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**BEFORE THE ARIZONA CORPORATION COM**

WILLIAM A. MUNDELL
CHAIRMAN
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COMMISSIONER
MARC SPITZER
COMMISSIONER

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| IN THE MATTER OF THE GENERIC PROCEEDING CONCERNING ELECTRIC RESTRUCTURING ISSUES. | DOCKET NO. E-00000A-02-0051 |
| IN THE MATTER OF ARIZONA PUBLIC SERVICE COMPANY'S REQUEST FOR A VARIANCE OF CERTAIN REQUIREMENTS OF A.A.C. R14-2-1606. | DOCKET NO. E-01345A-01-0822 |
| IN THE MATTER OF THE GENERIC PROCEEDING CONCERNING THE ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR. | DOCKET NO. E-00000A-01-0630 |
| IN THE MATTER OF TUCSON ELECTRIC POWER COMPANY'S APPLICATION FOR A VARIANCE OF CERTAIN ELECTRIC COMPETITION RULES COMPLIANCE DATES. | DOCKET NO. E-01933A-02-0069 |
| IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS STRANDED COST RECOVERY. | |



TESTIMONY OF
CRAIG R. ROACH, Ph.D.

ON BEHALF OF
PANDA GILA RIVER, L.P.

November 12, 2002

BOSTON PACIFIC COMPANY, INC.

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## I. INTRODUCTION AND PURPOSE OF TESTIMONY

Q. Please state your name, position, and business address?

A. My name is Craig R. Roach. I am a Partner with Boston Pacific Company, Inc. My business address is 1100 New York Avenue, NW, Suite 490 East, Washington, DC 20005.

Q. Are you the same Craig R. Roach who testified in both the Track A and Variance proceedings on behalf of Panda Gila River, L.P.?

A. Yes.

Q. Did you participate in the Track B workshops sponsored by Staff?

A. Yes, along with business representatives and counsel of Panda Gila River, L.P., I participated in each of the Track B workshops.

Q. What is the purpose of your Testimony?

A. The purpose of my Testimony is to respond to (a) Arizona Public Service Company's (APS') needs assessment and procurement proposal as presented in two testimonies dated November 4, 2002,[1] and (b) the Staff's Report on Track B dated October 25, 2002 (the "Staff Report").[2]

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[1] Direct Testimonies of Peter M. Ewen and Thomas J. Carlson, Docket No. E-00000A-02-0051, et al., November 4, 2002.

[2] Staff Report on Track B: Competitive Solicitation, Docket No. E-00000A-02-0051 et al., October 25, 2002.

## II. SUMMARY OF TESTIMONY

### A. APS' needs assessment and procurement proposals

Q. Can you summarize your overall opinion of APS' needs assessment and procurement proposal?

A. I am greatly disappointed with APS' needs assessment and procurement proposal. APS' proposal is more an attempt to undermine the competitive solicitation required by the Track A Order, than it is an attempt to implement it.

To start, APS' needs assessment significantly understates its unmet needs. The Commission's Track A Order required APS to solicit competitive proposals for "at a minimum" the capacity and energy that APS could not produce from its existing assets.[3]

In its proposal, however, APS has artificially minimized the amount of energy to be solicited by defining its "unmet energy needs" as the amount of energy it would need if it ran its existing assets at full output *regardless of cost*. Clearly, by ignoring the cost of its own power plants, APS overstates the amount of energy it should procure from its own high-cost units and, thereby, underestimates the amount of energy it would need from new suppliers.

[3] Decision No. 65154, Docket No. E-00000A-02-0051, September 10, 2002 ("Track A Order") at page 30 Finding of Fact 36.

Q. Do you believe APS should forecast its unmet energy needs without regard to what it costs to supply energy from its own assets?

A. No, of course not. Nor could the Commission have intended this since APS' interpretation would violate one of the most basic requirements for any utility: meet your ratepayer's needs *at reasonable cost*.

Q. What is your opinion of APS' estimate of unmet capacity need?

A. I have three concerns. I believe APS has understated its unmet capacity needs by (a) calculating its 15% reserve margin on just APS capacity rather than on peak load as is traditionally done; (b) excluding the non-APS RMR units (Pinnacle West's new West Phoenix units) from unmet needs; and (c) not correcting for its persistent under forecasting of peak load.

Q. What is the concern with excluding non-APS RMR generation from unmet needs?

A. APS attempts to shield Pinnacle West's new West Phoenix units from area-wide competition. APS' premise for this shielding is that these non-APS units will be needed in certain hours for reliability must run service. However, by APS' own estimates, even these non-APS units would be needed at most for 159 hours for RMR service though the year 2006; in 2003, RMR service is required in only 6 hours.[4] These few hours are not sufficient to justify excluding these units, in their entirety, from unmet capacity needs and, thereby, shielding its Affiliate's units from area-wide competition year-round.

[4] (Exhibit No.___(CRR-3)).

Q. How does APS' estimate of its unmet energy and capacity needs compare to those from Staff and to those you would recommend?

A. Table One below compares the three estimates of unmet needs for both capacity and energy in 2006. As you can see, my estimate and those from Staff are reasonably close. APS' estimate of unmet energy needs is a fraction of our estimates; APS' estimate of unmet capacity needs is also significantly lower--indeed, it is 1,119 MW lower than Staff's.

TABLE ONE

THREE ALTERNATIVE CALCULATIONS
OF APS' UNMET NEEDS
IN 2006

| | CAPACITY | ENERGY |
|---|---|---|
| APS[a] | 1,779MW | 1,469GWH |
| STAFF[b] | 2,898MW | 9,754GWH |
| PANDA[c] | 2,644MW | 8,801GWH |

[a]Exhibit No.___(CRR-2) reproducing APS Schedule PME-1
[b]Staff Report page 7, energy reflects 38% capacity factor
[c]Uses Staff's 38% capacity factor for energy

Q. Aside from your concerns with APS' needs assessment, do you have any concerns with its procurement proposal?

A. Since APS' estimate of unmet needs is intentionally low, it naturally chose the wrong products to procure. Thus, APS proposes to *solicit capacity* from competitive power suppliers through its RFP, but it *will not solicit much actual energy (electric generation)* from those same suppliers at the time of the RFP.

Q. Does APS say it intends to get all the energy from its existing assets?

A. No. APS does not propose to get the energy it needs from running its existing assets at their physical maximums, as APS assumed in the calculation of its unmet energy needs. APS must have seen just how expensive that would be for its ratepayers. Rather, APS proposes to solicit energy later (most likely in real time or monthly) from the Western spot market. I will refer to this as APS "economy energy proposal."[5]

Q. What do you think of APS' economy energy proposal?

A. APS' economy energy purchases are the element of APS' procurement proposal that is potentially most harmful to APS' ratepayers. This is because APS' proposal puts its ratepayers at risk in the volatile spot markets of the West. If we learned anything from the California Crisis, it is that overexposure to spot markets is dangerous to consumers. For this reason alone, APS' economy energy proposal must be rejected at the outset.

Q. Please summarize your recommendations regarding APS' needs and assessment and procurement proposal?

A. I recommend that the Commission reject APS' estimates of its unmet energy and capacity needs as well as APS' product definition. Instead, for 2006, APS should solicit 1,891 MW of asset-backed, dispatchable unit sales under traditional pay-for-performance PPAs. The remainder of unmet capacity needs in 2006 should be solicited as seasonal call options. The unit sales offers should assume non-APS

[5] Carlson Direct at page 4, page 12 to 14.

RMR units will be required to run in RMR hours, and this non-APS RMR service will be contested in a separate solicitation.

**B. The Staff Report**

Q. Can you summarize your overall assessment of Staff's Report?

A. I agree with much of what I see in the Staff Report. For example, the Staff requires that the solicitation be monitored by an independent third party (the "Independent Monitor"). Also, as I showed earlier, my estimate of APS' "unmet needs" is very close to that presented in the Staff Report.

Q. Are there areas of the Staff Report that you would like to see changed?

A. Yes. There are four key areas in which the findings should be more clearly specified: Specifically, I call for (a) APS responses to comments by interested parties; (b) adjustment in the manner in which Staff develops its "Price to Beat;" (c) a requirement that the Independent Monitor concur in the selection of winning bidders or the solicitation does not get certified by the Commission as being prudent; and (d) allowing the Independent Monitor to ask the Commission to stop the solicitation process if APS fails to act in good faith.

## III. ONCE AGAIN APS HAS MADE A PROPOSAL THAT OBVIOUSLY IS NOT IN THE BEST INTEREST OF APS' RATEPAYERS.

### A. APS has consistently made proposals that benefit its shareholders at the expense of its ratepayers.

Q. You say you are disappointed in APS's propsal, why?

A. Staff and its consultants did a good job attempting to get consensus through a series of workshops, and demanding that the process work to benefit Arizona ratepayers. My client, Panda Gila River, L.P. went to considerable effort and expense to participate in those workshops in good faith, as well as in the Track A and Variance proceedings. In sharp contrast, APS' testifying witnesses did not participate in any of the three workshops held prior to submitting testimony. Moreover, over the past year, APS has put forth a string of proposals that benefit its shareholders at the expense of its ratepayers. Its most recent testimony is more of the same.

