BEFORE THE ARIZONA CORPORATION COMMISSION

WILLIAM A. MUNDELL
CHAIRMAN
JIM IRVIN
COMMISSIONER
MARC SPITZER
COMMISSIONER

IN THE MATTER OF THE ARIZONA PUBLIC SERVICE COMPANY'S REQUEST FOR VARIANCE OF CERTAIN REQUIREMENTS OF A.A.C. R14-2-1606.

DOCKET NO. E-01345A-01-0822

REQUEST FOR ORDER TO SHOW CAUSE

Panda Gila River, L.P. ("Panda")[1] hereby moves the Arizona Corporation Commission ("Commission") to order Arizona Public Service Company ("APS") to appear and show cause why the procedural schedule in this Docket should not immediately be stayed until such time as APS issues and evaluates responses to a Request For Proposal ("RFP") seeking competitive supply of at least half of APS's projected Standard Offer Service requirements. By staying determination of APS's Request for a Partial Variance from Rule 1606(B) (A.C.C. R14-2-1606(B)) until the results of the RFP are evaluated, the Commission will most effectively protect Arizona ratepayers, continue the development of competitive wholesale markets, and preserve Commission and Intervenor resources. Requiring APS to comply with Rule 1606(B) by issuing a real RFP will be considerably more effective in demonstrating what the competitive market can and cannot do to meet APS's projected requirements, and would require considerably less effort by APS, Intervenors and the Commission than will be required to proceed with the virtual RFP that APS is attempting to conduct and, indeed, has recognized that it must

[1] Panda Gila River, L.P. is a Limited Partnership, whose General Partners are Panda GS I, Inc. and TPS GP, Inc. TPS GP, Inc. is a wholly owned subsidiary of TECO Power Services Corporation.

conduct, in order to meet its burden of showing that the requested variance is in the public interest.

As discussed more fully below, to sustain its argument that the proposed PPA is prudent and in the public interest, APS must show that, as a practical matter, even if it were to issue an RFP, no supplier other than Pinnacle West Capital Corporation ("PWCC") could respond with an offer for all or a portion of APS's projected Standard Offer Service requirements that is as or more attractive than the contemplated affiliate deal between APS and PWCC. Much of APS's discovery seeks to demonstrate exactly this point. Parties opposing the PPA, on the other hand, will attempt to show that APS's assertion is not true, and that enough bidders would respond to the solicitation with sufficiently attractive offers to justify its issuance. Either way, then, both sides will try to show what would happen were there to be an RFP. It would, therefore, be far more efficient and infinitely more prudent to just have a real RFP, rather than to create a surrogate solicitation during the course of this proceeding (through testimony and discovery), especially because an RFP could be undertaken quickly and without any harm whatsoever to Arizona ratepayers. Indeed, the only way an RFP could take "the better part of a year" to complete, as APS contends (Request for Partial Variance ("Request") at 8), would be if APS actually were to receive one or more *bona fide* offers, which, however, would only prove that APS's request for a partial variance was not justified in the first place.

The plain and simple fact is that APS's request for a variance, together with its request for approval of the associated PPA, cannot be sustained unless both are shown to be in the public interest. Neither can be in the public interest unless APS was prudent to pursue the request and enter into the PPA. Unless APS first is required to issue an RFP or otherwise attempt in good faith to seek to procure supplies at arms-length from non-affiliated suppliers, as it is required to do under Rule 1606(B), it cannot show that its actions were prudent. Indeed, this must be so, because it is impossible for APS ever to prove that it acted prudently in shunning competing offers from *all* interested suppliers capable of serving all or a portion of APS's Standard Offer Service requirements, in favor of whatever limited number of offers APS succeeds in eliciting from the limited number of Intervenors in this proceeding.

This request is supported by the following Memorandum of Points and Authorities.

MEMORANDUM OF POINTS AND AUTHORITIES

I. IT IS PREMATURE TO CONSIDER GRANTING APS A VARIANCE FROM COMPLIANCE WITH RULE 1606(B).

A. Introduction.

In promulgating the Competition Rules, this Commission determined that wholesale and retail electric competition were in the public interest, and that, to encourage the further development of the competitive wholesale market necessary to allow development of a competitive retail market, utilities like APS should be required to separate their generation assets from their transmission and distribution facilities and to procure the power required to serve Standard Offer customers from the competitive market, with no less than half procured through competitive bids (with the remainder purchased through arms-length bilateral contracts). *See* Decision No. 61272 (December 11, 1998).

On October 6, 1999, the Commission issued Decision No. 61973 approving the May 14, 1999 Settlement Agreement entered into by APS (the "APS Settlement Agreement"). The APS Settlement Agreement, among other things, included retail rate reductions and set the amount, method, and timing of APS's stranded cost recovery. As part of the negotiated compromise, the Settlement Agreement also granted APS a two-year extension (until January 1, 2003) to transfer its generation assets to an affiliate and to comply with Rule 1606(B)'s competitive procurement requirements. *See* Decision No. 61973 at 4.

B. <u>APS has made no effort to comply with Rule 1606(B)</u>.

Despite agreeing to comply with Rule 1606(B) no later than by the end of 2002, APS has utterly failed to take any significant action to do so. *See* APS Responses to Panda Gila River L.P.'s First Set of Data Requests, copy attached hereto at Tab 1. Indeed, even though APS took many months to complete its agreement with PWCC, months that it could have used to proceed with an RFP, it has done nothing to satisfy its 1606(B) or Settlement obligations. Instead, it now asks this Commission to change the Rule, a change that APS attempts to justify by asserting that the competitive market "will not produce the intended result of reliable retail electric service for Standard Offer customers at reasonable rates." Request at 1. Hence, in the instant proceeding APS seeks to show through discovery and by expert opinion and other testimony that there could not possibly be any attractive alternatives to the APS-PWCC PPA. *See* APS Data Request 1-3, attached hereto at Tab 2. Obviously, however, the prudent way to assess the truth of APS's assertion with any degree of certainty and fairness is to ask the competitive market to respond to, and for the Commission to interpret the results of, a real RFP.

Furthermore, allowing APS to be exempted from Rule 1606(B), without ever issuing an RFP to determine market participant interest and ability to supply up to half of its Standard Offer Service load, will cause substantial uncertainty in the developing wholesale market, threatening the foundation upon which all of the Competition Rules are built. On the other hand, requiring APS to immediately comply with the Rules through issuance of an RFP under the procedures outlined below before commencement of the Commission hearing on the requested variance will not require substantial effort by APS, will obviate the need for ill-conceived regulatory substitutes for the competitive market, and will protect the public interest. Indeed, Panda expects that an APS RFP under

Commission supervision will clearly demonstrate that APS's request for an exemption from the Rules is wholly unjustified and, therefore, completely unnecessary and counterproductive from the standpoint of the public interest.

Finally, APS also appears to believe that it is too late for it to proceed with an RFP and that it would take too long for the results to be known and for contracts to be negotiated. Even if this were true (which, as shown below, it plainly is not) the fact is that APS itself decided, unilaterally and without timely seeking the approval of this Commission, to effectively suspend Rule 1606(B) and not to honor its Settlement obligations. Panda respectfully suggests that this Commission should not let APS's own neglect of a Commission Rule and of a Commission approved Settlement Agreement form the predicate for the relief APS now seeks.

C. <u>The Process Proposed in this Proceeding Will Result in a Poorly Conceived Regulatory Substitute for Competitive Bidding</u>.

As discussed above, Rule 1606(B) requires APS to procure all of the power needed for Standard Offer Service customers from the competitive wholesale market no later than the beginning of 2001. The APS Settlement Agreement extended this deadline to January 1, 2003. But rather than honor its obligations under both the Rules and the Settlement Agreement, APS now asks to be excused from its failure to comply before the fast-approaching deadline. So much is clear from APS's discovery responses in which APS admits that it "had not completed procedures or a schedule to implement the competitive bidding process as set forth in Rule 1606(B) [and that its] effort is somewhat dependent on the substance and timing of the Commission's actions on APS's request for a partial variance . . ." APS Response to Data Request 1.3, Tab 1. When asked whether it had issued any RFPs or other solicitations to purchase power through prudent, arms-length transactions, APS responded that not only had it yet to issue a formal RFP, but that there was no requirement to do so, and that certainly "there is no requirement prior to 2003."

APS's Response to Data Request 1.6, Tab 1. Plainly, APS is using its request for a partial variance, together with the APS-PWCC PPA, as a substitute for its actually determining the ability of the competitive market to meet the Standard Offer needs of APS's ratepayers.

There can be little doubt that were the PPA to be accepted, this would effectively eliminate any meaningful competitive procurement of APS's Standard Offer Service requirement. This result would be particularly damaging to APS's ratepayers insofar as the PPA also contains terms favorable to the affiliate that would never be found in a competitively-procured purchased power contract. But even if the Commission were now to agree with these contentions, the fact is that in order to prove that its variance request and proposed affiliate transaction are prudent and in the public interest, APS must demonstrate that there are no competitors in the wholesale market able to supply power to meet all or a portion of APS's Standard Offer Service requirements during the term of the PPA, and that, were APS to issue an RFP in accordance with the Rules, no competitive supplier would step forward with an attractive offer. Those opposing the requested variance, on the other hand, will have to respond that they are willing to make a more attractive offer than the proposed PPA for all or a portion of APS's requirements, and for all or a portion of the PPA's term, which could be as long as 30 years. Of course, this is just what they would have to do in response to a formal RFP.

