEND TO EXPOSE ITS CUSTOMERS TO THE TYPE OF SPOT MARKET RISK THAT PROVED SO EXPENSIVE IN CALIFORNIA?

A. Just the opposite. APS has voluntarily sought short-term (day-ahead, month-ahead and real-time), economy purchases for many years, including during all of the California mess. It has done so within the confines of frozen or declining retail rates. So I think we know a thing or two about managing short-term market risk and volatility. It involves close cooperation between both the power desk and the natural gas desk to come up with the right combination of hedges and counter-hedges. This permits APS to more closely align needs with resources while mitigating and managing market price risk.

What California did wrong in the first instance was <u>not</u> its creation of a highly liquid spot market, which was a very good thing. Their mistake was to <u>force</u> (not allow) its utilities to purchase <u>all</u> (not a small portion) of <u>both</u> their reliability and economy needs (APS is generally only talking about purchasing the latter) <u>in the real-time market</u> (APS usually buys only a very small percentage of its economy energy in the real-time or even day-ahead markets, with the balance coming from month-ahead purchases, which along with APS generation and gas hedges, are then used to hedge the real-time and day-ahead purchases). California's utilities were not permitted to protect themselves with either physical or financial hedges, and they were stripped of much of their native load generation, which is the ultimate hedge. California then set up a wholly separate day-ahead market and allowed traders and marketers to arbitrage between the two, create congestion in one to drive up prices in the other, and employ any other "creative" market manipulation they could think of at the time. <u>None</u> of these factors are present in the APS proposal, and the suggestion by Dr. Roach and others to the contrary are an attempt to lead the

Commission in the direction of the second, and larger, major mistake made in California.

In response to an inherently flawed and manipulated market structure and set of market rules, which had bled California's major electric utilities of their credit, the state next overreacted by hastily negotiating a multitude of precisely the sort of unit-contingent, "pay for performance," long-term contracts as are urged by Dr. Roach and other merchant witnesses. Convinced then, as these witnesses are now attempting to convince this Commission, that market prices could only go up, California now turned a one or two year problem (from the inflated spot market purchases) into a 10 or 20 year problem with uneconomic long-term contracts.

Arizona's utilities avoided the mistakes caused by California's spot market straightjacket. They do not want to now fall victim to the greater mistake of assuming, as did California, that the merchants will voluntarily negotiate below-market price agreements for our benefit.

Q. IS APS UNALTERABLY OPPOSED TO ANY CHANGE IN ITS ECONOMY PURCHASE PROGRAM?

A. APS is aware that many parties in Track B are disappointed at the relatively small amount of APS' and TEP's energy needs. And despite the heavy and increasing usage by APS of "blind" procurement techniques for short-term and economy purchases, they are still suspicious of APS dealing with PWEC and Pinnacle West Marketing and Trading ("M&T") in some unfair manner. Therefore, and solely in the spirit of compromise, APS would consider a "mini-Track B" program whereby it would solicit bids for 50% of its annual anticipated economy energy needs on a quarterly basis. For example, if the annual anticipated need were 4,000 GWH, with 3,000 GWH needed in Q3 and 500 GWH each in Q2 and Q4, with zero in Q1, APS would solicit bids for 50% of each quarter's estimated economy energy need beginning with the first business day of Q1. Sellers could bid on Q2 needs, Q3 needs, Q4 needs, or any combination. If the bids were such that less than 50% of a quarter's needs did not actually end up in signed contracts, the underfilled need would not roll into subsequent quarters. Now, this proposal may be introduced mid-year in 2003, and APS might actually have economy needs even in Q1 of a given year, so the actual sequence of quarters and their respective economy energy needs would be different than in my hypothetical, but the structure would be identical.

Volume, product (for example, peak, super-peak, off-peak, and shoulder) and delivery information would be posted on the Company website prior to the bid date, which will be the first business day of the quarter preceding the quarter for which the energy is first being solicited. Bidders would be pre-qualified as to credit and other contract terms as agreed to by Staff and the independent monitor. Although the bidding would be conducted quarterly, APS would accept bids from and award contracts to bidders for up to four consecutive quarters.

All sealed or faxed bids could be opened and presented, or if conducted electronically through a secure website, received in the presence of Staff and/or the independent monitor. All awarded contracts could be subject to Commission or Staff approval. After the first quarterly solicitation, both APS and the independent monitor would prepare a report evaluating the solicitation both procedurally and substantively. These quarterly formal solicitations of economy energy could be discontinued after 2004 at the Company's discretion unless prior to September 30, 2004, the Commission found this process to be superior to the Company's traditional method of securing economy energy and ordered its continuance for some specified period of additional time.