Q. You mentioned a "string of proposals" over the past year by APS. What specific proposals do you have in mind?

A. I have three proposals in mind. On October 18, 2001, APS proposed that its ratepayers take on the burden of a 29-year power purchase agreement (PPA) with its Affiliate, Pinnacle West.[6] This Affiliate PPA was a high-cost offer that

[6] Request of Arizona Public Service Company for a Partial Variance to A.A.C. R14-2-1606 (B) and for Approval of a Purchase Power Agreement, Docket No. E-01345A-01-0822, October 18, 2001.

afforded none of the risk protection or reliability guarantees offered in the standard pay-for-performance PPA from competitive power suppliers.[7]

On July 11, 2002, in a letter from Chairman Post to the Commission, Pinnacle West suggested that the merchant plants built by Pinnacle West (Redhawk and new West Phoenix) be put into APS' rate base at full cost.[8] Again, this was a full-cost, cost-plus deal despite the fact that Arizona now has a glut of merchant capacity built by others, which means that APS' ratepayers could get a better deal.

On September 16, 2002, APS proposed that it would loan $500 million to its Affiliate because Pinnacle West could not stand on its own.[9] A proposal it has now advanced again with an "emergency" request to create a $125 million credit fund for Pinnacle West. In my view, this might be the most blatant attempt to benefit shareholders at the expense of ratepayers since the ratepayers get absolutely nothing in exchange for shouldering the debt burden of Pinnacle West's unregulated investments.

Q. What is the point you are making by citing these three proposals?

A. My point is that APS has consistently acted to benefit it Pinnacle West Capital Corp.'s shareholders at the expense of its ratepayer.

Q. Why is this important?

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[7] See Direct Testimony of Craig R. Roach, Docket No. E-00000A-02-0051, March 29, 2002.
[8] Letter by Chairman William J. Post to the Arizona Corporation Commission, July 11, 2002.
[9] Application of Arizona Public Service Company, Docket No. E-01345A-02-0707, September 16, 2002.

A. It is important for two reasons. First, the procurement mechanism proposed by Staff is based on an assumption that the utility is operating in the best interest of ratepayers in making its choices. As I describe above, that has not been the case here. This lays the framework for the second point, which is it demonstrates the affiliate bias inherent in APS' actions and demands that APS be denied the discretion Staff proposes for purchasing utilities.

**B. APS' most recent proposal will also harm ratepayers. APS understated its unmet energy needs to justify its economy energy proposal, and that proposal will leave its ratepayers at the mercy of the volatile Western spot market.**

Q. Let's return to your concern about APS' economy energy proposal. Please summarize your concern.

A. The Commission's Track A Order required that "upon implementation of the outcome of Track B, APS shall acquire, at a minimum, any required power that cannot be produced from its own existing assets, through the competitive procurement process as developed in the Track B proceeding. The minimum amount of power, the timing, and the form of procurement shall be determined in the Track B proceeding."[10] The "economy energy" proposal artificially minimized the amount of energy it should solicit through the Track B process by using a calculation of the maximum output its assets could physically produce

[10] Decision No. 65154, 4th ordering paragraph.

*regardless of cost*. The Commission clearly did not limit the solicitation in this manner.

Based on this faulty calculation of unmet energy needs, APS proposes to conduct a competitive solicitation and to contract for capacity, but, rather than simultaneously locking in fixed-formula pricing for energy production from those same power plants, APS proposes to buy its unmet energy needs (the electricity actually generated) through what it calls "short-term and economy energy" purchases.[11] APS' economy energy proposal would subject its ratepayers to the mercy of the spot market for much of their energy needs. Indeed, APS' own forecast shows that economy energy would account for 23% of total energy needs in 2006.[12] If there is any lesson from the California Crisis it is that overdependence on spot market purchases is dangerous for ratepayers.

Q. Could APS' dependence on the Western spot market prove to be even greater were its proposal accepted?

A. Yes. APS' own testimony shows that it consistently underestimates energy needs. When the forecast horizon is four years, as it is today for 2006, on average, APS underestimates its energy needs by 7.4%.[13] If APS' forecast for 2006 has the usual underestimation, economy energy sales could account for 28% of all ratepayer energy needs in that year.

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[11] Carlson Direct at pages 12 to 14.
[12] (Exhibit___(CRR-4)) and (Exhibit___(CRR-2)) reproducing APS Schedules PME-13 and PME-1).
[13] (Exhibit No.___(CRR-5)).

Q. Does APS have an alternative to these spot purchases?

A. Under its proposal, the only apparent alternative to spot purchases is additional generation from APS' existing assets. However, based on APS' own workpapers additional energy from existing assets is expensive as compared to what might be secured through a winning bid from a new combined cycle plant.[14] In Schedule PME-13 from APS' Testimony, the third column from the left shows the economy energy prices APS is projecting on average.[15] For 2006, for example, the forecast is $40.53/MWH. Since APS projects it would buy 23% of its needs through economy energy instead of generating additional energy from existing assets, we can assume this additional energy has incremental costs greater than $40.53/MWH on average, although we do not know how much greater.

Q. Why do you say energy from a winning bid would be cheaper?

A. I say this based on some simple calculations. The fourth column from the left of APS' Schedule PME-13 provides APS' forecast of natural gas prices.[16] In 2006, that price is $3.35/MMBtu. Assume a combined cycle plant wins the capacity solicitation, and assume further it has a heat rate of 8,000 Btu/kwh (HHV). With that heat rate, and the APS gas price of $3.35/MMBtu, the plant's energy price bid could be as low as $26.80/MWH, which is 34% lower than APS' projected average economy energy price of $40.53/MWH in 2006.[17]

[14] (Exhibit No.___(CRR- 4)).
[15] Exhibit No.___(CRR-4)).
[16] Ibid.
[17] This example is meant as an illustration, and therefore does not include Variable O&M and transmission losses.

Q. What is the point you are making with this calculation?

A. The point is that, using APS' own projections, there is the potential for considerable cost savings to its ratepayers from soliciting energy bids from the same combined cycle plants from which capacity bids will be solicited. The most important point, however, is that APS ratepayers, Commission Staff and the Independent Monitor would be deprived of knowing whether this better deal is available because APS will not have asked.

Q. What approach do you recommend in place of APS' economy energy proposal?

A. Obviously, the approach that is in the best interest of APS' ratepayer is to attempt to get the best of both worlds, and the way to do that is to have a majority of the solicited capacity procured through dispatchable unit sales. If Redhawk and new West Phoenix had been put in rate base, their capacity and energy, in effect, would have been sold under an asset-backed, dispatchable unit sales agreement. Indeed, all rate-based power plants are, in effect asset-backed, dispatchable unit sales agreements, although, in ratebase they do not offer the consumer risk protection and availability guarantees of a pay-for-performance unit sales agreement.

Dispatchable unit sales agreements with competitive power suppliers secure the best of both worlds for APS' ratepayers because, while they assure sufficient capacity to keep the lights on, they can also pre-set to various extents the price at which energy will be generated thus protecting consumers from high-end spot prices. At the same time, because they are dispatchable, if spot energy prices are low, APS can buy spot energy instead of running these units at full tilt.

Q. Are there other reasons to recommend asset-backed dispatchable unit sales?

A. Yes. Asset-backed, dispatchable unit sales are better for APS' ratepayers at this point in time for two other reasons. First, there is a glut of power plant capacity in Arizona and allowing those power plants to compete head-to-head will get the best bargain for ratepayers. Head-to-head competition is best in the context of unit sales. Second, unit sales are the best way to secure asset-backed deals where the Staff and the Commission can go out and "kick the tires." In the Staff's request that all bidders agree to site visits I detect a real interest in such "steel in the ground" proposals.

Q. How would you contrast your asset-backed, dispatchable unit sales to APS' proposal?

A. In sharp contrast to the traditional unit sales proposal, APS would solicit bids for capacity and then buy energy in the spot market. Even putting aside the inherent spot market risk of its economy energy purchases, I think the Commission should question the capacity products APS proposes to solicit. APS proposes to solicit (a) capacity-only; (b) capacity plus minimum energy; and (c) call option capacity. I do not see that APS has much experience with these products. At the moment, through data requests we see only four contracts for a total of 125 MW of summer purchases in 2003, of both capacity and associated energy.[18] I do not doubt that all three of these capacity products could be beneficial in the right circumstances. However, I do not see the need to (or the prudence of a) jump from (a) 125 MW of straightforward peak purchases to (b) 1,700 MW of the more complex, new products.

Q. Do you believe APS is aware of the potential benefits of asset-backed, dispatchable unit power sales?

A. Yes. APS must be aware of the potential ratepayer benefits of asset-backed, dispatchable unit power sales from new combined cycle plants. It endorsed those benefits every time it claimed Pinnacle West's Redhawk and new West Phoenix units were the best deal for APS' ratepayers.

Q. Did APS previously reveal its economy energy proposal and capacity RFP?

A. No, at least not to me or other workshop participants. I was intensely involved in all of Staff's workshops and I had no indications of APS' scheme.

Q. Did you previously reveal your asset-backed, dispatchable unit sales approach?

A. Yes, absolutely. On Panda's behalf, I promoted this approach during Staff's workshops by presenting several versions of Panda Gila River's "Strawdog" proposal. I have attached the last version of Panda Gila River's Strawdog, which

[18] APS Response to Staff's First Set of Data Requests MR 1.4 (Exhibit No.___(CRR-6)).

was presented to the Commission on August 28th (please note that this proposal has not been updated since that time).[19]

Q. Why did APS propose this now?

A. I cannot know APS' intent, but I can only deduce that APS hopes its proposal will subvert the solicitation. I suspect that, with the economy energy plan, APS hoped to purchase from its Affiliate's Redhawk plant at spot market prices. I believe all bidders would have this same suspicion.