In short, then, both sides in this proceeding will present evidence designed to show what would happen if APS were to comply with the Rules. Indeed, it is precisely for this reason that APS issued data requests designed to elicit exactly the same information that it would request and receive through an RFP, albeit from a much narrower group of potential suppliers (as only certain suppliers that are Intervenors in this proceeding received the requests) and without the confidentiality provisions included in true RFPs to protect bidders from having to divulge their individual business plans. For example, APS asked Panda, to:

> [S]tate whether Panda is willing to offer APS power for any of the years 2002 through 2015 at a lower delivered cost than available to APS from the Dedicated Units under the proposed PPA. If the answer is yes, please state the years for which such an offer is made, the amount of energy and capacity Panda is willing to supply in each of the years 2002-2015, the price of energy and capacity offered for each of the years 2002-2015, and all other relevant terms and conditions under which such offer is made for each of the years 2002-2015.

APS Data Request 1-3, attached hereto at Tab 2. Panda is informed that APS made identical requests to Reliant, Duke, Sempra and other Intervenors.

Even without APS's data requests, however, parties opposing APS's proposed variance and PPA obviously will attempt to present evidence that is, for all practical purposes, identical to the information they would be required to provide pursuant to an RFP. Indeed, *any* information APS believes to be important can be requested in an RFP, and the RFP can be scored on the basis of this information, or any other reasonable criteria APS believes would be appropriate in assessing the bids. Put simply, undertaking a properly administered RFP, as opposed to an RFP established and scored through discovery, testimony and cross examination at a hearing, is the best and only way for APS to establish any predicate for the Commission granting its variance request in the first place.

Unless this Commission orders APS to conduct a commercially reasonable RFP, a quasi-RFP *will* be conducted in this proceeding, not through a competitive process, but through a wasteful litigated process that, at best, will result in an inadequate regulatory substitute for a true RFP and the squandering of Commission resources and ratepayer dollars. And, unlike a case where APS actually sought arms-length bids, even if APS were correct in rejecting all of them, here, APS cannot possibly be deemed to have been prudent in not even seeing if the market could satisfy all or a sizable portion of its needs.

Finally, the makeshift "solution" developed by APS through this proceeding not only will take longer than would a properly conducted RFP process, likely place an unnecessary strain on Commission resources, and cost all parties involved far more in litigation expenses and consultants' fees than would be expended in a proper RFP (in which power suppliers participate as an ordinary cost of doing business), but it also will provide the Commission with a very poor mechanism to meet its statutory obligation of determining whether APS's requested variance is in the best interest of APS's Standard Offer Customers. *See* A.R.S. § 40-361 (requiring charges to be just and reasonable). Indeed, by adopting the procedure outlined below, the Commission will be in a much better position to rule on APS's request and to issue a factually supportable decision.

II. THE COMMISSION SHOULD REQUIRE APS TO COMPLY WITH RULE 1606(B).

A. An RFP Issued Pursuant to Rule 1606(B) Would be Easy to Administer and May be Done Quickly.

APS's suggestion that it is unable to comply with Rule 1606(B) because an RFP would take at least "the better part of a year" (Request at 8) is simply not true. In 1998, for example, Virginia Electric and Power Company ("VEPCO") also attempted to argue that it did not have time to pursue an RFP. The Virginia Corporation Commission rejected VEPCO's contentions and ordered it to issue an RFP on an accelerated timetable. In a hearing, the Virginia Commission solicited and received interest in bidding, and also heard about market power concerns if the utility were to build certain new plants. As a result of the hearing, the Virginia Commission ordered the utility to issue an RFP with the oversight of its Staff. *Application Of Virginia Electric And Power Company For Approval Of Expenditures For New Generation Facilities Pursuant To Va. Code § 56-234.3 And For A Certificate Of Public Convenience And Necessity Pursuant To Va. Code § 56-265.2*, slip op. at 15-16 (Jan. 14, 1999) (attached hereto at Tab 3). Unlike the schedule that APS assumes would be required, the Virginia Commission Order was issued on January 14, 1999; a draft RFP, with an online date for the capacity of July 2000, was required five days later; three days were set for review of the RFP by Virginia Commission Staff; and bids were due by March 26, 1999. *Id.* at 18. On March 26, 1999, Virginia Commission Staff witnessed the opening of the bids, which had previously been sealed. Thereafter, the Company analyzed the bids received and submitted its analysis to the Staff for its review. The Virginia Commission Staff then filed a report of its own analysis and review of the bids on April 2, 1999, in both public and proprietary versions. Thus, the entire process, from Commission order to Staff report, took only 71 days. And even had there been detailed review and scoring of the bids by an independent consultant (instead of Virginia Commission Staff), the entire process could easily have been completed in 90 days.

Similarly, Arizona Electric Power Cooperative issued an RFP on August 15, 2001, with the stated intention of completing the process by the end of 2001, a period of no more than four-and-a-half months. *See* AEPC RFP, attached hereto at Tab 4. While each of these RFPs was for less power than is projected to be required to serve APS's needs, the process of developing and issuing the RFP and scoring any submitted bids should not impact the timing. If the Commission issues an order similar to that issued by the Virginia Commission, the entire process, from issuance of the RFP to review of bids, could be completed in three months. The fact is that numerous Fortune 100 companies have been acquired in much less time, as have many utility-divested generating plants.

Significantly, though, here the process should be substantially easier because APS already has determined its power and other requirements, as well as how to evaluate any offer to satisfy these requirements. Presumably, these determinations are reflected in the APS-PWCC PPA. Thus, it should require little additional effort for APS to draft an RFP for release to interested suppliers (including Pinnacle West Energy Company ("PWEC") or PWCC) stating just what it needs and how it expects to evaluate or score any offers to satisfy all or a portion of those needs.

APS clearly believes, as did VEPCO, that sufficient competitors will not come forward to submit bids in response to any RFP. As the Virginia Commission concluded, if "this is the case, then evaluation of any responses to the RFP . . . should not be difficult. However, the Commission finds that the Rules, and sound policy, dictate that the market be provided the opportunity to express itself through the bidding process." Slip op., Tab 3 at 15. Only if the RFP results in one or more *bona fide* offers will the evaluation process be time-consuming.

As was also the case in Virginia, to ensure the process is fair and objective, the RFP must either be supervised by Commission Staff or by an independent, third-party consultant proposed by APS and approved by the Commission.[2] This is particularly the case, here, since APS has already stated its intention to take its entire Standard Offer Service requirements from its affiliate. Given that APS's proposed PPA provides for use of a consultant if the utility seeks competitive bids for additional power and PWCC seeks to compete for such load, use of an independent consultant in the first instance should be no more objectionable.

While the Commission need not dictate a specific process for all details of the RFP, the Commission should consider establishing the following milestones, similar to the procedure followed in Virginia:

- APS submission of proposed RFP to the Commission or consultant and Intervenors – within 5 days of Order in response to this Motion;

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[2] The consultant would ensure that the RFP was designed so as not to favor any particular party, including APS and its affiliates. At a minimum, Panda expects that the RFP would require APS/PWCC to bid individual units on a pay-for-performance basis, and that the RFP would allow bids for generation facilities not expected to come on-line until after 2003. Other interested parties would be permitted to present additional issues to the consultant after APS proposes terms of an RFP.

- Interested parties submit comments on proposed RFP to Commission or consultant – within 5 days of submission of proposed RFP (10 days after Order);
- Commission/consultant revisions to RFP – within 5 days of submission of RFP (15 days after Order);
- APS issuance of approved RFP – day after receipt of approved RFP (16 days after Order);
- Bids submitted to Commission/consultant – 45 days after issuance of RFP (61 days after Order);
- Preliminary report of bidders submitting bids, capacity bid, and assessment of bid prices by Commission or consultant – 3 days after submission of bids (64 days after Order); and
- Final scoring of bids submitted – 20 days after preliminary report (84 days after Order).

Moreover, in preparing the RFP, APS should be required to develop and publish (1) proposed bid evaluation criteria; (2) its timetable for compliance with the schedule set forth above; and (3) a mechanism whereby all bidders are notified concerning all questions and associated responses during the bid process.

Finally, in order to ensure that APS is fulfilling the Commission's order in a timely manner, the Commission should appoint a member of its Staff or other designee to monitor and report on APS's RFP process and whether APS is adhering to the proposed timetable. Only by requiring the participation of an independent monitor can the Commission be assured that APS will be able to timely and adequately comply with Rule 1606(B).

B. Use of an RFP as Discussed Herein Will Preserve Commission Resources.

An open and fair RFP is the only means by which the Commission can adequately determine if sufficient competitors are willing and able to serve APS's Standard Offer Service load. It is true that the RFP process will itself require Commission oversight, but overall Commission administration resources will be preserved, in at least two ways. First, APS and other parties will not be forced to submit "bids" through discovery and testimony, and the Commission will not be required to rule on the numerous disputes that will arise in connection therewith or to issue a ruling on the ultimate issue in the variance proceeding, namely, whether sufficient competitors exist to satisfy APS's requirements, without being afforded the opportunity to review the best evidence on this issue, *i.e.*, the results of a real RFP. Any necessary hearing after the RFP could be limited to an assessment of the bids received and the scoring of the bids.

Second, winning bidders from an open and fair RFP (even APS's affiliates) would face a substantially easier Federal Energy Regulatory Commission ("FERC") approval process. Thus, the Commission would be saved from a potential situation in which it approves the APS-PWCC PPA, but the PPA is then modified by the FERC, in which case the Commission either would have to approve it yet again, or the PPA never goes into effect because it is rejected by the FERC. It is simply a waste of administrative resources to conduct a hearing to approximate an RFP instead of conducting a real RFP, particularly in circumstances where the Commission has a good reason to believe that APS will again require the Commission to approve the PPA following its consideration by the FERC.

C. APS Had Plenty of Time To Issue An RFP But Chose Instead To Spend Months Negotiating A Self-Dealing PPA That Calls Into Question Its Grant Of Market-Based Rate Authority.