Q. COULD THE MERCHANT INTERVENORS USE SUCH A SYSTEM TO SELL APS ECONOMY ENERGY?

A. Absolutely. I know that TECO, Sempra, Reliant, PPL and, I believe, an affiliate of Wellton-Mohawk are already participating in ICE. APS routinely has had transactions executed on its behalf with these entities under the present method of meeting our economy energy needs.

Q. WHAT ABOUT THE ECONOMY AND OTHER SHORT-TERM ENERGY AND CAPACITY NEEDS NOT PURCHASED THROUGH THIS QUARTERLY PROGRAM?

A. APS will acquire all such needs, excepting for immediate reliability needs or when it receives no bids from non-affiliates in response to a solicitation, through non-affiliated suppliers, independent brokers, or electronic trading platforms such as I have discussed both in my direct and rebuttal testimony. Staff could monitor this process and/or conduct audits after-the-fact to assure the Commission that the process is prudent, reasonable and unbiased.

Q. DO YOU BELIEVE THAT THIS PROGRAM COULD RESULT IN HIGHER COSTS TO APS AND APS CUSTOMERS?

A. Quite frankly, yes. It will cost thousands of dollars to set up and administer. And I believe the resulting bids may not be as economical as using our current system of largely electronic procurement. That is because we presently acquire our economy energy in smaller batches (which is less likely to move the market upward simply by the fact of having such a large procurement at one time). We also would normally spread our economy purchases over several short-term "sub-markets" (real time, day-ahead, month-ahead, etc.) rather than soliciting bids for so much power at one time on a essentially a quarter or year-ahead basis. I am also giving up a little of the present flexibility the Company enjoys in purchasing its remaining economy and short-term energy needs. That is why I am willing to offer this only as a compromise to get this issue resolved and only then on an experimental basis.

Q. ARE THERE ANY OTHER CONDITIONS THE COMPANY WOULD INSIST UPON BEFORE AGREEING TO TEST SUCH AN ECONOMY ENERGY PROCUREMENT PROGRAM?

A. Yes. APS must retain the right to reject all economy energy proposals that it finds unsatisfactory from the standpoint of price or other terms and will be willing to justify that rejection to Staff or to the Commission. Second, if the Commission directs that the program be retained after 2004, such Commission order must authorize full and timely recovery of economy energy costs. Third, any similar economy energy procurement program ordered for TEP should be staggered such that we both are not trying to buy at the same time, which would add to the potential for upward pressure on market prices discussed in my prior answer.

Q. WILL THIS OR ANY ECONOMY ENERGY PROPOSAL, INCLUDING THEIR OWN, SOLVE THE FUNDAMENTAL MARKET CHALLENGES FACED BY ALL THE MERCHANT INTERVENORS?

A. No. The Company's total unmet reliability and economy energy needs are estimated to be in the range of approximately 4,450 GWH (2003) to just under 14,100 GWH (2012), depending on a wide variety of assumptions and forecasts of future events. (See Direct Testimony of Peter M. Ewen at Schedules PME-1 and PME-13.) There are presently some 14,000 MW of merchant generation that has been granted a certificate of environmental compatibility in Arizona alone. All but 500-600 MW of this is combined-cycle gas-fired generation, which is most economical if run at capacity factors in the range of at least 40%. This means there are some 50,000 GWH looking for a home, or approximately 10 times any remotely realistic determination of the Company's unmet needs for 2003-2004. Even by 2012, only about one third of this generation could be supported by APS customers. And this does not consider the additional resources in the market offered by other utilities, merchant plant owners, and energy brokers outside Arizona. Adding all of TEP's unmet reliability and economy energy needs would not materially change this disparity. If these projects are to survive, they are going to have to find markets in California, Nevada, the Pacific Northwest and perhaps Mexico.

V. THE PANDA/TECO PROPOSAL

Q. WOULD APS LIKE TO ACQUIRE CAPACITY PLUS DISPATCHABLE ENERGY AS PROPOSED BY PANDA/TECO WITNESS DR. ROACH?

A. If the price is right for the time I could use that product, yes. In fact, I discussed this in my direct testimony. The second energy product I identified was capacity plus a minimum amount of energy. (See Direct Testimony of Thomas J. Carlson at 3.) I used the word "minimum" purposely to allow for the potential for additional dispatchable energy above that minimum. It would, of course, be up to the bidder to determine whether it was willing to commit any additional energy resources and if so, at what price. I also noted that physical call options, my third energy product, could be dispatchable but that this would carry a premium and might eliminate bidders if I insisted on dispatchability. (*Id.* at 8.)