Q. Are there other facts that fuel this suspicion?

A. Yes. I will mention two. First, in the Staff's August 13/14 Workshop, when APS believed its Affiliate's combined cycle Merchant plants (Redhawk and new West Phoenix) might be put into rate base, APS presented a table showing that those plants (with 1,700 MW of capacity) would generate 6,170 GWH of energy and, therefore, would have a 41% capacity factor in the year 2004.[20] But once APS realized that a competitive supplier could own the combined cycle power plants from which energy will be procured, APS began using a capacity factor of about 6% for approximately the same amount of capacity (1,634 MW), which means these power plants will generate just 840 GWH in 2004.[21] Thus, with this one forecasting gimmick, APS has wiped out more than 86% of its unmet energy need.

[19] (Exhibit No.___(CRR-7)).
[20] (Exhibit No.___(CRR-1)).
[21] (Exhibit No.___(CRR-2) reproducing APS Schedule PME-1).

Second, in a similar vein, the Commission will recall APS' proposed Affiliate PPA in which 4,720 MW of divested assets (including all existing APS units plus Redhawk and new West Phoenix) were offered and committed to produce 21,090 GWH of energy. Contrast that with APS' current claim that just its existing assets could be used to produce up to 29,931 GWH.[22] APS is claiming that, with 15% less power plant capacity (4,001 MW of capacity vs 4,720 MW), it intends to produce up to 42% more energy than it offered in the Affiliate PPA.

Q. Are there specific anti-competitive tactics that bidders will anticipate?

A. Yes. For example, assume APS issues a capacity-only RFP in which only a capacity price is allowed. If Pinnacle West knows it will be favored in the economy energy purchases it can bid an artificially lower capacity price. It could artificially lower its capacity price bid because (a) it can anticipate spot prices sometimes embedding a fixed cost contribution (an implicit capacity payment) and/or (b) it can be assured its start-up costs and minimum load energy costs will be covered so these costs need not be reflected in the capacity price Pinnacle West bids.

Q. You mentioned an "implicit capacity price" in spot prices. Does that mean that ratepayers could pay twice for capacity?

A. Yes. It is a possibility, but not a certainty, that APS ratepayers could pay twice for capacity under APS' economy energy proposal.

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[22] (Exhibit No. ___ (CRR-2)).

**C. APS has understated its unmet capacity needs by using a double standard for reserves, overstated its RMR needs, and failed to correct its persistent underestimation of peak load.**

Q Let's turn now to your concern about APS underestimating its unmet capacity needs. Please summarize your concerns.

A. I have three concerns. I believe APS has understated its unmet capacity needs by (a) calculating its 15% reserve margin on just APS capacity rather than on peak load as is traditionally done; (b) excluding the non-APS RMR units (most likely Pinnacle West's new West Phoenix units) from unmet needs; and (c) not correcting for its persistent under forecasting of peak load.

Q. How did APS justify its approach to calculating reserves?

A. APS justifies calculating a 15% reserve margin on just APS capacity by stating that all competitive power suppliers would be expected to bring their own reserves. It is true that competitive power suppliers may bring their own reserves – they do so with my Firm LD unit sales, as well as with my call option product. However, this does not suggest that unmet capacity needs be calculated without reserves, rather, it necessitates a change in how we measure the products that meet those needs. Put simply, 100 MW of APS existing capacity or 100 MW of my unit contingent capacity fills 100 MW of Standard Offer capacity needs (when that need is calculated to include reserves). However, 100 MW of Firm LD unit sales or 100 MW of call options fills 115 MW of Standard Offer needs.

Q. Why is your approach better?

A. The approach outlined herein is better for two reasons. First, unlike APS' approach, it does not hide the fact that the products which bring reserves are higher quality products. That is, it does not hide the fact that these premium products from competitive power suppliers are more valuable than APS' own assets.

Second, it is better because it allows the power plants that provide reserves to be determined by economics. For example, in a world of all unit-contingent sales (the same as in the world of standard utility-owned plants), the plants that provide reserves are higher-cost plants. So if we brought on several new, low-energy cost combined cycle plants, this could mean that APS' higher cost plants are pushed into the role of providing reserves. Even more broadly, my approach will let economics dictate whether products that include reserves are more economical than products that do not.

Q. What is the impact of calculating reserves on total peak load?

A. Calculating unmet needs with a 15% reserve margin on peak load, not just on APS' owned generating assets, increases the amount of unmet needs. In 2006, for example, this one change would increase APS' unmet capacity needs from 1,779 MW to 2,161 MW, or by 21%.

Q. Has APS ever used your method?

A. Yes. Indeed, when APS thought that its Affiliate's merchant plant would not have to compete, it calculated its reserves on peak load just as I propose here, although APS used a 12% reserve margin at the time.[23]

Q. Let's turn to your second concern about APS' calculation of unmet capacity needs. How does APS justify excluding Pinnacle West's new West Phoenix units?

A. APS attempts to shield its Affiliate's new West Phoenix units from area-wide competition by declaring those units to be essential reliability must run (RMR) units year-round despite the fact that its own forecasts show them to be needed for very limited hours in all years through 2006. APS refers to these as non-APS RMR needs and the hours of RMR service are shown in Table Two below.

TABLE TWO

NON-APS RMR NEEDS
2003 Through 2006

| Year | Capacity Need | Number of RMR Hours |
|---|---|---|
| 2003 | 29 | 6 |
| 2004 | 184 | 19 |
| 2005 | 338 | 57 |
| 2006 | 493 | 159 |

*SOURCE*: Exhibit No.___(CRR-3) reproducing APS' workpaper at page 76.

23 (Exhibit No.___(CRR-1)).

Q. Is it necessary to exclude Pinnacle West's new West Phoenix units from unmet capacity needs and, thereby, to shield those units from area-wide competition?

A. No, not at all. A much better approach is to simply carve out the few hours in which these units actually provide RMR service, require those units to run in those hours at a price no higher than the protocol price established in APS' OATT, and then allow full area-wide competition for all the other hours of the year. This is consistent with the Staff Report, which allows capacity to be excluded from unmet needs for RMR service *during RMR hours*.

Q. Could the carved out RMR hours be subject to competition separately?

A. Yes. As APS suggested, competition for Pinnacle West's new West Phoenix units during RMR hours should be allowed from other in-area (in-Valley) plants or by plants that could deliver to the Valley via non-APS transmission lines.[24]

Q. Let's turn to your third concern. What is your point about APS' forecast errors?

A. My concern is that APS' own workpapers show it has consistently under-forecasted peak load, especially when the forecast is four years out, as it would be here. Table Three below reveals that forecasts (a) have been too low and (b) the forecast errors increase as the forecast horizon is extended.

[24] Carlson Direct at page 10 lines 5 to 9.

TABLE THREE

APS UNDER FORECASTS PEAK LOAD
(Percent Error for Peak Demand)

Forecast Horizon

| Forecast Date | 1 year | 2 years | 3 years | 4 years |
|---|---|---|---|---|
| Jan-92 | 6.77% | 15.45% | 16.75% | 17.94% |
| Feb-93 | 15.23% | 16.56% | 19.05% | 18.33% |
| Oct-93 | 13.74% | 16.59% | 20.27% | |
| Feb-94 | 16.59% | 20.27% | 18.67% | 28.54% |
| Oct-94 | 15.31% | 16.59% | 15.20% | |
| Jun-95 | 16.59% | 15.20% | 22.87% | 15.87% |
| Oct-95 | 14.23% | 12.83% | 21.98% | |
| May-96 | 12.83% | 21.98% | 16.86% | 26.24% |
| Oct-96 | 9.56% | 18.06% | 12.88% | |
| Feb-97 | 18.84% | 13.60% | 22.35% | 22.91% |
| Oct-97 | 13.01% | 5.81% | 13.41% | |
| Feb-98 | 5.81% | 13.41% | 14.04% | 13.07% |
| Oct-98 | 3.29% | 10.96% | 11.23% | |
| Apr-99 | 9.36% | 9.47% | 9.04% | |
| Oct-99 | 8.54% | 8.12% | 7.13% | |
| Apr-00 | 6.08% | 3.68% | | |
| Oct-00 | 3.78% | 1.82% | | |
| Apr-01 | -0.09% | | | |
| Oct-01 | 3.44% | | | |
| Average | 10.15% | 12.97% | 16.11% | 20.42% |

*Note that positive numbers indicate the amount that was under forecast. For example, in January 1992 the forecast predicted a demand that was 6.77% lower than actual demand in 1993.
*SOURCE*: Ewen Direct at PME-7.

Q. What would it mean if APS' forecast presented in its recent Testimony suffered the same forecast error as shown in the past?

A. The effect would be a dramatic increase in unmet capacity needs. For example, in 2006, the unmet capacity need would have to be increased to reflect a 20.42% under estimate of peak load. By my calculations, and correcting for my other two concerns, that would increase 2006 unmet capacity need from APS' estimate of 1,779 MW to 4,176 MW, which is more than a doubling.

Q. Do you recommend that APS' estimate of unmet needs be corrected for this forecast error?

A. No, not in terms of raising the forecast. I just wanted to make the Commission aware of it. However, the Commission should find that persistent under forecasting, as compared to errors in both directions, is indicative of either poor forecasting or forecasting gimmicks. Moreover, the Commission should put APS on notice that, if its under forecasting leads to greater expense or lower reliability for its ratepayers, APS will be subject to a finding of imprudence. And, further, that when an under forecast is discovered, any additional need must be competitively procured under the Track A Order.