APS will have only itself to blame if it is required to initiate an RFP on an accelerated schedule. By APS's own admission, "months of analysis and negotiation . . .

went into the final form of the PPA." Testimony of Jack E. Davis at 3. During this time, APS easily could have sought competitive bids, and had it not received any offers that it considered to be as attractive as what it expected to receive or that it already knew it could receive from its affiliate, *then* it could have requested an appropriate variance from Rule 1606(B). It would be most unfair, however, not only to the numerous non-affiliated wholesale suppliers, many of whom are not even Intervenors in this case, but to APS's ratepayers as well, to reward APS's delay by allowing its actions to become a self-fulfilling prophecy.

Furthermore, in light of its FERC filing to retain its market-based rate authority, APS should be estopped from arguing to this Commission that a competitive bidding process would be a waste of time. As recently as March 2000, APS informed the FERC that the wholesale market in Arizona was competitive and APS did not have generation market power.[3] In that filing APS noted that it controlled only 5.2% of the generation in the relevant first tier markets. On April 21, 2000, PWCC filed a request for Market-Based Rates, relying in large part on the APS market power study. In granting PWCC market-based rate authority, as with APS before it, the FERC ordered each to "inform the Commission of any change in status that would reflect a departure from the characteristics the Commission has relied upon in approving market-based pricing." *Pinnacle West Capital Corporation et al.*, 91 FERC ¶ 61,290 (2000). Neither PWCC nor APS has informed the FERC of any such change in circumstances and APS should not be heard to argue to this Commission that there is simply no relevant competitive alternative to supply all or a portion of its Standard Offer Service requirements.

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[3] Updated Market Power Study of Arizona Public Service Company, filed March 13, 2000 in Docket No. ER00-1875-000.

III. EVEN IF THE COMMISSION APPROVES APS'S REQUEST, FEDERAL APPROVAL OF THE PPA IS UNLIKELY ABSENT APS CONDUCTING A FORMAL RFP OR OTHERWISE ENTERING INTO ARMS-LENGTH TRANSACTIONS WITH NON-AFFILIATES.

A. Federal Standard for Approval of Affiliate Transactions.

As noted in Section 11.1 of the PPA, the PPA cannot become effective until approved by the FERC. In addition to the APS-PWCC PPA, the FERC also must approve the contract between PWCC and PWEC.[4] APS has not indicated whether it intends to justify the contracts at the FERC on a cost-of-service or market basis. As discussed below, APS will be unable to justify the contracts on a market basis unless it first seeks competitive offers from the market. And if APS attempts to justify the contracts on a cost-of-service basis, it would then, absent an RFP, be unable to demonstrate to the Arizona Commission that the contracts were prudent, as such an argument requires APS to prove that there will be no competitive suppliers able to supply all or a portion of APS's Standard Offer Service requirements during any relevant time period. Indeed, Rule 1606(B) implicitly recognizes that the only prudent purchase is one from the market, if market alternatives exist.

As the FERC has stated on numerous occasions, transactions between traditional public utilities with captive customers, such as APS, and an affiliated power supplier, like PWCC, raise concerns of cross-subsidization and market power gained through the affiliate relationship. In *Boston Edison Company Re: Edgar Electric Energy Company*, 55 FERC ¶ 61,382 (1991) ("*Edgar*"), the FERC held that, in analyzing market rate transactions between an affiliated buyer and seller, it must ensure that the buyer has chosen the lowest cost supplier from among the options presented, taking into account

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[4] Under the Federal Power Act, the FERC has jurisdiction over wholesale sales of energy in interstate commerce. 16 U.S.C. § 824 (2000). Wholesale contracts are not effective unless and until the FERC determines that the rates and terms of the agreement are just and reasonable. 16 U.S.C. § 824d.

both price and non-price terms. Stated another way, the FERC must ensure that the buyer has not preferred its affiliate without justification. *Id.* at 62,168.

In *Edgar*, the FERC noted that it may be possible for a utility to demonstrate that it had not unduly favored its affiliate through a market test, which uses a bid or benchmark analysis to determine whether the transaction in question was one that could have resulted through arms-length negotiations between an unaffiliated buyer and seller. Specifically, the FERC presented three means (which it stated were nonexclusive) to demonstrate lack of affiliate abuse: 1) evidence of direct head-to-head competition between the affiliated seller and competing unaffiliated suppliers in either a formal solicitation or in an informal negotiation process; 2) evidence of the prices that nonaffiliated buyers were willing to pay the affiliated seller for similar services; or 3) benchmark evidence of market value, based on both price and non-price terms and conditions, of contemporaneous sales made by nonaffiliated sellers for similar services in the relevant market. *See id.*; *see also Ocean State Power II*, 59 FERC ¶ 61,360, 62,332 (1992), *order denying reh'g and granting clarification*, 69 FERC ¶ 61,146 (1994) ("*Ocean State II*").[5]

1. Head-to-Head Competition.

The FERC did not review an affiliate contract justified on the basis of head-to-head competition until 1999. *See Aquila Energy Marketing Corp.*, 87 FERC ¶ 61,217 (1999) ("*Aquila*"). In *Aquila*, the FERC approved proposed contracts between a utility and its affiliated power marketer based on a brief review of the RFP process used by the utility to solicit bids for capacity and energy. Since *Aquila*, the FERC's review of affiliate contracts has been more cursory where the contracts arose out of an RFP process. *See, e.g.*, *Southern Power Co.*, 97 FERC ¶ 61,279 (2001) (accepting several affiliate PPAs, noting in a footnote that "[t]he PPAs accepted for filing herein were entered into pursuant to an RFP process that [the FERC] has found adequately addresses affiliate abuse

[5] To date, no utility has attempted to justify a contract through prices nonaffiliated sellers have been willing to pay in a bilateral contract, although FERC has indicated that such an approach would be acceptable.

concerns"). It is clear that affiliate contracts that are the result of a fair RFP process will be accepted by the FERC.

2. Benchmark Analysis.

Ocean State II remains the only case in which the FERC approved a contract between a public utility and its affiliate based solely on "benchmark" testimony. There, the FERC explained that several factors must be considered when performing and reviewing a benchmark analysis: 1) the relevant market; 2) the contemporaneousness of the benchmark evidence; and 3) comparability. In addition, the FERC will review the non-price terms of the contract as well.

In *Ocean State II*, the FERC defined the relevant market as the market for long-term bulk power, the same product being sold under the APS-PWCC affiliate contract, and noted that the market consists of all sellers capable of supplying the relevant product to the buyer or set of buyers. The pertinent benchmark evidence consisted of all contracts for comparable delivery to, and negotiated in the relevant market during the period in which the purchasing utility decided to enter into a contract with its affiliate. *See Ocean State II* at 62,333; *Edgar* at 62,169.

The FERC also requires a comparative analysis of non-price terms, including availability guarantees, fuel price risks, development and regulatory risk, inflation, taxes, and purchase and renewal options. Indeed, because benchmark comparisons necessarily involve "projections of formula variables (e.g., fuel cost, plant factors and economic indices) over the life of the project, . . . [t]he assumptions underlying these projections and the significance ascribed to non-price factors are critical to the analysis." *Ocean State II* at 62,335 (quoting *Edgar* at 62,129). Hence, in *Ocean State II,* the applicant made price comparisons by making certain "stated assumptions" with regard to fuel price escalation, inflation rates, O&M expenses, availability factors, and capacity factors so that the price of each benchmark contract could be restated in mills/kWh based on these common assumptions.

B. Because FERC Approval of the Two PPAs is Unlikely Absent APS Attempting to Procure its Requirements Competitively, Requiring APS to Undertake an RFP Will Not Delay Either the Divestiture Plan Nor Any of the Commission's Competition Goals or Otherwise Adversely Affect Ratepayers.

To obtain FERC approval of the APS-PWCC and PWCC-PWEC contracts, APS and its affiliates must either demonstrate that the contracts were the result of a competitive solicitation providing for direct head-to-head competition with unaffiliated sellers or that the affiliate contract is equivalent, both on price and non-price terms, to other agreements entered into in the same relevant product market at the same time as the affiliate contract.[6]

Clearly, APS cannot rely on the former justification, as the sole purpose of its filing in this proceeding is to evade direct competition. And, try as it may, APS also will not likely succeed in justifying the contracts based on competitive benchmarks. APS's benchmark analysis relies exclusively on contracts entered into between the California Department of Water Resources ("DWR") and merchant generators negotiated nearly a year ago, for delivery only into the California market. *See* Testimony of William H. Hieronymus at 5. Interestingly, these contracts have recently been challenged by the California Public Utility Commission and the California Electricity Oversight Board at the FERC, on the grounds that the contracts, "which were executed at the height of the California electricity crisis and tainted by market power, are unjust and unreasonable." *California Electricity Oversight Board v. Sellers of Energy and Capacity Under Long-Term Contracts with the California Department of Water Resources*, Docket No. EL02-62-000 (filed February 26, 2002).[7]

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[6] Because the divestiture has not yet occurred, APS cannot argue that the services and prices offered by PWCC to APS are similar to what other non-affiliated buyers agreed to accept from PWCC. And, given the PPA's terms, neither will it be able to justify the PPA on a cost-of-service basis.

[7] The use of these California contracts for comparison purposes is especially troubling given that APS made it a point to highlight its "comprehensive education campaign" to "educate and reassure customers that the energy situations in

Regardless of whether the DWR contracts in fact are comparable, the FERC certainly <u>will not</u> accept this argument before it resolves the DWR complaints on the merits. Moreover, even were it to take on the DWR issues today, and APS were to submit its PPA today, the FERC undoubtedly would convene at least a paper hearing, if not a full-blown trial-type hearing, either of which would take months to conclude. Then it would take many more months for the FERC actually to rule on APS's application. Without question, then, the FERC approval process will take at least as long as it would take for APS to issue and score an RFP.