What I am not looking for, because there is no need from either a reliability or an economy point of view, is year-round and high-priced capacity bundled with that low-cost energy, dispatchable or otherwise. And that is precisely what some of the merchants are trying to sell me. And why do they want to sell me this bundled product even though the Company and its customers don't need it? Because they believe it produces higher margins than selling either the capacity or the energy separately. I do not blame a seller for wanting to sell me its most expensive bundled package of services any more than I should be blamed for wanting to purchase the lowest cost individual services and assembling them into my own package for the benefit of APS customers.

Q. WHY DOES NOT A SIMPLE COMPARISON OF HEAT RATES BETWEEN APS' OLDER GAS-FIRED GENERATION AND THE NEWER COMBINED-CYCLE UNITS OF PANDA AND NEG TELL YOU THAT YOU SHOULD BE SIGNING UP ALL THE UNIT-CONTINGENT, "PAY FOR PERFORMANCE" DEALS YOU CAN GET?

A. Because neither Panda/TECO nor NEG proposes to sell me that low heat rate energy unless I purchase their new capacity on a year round basis. (See Testimony of Dr. Craig R. Roach at 24 – 25.) And the price of that capacity, including fixed O&M, instead of declining every year as it does under cost-of-service pricing, would actually increase by some multiple of inflation. (*Id.*) To then say I can still displace this dispatchable energy on an economic basis (assuming I am not committed by Dr. Roach's and Mr. Broderick's client to minimum take provisions) is like saying I'm free to go to a motel after I've already bought their house.

There is a competitive market for capacity in which the low capacity-cost higher heat rate units determine the lowest price. APS is not the only entity that owns older low cost capacity in the West. Virtually every utility has its own "Ocotillos" and "Saguaros." These units have depreciated capacity costs in the range of \$2-5/kW/mo for year-round capacity. This is consistent with the current market value of this kind of capacity, which is only about \$2-3/kW/mo. If I limited my purchases to just Q3, that would probably double that figure to, say, \$5/kW/mo. In contrast, the cost of a new combined-cycle unit is about \$10-15/kW/mo. for year-round capacity. Expanding this differential to the 2000 MW of unit-contingent capacity Dr. Roach would have us bid, this amounts to between \$200 million and \$300 million in additional capacity costs. Of course, the present market cannot support capacity prices in the \$10-15 range, which is why merchant generation is struggling so much. Capacity with a 7000 MMBTU heat rate commands about \$4/kw/mo for year-round capacity in today's market. This is still significantly about the price of capacity from 14,000 MMBTU heat rate units, which I previously indicated was in the \$2-3 range. Using the \$5 price for just Q3 capacity from these admittedly higher heat rate units produces a cost to APS of \$30 million compared with the 12-month capacity cost of \$96 million from the 7000 MMBTU unit. Thus, unless Panda/TECO is willing to sell me its capacity at a very significant discount from market, let alone from cost, I'm far better off both using my own older generation to firm up energy purchases or buying additional capacity in the market for the same purpose.

I should also add that even on an energy-only basis, the newer combined-cycle units would not always be the best energy solution for our customers. The older APS combustion turbines and combined-cycle units are cheaper to run at low capacity factors and can be more easily cycled without damage to the unit. They are also essential for reliability, and provide spinning reserves and voltage regulation even during non-RMR hours of the year, as well as providing economic value to APS customers and customers throughout the Southwest through the reserve sharing pool of which APS is a member.

Q. BUT ARE NOT THE HIGHER CAPACITY COSTS OF NEW COMBINED-CYCLE GENERATION OFFSET BY THOSE HIGHER OPERATING EFFICIENCIES THAT BOTH MR. BRODERICK AND DR. ROACH SPEAK OF IN THEIR TESTIMONIES?

A. Over the long run, that might be true, especially if there were not all the indexed escalators to the capacity costs suggested by Dr. Roach. But it's not an "either/or" situation. The current market allows me to get both cheap capacity and Dr. Roach's low cost energy. This is exactly what I was talking about when I indicated that APS should be able to assemble its own package of needed services and not have to accept the package of bundled options proposed by the seller. Anyone who has bought a new car knows the dealer package is seldom the best combination of features at the best price for the buyer's particular needs.