**D. The best approach for APS' ratepayers is to solicit the majority of unmet needs through asset-backed, dispatchable unit bids that would sell under traditional pay-for-performance PPAs. The remainder of unmet needs would be met with seasonal call options with pre-established energy prices.**

Q. How should the Commission require APS to amend its calculation of unmet capacity needs?

A. APS must be required to recalculate unmet needs with a 15% reserve margin on peak load, and without excluding non-APS RMR capacity. That would change the calculation of unmet capacity need as shown below in Table Four.

TABLE FOUR

CORRECTED UNMET NEEDS
WITH FULL 15% RESERVE AND NO NON-APS RMR
EXCLUSION

| Capacity | 2003 | 2004 | 2005 | 2006 |
|---|---|---|---|---|
| Total Standard Offer Load | 5,723 | 6,023 | 6,269 | 6,522 |
| +15 % Reserve Margin | 858 | 903 | 940 | 978 |
| APS Units | (3,927) | (3,953) | (3,949) | (3,975) |
| Purchase Contracts | (955) | (837) | (844) | (852) |
| EPS | (9) | (17) | (23) | (29) |
| Net Unmet Needs | 1,690 | 2,119 | 2,393 | 2,644 |

Includes 15 % Reserve Margin on Total Standard Offer Load, and does not exclude Non-APS RMR generation from Unmet needs.

Q. Should the Commission require changes in APS' procurement plan?

A. Yes. Because the initial solicitation is so important in setting the stage for success in future solicitations, the Commission should set some boundaries.

Q. What boundaries do you have in mind?

A. The majority of the unmet needs must be met by asset-backed, dispatchable unit sales with traditional pay-for-performance PPAs. The amount of capacity solicited for unit sales would be equal to that intended to be met by Pinnacle West's Redhawk and new West Phoenix units; this is a total of 1,644 MW plus 15% reserves for a solicitation total of 1,891 MW in 2006. The logic here is obvious: APS had argued that these units were needed now and, had they been put in rate base, they would have been treated akin to unit power sales.

Q. What reliability offers would be required?

A. Two reliability offers would be accepted. The first would be a unit contingent offer with an Availability Guarantee of 95%. The second would be an offer of firm power that would include a 100% Availability Guarantee and the requirement to pay for replacement capacity and energy if the 100% guarantee is not met; this offer is also called "Firm LD" because it is made firm with its liquidated damages provision.

Q. What pricing structure should be set for these unit sales?

A. With respect to pricing, the RFP for unit sales would allow bidders to offer up to five components of price:

- A Capacity Price stated in S/kw-year for each year of the contract term, or initial-year stated and then indexed to inflation; payments of the Capacity Price must be tied to the Availability Guarantee;

- An Energy Price that is either a fixed price (S/MWH) stated for each year or stated as a guaranteed heat rate and a fuel price tied to some publicly available fuel price index; a gas tolling offer is also allowable in which the heat rate is guaranteed, but APS provides the gas;
- A Fixed Operation & Maintenance (FO&M) Price in S/kw-year for each year of the contract length, or an initial-year price indexed to inflation; payments of this price, too, must be tied to the Availability Guarantee;
- A Variable Operation & Maintenance (VO&M) Price (S/MWh) stated for each year or an initial-year price indexed to inflation; and
- A Start Price in dollars per start stated for each year or indexed.

Q. How would APS determine the amount of energy it would procure from this capacity?

A. These unit sales offers would be dispatchable within specified limits such as minimum load and ramp rates, based on the offered energy price plus variable operation and maintenance price and transmission losses. This is no different from how APS "procures" power today from its own power plants. So a supplier's offered prices would determine how much energy it would sell.

Q. Does your approach mean that APS could not buy from the Western spot market?

A. No, not at all. My proposal allows APS to get the best deal for ratepayers by taking the cheapest energy, whether it was from these contracts or the spot market, whatever is best for ratepayers. Dispatchability would allow APS to take advantage of the spot market if and when it was to the benefit of ratepayers, but the guaranteed energy from these PPAs would give the risk protection inherent in a pre-set, fixed-formula energy price. In this way, APS' ratepayers would get the best of both worlds.

Q. How would the remainder of unmet capacity needs be met?

A. The remainder of the unmet needs (753 MW in 2006) can be met with seasonal call options. The call option gives APS the right (but not the obligation) to call on the bidder during the summer months (June, July, August and September). APS could structure this product to be callable for either 16 peak hours in a day or just in 6 super-peak hours. All of the calls are under day-ahead scheduling. Once called to run, the unit would be guaranteed to run for the full 16 or 6 hours depending upon the product. This call option product would also be Firm LD; that is, it would guarantee 100% availability backed by liquidated damages.

Q. What pricing structure would be used for the call options?

A. Pricing would be in the form of a two part-price: (a) a call option payment paid at the start of each year (or monthly) in S/kw and (b) a strike price paid when called that can be fixed (S/MWh) or fixed-formula (guaranteed heat rate tied to a fuel index).

Q. Must APS stick with the amount in your unit sale/call option split regardless of the bids it receives?

A. No. APS should always act in the best interests of its ratepayers. If one type of bid is clearly superior in terms of price, risk and reliability, then APS should procure more of it. This would be determined jointly by APS, Staff, and the Independent Monitor as part of the Bid Evaluation Team.

Q. How would non-APS RMR service be reflected in the RFP?

A. The RFP for unit sales would take account of the expected RMR service of the non-APS RMR units, whether that is the new West Phoenix units or competing units. Specifically, non-APS RMR units would be required to be available for RMR service in RMR hours and would be paid no higher than the Arizona protocol price for load pocket pricing. My understanding is that APS' OATT requires a price set to variable costs plus a share of fixed costs – the share of fixed costs would bet set at the share of total hours of operation which are attributed to RMR service. In the non-RMR RFP, bids from competing suppliers would be accepted for all the remaining non-RMR hours in the year.

Q. Would you endorse APS' call for a separate RFP for RMR service?

A. Yes. The RMR hours can be contestable too, with APS running a separate RFP for RMR service. Bids would be accepted from: (a) in-Valley generation; (b) out-of-Valley generation that has non-APS firm transmission service to the Valley during RMR hours; and (c) out-of-Valley generation that offers to finance new transmission capacity to the Valley. For purposes of the RMR RFP, APS must offer to re-start and run mothballed generation (e.g., old West Phoenix 4 and 6) at a bidder's expense.

Q. Are there any boundaries the Commission should set with respect to the term of PPAs?

A. Yes. APS states that it will not consider offers with longer than a four-year term. In contrast, Staff's Report gives APS the discretion to seek contracts with options to extend if that would be in the ratepayers' best interests.[25] With APS' approach, many contracts will expire in about 2006. I think this is risky for APS' ratepayers since the capacity glut should be absorbed by then. The Commission should put APS on notice that, if it fails to implement Staff's option to extend, and prices spike in 2006, APS will be at risk for a finding by the Commission of imprudence.

## IV. I AGREE WITH MUCH OF WHAT I SEE IN THE STAFF REPORT, BUT I WOULD LIKE TO SEE THREE OF STAFF'S PROPOSALS BE MORE FULLY SPECIFIED.

Q. What is your overall assessment of the Staff Report?

A. I agree with much of what I see in the Staff Report. There are three areas in which I would like to see the Report be more specific.

[25] Staff Report at page 25 lines 15 to 16.

Q. What are your areas of agreement with the Staff?

A. There are several, I will mention five.

First, I agree with Staff that "[c]ompetition can help to obtain the best deal for ratepayers,"[26] and believe that my proposal has several positive aspects which are meant to ensure competition will work to the benefit of Arizona ratepayers. Futhermore, I agree with Staff's goal of creating an equitable and transparent process that "facilitate[s] a manageable transition to a competitive wholesale power market that provides economic benefits to customers in Arizona...".[27]

Second, and most notably, I agree with Staff's analysis of APS' unmet needs for capacity and energy, particularly the approximately 38% load factor Staff used to calculate the energy portion.[28]

Third, I concur with Staff that the unmet needs for each of the next four years should be the minimum amount that is included in the 2003 solicitation.[29]

Fourth, in many respects its proposal achieves Staff's stated purpose of ensuring a fair and equitable solicitation. Specifically, the Staff is right to endorse a bid evaluation format that compares bids using an equivalent annual annuity

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[26] Staff Report at page 1 line 6.
[27] Id at page 1 lines 8 to 9.
[28] Id. at page 7.
[29] Id. at page 35 lines 7 to 8.

method.[30] I also agree with Staff that APS must be required to provide ancillary services to all bidders if it provides them to any generating asset not included in rate base.[31] And I agree that APS should make transmission access on its system available to all bidders in an unbiased fashion.[32]

Fifth, I support Staff's proposal for a solicitation website, which monitors all contact between the utility and bidders, as a positive step in ensuring that there is no bias toward Pinnacle West.[33]

Q. Are there areas of the Staff Report that you would like to see changed?

A. Yes. There are three areas in which the findings should be deepened.

First, I appreciate Staff recognizing the importance of allowing Intervenors to have specific opportunities to comment on each step of the solicitation process through written comments provided to APS, Staff, and the Independent Monitor. However, equally important, APS must be required to respond to these comments in writing within seven days.

Second, the Staff's price to beat estimate must focus on the question ratepayers care about most: will my monthly bills increase over time with the winning bids? To that end, it would be best if Staff compared the winning bids in any solicitation

[30] Id. at page 23 lines 8 to 11.
[31] Id. at page 16 lines 7 to 11.
[32] Id. at page 5 lines 6 to 9.
[33] Id. at pages 19 to 21.

to the unbundled generation cost of APS' existing power resources as adjusted for fuel costs and inflation. If Staff chooses to also incorporate a forecast of spot market purchases in its price to beat, it should reflect the consumer risk of such a dependence on spot purchases; one way to reflect this risk is to use a Black and Scholes calculation to estimate what would be charged to lock into the forecast used by Staff.