In short, APS faces the Sisyphean task of convincing the FERC that both affiliate contracts (the APS-PWCC PPA and the PWCC-PWEC PPA) are just and reasonable based on a comparison to non-contemporaneous contracts for different products and with vastly different nonprice terms entered into a year earlier under circumstances leading the power purchaser itself (through its agents) to challenge the contracts and to seek their selective abrogation due to alleged overcharges exceeding $13 billion. APS does so, presumably, knowing that if it conducted a fair RFP that resulted in awarding the contract to its affiliate, FERC approval would likely be a simple matter.

IV. CONCLUSION.

Absent an order staying the procedural schedule in this proceeding and directing APS to conduct an RFP as outlined above, the Commission, ratepayers and market participants cannot be assured that APS will timely comply with Rule 1606(B), or, indeed, ever will meaningfully comply with the Rule. If, however, APS issues an RFP, the question as to whether a contract between APS and its affiliates is even necessary will be answered. The end result will be that APS either will have competitively procured wholesale power contracts for Standard Offer Service, as contemplated by Rule 1606(B), or the bidding process will prove that its affiliate PPA is appropriate. Either way, the need

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California and Arizona were much different . . . ." Testimony of Jack E. Davis at 15.

for the Commission to hold a lengthy hearing will be obviated, and an RFP process, therefore, would not take any more time to conclude than would the Commission's proceeding to hear APS's request for a partial variance on the schedule currently contemplated. In addition, and perhaps ultimately most importantly, if the Commission were to require APS to undertake an RFP, it then would be able to take comfort that any wholesale contract, even one between APS and its affiliate, that emanated from that RFP process would not only be more likely to be approved by the FERC, but would in fact be prudent from the standpoint of APS's ratepayers.

RESPECTFULLY SUBMITTED this 19th day of March, 2002.

FENNEMORE CRAIG

By: ______________________________

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1282642.1/73262.005

1

PANDA GILA RIVER L.P.'S FIRST SET OF DATA REQUESTS TO

ARIZONA PUBLIC SERVICE COMPANY

DOCKET NO. E-01345A-01-0822

Instructions

In responding to these Data Requests, please indicate the person or persons responsible for the compilation of the information provided in response to each request.

These Data Requests are intended to be continuing in nature. Accordingly, Arizona Public Service Company ("APS") is requested to supplement prior responses if it receives or generates additional information, reports or other data within the scope of any of the Data Requests between the time of the original response and the hearing to be held in connection with APS' variance request.

Included within this set of Data Requests are several Requests for Admission. A request will be deemed admitted unless APS serves a specific denial thereof or a written objection and the reasons therefore, or a statement explaining why APS can neither admit or deny. If APS denies or fails to admit any of the attached Requests for Admission or any portion thereof, for each denial or failure to admit APS must:

a. State each and every fact which supports or tends to support the denial of the specific Request for Admission;

b. State the name, address, and telephone number of each and every person who has personal knowledge of the facts alleged in APS's answer to (a) above;

c. Identify with sufficient particularity each and every document, memorandum, or writing of any kind which substantiates or tends to substantiate the facts alleged in subpart (a) above;

d. If APS answers any Request for Admission by stating that it lacks information or knowledge as to a reason for the failure to admit or deny, state specifically what "reasonable" inquiry was made to obtain sufficient information to enable APS to admit or deny such request for admission;

e. If APS can admit a portion of said request for admission, please indicate the portion which APS admits; and

f. State the legal authority which supports said denial.

If any information is withheld under claim of privilege, confidentiality or proprietary trade secret, you are required to: (1) identify in writing such information with sufficient particularity as to permit the Commission to make a full determination as to whether the claim or privilege is valid; (2) identify the nature of the privilege(s) asserted; and (3) identify the factual basis of the claim of privilege.

Definitions

"APS" refers to Arizona Public Service Company, and its parents, subsidiaries and affiliates, any employee, servant, agent, consultant, expert advisor, attorney, representative, or other person acting under its control or on its behalf.

"Commission" or "ACC" refers to the Arizona Corporation Commission, any employee, servant, agent, consultant, expert advisor, attorney, representative, or other person acting under its control or on its behalf.

The term "document" includes all written matter of every kind and description, whether draft or final, original or reproduction, including but not limited to, correspondence, memoranda, notes, transcripts, contracts, agreements, memoranda of telephone conversations or personal conversations, notices, reports, rules, regulations, facsimile messages, minutes of meetings, interoffice communications, reports, tapes for visual or audio reproduction, drawings, graphs, charts, electronic mail message, and other compilations from which information can be obtained. The term "document" includes all copies of the document which contain any additional writing, underlining, notes, deletions, or any other markings or notations, or otherwise not identical copies of the original.

Identify" when used in referring to a person, shall mean to state the following with regard to the person: (a) name; (b) last known address; (c) residence and business telephone numbers; (d) relationship to you; and (e) occupation at the date of these interrogatories.

The terms "identify" and "identity" with respect to a document mean to state the name or title of the document, the type of document (e.g., letter, memorandum, telegram, computer input or output, chart, etc.), its date, the person(s) who authored it, the person(s) who signed it, the person(s) to whom it was addressed, the person(s) to whom it was sent, its general subject matter, its present location, and its present custodian. If any such document was in APS's possession or subject to its control, but is no longer, state what disposition was made of it and explain the circumstances surrounding, and the authorization for, such disposition, and state the date or approximate date of such disposition.

"IPP" refers to independent power producers.

"List," "describe," "explain," "specify" or "state" shall mean to set forth fully, in detail, and unambiguously each and every fact of which APS has knowledge which is relevant to the answer called for by the data request.

"Merchant Intervenors" refers to the merchant generators that have intervened in Docket No. E-01345A-01-0822.

"Pinnacle West" or "PWCC" refers to Pinnacle West Capital Corporation, and its parents, subsidiaries and affiliates, any employee, servant, agent, consultant, expert advisor, attorney, representative, or other person acting under its control or on its behalf.

"PPA" refers to the Purchase Power Agreement between APS and Pinnacle West Capital Corporation.

"PWEC" refers to Pinnacle West Energy Corporation.

"Rules" refers to the Retail Electric Competition rules at A.A.C. R14-2- 1601 *et seq*.

Data Requests

1.1 Admit that after January 1, 2003, power purchased by APS for standard offer service must be acquired from the competitive market through prudent, arm's length transactions, with at least 50% through a competitive bid process.

1.2 Admit that APS will fully comply with this requirement beginning January 1, 2003.

If not, please state:

(1) why not; and

(2) when APS intends to fully comply with Rule 1606(B).

1.3 Has APS developed a competitive bid process for purchasing power for at least 50% of the power necessary to provide APS's standard offer service?

(1) If not, why not?

(2) If so, please describe the competitive bid process APS is using or will use to purchase power for at least 50% of the power necessary to provide APS's standard offer service.

1.4 Does APS have a schedule for implementing a competitive bid process for purchasing power for at least 50% of the power necessary to provide APS's standard offer service?

(1) If not, why not?

(2) If so, please provide APS's schedule for implementing a competitive bid process for purchasing power for at least 50% of the power necessary to provide APS's standard

offer service.

1.5 Please identify all steps APS has undertaken to purchase power for at least 50% of the power necessary to provide APS's standard offer service through a competitive bid process.

1.6 Please identify all requests for proposals or other solicitations made by APS to purchase power through prudent, arm's length transactions for APS's standard offer service.

1.7 Please describe all steps taken by APS to ensure that power purchased for standard offer service is acquired through prudent arm's length transactions.

1.8 Please identify each IPP with whom APS has had discussion(s) concerning purchasing power for APS's standard offer service.

For each IPP please state:

(1) when the discussion(s) occurred;

(2) the nature of the discussion(s): and

(3) the outcome of the discussion(s).

1.9 Admit that Jack Davis, speaking at the Western Governors Association, winter meeting in El Paso, Texas, stated that retail competition is not viable at this time and there are no workable models, except possibly Texas, but that model is not transferable to other markets and, therefore, the focus should be shifted to developing the wholesale market.

1.10 Admit that, if the Commission were to grant APS's Variance Request and approve the PPA, there would no longer be a competitive retail and/or wholesale market in Arizona. If denied, please describe the impact of the PPA on the competitive retail market in Arizona.

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ACTION______

FIRST SET OF DATA REQUESTS
FROM ARIZONA PUBLIC SERVICE COMPANY
TO PANDA GILA RIVER L.P.
(Docket No. E-01345A-01-0822)

Q.1-1 Please provide a copy of all documents that evidence the intent of Panda Gila River L.P. (hereinafter referred to as "Panda"), to provide electric power to APS or to otherwise serve APS Standard Offer customers in any of the years 2003 through 2015.

Q.1-2 Please provide a copy of all documents including but not limited to internal correspondence, memoranda, notes, business plans, and e-mails that evidence the intent of Panda to provide electric power to APS or to otherwise serve APS Standard Offer customers in any of the years 2003 through 2015.

Q.1-3 Please state whether Panda is willing to offer APS power for any of the years 2002 through 2015 at a lower delivered cost than available to APS from the Dedicated Unites under the proposed PPA. If the answer is yes, please state the years for which such an offer is made, the amount of energy and capacity Panda is willing to supply in each of the years 2002-2015, the price of energy and capacity offered for each of the years 2002-2015, and all other relevant terms and conditions under which such offer is made for each of the years 2002-2015.

Q.1-4 Please describe the transmission paths Panda would use to deliver power from its Arizona generation to the APS service area.

Q.1-5 Describe in detail all arrangements Panda has in place to secure transmission rights on any of the transmission paths identified in response to the preceding Question.

Q.1-6 Please provide all analyses conducted by or on behalf of Panda, or of which Panda is otherwise aware, that demonstrate that there is sufficient available transmission capacity to transmit the output of Panda's Arizona generation to the APS service area for each of the years 2002-2015.

Q.1-7 Please provide all economic and financial analyses of the impact on Panda's generating facility(ies) in Arizona if the requested variance is granted and the proposed Purchase Power Agreement ("PPA") approved.