Q. DOES THIS MEAN THAT NO UNIT-CONTINGENT BIDS WILL BE CONSIDERED BY APS?

A. No. I am just trying to tell the Commission and prospective buyers the products I need and want, as well as the market criteria by which I will judge these products. If they wish to discount their offers to meet these criteria, I would be more than happy to seriously consider and even accept such offers.

VI. LONG VS. SHORT-TERM AGREEMENTS

Q. SOME OF THE MERCHANT INTERVENOR WITNESSES, AND EVEN RUCO WITNESS DR. ROSEN, HAVE URGED THE COMPANY TO CONSIDER LONGER TERM PURCHASE AGREEMENTS. WOULD THE COMPANY CONSIDER AGREEMENTS LONGER THAN FOUR YEARS?

A. I would consider any proposal that I thought might be of benefit to the Company and its customers. But I wouldn't compromise their interests just because this or that merchant wished to tie APS up in an above-market deal. The reasons I have proposed limiting the initial Track B solicitation to four years are described in my direct testimony. However, I will elaborate on some of these points in response to the merchants' testimony.

Both NEG and Panda/TECO suggest that asset-backed sales somehow reduce or even eliminate credit concerns. Nothing could be further from the truth. Asset-backed contracts have little value in the market if there is no credit to back up the default risk to the Company. It is fine to say that APS can stop payments for capacity if the seller's unit fails to operate or if the seller simply fails to deliver for any reason. But can the seller pay to the Company and its customers the damages incurred in covering for that default? And can the seller cover these potential damages not just when the contract is entered into, but 10 years down the road?

It has also been suggested at the workshops that if the banks have given a certain generation project total financing, APS ought to be satisfied from a credit perspective. Just because some bank is willing to risk its money without adequate collateral is a poor argument for me risking our customers' money on these same sellers.

Q. AREN'T YOU WORRIED THAT WHEN SOME OF YOUR PROPOSED AGREEMENTS EXPIRE IN 2006, PRICES WILL BE MUCH HIGHER, AS IS SUGGESTED BY DR. ROACH?

A. Dr. Roach discusses this issue at page 28 of his testimony, and yes, I would be concerned if I planned on sitting around until 2006 to see if the situation hypothesized in Dr. Roach's testimony (the end of the power glut) actually materialized. It just doesn't work that way. Risk management is a 365-day per year responsibility, and one that must be met every year. Even assuming that I will have contracted for 100% of all my unmet needs for the next four years during the 2003 Track B solicitation, I could solicit additional contracts in 2004 for delivery in 2007 and beyond, if in fact I believed Dr. Roach's predictions about future power prices. Indeed, the only risk APS faces in this regard would be an inflexible Track B procurement process that prohibited me from making purchases outside some formal, once-a-year RFP.

Q. BUT ARE NOT LONG-TERM AGREEMENTS A HEDGE AGAINST FUTURE PRICE INCREASES?

A. They could be <u>a</u> hedge, especially if not burdened by unlimited price escalators, but they are not the <u>only</u> hedge, and they may not be the <u>best</u> hedge. I certainly believe they may not be a prudent hedge under present market conditions. If you think about it, APS already has the equivalent of long-term contracts for the vast majority of its capacity and energy needs in the form of its rate-based generation assets and existing long-term agreements with SRP and PacifiCorp. APS has proven it can successfully manage price and volume risk, and market volatility, without repeating the mistake of being forced to buy what others want to sell you rather than what you need. When you read about other utilities fleeing into long-term contracts in the present market, they are often utilities that are very short on existing resources or historically unsuccessful in managing market risk, or both. APS is neither.

Q. ARE YOU SUGGESTING THAT NON-COMFORMING BIDS SUGGESTING LONGER TERMS WOULD BE REJECTED OUT OF HAND IN THE COMPANY'S PROPOSED TRACK B SOLICITATION?

A. No. But I would also counsel that bidder to also submit a conforming bid. The two weeks allotted in the Staff Report is not much time to evaluate longer term proposals, as is suggested in Sempra witness Mitchell's testimony, and so such a proposal would be better considered outside of the formal Track B procedures. As it is, any such long-term bid proposal should be prepared to show:

(1) how APS can be assured of credit-worthiness throughout the proposed term of the agreement;

(2) that the economics of the proposal are relatively insensitive to transmission costs, so that the implementation of RTOs and some form of SMD become less of a concern;

(3) how APS could be protected if it lost significant parts of its retail load to direct access during the term of the agreement; and

(4) that the proposal is not "Christmas-treed" with a bunch of cost escalation provisions unrelated to actual cost increases and limits on even the latter.