Third, while Staff assures the third-party Independent Monitor access to all the information used by APS to solicit and choose among bids, it fails to give the Independent Monitor any means of leverage. Specifically, while APS must allow the Independent Monitor access, there is no pressure on APS to work to win the Independent Monitor's concurrence on both its process and, more importantly, its choice of winning bids. I recommend that the Independent Monitor's Report to the Commission, which is required by Staff, include a headline statement by the Monitor on whether he or she concurs with the ultimate selection of winners. Moreover, that concurrence or lack thereof should be given considerable weight in the Commission's approval or disapproval of the purchase contracts, which result from the solicitation. In addition, the Independent Monitor should have the right to ask the Commission to stop the solicitation process if APS acts in bad faith.

## V. RECOMMENDATIONS

Q. What are your recommendations based on your Testimony?

A. I have five recommendations with respect to APS based on my Testimony:

First, the Commission must reject APS' estimate of its unmet energy needs because its economy energy proposal puts its ratepayers at risk in the volatile Western spot market. Instead, consistent with its approach when promoting its Affiliate's Redhawk and new West Phoenix units, APS must estimate this need assuming new, dispatchable combined cycle plants will fill its capacity need.

Second, the Commission must reject APS' estimate of unmet capacity needs because (a) it fails to calculate the 15% reserve on total peak load as it has done in the past and as is traditional; and (b) it shields Pinnacle West's new West Phoenix units from area-wide competition by excluding them from unmet capacity needs based on limited RMR service. The Commission should also take note that APS consistently under forecasts peak load by more than 20% when looking out four years, as would be the case here, and that APS is liable for ratepayers harm due to its under forecasting.

Third, the Commission must reject APS' product definition, which I see as an attempt to undermine, rather than implement, the competitive solicitation required by the Commission's Track A Order. Instead, for 2006, APS should solicit 1,891

MW of asset-backed, dispatchable units sales offers under traditional pay-for-performance PPAs with both unit contingent and Firm LD options allowed. The remaining 753 MW of unmet capacity need in 2006 should be solicited as seasonal call options that are Firm LD.

Fourth, for the unit sales RFP, bidders should assume that non-APS RMR units will be required to run in RMR hours under the Arizona protocol and that competition will be for all non-RMR hours of the year.

Fifth, a separate RFP for non-APS RMR service can be held. To support this RFP, APS must offer to re-start mothballed in-Valley units fully at a bidder's expense.

Q. Do you have any recommendations with respect to the Staff Report?

A. The Commission should generally accept Staff's Report. I would recommend that it deepen the Staff's recommendation in three areas.

- First, APS must be required to respond in writing to comments by interested parties in seven days.
- Second, Staff's price to beat should compare unbundled generation rates today with the rates resulting from winning bids. If Staff adds wholesale spot prices to its price to beat, it must reflect the consumer risk of relying on spot purchases.

- Third, the Independent Monitor must be asked to announce whether he or she concurs with APS' process and selection of winning bids. And, that announcement must be given considerable weight in the Commission's approval or pass through of winning contracts to ratepayers. The Independent Monitor must also have the right to ask the Commission to stop the solicitation process if APS acts in good faith.

Q. Does this conclude your Testimony?

A. Yes.

Exhibit No. ___ (CRR-1)

# APS LOAD AND RESOURCE FORECAST
# FROM AUGUST 13/14, 2002 WORKSHOP

# APS Load and Resource Forecast
# 2003-2004

| | Units | 2003 | 2004 |
|---|---|---|---|
| APS Retail Peak Load [1] | MW | 6,647 | 7,019 |
| APS Existing Generation [2] | MW | 4,697 | 4,730 |
| PWEC Dedicated Generation [3] | MW | 1,700 | 1,700 |
| Purchases | MW | 251 | 589 |
| | | | |
| APS Retail Load | MWH | 26,404,986 | 27,733,094 |
| APS Existing Generation [2] | MWH | 20,669,120 | 21,543,806 |
| PWEC Dedicated Generation [3] | MWH | 5,728,434 | 6,170,100 |
| Purchases | MWH | 7,432 | 19,188 |

[1] Includes 12% Reserves

[2] Generation, Long-term Contracts and Renewable Energy

[3] West Phoenix CC Units 4 & 5, Saguaro CT Unit 3, and Redhawk CC Units 1 & 2

The data presented in this summary is estimated planning data for internal APS planning purposes only. Actual APS load and requirements will depend on numerous variables, such as weather, actual load and demand growth, and plant outages, which are not necessarily included in the figures above. Accordingly, this data is provided for discussion purposes only and APS makes no representations or warranties as to its ultimate accuracy.

1224895.1

Exhibit No. ___ (CRR-2)

# APS LOAD AND RESOURCE FORECAST
# FROM DIRECT TESTIMONY OF PETE EWEN,
# SCHEDULE PME-1

**SCHEDULE PME-1**
**APS Projected Unmet Capacity and Energy Needs**
**2003 - 2012**

| Capacity (MW) | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 |
|---|---|---|---|---|---|---|---|---|---|---|
| Total standard offer load [1] | 5,723 | 6,023 | 6,269 | 6,522 | 6,787 | 7,064 | 7,357 | 7,667 | 7,914 | 8,127 |
| + 15% reserve margin [2] | 598 | 602 | 602 | 606 | 606 | 609 | 609 | 609 | 609 | 609 |
| - Physical capability of APS units [3] | (3,927) | (3,953) | (3,949) | (3,975) | (3,975) | (4,001) | (4,001) | (4,001) | (4,001) | (4,001) |
| - Full capability of purchase contracts [4] | (955) | (837) | (844) | (852) | (860) | (868) | (876) | (884) | (893) | (902) |
| - RMR generation from non-APS units [5] | (29) | (184) | (338) | (493) | (647) | (802) | (956) | (1,111) | (1,265) | (1,426) |
| - Planned renewable energy supply under EPS [6] | (9) | (17) | (23) | (29) | (34) | (46) | (56) | (70) | (79) | (89) |
| = Net unmet reliability needs [7] | 1,401 | 1,634 | 1,717 | 1,779 | 1,877 | 1,956 | 2,077 | 2,210 | 2,285 | 2,318 |

| Energy (GWH) | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 |
|---|---|---|---|---|---|---|---|---|---|---|
| Total standard offer load [1] | 26,494 | 27,841 | 28,999 | 30,178 | 31,388 | 32,670 | 33,983 | 35,305 | 36,425 | 37,531 |
| - Physical capability of APS units [3] | (24,016) | (25,242) | (25,663) | (26,496) | (26,941) | (28,179) | (28,707) | (29,182) | (29,567) | (29,931) |
| - Full capability of purchase contracts [4] | (1,798) | (1,672) | (1,986) | (2,044) | (2,281) | (2,140) | (2,358) | (2,551) | (2,719) | (2,870) |
| - RMR generation from non-APS units [5] | (0) | (2) | (8) | (27) | (72) | (141) | (248) | (398) | (540) | (705) |
| - Planned renewable energy supply under EPS [6] | (41) | (85) | (114) | (142) | (154) | (197) | (221) | (267) | (290) | (312) |
| = Net unmet reliability needs [7] | 639 | 840 | 1,228 | 1,469 | 1,940 | 2,013 | 2,449 | 2,907 | 3,309 | 3,713 |

1) Standard offer load includes all retail customer energy and coincident peak demands plus APS wholesale contracts served by APS resources from Oct 2002 budget projections. Under Staff's proposal, this calculation would be updated prior to any actual procurement.

2) Reserve margin is calculated on APS generation and known contingent purchases only.

3) Includes the production from all rate-based APS generation units subject to standard planned and forced outage assumptions.

4) Includes firm purchase contracts entered into prior to September 1, 2002.

5) RMR generation assumes a Valley import limit of 3,535 MW, 660 MW of local APS generation, and 110 MW of required reserves. To the extent that bidders can demonstrate higher import capability or import capability is increased, RMR would be reduced, all else remaining the same. The present import limit of 3,535 MW assumes timely completion of the Southwest Valley line and also uses its most recent (and higher) capacity rating.

6) Includes solar and renewable resource additions planned each year under current funding levels. To the extent the Commission approves higher funding levels, capacity and energy under EPS will increase.

7) Energy figures do not include economy purchases, which as noted in Schedule PME-13 would add some 3,700 gwh in 2003 (and more in subsequent years) assuming present forecasts of gas and power costs.