Q.1-8 Please provide a copy of all materials provided to banks and/or other lenders in conjunction with Panda's Arizona generation facility(ies) that relate to Panda's expectation or need to sell output to APS.

Q.1-9 Please provide all analyses prepared by or for Panda, or of which Panda is otherwise aware, that would support the 50% competitive-bidding requirement of Rule 1606(B) as being the least-cost alternative for APS to secure power on behalf of Standard Offer consumers for any of the years 2003-2015.

3

Exhibit No. ___ (CRR-2)

VIRGINIA STATE CORPORATION COMMISSION'S ORDERS REGARDING VIRGINIA ELECTRIC AND POWER COMPANY'S RFP

COMMONWEALTH OF VIRGINIA

STATE CORPORATION COMMISSION

AT RICHMOND, JANUARY 14, 1999

APPLICATION OF

VIRGINIA ELECTRIC AND
POWER COMPANY CASE NO. PUE980462

For Approval of Expenditures
for New Generation Facilities
pursuant to Va. Code § 56-234.3 and
for a certificate of public
convenience and necessity pursuant to
Va. Code § 56-265.2

ORDER

On August 11, 1998, Virginia Electric and Power Company ("Virginia Power" or "Company') filed the instant application (the "Application"), requesting regulatory approval for the construction of five new gas-fired turbine generator units of approximately 150 megawatts ("MW") capacity each, to be installed either at a site in Caroline County or a site in Fauquier County. A related application seeks regulatory approval for construction of transmission facilities necessary to connect these generators to the electric transmission grid.

The Application has been twice amended. First, Virginia Power sought to increase the number of units from five to six, and also to utilize both sites. Later, in its rebuttal testimony, the Company modified the request to seek authority to construct only the first four units, using only its site in

Fauquier County. It is proposed that the 4 units would begin operation on or about July 1, 2000.

On September 2, 1998, the Commission Staff ("Staff") moved for a ruling as to whether the Rules Governing the Use of Bidding Programs to Purchase Electricity from Other Power Suppliers, now codified at 20 VAC 5-301-10 ("Rules"), were applicable to Virginia Power's filings. Pursuant to the Commission's order, also issued on September 2, 1998, the Company filed its response to the motion on September 16, 1998, and replies to this response were filed by other interested parties and by the Staff.

Virginia Power's response to the motion stated that it no longer had either an active bidding program or a long term resource plan, and so was not subject to the Rules, but if the Commission found otherwise, requested an exemption from the Rules. The Company asserted that the "critical need in 2000 and 2001 for extensive capacity warrants an exemption" for its Application, and that the Application could not be "accommodated within a competitive bidding process because of the quick timetable." The Company requested the Commission grant an exemption from the Rules "in order to assure the timely availability of this peaking capacity in 2000."

On October 20, 1998, the Commission issued an order establishing a procedural framework within which to resolve the issues raised by Staff's request for a ruling and the responses filed. The Commission found that an expedited hearing should be convened to determine, "the need for capacity and how any need can best be met, whether the Bidding Rules are applicable and if so whether Virginia Power should be granted an exemption from them, and whether the Virginia Power's asserted 'quick timetable' can accommodate meaningful participation from other parties." To encourage meaningful participation by other potential energy suppliers, the Commission further directed Virginia Power to file, "documents and materials necessary to enable interested parties to determine whether, if there is a need for additional capacity, they can meet such need through construction or purchase of generating capacity, demand side measures, or otherwise." A number of parties did respond to our order of October 20, 1998, by prefiling an intent to bid or testimony indicating their interest in submitting bids for capacity that the Commission may ultimately find to be needed by Virginia Power.[1]

The Commission convened a public hearing on January 5, 1999, which concluded three days later after receiving testimony

[1] Florida Power & Light filed notice of its intent to bid and Verified Declaration. Other parties presenting testimony indicating an interest in submitting bids included Edison Mission Energy, LG&E Power, Dynergy Power Corp., Westmoreland Energy Inc., and Calpine Corporation. Westvaco and the Virginia Independent Power Producers indicated an interest in extending existing power contracts. Additionally, Ingenco, a small scale provider of distributed generation capacity, provided testimony through Public witnesses.

from five witnesses for Virginia Power, eight witnesses from other power producers, a witness for the Attorney General, and two Staff witnesses. The witnesses testifying on behalf of potential bidders gave few specific details on their individual proposals to provide peaking capacity. Thus, the record is unclear as to whether timely bids could be received after the hearing and, if so, whether such bids would be under the benchmark pricing established by Virginia Power's construction proposal. We understand the reluctance of these parties to disclose the competitively sensitive details of their potential bids.

In addition to evidence of potential bids, the prospect for greater market power concentration resulting from Virginia Power constructing the requested gas-fired turbine generator units was also addressed by witnesses for the Attorney General, Staff, Old Dominion Electric Cooperative and the Virginia Independent Power Producers.

We will begin with an analysis of the Rules and the reasons for their promulgation to determine their applicability to Virginia Power today.

The Commission promulgated the Rules by order dated November 29, 1990, in Case No. PUE900029.[2] This case was established because:

> issues relative to the bidding process, including the propriety of an exclusive bidding program and the proper weighting of utility construction compared to purchase options, have arisen in a number of recent certificate and arbitration proceedings filed with this Commission. The growing use of bidding programs and the questions raised in those several proceedings resulted in our determination that it was necessary to initiate this investigation to revisit the principles discussed in the January 1988 Order and to adopt clear rules to delineate a framework for the contracting process between utilities and other power suppliers, both qualifying facilities under PURPA and non-PURPA independent power producers.

The Commission concluded in this order that "bidding programs continue to provide electric utilities with an excellent option for acquiring necessary capacity in an orderly and reasonable manner," and that a utility that establishes such a program "should be free to refuse offers of capacity that have been received outside of its bidding program."[3]

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[2] Commonwealth of Virginia, ex. rel State Corporation Commission, Ex Parte: In the matter of adopting Commission rules for electric capacity bidding programs, 1990 S.C.C. Ann. Rep. 340. The Commission had earlier announced policy guidelines regarding utility capacity bidding programs in Commonwealth of Virginia, ex. rel State Corporation Commission, Ex Parte: In the matter of adopting Commission policy regarding the purchase of electricity by public utilities from qualifying facilities when there is a surplus of power available, Case No. PUE870080, 1988 S.C.C. Ann. Rep. 297, Final Order, January 29, 1988 ("January 1988 Order").

[3] 1990 S.C.C. Ann. Rep. 340. Rule IX codifies this statement.

In the January 1988 Order, the Commission noted it had instituted the proceeding "to consider questions surrounding the acquisition of additional generating capacity by electric utilities." A comprehensive review of this subject was needed "as a result of the contention by one of the state's major utilities, Virginia Power, that it was receiving capacity offers in amounts greater than its projected needs for the foreseeable future."[4]

Both the guidelines and the Rules were intended to impose some structure in utility capacity acquisition at a time when federal law[5] and regulations had caused numbers of new participants to respond to a newly created opportunity to market power to traditional utilities. Prior to the implementation of the Rules, utilities were required to accept capacity offers from qualifying facilities and small power producers whenever they had need for capacity additions and to establish the price for such purchases at the utility's "avoided cost" on a case-by-case basis. Soon, both Virginia Power and this Commission were embroiled in numbers of protracted and contentious negotiations. Hence, the Rules established the important *quid pro quo* that utilities that established bidding programs could refuse offers

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[4] 1988 S.C.C. Ann. Rep. 297.

[5] The Public Utility Regulatory Policies Act of 1978, 16 U.S.C. 2601 et seq., ("PURPA").

received outside the bidding program. With limited exceptions, all capacity acquisition was to be conducted through the utility's bidding program. The bids themselves, compared against the utility's benchmark cost of building the capacity itself, which by rule it must determine, established an acceptable proxy for avoided costs.

In the January 1988 Order, the Commission stated that it "envisions a system in which a utility determining a need for additional power would issue, probably on an annual basis, a form of 'Requests for Proposals,' ("RFP") identifying its requirements in broad general terms, and the factors to be used in selecting projects to meet those needs. Participants in the market would evaluate this RFP in light of their own best interests and respond accordingly." The Commission cautioned utilities to "guard against the temptation to make an RFP overly restrictive in terms of the types of projects which could reasonably meet the threshold requirements. It is important that the process give a fair opportunity to all participants."[6]

It is unquestioned that Virginia Power established and maintained a bidding program. The record is replete with references to various RFPs issued by the Company over the years. At no time has Virginia Power advised the Commission or the

[6] 1988 S.C.C. Ann. Rep. 298 (footnote 3).

interested public that it has abandoned its bidding program, which would re-open its obligation to accept capacity offers. If at any time Virginia Power intends to formally abandon its bidding program, then the Company is directed to file with this Commission its notice of election to do so. Included in such notice shall be a complete description of the Company's methodology for determining its avoided costs under PURPA. This methodology will be in lieu of the use of competitive bids for determining avoided costs.

While Virginia Power has not issued an RFP recently, it requested and received waivers of the Rules as recently as 1996 and 1997.[7] Further, its witness, Mr. Rigsby, testified during the hearing that on the day the Application was filed, August 11, 1998, the utility intended to "go to the market" for at least 264 MW of additional capacity, and would go to the market by issuing an RFP.

The Commission concludes that the Company's contention that it could solicit competitive bids for power without regard for

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[7] Application of Virginia Electric and Power Company, For a Certificate of Public Convenience and Necessity Pursuant to Va. Code § 56-265.2 and Joint Application of Virginia Electric and Power Company, Richmond Power Enterprise, L.P. and Enron Power Marketing, Inc., For authority to enter into a purchased power contract without competitive bidding, Case No. PUE960062, Final Order, November 18, 1996. Application of Virginia Electric and Power Company, Virginia Power SPC-1, Inc., Virginia Power SPC-II, Inc. and Cheasapeake Paper Products Company, For issuance of Certificates of Public Convenience and Necessity Pursuant to Va. Code § 56-265.2 and related regulatory approvals, Case No. PUE950131. The exemption was granted in a 1997 Commission order that was later withdrawn.

or compliance with the Rules is unfounded and untenable. We find that Virginia Power presently has an active bidding program.