VII. <u>APS EVALUATION CRITERIA</u>

Q. YOU EARLIER DISCUSSED THE COMPANY'S USE OF LEAST COST CRITERIA FOR ITS EVALUATION OF OFFERS. IS COST THE ONLY CRITERION?

A. No, but along with credit (which encompasses a prospective seller's past record of performance), it is probably the most important. Other important criteria include deliverability and point of delivery. As discussed in the Staff Report, these criteria will be spelled out in the bid package.

Q. MR. MITCHELL SUGGESTS THE USE OF SOPHISTICATED SYSTEM DISPATCH AND SIMLULATION MODELS TO EVALUATE BIDS? DO YOU AGREE?

A. That is one way, although Mr. Mitchell himself admits there isn't enough time to do that kind of analysis. In fact, the Company does use such tools for its long-term resource planning. But this does not mean that I limit the solicitation to certain products and then try to make those products fit my needs, as is perhaps suggested by Mr. Mitchell at page 8 of his testimony. For my purposes, we use sophisticated market-based models such as RTSIM and UPLAN to first determine the products that best suit our system, and then acquire those products using the various criteria discussed above and also in my direct testimony. Once the bids are received, we will rerun the simulations to make sure we still have the right products for our needs and evaluate the bids accordingly. But I don't want to leave the impression that I allow a computer to decide what the best deal is for our customers. With all the analytical tools available and even with relatively objective evaluation criteria, there is still an element of judgement involved that cannot be delegated to a machine.

Q. MR. KENDALL APPEARS CONCERNED ABOUT HOW APS WILL EVALUATE BIDS OF RENEWABLE ENERGY? DOES RENEWABLE ENERGY HAVE ADDITIONAL ECONOMIC WORTH TO THE COMPANY AND ITS CUSTOMERS?

A. Yes. APS is required to satisfy certain renewable quotas, and if part of that requirement can be obtained as part of this procurement, it reduces the amount that would have to be otherwise obtained. Thus, if a bid including such resources were received, I would consult with those involved in the renewable program at the Company to determine the additional value such a bid brought to the table. I can say that the additional value is not measured by how much APS collects for renewables, as proposed by Mr. Kendall at page 19 of his testimony. Much of that money will go to existing or already committed renewable projects. I can also say that the Company does not support acquiring all of its renewable energy through one giant hybrid renewable project as suggested by Mr. Kendall at page 17. Distributed as well as grid-connected projects, and projects using different solar and non-solar projects, would appear to me to provide for a more diverse portfolio of renewable investments for the Company and its customers.

VI. CONCLUSION

Q. DO YOU HAVE ANY CONCLUDING REMARKS?

A. Yes. I have attempted to respond to the major points raised by Intervenor witnesses concerning how APS has determined the products for its unmet needs and how the Company proposes to evaluate and acquire its unmet needs for at least the period 2003 through 2006. The fact that I may not have addressed this or that Intervenor witnesses' argument does not imply agreement with such argument. I also hope I have dispelled the notion that APS is some sort of novice in the field of power procurement and risk management, or that it is trying to favor its affiliates at the expense of customers at every turn, as some have alleged. Finally, I have suggested a compromise proposal that, although less flexible and likely to be at least marginally more costly to customers than our current method of procuring economy energy, the Company would be willing to try on at least a test basis.

Q. DOES THAT CONCLUDE YOUR PREFILED REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. Yes.

WORKPAPERS

Thomas J. Carlson

November 18, 2002

Arizona Public Service Company
Track B Workpapers
Nov 18, 2002

Arizona Merchants
Available Generation
18-Nov-02

	MWs	Capacity Factor (%)	Total Ability GWH
On-line Generation	4,307	40	15,092
Under Construction	4,960	40	17,380
Sub-Total	9,267		32,472
CEC Permitted	5,000	40	17,520
Total	14,267		49,992

Note: Above table reflects generating capacity for State of Arizona. Total GWH is based on 40% capacity factor only

Comparison of installed versus market capacity values
18-Nov-02

	Installed Capacity Costs 18-Nov-02			Market Capacity Values 14-Nov-02	
	Case 1 Older Capacity	Case#2: High New Capacty	Case#3: Low New Capcity	Case #4 Mkt 7 HR Capacity	Case #5 Mkt 12 HR Capacity
MWs	2000	2000	2000	500	500
Cost $ / KW - Mo	4	15	10	4	2.5
Annual Cost Millions	96	360	240	24	15

Market Capacity values based on Independent broker market quotes for Calendar 04 on Nov 14, 2002