Exhibit No. ___ (CRR-3)

## APS METRO PHOENIX RELIABILITY MUST RUN ESTIMATES FROM PAGE 76 OF PETE EWEN'S WORKPAPERS

# APS Metro Phoenix Reliability Must Run Estimates
## 2003 - 2012

| | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Capacity Need (MW)** | | | | | | | | | | |
| Metro Phoenix Peak Demand | 4,114 | 4,269 | 4,423 | 4,578 | 4,732 | 4,887 | 5,041 | 5,196 | 5,350 | 5,511 |
| Transmission Import Limit | 3,535 | 3,535 | 3,535 | 3,535 | 3,535 | 3,535 | 3,535 | 3,535 | 3,535 | 3,535 |
| RMR Need | 579 | 734 | 888 | 1,043 | 1,197 | 1,352 | 1,506 | 1,661 | 1,815 | 1,976 |
| APS Resources | 660 | 660 | 660 | 660 | 660 | 660 | 660 | 660 | 660 | 660 |
| APS Reserves | 110 | 110 | 110 | 110 | 110 | 110 | 110 | 110 | 110 | 110 |
| Unmet Need | 29 | 184 | 338 | 493 | 647 | 802 | 956 | 1,111 | 1,265 | 1,426 |
| **Energy Need (GWH)** | | | | | | | | | | |
| Total Energy | 37 | 92 | 172 | 291 | 445 | 633 | 862 | 1,124 | 1,366 | 1,628 |
| APS Supplied | 37 | 90 | 165 | 263 | 373 | 492 | 614 | 727 | 826 | 923 |
| Unmet Need | 0 | 2 | 8 | 27 | 72 | 141 | 248 | 398 | 540 | 705 |
| **RMR Hours** | | | | | | | | | | |
| Total | 210 | 455 | 640 | 862 | 1,099 | 1,293 | 1,511 | 1,723 | 1,909 | 2,103 |
| APS Supplied | 210 | 455 | 640 | 862 | 1,099 | 1,293 | 1,511 | 1,723 | 1,909 | 2,103 |
| Unmet Need | 6 | 19 | 57 | 159 | 313 | 510 | 737 | 944 | 1,114 | 1,282 |
| **RMR Capacity Factor** | | | | | | | | | | |
| APS Supplied | 0.8% | 1.9% | 3.4% | 5.5% | 7.7% | 10.2% | 12.7% | 15.1% | 17.1% | 19.2% |
| Unmet Need | 0.1% | 0.1% | 0.3% | 0.6% | 1.3% | 2.0% | 3.0% | 4.1% | 4.9% | 5.6% |
| Total | 0.7% | 1.4% | 2.2% | 3.2% | 4.2% | 5.3% | 6.5% | 7.7% | 8.6% | 9.4% |

Exhibit No. ___ (CRR-4)

# APS ECONOMY ENERGY PURCHASES
# FROM DIRECT TESTIMONY OF PETE EWEN,
# SCHEDULE PME-13

# SCHEDULE PME-13
# POTENTIAL ECONOMY ENERGY PURCHASES

| | With Current Market Prices | | | Electric Prices 10% Higher | | Electric Prices 10% Lower | |
|---|---|---|---|---|---|---|---|
| Year | Economic Purchase Amount (GWH) | Average Palo Verde On-Peak Electric Price ($/MWH) [1] | Average San Juan Basin Natural Gas Price ($/MMBTU) [1] | Economic Purchase Amount (GWH) | Percent Change | Economic Purchase Amount (GWH) | Percent Change |
| 2003 | 3,705 | 39.42 | 3.60 | 3,122 | -15.7% | 4,418 | 19.2% |
| 2004 | 4,033 | 40.13 | 3.50 | 3,465 | -14.1% | 4,699 | 16.5% |
| 2005 | 6,695 | 40.25 | 3.36 | 5,795 | -13.4% | 7,673 | 14.6% |
| 2006 | 6,948 | 40.53 | 3.35 | 6,032 | -13.2% | 8,025 | 15.5% |
| 2007 | 8,320 | 40.77 | 3.38 | 7,341 | -11.8% | 9,296 | 11.7% |
| 2008 | 6,785 | 41.79 | 3.46 | 6,095 | -10.2% | 7,591 | 11.9% |
| 2009 | 7,964 | 42.83 | 3.55 | 7,274 | -8.7% | 8,787 | 10.3% |
| 2010 | 9,136 | 43.90 | 3.64 | 8,427 | -7.8% | 9,911 | 8.5% |
| 2011 | 10,167 | 45.00 | 3.73 | 9,428 | -7.3% | 10,951 | 7.7% |
| 2012 | 11,099 | 46.13 | 3.82 | 10,300 | -7.2% | 11,871 | 7.0% |

[1] Power and natural gas prices were determined from market quotes through 2007 and escalated by 2.5% per year thereafter.

Exhibit No. ___ (CRR-5)

**APS UNDER FORECASTS ENERGY NEEDS**
**(PERCENT ERROR FOR ENERGY DEMAND)**

## APS UNDER FORECASTS ENERGY NEEDS
(Percent Error for Energy Demand)

Forecast Horizon

| Forecast Date | 2 years | 3 years | 4 years |
|---|---|---|---|
| Jan-92 | 1.71% | -0.70% | 2.95% |
| Feb-93 | -0.07% | 5.83% | 8.87% |
| Oct-93 | 0.16% | 7.50% | |
| Feb-94 | 5.82% | 12.95% | 13.07% |
| Oct-94 | 5.82% | 12.95% | |
| Jun-95 | 5.24% | 5.85% | 7.51% |
| Oct-95 | 2.29% | 2.54% | |
| May-96 | 2.46% | 2.59% | 6.49% |
| Oct-96 | 1.12% | 0.73% | |
| Feb-97 | 1.19% | 4.98% | 5.49% |
| Oct-97 | -0.46% | 2.65% | |
| Feb-98 | 2.65% | 3.33% | |
| Oct-98 | 3.15% | 3.49% | |
| Apr-99 | 3.49% | | |
| Oct-99 | 5.61% | | |
| Apr-00 | | | |
| Oct-00 | | | |
| Average | 2.68% | 4.98% | 7.40% |

*Note that positive numbers indicate the amount that was underforecast. For example, the January 1992 forecasted a demand which was 2.95% lower than the actual demand for energy in 1996.

Exhibit No. ___ (CRR-6)

**APS' FIRST SET OF DATA RESPONSES TO STAFF**
**DATED OCTOBER 15, 2002**
**MR 1.4**

**STAFF'S FIRST SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE IN DOCKET NO's. E-00000A-02-0051, E-01345A-01-0822, E-00000A-01-0630 AND E-01933A-02-0069 (TRACK B)**
**October 15, 2002**

MR 1.4 Please list each contract under which APS obtains capacity and energy to serve its retail load. For each contract listed, please specify the contract's capacity and energy or load factor and the date it was entered into.

RESPONSE:

PacifiCorp Diversity Exchange

480 MW on-peak capacity limited to maximum 40% capacity factor May 15-Sep 15 each year. The contract was entered into September 1990.

Salt River Project Territorial Agreement

350 MW capacity for delivery January-December each year. This amount increases per a formula by 7 or 8 Mw per year. Energy is distpatchable and varies as a function of APS economics and to meet the needs of APS system reliability. The annual capacity factor has ranged from 31% to 59% in the 2000-2002 time frame. The contract was entered into in 1955 and was most recently amended in 1998.

Constellation Power (entered into March 2000)

25 MW on-peak capacity with 100% capacity factor during on-peak period for delivery July 2003 - September 2003

Williams Energy Marketing and Trading (entered into March 2000)

25 MW on-peak capacity with 100% capacity factor during on-peak period for delivery July 2003 - September 2003

Morgan Stanley Capital Group (entered into March 2000)

50 MW on-peak capacity with 100% capacity factor during on-peak period for delivery July 2003 - September 2003

Morgan Stanley Capital Group (entered into November 2001)

25 MW on-peak capacity with 100% capacity factor during on-peak period for delivery July 2003 - September 2003

NOTE: APS also has a QF agreement with Abitibi, but it is not for firm capacity or energy and thus has been excluded from APS resources for Track B purposes.

Exhibit No. ____ (CRR-7)

# PANDA GILA RIVER, L.P.
# REVISED STRAWDOG PROPOSAL
# DATED AUGUST 28, 2002

# TRACK B PROCEEDING

## REVISED STRAWDOG PROPOSAL
## FOR COMPETITIVE PROCUREMENT BY APS


*Presented by*
Craig R. Roach, Ph.D
Boston Pacific Company, Inc.

*On Behalf of*
Panda Gila River, L.P.


REVISED

August 28, 2002

TABLE OF CONTENTS

## I. STARTING POINT AND SUMMARY FOR THE REVISED PROPOSAL

A. The starting point for this strawdog proposal lies in three central points in the ALJ's recommended order on Track A issues. (Although the Commission spoke this week to the ALJ's Order, we do not have final written guidance to reflect herein.)

- First, APS must competitively procure power that it cannot produce from its existing generation assets ("unmet needs"). It is assumed that APS will want to replace its older, less efficient and environmentally unfriendly plants so that its "existing" generation will decline over time.

- Second, the Track A proceeding is not the appropriate forum to justify the transfer of APS' Merchant units (Redhawk and the new West Phoenix) from Pinnacle West to APS.

- And third, divestiture should be delayed until at least 2004.

## II. THRESHOLD QUESTIONS

A. What is the format of the competitive solicitation?

- The competitive solicitation will be a three-phase Request for Proposals (RFPs) for all unmet needs.

B. What products are offered in the solicitation?

- The RFPs will solicit asset-backed offers only for capacity and energy. This includes unit sales and system sales.

C. What is the structure of the final contract to be signed in the solicitation?

- The final contract to be signed will be a standard pay-for-performance contract.

D. How will APS and its affiliates be treated in the solicitation?

- PWEC or any other APS affiliate must bid under the same rules as any other bidder and must be held to its bid if it wins.

- Under no circumstances will power from APS' Redhawk and new West Phoenix units be sold to APS, for other than an interim period, except as a result of competitive solicitation.

E. Who will evaluate the bids in the RFP?

- If the utility or its affiliate bids, a Bid Evaluation Team will be formed. The Team will include the Commission Staff plus a Third-Party Evaluator chosen by the Commission. APS will be the other member of the team.