It is similarly unreasonable for the Company to contend as it did in its responsive pleading filed September 16, 1998, that it has no long-term resource plan as contemplated by the Rules. Rule III states that any utility's need for capacity identified in an RFP "should be consistent with its long-term resource plans. The capacity need identified by an investor owned electric utility should be consistent with the resource plans filed most recently with the Commission." Virginia Power subsequently acknowledged through its witnesses Cartwright and Green that the capacity need identified in this proceeding is consistent with Virginia Power's most recent long-term resource plans and consistent with its plan "filed most recently with the Commission."

The Rules apply.

We turn now to the request for an exemption from the Rules. We will deny this request. Virginia Power's reason for the exemption is that the Rules cannot accommodate the "quick timetable" for adding the capacity in the year 2000.

In testimony filed with the Application, Virginia Power witness Cartwright asserted that unit construction must begin on the site selected approximately one (1) year in advance of the planned in-service date for the units. This in-service date is July 1, 2000.[8] Mr. Cartwright, in ore tenus testimony during the hearing disclosed, however, that construction in the form of site preparation should begin by April 1, 1999.[9] While this date was challenged as too early, the procedures that this Order will implement are designed to, and will, accommodate the Company beginning work on the Remington site on April 1, 1999, as proposed.

Concerning the Company's timetable, evidence was brought forward during the hearing that in 1988, while also soliciting bids for peaking capacity, Virginia Power had issued an RFP on November 15, 1988, for capacity with an in-service date of December 31, 1989. Thus, the period from issuance to capacity availability was 13 1/2 months for the 1988 RFP. July 1, 2000, is roughly 18 months from now. No persuasive reason was offered to show that bids for supply of the July 1, 2000, capacity could not reasonably be received and evaluated on a timetable that would accommodate this schedule.

During the hearing, as noted, Virginia Power revealed both that it had finalized the contract for the purchase of the six

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[8] Exh. WRC-6, at 4.

[9] We note, however, that the April 1, 1999, date for beginning site preparation does not appear in the Company's Application or Supplemental Application, nor in its direct, supplemental, additional supplemental, or rebuttal testimonies.

CTs[10] and also that it intends to soon "go to the market" with an RFP. Its last reported intent is to solicit bids for 264 MW of capacity for July 1, 2000, as well as bids for about 850 MW for July 1, 2001, and July 1, 2002. Virginia Power's intent to solicit bids for power delivery on July 1, 2000, indicates its belief that even its "quick timetable" can be accommodated within the Rules for some increment of capacity. We are not persuaded from the evidence that a solicitation for the 600 MW of capacity represented by the units it asks to build cannot also be accommodated. Delivery of both increments of capacity will fall due on the same date.

To the extent that there is time pressure present in this case, the responsibility for such lies squarely with the Company. Further, the record supports and the Rules require that others be permitted an opportunity to supply some or all of the Company's identified peaking capacity requirements.

We are also mindful of the valid concerns over increased market power expressed by Staff, the Attorney General, Old Dominion Electric Cooperative, and others on cross examination. We share their concern that our approval of the proposed construction program will increase the Company's generation market power just when the Commonwealth may undertake to provide

[10] Further, the Company disclosed that it had not finalized its construction contract for installation of the units.

retail customer choice. In light of these market power concerns, we believe it appropriate for this Commission to encourage new entrants into Virginia's electricity market.

Therefore, we will order the Company to issue an RFP for at least the entire increment of capacity needed by July 1, 2000, and we direct our Staff to oversee the immediate development of the RFP and to review the Company's evaluation of all responses to it. The Staff is also directed to report any irregularities or complaints about the procedures promptly to the Commission for our further consideration. At the hearing, the Company indicated that its RFP would be ready in a matter of days. Accordingly, the Company should, no later than January 19, 1999, at noon, deliver to the Staff its proposed RFP and the Staff will promptly review and amend the proposal, as it deems appropriate.

Thereafter, Virginia Power will disseminate the RFP approved by Staff broadly within the interested marketplace by publication in appropriate newspapers and trade journals, by distribution via the Internet, and by direct delivery of the RFP to the Virginia Independent Power Producers ("VIPP") and other parties in this case, to parties that have previously entered into purchased power contracts with Virginia Power, to surrounding utilities, and to other organizations of potential suppliers. Responses for the capacity need identified for

July 1, 2000, will be received and considered on an expedited schedule set out below, while the solicitation process for the 2001 and 2002 capacity may occur at a more measured pace. The Company is, however, free to include the 2001 and 2002 capacity requirements within the RFP to be issued in conformance to this order, with notification that the scheduling of responses and evaluation of these bids will be issued separately.

We again caution Virginia Power, as we did in our January 1988 Order, to "guard against the temptation to make an RFP overly restrictive in terms of the types of projects which could reasonably meet the threshold requirements. It is important that the process give a fair opportunity to all participants."[11] We direct the Company to consider any and all options that might reliably meet the identified need, including those that would utilize power wheeled into Virginia Power's service territory making use of the Company's available transmission capability as identified during the hearing.

The RFP shall clearly state preferences for purchased power arrangements such as the nature, operating characteristics and location of capacity. The Company may also include appropriate provisions for discouraging frivolous bids and for requiring surety for contracting parties. The Company should consider

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[11] 1988 S.C.C. Ann. Rep. 298 (footnote 3).

bids for offers of up to 30 months, for offers to meet the July 1, 2000, need. Provisions for extending such arrangements should also be considered by the Company.

The Company shall compare any offers so received against the benchmark cost of its proposed units as set out in its Application as amended. We agree with Virginia Power that non-price factors should be weighed less heavily than in earlier solicitations. However, we believe that reliability is an appropriate non-price factor for consideration. For example, "iron in the ground" within the Company's control area should be viewed as being more reliable than a proposal for firm energy from an unspecified source. Consistent with the market power concerns raised by the Staff and other parties, mitigation of Virginia Power's market power is another non-price factor for consideration. We will grant an exemption from consideration of additional non-price factors, to the extent such consideration is mandated by the Rules.

We further agree with the Company that, since the RFP to be ordered herein may generate a wide variety of offers, it should be exempted from the Rules' requirement of issuing a form purchase contract together with the RFP.

If the Company's build option is the successful bid (and its testimony indicates strong confidence that it will be), Virginia Power will be required to install the capacity at a capped price not to exceed the amount set out in its testimony and Application. This "price cap" is needed to ensure that the Company's and any potential bidder's financial risks are comparable.

Virginia Power's witnesses all expressed strong belief that the market will unlikely be able to supply the entire increment of July 1, 2000, capacity at prices below the build option. The witness for the Old Dominion Electric Cooperative, Mr. Kappatos, voiced a similar opinion, as did the Staff. If, as is believed by these entities, this is the case, then evaluation of any responses to the RFP for the July 1, 2000, block of capacity should not be difficult. However, the Commission finds that the Rules, and sound policy, dictate that the market be provided the opportunity to express itself through the bidding process.

The Commission also finds that the Company's contention that there is a critical need for additional capacity in the summer of 2000 is well-founded. In order to meet this need, the Commission will, pursuant to § 56-234.3 of the Code of Virginia, conditionally grant the Company the authority to make financial expenditures for the proposed units at its Remington site in Fauquier County. Virginia Power is authorized and directed to begin such necessary permitting and site preparation work as needed to ensure the timely installation of the proposed combustion turbines. The Company is to continue such activity during the pendency of the bidding process, at its expense and risk, until such time as the Commission orders differently. The Company is further directed to maintain its ownership of the combustion turbines while this action remains pending. The authorization granted herein is conditioned upon the bidding process uncovering no superior bid or bids for the supply of the needed capacity.

The Commission directs its Staff to review offers for capacity for July 1, 2000, and to report to the Commission as set out below the results of its review of the Company's evaluation of said offers. If no superior bids are received, the Commission will issue to Virginia Power certificates of public convenience and necessity by further order, which may impose additional conditions relative to the Company's use of the units.

Should reliable suppliers willing to meet the capacity needs at lower prices come forward, the Commission will issue a further procedural schedule. We expect and direct Virginia Power, however, to begin immediate negotiation to finalize an agreement with any such supplier who comes forward in response to the solicitation and offers to meet any portion of the identified capacity need at a superior price. Such negotiations, if any, over final contract details need not await the establishment of the further procedures contemplated herein.

Accordingly, IT IS ORDERED THAT:

(1) Virginia Power shall, no later than January 19, 1999, at noon, deliver to the Commission Staff its proposed Request for Proposals ("RFP");

(2) Staff shall review and, if necessary amend, the RFP and return the document to Virginia Power on or before January 21, 1999;

(3) Virginia Power shall immediately cause the RFP approved by Staff to be published and distributed as discussed herein;

(4) Interested parties shall submit to the Company, and may submit to the Commission's Division of Energy Regulation, responses to the solicitation for the July 1, 2000, capacity on or before March 26, 1999;

(5) Staff shall file with the Clerk of the Commission on or before April 2, 1999, a preliminary report detailing whether it appears that any responses so received indicate supplier or suppliers willing and able reliably to meet the need at prices below the Company's build option, and if so, how much further analysis of such offer or offers is required;

(6) To the extent that the requirements of this Order do not comply with the Rules, appropriate exemption therefrom is granted;

(7) The financial expenditures of Virginia Power proposed herein are approved, conditioned as set forth herein, pursuant to Code of Virginia § 56-234.3; and

(8) This matter is continued for further order of the Commission.