F. How will transmission expansion costs be reflected in the bid evaluation?

- Emerging FERC policy will guide how transmission costs are reflected in the Bid Evaluation. This policy is that (a) each power project must pay for its transmission *interconnection* cost and those costs are presumed to be reflected in its bid; and (b) transmission *integration* costs (system upgrades) will be rolled into transmission rates, but the power projects driving the need for those upgrades will finance the system upgrades (i.e., they will pay for them upfront and then receive credits for transmission service once service begins). Transmission expansion costs will be treated in the bid evaluation process in a non-discriminatory manner.

G. Who will sell power until other winning bids in the RFPs come on-line?

- If a winning bidder is not immediately on-line to supply power, the Bid Evaluation Team should initiate bilateral negotiations with the three next-best bidders that are already on-line and ready to supply power on an interim basis.

## III. TIMING AND SCALE OF THE THREE-PHASE RFPS

A. The proposed RFP will be conducted in three phases.

- The Phase 1 RFP will be issued in Fall 2002;

- The Phase 2 RFP will be issued in Spring 2004; and

- The Phase 3 RFP will be issued in Spring 2007.

- The timing and scale is such that, by the end of Phase 3 in 2010, APS' Standard Offer load will be 100% competitively procured.

B. The amount of power to be solicited in Phase 1 is 2,513 MW. This is the estimate of year 2005 peak load that APS cannot serve with its existing generation. Bids are accepted for power plants with in-service dates up to May 2005. Estimates of load growth and existing generation are shown in Table One. The amount of power solicited will be higher if APS retires its older, less-efficient, environmentally challenged units.

- Phase 2 will solicit between 2,981 MW and 5,494 MW. The 2,981 MW reflects the estimate of load growth from 2005 to 2007 (581 MW) plus the load served by 2,400 MW of APS' existing generation assets, which will be divested at this time. The 5,494 MW reflects the fact that, if only three-year PPA terms are accepted, some or all of the load from the first RFP (2,513 MW) must be re-bid. Bids are then accepted for power plants with in-service dates of up to May 2007.

- Phase 3 will solicit between 3,473 MW and 8,967. The 3,473 MW reflects the estimate of load growth from 2007 to 2010 (1,028 MW) plus the load served by the remaining 2,445 MW of APS' existing generation assets, which will be divested at this time. The 8,967 MW reflects the fact that, if only three-year PPA terms are accepted, some or all of the load from the Phase 2 RFP (5,494 MW) must be re-bid. Bids are accepted for power plants with in-service dates of up to May 2010.

## IV. MODEL PPA

A. The RFP will include a model PPA to be used as a template for all bids. This PPA will detail all the required and/or preferred price and non-price terms. The goal is to streamline the bid evaluation process by settling most contract issues upfront.

B. Length of Contracts

In order to reach a compromise, we have suggested that the Phase 1 RFP solicit shorter term contracts (three-years) with an option to extend the contract for an additional five-years. However, because we believe there is significant consumer benefit to long-term contracts we believe that the issue should be revisited and that Phase 2 should entertain longer term contracts.

- For Phase 1, the contract term submitted by a bidder will be for three years. In addition, the bidder may choose to submit an option price to extend the contract life for an additional five years. APS may either pay the option price, and in three years extend the contract, or ignore the option price and take the contract as a three year deal.

- We realize the Staff is reluctant to commit ratepayers to longer-term contracts, however, once the benefits of competitive solicitation have been demonstrated in Phase 1, the Commission may endorse longer-term contracts for the Phase 2 and 3 RFPs. In this event, APS will file with the Commission their portfolio-term preferences for approval (e.g. APS prefers 60% of the RFP capacity procured under 10-year terms, 20% under 5-year and 20% under 15-year). This preference will be made public as part of the RFP process.

C. Structure of Price Bids

1. Capacity Price

- Stated in S/kw-year for each year of the contract term; or, initial-year stated and then indexed to inflation.

- The capacity price must be tied to an availability guarantee.

2. Availability Guarantee

- The capacity price would be paid in full if, and only if, the facility was available for service 95% of the time, on average, over the previous 12 months. If it was available for less than 95% of the time, capacity payments would be reduced proportionally and the seller is responsible for the replacement cost of power. If the performance fell below 50% availability, no capacity payment would be made.

- If availability was above 95%, then the supplier would receive a proportional bonus for each percentage point above 95%.

- A guaranteed megawatt output will be stated.

3. Energy Price

- The energy price will either be a fixed price (S/MWH) stated for each year; or,

- Stated as a guaranteed heat rate and a fuel price tied to some publicly available fuel price index.

- Gas tolling offers are acceptable and, in this case, a guaranteed heat rate must be offered.

4. Fixed Operation & Maintenance (FO&M) Cost

- An explicit fixed cost in terms of S/kw-year for each year of the contract length, or an initial-year price indexed to inflation.

- FO&M will also be tied to the Availability Guarantee.

5. Variable Operation & Maintenance (VO&M) Cost

- VO&M will be a fixed price in terms of S/MWH stated for each year or an initial-year price indexed to inflation.

- Start Price: The cost in S/start can be fixed or tied to a publicly available index.

D. Non-Price Terms

1. Dispatchability: Each generation asset is dispatchable based on its energy price plus VO&M plus transmission losses. Each bid must submit the necessary parameters for dispatch such as:

- Minimum load level,
- Ramp rates,
- Minimum run times, and
- Start-up times.

2. No Regulatory-Out Clause

- The RFP itself will be the prudence review, and, therefore there is no need for an ongoing prudence review of the contract. Since there is no risk of a disallowance, there is no need for a regulatory-out clause.

3. *Force Majeure* will be defined using the industry standards for events out of the control of the parties.

4. Security Deposit

- Construction Period Security Deposit shall be in the form of a Letter Of Credit (or an acceptable substitute) for S30,000/MW and be applicable from the date that the winning bidder(s) sign the PPAs until the in-service date of the asset.

- Operation Period Security Deposit shall be in the form of a Letter of Credit (or an acceptable substitute) for S30,000/MW and be applicable for the entire term of the contract.

5. Construction Milestones

- If a bidder's asset is not on-line, it must contractually guarantee to meet milestones, including milestones such as the completion of permitting, financial close, and equipment delivery.

6. Liquidated Damages

- A bidder is liable for the replacement cost of power in the event of (a) early contract termination, (b) under-performance, or (c) failure to meet in-service date.

- The Construction or Operation Period Security Deposits are the source of payment and set the limit for replacement costs.

7. Creditworthiness: Prospective bidders may submit bids only if they meet one of the following creditworthiness standards:

- Bond rating of the company is investment grade;
- The asset to be bid has been financed;
- The asset has an investment grade guarantor; or
- Both Construction and Operation Period Security Deposits are increased to \$100,000/MW.

## V. BID EVALUATION IN THE RFP

A. A Bid Evaluation Team will be created to ensure fair treatment for all bids.

- The Team will consist of APS, the Commission Staff, and an Independent Third-Party Evaluator chosen by the Commission.

B. The bid evaluation will be in two stages. The first consisting solely of an assessment of generation costs, and the second taking into account possible transmission system upgrade costs.

C. To compare the contracts with unequal lives (i.e. a three-year contract as compared to a three-year contract with an option for five-year extension) the bid evaluation should follow the annuity method detailed in Attachment One.

## VI. OTHER ISSUES

A. Confidentiality: All bids are confidential, including those from PWEC. The PPAs from winning bids will be made public upon contract signature.

B. Dispute Resolution: Each bidder is entitled to a post-bid meeting with the Bid Evaluation Team if it is omitted from the short-list, or it is not a winner after being on the short-list. If a grievance remains, losing bidders (a) will agree to arbitration on matters concerning the evaluation of its bid or (b) can appeal to the Commission for serious breaches of procedure only. The entire RFP must be re-opened if procedural breaches are found.

C. Demand-Side Bids: Demand-side bids will be accepted if they can demonstrate that they are effective alternatives to peaking capacity.

D. Bid Fee: A non-refundable $10,000 fee per bidder (covering up to three bid alternatives) will be assessed to defray the cost of the Third-Party Evaluator.

## VII. BROADER ISSUES

A. Consistency with FERC's Standard Market Design (SMD) Notice of Proposed Rulemaking (NOPR) with respect to long-term power sales contracts.

The Strawdog Proposal is consistent with the SMD NOPR[1] in the sense that both encourage generation and transmission investment through a preference for longer-term contracts. FERC's clear expectation is that bilateral contracts are used to serve most of the retail load, noting that these contracts account for 85% of the load in the Eastern ISOs.[2] FERC states that a mitigated spot market does not give sufficient incentive to invest.[3] Through its Resource Adequacy requirement, and the use of a longer-term planning horizon within that requirement, FERC says it is encouraging infrastructure investment by promoting longer-term contracts.[4] FERC proposes a forward looking Resource Adequacy requirement, possibly in the 3-year to 5-year range, but will allow the final choice to be made in different regional planning efforts.[5] FERC is also clear that the Resource Adequacy requirement is asset-backed, meaning that the generation assets used to meet the requirement must be specified.[6] FERC does ask for comments on allowing the requirement to be met with offers backed by liquidated damages, but with unspecified generation sources.[7]

FERC also accommodates longer-term contracts by allowing for longer-term transmission rights. FERC speaks of "life of the facility" rights being earned by a customer who pays for network upgrades; these rights are even exempt from the auction requirement four years hence.[8] These lifetime rights can go to merchant transmission

[1] See Notice of Proposed Rulemaking, Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design in Docket No. RM01-12-000 (July 2002).
[2] Id. at page 6 and page 10 of Appendix E.
[3] Id. at page 253.
[4] Id. at page 276.
[5] Id. at page 277.
[6] Id. at page 272 and page 273.
[7] Id. at page 273.
[8] Id. at page 6 of Appendix F.

builders, too.[9] FERC wants to allow transmission rights to match the terms of longer term power sales contracts, specifically asking for comments on whether contract terms for transmission rights should be required to match the planning horizon of the Resource Requirement.[10]

B. The Strawdog Proposal calls for unit contingent bids because PWEC's Redhawk and new West Phoenix units are unit contingent.

The Strawdog calls for unit-contingent bids because that is how PWEC's merchant units (Redhawk and new West Phoenix) are accepted by APS; PWEC's units should not have an artificial competitive advantage over competitors. Put simply, this means that PWEC's units do not supply their own operating reserves, but, rather, are backed up by the reserve margin constituted by APS' portfolio of power plants. There is no reason to treat merchant plants developed by competitive power producers differently than merchants developed by an APS affiliate. Moreover, since Arizona ratepayers are already paying for those APS reserves, the unit contingent sale offers the lowest cost to consumers.

We would entertain a 100% availability guarantee if all merchant suppliers, including PWEC, had to meet the requirement. That is, APS could not use its portfolio of assets to back up PWEC's merchant units at Redhawk and new West Phoenix. In addition, we would recommend that the 100% availability requirement be met by membership in the Southwest Reserve Sharing Group (SRSG).[11] An alternative would be that the requirement could be met by a purchase of ancillary services from APS at FERC-approved tariff rates.

[9] Id. at page 10.
[10] Id. at page 140.
[11] Our understanding is that the SRSG currently has 11 members. The calculation of the contingency reserve requirement for each member is in two parts. The first part results in the percentage share (the Reserve Responsibility Ratio) of the regional reserve requirement for which an entity is responsible. (It is that entity's percentage share of the sum of 25% of each entity's firm load plus its most severe single contingency). The second part sets the actual megawatt contingency reserve requirement for each entity. (This is equal to an entity's reserve responsibility ratio times the region's most severe single contingency.)

## TABLE ONE

**Proportion of Load Served by Existing APS Resources and Competitive Procurement**

| Year | Forecasted Peak Summer Load Plus 12% Reserve Margin* | Existing APS Resources (MW)** | % Served by APS Existing Resources | MW Available for Competitive Procurement RFP Minimum | MW Available for Competitive Procurement RFP Maximum |
|---|---|---|---|---|---|
| 2002 | 6,204 | 4,845 | 78% | | |
| 2003 | 6,647 | 4,845 | 73% | 2,513 | 2,513 |
| 2004 | 7,019 | 4,845 | 69% | | |
| 2005 | 7,358 | 4,845 | 66% | 2,981 | 5,494 |
| 2006 | 7,628 | | | | |
| 2007 | 7,939 | 2,445 | 31% | 3,473 | 8,967 |
| 2008 | 8,262 | | | | |
| 2009 | 8,604 | | | | |
| 2010 | 8,967 | 0 | 0% | All Load | All Load |

Load forecast was taken from APS' FERC Form 714, dated 5/22/02; the 12% Reserve Margin was added. The 12 % appears to be what APS currently utilizes. If APS uses a higher planning Reserve Margin, then these numbers would increase. APS informs us that this load only includes retail load. We propose that wholesale load that cannot be served by APS' Existing Resources also be put out for bid.

**Includes all current rate-base plants and contracts with SRP and Pacificorp. Does not include new West Phoenix units and Redhawk 1 and 2. If Ocotillo and West Phoenix are shut down, APS' existing resources decreases by 433 MW (Ocotillo 325, Old West Phoenix 108 MW).

## ATTACHMENT ONE

### BID EVALUATION IN THE RFP

A. A Bid Evaluation Team will be created to ensure fair treatment for all bids.

- The Team will consist of APS, the Commission Staff, and an Independent Third-Party Evaluator chosen by the Commission.

B. The bid evaluation will be in two stages. The first consisting solely of an assessment of generation costs, and the second taking into account transmission costs.

C. Stage One: Generation Cost Bid Evaluation

1. The initial generation cost bid evaluation will be done across a range of uniform capacity factors. The Team will specify the uniform capacity factors to be used (e.g.10%, 20%, and so on) and each bid will yield a price at each capacity factor (a screening curve).

2. In addition to specifying the uniform capacity factors, the Team will specify all other assumptions for evaluation such as natural gas prices or other fuel costs, and inflation.

3. With the uniform capacity factor evaluation, the costs will be represented as an annuity cost per MWH. The steps are as follows:

- The annual costs for each price component (capacity, energy, VO&M, FO&M and starts) will be projected over the proposed term of the offer, at each of the uniform capacity factors.

- The present value of these projected costs will be determined using APS' after-tax weighted cost of capital as the discount rate.

- A cost annuity will be calculated for the bid over the proposed term. To be clear, if a 3-year offer is made, a 3-year annuity would be calculated. An annuity is used to allow the comparison of bids with unequal lives.

- To adjust for unequal bid sizes, the annuities would be divided by the MWH of the bid as dictated by each uniform capacity factor.

- The Team will rank the annuities per MWH and choose the lowest-cost bids sufficient to meet the megawatt level solicited (e.g. 2,513 MW for the Phase 1 RFP).

4. If the Team is satisfied with the uniform capacity factor evaluation, it need not go further in the generation cost evaluation. If however, the Team wants an additional analysis, it is entirely appropriate to add a production simulation based-bid evaluation.

   - Capacity factors for each bid would be determined through production simulation.

   - Bid comparison would be done on the basis of the cumulative present value of the revenue requirement adjusted for difference in contract term and project size.

D. Stage Two: The Bid Evaluation Team will next take account of the costs of transmission system upgrades.

   1. The winning bidders based on generation costs, as a group, will be called the Minimum Generation Cost Portfolio (MGC Portfolio).

   2. Transmission modeling will be used to determine the system upgrade costs, if any, associated with the MGC Portfolio. System upgrades will be made to assure reliability criteria are met.

   3. Transmission system upgrades will be translated into transmission rates and, if transmission rates do not rise by more than 5%, these system upgrade costs are considered reasonable and the MGC Portfolio is the winning Portfolio.

   4. If the 5% transmission rate impact is exceeded, another portfolio of generation bids will be created. This will be called the Second-Best Generation Portfolio. (SBG Portfolio). The SBG Portfolio will include higher-cost generation bids that are expected to require lower transmission system upgrades. Transmission modeling will be used to determine the system upgrade costs of the SBG Portfolio.

   5. The costs of the MGC and SBG Portfolio now would be compared with the transmission costs included. The annuity cost of transmission upgrades would be added to the annuity cost of the generation bids. The lower cost Portfolio would win.

   6. All bids in the winning portfolio are considered responsible for and must offer to finance a *pro rata* share of the transmission system

upgrades in their region. An exception occurs when a bidder has secured firm transmission service already over non-APS transmission facilities.

E. Load-Pocket Location

- A separate analysis for load-pocket location for generation is required to determine if, and only if, system reliability requires load-pocket location for physical needs regardless of transmission capability.

- If a load pocket is a result of insufficient transmission capability, it is an economic decision captured in the transmission cost analysis detailed above. That is, if the cost of (a) generation outside the Valley plus the cost of required system upgrades is more expensive than (b) the cost of in-Valley generation, then in-Valley generation will win the RFP without any locational preference. There is no need for a location preference if the reason for the load-pocket is insufficient transmission capability.

- APS must allow bidders to co-locate facilities with APS, as possible, on its existing in-Valley sites.

- If APS mothballs or retires in-Valley units, it will include in the RFP a price at which out-of-Valley bidders may call on these units when transmission constraints are binding.

F. Non-Price Factors

- Although many non-price factors are made comparable by the Model PPA, the value of non-price factors in bid evaluation must be made clear in the RFP evaluation process beforehand.

- For example, some value can be assigned to having completed construction or being in an advanced stage of construction.

**BEFORE THE ARIZONA CORPORATION COMMISSION**

WILLIAM A. MUNDELL
Chairman
JIM IRVIN
Commissioner
MARC SPITZER
Commissioner

| | |
|---|---|
| IN THE MATTER OF THE GENERIC PROCEEDINGS CONCERNING ELECTRIC RESTRUCTURING ISSUES | Docket No. E-00000A-02-0051 |
| IN THE MATTER OF ARIZONA PUBLIC SERVICE COMPANY'S REQUEST FOR A VARIANCE OF CERTAIN REQUIREMENTS OF A.A.C. R14-2-1606 | Docket No. E-01345A-01-0822 |
| IN THE MATTER OF THE GENERIC PROCEEDING CONCERNING THE ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR | Docket No. E-00000A-01-0630 |
| IN THE MATTER OF TUCSON ELECTRIC POWER COMPANY'S APPLICATION FOR A VARIANCE OF CERTAIN ELECTRIC COMPETITION RULES COMPLIANCE DATES | Docket No. E-01933A-02-0069 |
| IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS STRANDED COST RECOVERY | Docket No. E-01933A-98-0471 |

NOTICE OF FILING

Panda Gila River, L.P. ("Panda") hereby provides notice of filing the Direct Testimony of Craig R. Roach, Ph.D., as required by the Commission's procedural order in the above-captioned matter, dated October 9, 2002.

RESPECTFULLY SUBMITTED, Tuesday, November 12, 2002

PANDA GILA RIVER

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On behalf of Panda Gila River, L.P.

ORIGINAL and 15 copies of the
foregoing hand-delivered for filing,
Tuesday, November 12, 2002:

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Tuesday, November 12, 2002, to:

All parties of Record

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