4

ARIZONA ELECTRIC POWER COOPERATIVE, INC.

SOLICITATION FOR PROPOSALS

TO SUPPLY CAPACITY AND ENERGY

August 15, 2001

TABLE OF CONTENTS

TABLE OF CONTENTS

1. SCOPE

The growth of the electric loads of the areas served by Arizona Electric Power Cooperative, Inc.'s ("AEPCO's") six distribution cooperative owners ("Class A Members") is projected to exceed the capacity of AEPCO's power resources as early as the summer of 2002. AEPCO management and staff presented a generation alternative to the AEPCO Board at the May 2001 Board meeting and received Board approval to proceed with the installation of a 38 MW combustion turbine ("GT 4") at the Apache Generation Station. With this development, AEPCO is focusing on its long term requirements and has embarked on investigations into the further expansion of its existing generation resources and/or purchased power alternatives.

AEPCO is soliciting proposals from qualified entities to supply firm electric capacity and associated energy starting May 1, 2003 and continuing through December 31, 2010. AEPCO will consider proposals that will provide for all or part of its requirements (e.g., entity may bid any combination of Option 1 and/or Option 2 Parts A and/or B) as shown in Exhibit A or for resources to be added in incremental blocks to meet the growth over the period. In Exhibit A, Option 1 is for Base Load Capacity and Option 2 is divided into two parts: Part A for the Peaking Component, and Part B for the Base Load Component. The blend of demand and energy prices associated with each option and the energy rate relative to that of AEPCO's existing resources for dispatchability purposes will be factors in the determination of the contract(s) awarded. Depending primarily upon the cost of proposals, AEPCO may elect to contract for capacity beyond 2010. Proposers are encouraged to propose options that would allow AEPCO to continue the purchase after 2010. AEPCO reserves the right to modify the capacity and/or energy requirements at any time during the solicitation and evaluation process as conditions warrant.

AEPCO will consider proposals to meet its needs from any combination of the following sources:

- Any entity proposing to meet any portion of the needs through proven demand-side management measures involving energy efficiency.
- Any entity which currently owns, or proposes to develop, generating facilities.
- Any entity which currently owns, or proposes to develop, generating facilities utilizing renewable resources, that is, solar, thermal, photovoltaic, biomass, geothermal or wind power.
- Any entity proposing to meet any portion of the needs from energy stored during off-peak periods (e.g., batteries).
- Any entity proposing to provide power through alternative means (e.g., brokering or some combination of alternatives above).

It is AEPCO's intent that this solicitation is to only gather information for the purpose of later proposal/contract negotiations with those most likely to meet AEPCO's requirements. Such negotiations, if successful, would only then lead to binding commitments on AEPCO's part, if approved by AEPCO's Board of Directors and the requisite regulatory agencies.

AEPCO retains the right to reject any and all proposals responding to this SFP at its sole discretion for any reason whatsoever and to negotiate any proposal with any entity or with all entities responding at its sole discretion.

2. SFP COMMUNICATION

All questions concerning this SFP should be submitted in writing to Mr. James Rein, Director of Sales. AEPCO will provide written responses to all questions. At AEPCO's sole discretion, general information that is supplied in response to questions will be provided to all bidders.

3. SCHEDULE

All proposals must be prepared in accordance with the requirements of this SFP and must be received at AEPCO's Benson office no later than 4:00 p.m. Mountain Standard Time on Friday, September 28, 2001. AEPCO may request additional information at a later date to supplement that provided in response to this SFP in order to assist in its decision making process. Any entity taking exception to any part of these requirements must clearly state that exception. AEPCO, at its sole discretion, may disqualify the proposal.

It is AEPCO's intent to complete the evaluation and negotiations during the remainder of 2001.

AEPCO reserves the right to modify the schedule at its sole discretion for any reason.

4. BACKGROUND

4.1 Description of AEPCO

AEPCO is an electric generation cooperative organized and existing under the laws of the State of Arizona. AEPCO has constructed, operates and maintains the 520 MW Apache Generation Station located near Willcox in southeast Arizona. AEPCO supplements Apache capacity by purchasing power from third parties by contract, and AEPCO sells its surplus under wholesale power sales agreements to others, all for the benefit of its six Class A Members. Four of AEPCO's Class A Members are located in southeastern Arizona. They are Trico Electric Cooperative, Inc., which serves the outreaches of Tucson; Duncan Valley Electric Cooperative, Inc., which serves in Greenlee County; Graham County Electric Cooperative, Inc., which serves in Graham County and the outreaches of Safford and Thatcher; and Sulphur Springs Valley Electric Cooperative, Inc., which serves in Sierra Vista, Willcox and Benson and surrounding areas. The other two cooperatives served by AEPCO are Mohave Electric Cooperative, Inc., which serves in a large portion of Mohave County, including Bullhead City; and Anza Electric Cooperative, Inc., which serves the rural area south of Palm Springs, California. AEPCO sells surplus capacity and energy at wholesale to others, the majority of which are members of AEPCO under other classifications.

The combined services area of the Class A Members covers nearly 30,000 square miles in rural Arizona and portions of California and New Mexico where approximately 245,000 people live. Residential customers represent 87% of the customer base with commercial and industrial (excluding mines) customers account for an additional 12%. Residential and commercial sales accounted for 67% of AEPCO's total energy needs in 2000 (residential 40% and commercial and industrial 27%). The remaining energy requirements were for irrigation, public street lighting, public authority, mines, sales for resale customers, non-firm energy sales, members own use, and system losses. AEPCO also has Class B and Class C members that purchase only a portion of their total energy needs from AEPCO. AEPCO's historic Class A Member coincident loads are in Exhibit B.

AEPCO is regulated by the Rural Utilities Service ("RUS"), an agency of the U.S. Department of Agriculture. By virtue of its loans to AEPCO, RUS holds the mortgages on AEPCO assets. To promote loan security, RUS promulgates regulations which are encoded in 7 CFR 1710 Sections 253 and 254. AEPCO will need to abide by those regulations in this endeavor.

4.2 AEPCO Points of Delivery

AEPCO has identified the following delivery points that are acceptable locations to receive delivery of generated capacity and energy. There are transmission limitations associated with each delivery point and the responding entity may have to include deliveries to one or more of these delivery points in their proposal. The delivery points, including AEPCO's approximate limitations on the transmission system, are as follows:

	Name	**Limitation (S)summer**	**(W)winter**	**Location**
1.	Mead Substation	50MW (S)	45MW (W)	Clark County, NV
2.	Davis Dam Switchyard	50 MW (S)	45 MW (W)	Mohave County, AZ
3.	Topock Substation	50 MW (S)	45 MW (W)	Mohave County, AZ
4.	Westwing Substation	40 MW		Maricopa County, AZ
5.	Vail Substation	(See note below)		Pima County, AZ
6.	Greenlee Substation	35 MW		Greenlee County, AZ

7.	Hayden Substation	(See note below)	Gila County, AZ
8.	Apache Substation	(See note below)	Cochise County, AZ

***Note:** for the purposes of this SFP, no transmission limitations are anticipated.*

Other delivery points will be considered as a part of this SFP at AEPCO's discretion. Capacity and energy received at a delivery point must not adversely impact the integrity of the AEPCO system and other interconnected systems.

Any transmission facilities/contract required to deliver the capacity and energy pursuant to any proposal from generation site(s) to the designated delivery point(s) will be the sole responsibility of the responding entity. Responding entities must provide satisfactory evidence that they have firm transmission path(s) to the proposed point(s) of delivery. If a third party is used for wheeling any portion of the path between the generation site and the point(s) of delivery, the responding entity must so indicate that third party wheeling is required and must provide a copy of the wheeling agreement or a copy of an executed letter of understanding from such third party prior to any binding commitment by AEPCO.

5. PROPOSAL CONTENT

The following information is required for a proposal to be considered responsive to this SFP, unless the proposing entity can clearly demonstrate that such information is not applicable to its circumstances. Any additional information that the proposer considers useful for AEPCO to fully evaluate its proposal will be considered. AEPCO may request additional information at a later date to supplement that provided in responses to this SFP in order to assist in its decision making process.

5.1 Respondent Information

5.1.1 Name and address of responding entity.

5.1.2 Name, voice telephone number, fax number, and e-mail address of contact person for this proposal.

5.1.3 Current and last Annual Report.

5.1.4 Current and last SEC Form 10K.

5.1.5 Evidence of the entity's experience in providing the facilities and/or services proposed.

5.1.6 Evidence of the entity's financial viability to provide the facilities and/or services proposed.

5.2 Description of Proposal (Demand-Side Only)

5.2.1 Proposal Requirements (Demand-Side Only):

Respondent's proposal must include the following elements as a minimum:

- A description of proposed demand-side management (DSM) measures and programs.

- A forecast of capacity and energy avoided as a direct and indirect (market transformation or spillover) result of the proposed DSM measures and programs.

- A description of the proposed approach to estimate the capacity and energy actually avoided as a result of the proposed DSM measures and programs. As a minimum, the proposed measurement approach should include:

    The proposed sample comparison methodology. For example, whether a time series method or cross-sectional method will be employed, or a combination of the two.

    The proposed technique to model the net impact of the DSM measures and programs based on sample results. Such techniques may be statistical comparisons, regression analysis, engineering models, statistically adjusted engineering models or ratio estimation.

    The proposed direct impact measurement method, such as billing analysis or metering.

    The proposed method to measure or control self-selection bias in sample populations, free-riders, spillover, and persistence of the DSM effects.

5.2.2 Payment for DSM Results:

Payment will be based on a mutually agreed upon estimate of the actual avoided capacity due to Respondent's DSM measures and programs, net of free-riders and adjusted for lack of persistence.

5.3 Description of Proposal (Supply-Side Only)

5.3.1 General description of the generating facility(s) proposed.

5.3.2 Location of proposed generating facility(s).

5.3.3 Firm capacity to be supplied to AEPCO delivery point(s) by year.

5.3.4 Generation technology utilized.

5.3.5 Fuel(s) to be utilized.

5.3.6 Description of long term fuel arrangements, including fuel costs and fuel escalation 1rates.

5.3.7 Description of delivery efficiency.

5.3.8 Strategy for ensuring environmental compliance.

5.3.9 For units in the planning stage or not fully permitted at the time an entity responds to this SFP, provide evidence the facilities can obtain all regulatory permits and a guarantee that resources will be available to fulfill all contract requirements.

5.4 Transmission Information (Supply-Side Only)

5.4.1 Delivery point(s) proposed.

5.4.2 Transmission path(s) proposed.

5.43 To the extent available or necessary, wheeling agreement(s) or executed letter(s) of understanding from all third parties providing transmission to the proposed delivery point(s).

5.5 Pricing

5.5.1 Firm capacity rates by year reflecting all proposed fixed costs (for example, including any transmission losses and wheeling charges necessary to reach the AEPCO delivery point(s) and costs of emissions allowances).

Firm capacity rates should be fixed for the term of the proposal. Proposals containing liquidated damages provisions will not be considered.

5.5.2 Energy rates by year reflecting all proposed variable costs (for example, including any transmission losses and wheeling charges necessary to reach the AEPCO delivery point(s) and costs of emissions allowances). If energy rates are projected (not fixed for the term of the proposal), provide the basis and all underlying assumptions for the projected energy rates.

5.5.3 Avoided capacity rates by year due to DSM measures and programs.

5.5.4 All costs should be broken down by year for Option 1 - Base Load Resources and for Option 2 - Peaking Resources and broken down by month for Option 2 - Peaking Resources.

5.6 <u>Reliability (Supply-Side Only)</u>

5.6.1 Projected equivalent forced outage rate by year for existing and new resources.

5.6.2 5-year history of equivalent forced outage rates for each existing resource.

5.6.3 Days of required planned maintenance by year.

5.6.4 Proposed planned maintenance schedule for all years.

5.6.5 Availability provisions for system power or resource pools.

5.7 <u>Environmental Benefits</u>

5.7.1 A description of the environmental benefits that would result.

5.7.2 A detailed description of the basis for the claimed environmental benefits.

5.8 <u>Options</u>

Entities are encouraged to submit a detailed description of any available options to the base proposal. Options would be based on conditions particular to the entity that may be beneficial to AEPCO. (For example, a supply side option with a second quarter capacity and energy sale coupled with the base proposal.)

6. EVALUATION CRITERIA

Proposals will be judged on their ability to meet AEPCO's requirements for economical and reliable power supply. Respondents to this solicitation should provide all relevant information necessary to allow AEPCO to conduct a thorough analysis of the proposal. However, the principal criteria to be used by AEPCO in evaluating proposals include: total delivered cost of the power supply over the contract term, the reliability of the proposed power supply, and the financial and operational viability of the respondent. AEPCO reserves the right to consider any other factors that may be relevant to its power supply needs.

6.1 Persistence of Avoided Power Costs (Demand-Side Only)

Proposals for avoided capacity through DSM measures and programs will be evaluated with regard to the anticipated persistence of the effects of the DSM measures and programs in mitigating the need for future capacity additions. A net present worth of avoided capacity will be developed.

6.2 Total Delivered Cost of Power to AEPCO (Supply-Side Only)

The cost of power delivered to AEPCO, including losses, transmission charges, and the costs of any services provided by third parties must be competitive with AEPCO's alternatives. AEPCO will consider such factors as:

(a) Demand Charges
(b) Fuel Charges
(c) Other Energy Charges
(d) Emission Allowance Charges
(e) Transmission Charges
(f) Third Party Services
(g) Price stability of (a) through (f) and/or factors influencing future rates
(h) Losses
(i) Flexibility (0 to 100% monthly load factor) in scheduling and dispatching the resource
(j) Dispatchability of resource on an energy rate basis

6.3 Total DSM Cost to AEPCO of Avoided Power (Demand-Side Only)

The cost of DSM measures and programs to avoid additional capacity must be competitive with AEPCO's alternative supply-side options. AEPCO will compare DSM costs with such alternative factors as:

(a) Demand Charges
(b) Fuel Charges
(c) Other Energy Charges
(d) Emission Allowance Charges
(e) Transmission Charges
(f) Third Party Services
(g) Losses
(h) Price stability of (a) through (f) and/or factors influencing future rates

6.4 Term of Power Requirements

AEPCO's intent is to obtain a long-term source of power supply at least through 2010. Viable proposals for the years of 2003 to 2006 and the years 2007 to 2010 will be considered. Proposals with a term for the years 2003 to 2010 are desired.

6.5 Reliability of Power Delivered to AEPCO (Supply-Side Only)

Proposals containing liquidated damages provisions will not be considered. In general, firm power and energy provided to AEPCO should be available to AEPCO at all times, even during adverse conditions, subject only to interruption due to forces beyond the reasonable control of AEPCO or the respondent.

6.6 Viability of Respondent

The Respondent must provide sufficient evidence that it is financially and operationally capable of providing the services outlined in the proposal during the contract term.

7. PROPOSAL DURATION

All proposals must be valid through January 31, 2002, pending evaluation by AEPCO. Those proposals selected by AEPCO for initiation of contract negotiations must be extendable to accommodate the time needed for such negotiations.

8. PROPRIETARY DATA IN PROPOSAL

A proposal may include data which the respondent does not want disclosed to the public or used by AEPCO for any purpose other than proposal evaluation. Proprietary data should be specifically identified as such on every page where the same may be contained. Such information will be used by AEPCO or its designated representatives, including staff and consultants, solely for the purpose of evaluating the proposal. In such case, reasonable care will be exercised so that data so identified will not be disclosed or used without the respondents' permission except to the extent provided in any resulting contract or to the extent required by law. This restriction does not limit AEPCO's right to use or disclose any data contained in the proposal if it is obtainable from another source without restriction. In any event, AEPCO, its employees, and consultants will not be liable for the accidental disclosure of such data, even if it is marked.

9. COST INCURRED IN RESPONDING

All costs directly or indirectly related to preparation of a response to this SFP or any oral presentation required to supplement and/or clarify a submittal which may be required by AEPCO shall be the sole responsibility of and shall be borne by the respondent(s).

10. CONTRACT INCORPORATION

Respondents should be aware that the contents of a selected proposal may become a part of any subsequent contractual documents. Failure of the respondent to accept this obligation may result in the cancellation of any award.

11. REGULATORY APPROVAL

Any contracts which may be considered as a result of this SFP or subsequent negotiations are subject to appropriate regulatory approvals.

12. REJECTIONS OF PROPOSALS

AEPCO reserves the right to accept any proposal(s), or to reject any and all proposals and to re-solicit for proposals in the event that all proposals are rejected. Additionally, AEPCO reserves the right to accept proposals other than the lowest cost proposal. Respondents should recognize that factors other than cost, such as reliability, will be considered during the evaluation process.

13. RELEASE OF INFORMATION

Information submitted relative to this SFP shall not be released by AEPCO or its consultant during the evaluation process, except that AEPCO may provide information to the Rural Utilities Service during the proposal evaluation process.

14. WITHDRAWAL OF PROPOSALS

Any proposal may be withdrawn through written notice, such notice to be received by AEPCO before October 31, 2001.

15. SUPPLEMENTAL INFORMATION

AEPCO reserves the right to request additional information from individual respondents or to request all respondents to submit supplemental materials in fulfillment of the content requirements of this SFP or to meet additional information needs of AEPCO.

16. ADDITIONAL INFORMATION REGARDING THIS SFP

Any questions regarding this SFP should be directed and addressed in writing to AEPCO's representative - Mr. James Rein, Director of Sales.

James R. Rein
Director of Sales
Arizona Electric Power Cooperative, Inc.
1000 S. Highway 80
P.O. Box 670
Benson, AZ 85602-0670

Ph: (520) 547-7919
Fax: (520) 547-7920
e-mail: jrein@aepnet.org

17. SUBMITTAL INSTRUCTIONS

Three (3) copies of each proposal should be submitted. Proposals should be marked: "Confidential, Response to AEPCO SFP. Deliver to Addressee Unopened." Three copies of each proposal must be sealed and delivered by no later than 4:00 p.m. MST, Friday, September 28, 2001, to:

James R. Rein
Director of Sales
Arizona Electric Power Cooperative, Inc.
1000 S. Highway 80
P.O. Box 670
Benson, AZ 85602-0670

EXHIBIT A

OPTION 1 BASE LOAD RESOURCE

YEAR	MAXIMUM MW
2003	50
2004	60
2005	75
2006	90
2007	100
2008	110
2009	120
2010	130

OPTION 2 COMBINATION BASE LOAD AND PEAKING RESOURCE

PART A - PEAKING COMPONENT (MW)

YEAR	MAY	JUNE	JULY	AUGUST	SEPTEMBER
2003	45	80	70	50	40
2004	45	90	90	70	40
2005	45	90	90	70	40
2006	45	90	90	70	40
2007	45	90	90	70	40
2008	45	90	90	70	40
2009	45	90	90	70	40
2010	45	90	90	70	40

EXHIBIT A (continued)

OPTION 2 COMBINATION BASE LOAD AND PEAKING RESOURCE (continued)

PART B - BASE LOAD COMPONENT

YEAR	MAXIMUM MW
2003	10
2004	15
2005	25
2006	35
2007	40
2008	50
2009	60
2010	70

EXHIBIT B

HISTORICAL CLASS A MEMBER LOAD - MW

YEAR	PEAK
1993	242
1994	272
1995	294
1996	301
1997	296
1998	323
1999	334
2000	364
2001[1]	392

1.Peak is as of July 2001