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February 3, 2010

Jane L. Rodda
Administrative Law Judge
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

RE: Arizona Public Service Company Sale of Electrical Facilities to Electrical District No. 3, DOCKET NO. E-01345A-08-0426

Pursuant to the discussion held during the Procedural Conference in the above-referenced matter on January 21, 2010, Arizona Public Service Company ("APS") hereby submits: (1) APS's January 2008 application at FERC to increase wholesale rates charged to ED-3 as Late-Filed Exhibit 1; and (2) Contract No. 89695 between APS and Electrical District No. 3, as Late-Filed Exhibit 2.

If you have any questions regarding the information contained herein, please contact Jennie Vega at 602-250-2038.

Sincerely,

Leland R. Snook

Leland R. Snook

LS/sl

Attachments

CC: Steve Olea
Janice Alward
Lyn Farmer
Parties of Record
Docket Control

Copies of the foregoing hand-delivered/emailed
this 3rd day of February, 2010 to:

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January 31, 2008

VIA HAND DELIVERY
Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First St., NE
Washington, DC 20426

Re: Arizona Public Service Company
Docket No. ER08-

Dear Secretary Bose:

Arizona Public Service Company ("APS") hereby submits for filing an original and six copies of revisions to APS Electric Rate Schedule FERC No. 12 and APS Electric Rate Schedule FERC No. 68 (the "Lease Power Agreements"). The purpose of this filing is to change the current rates in these rate schedules to more closely reflect the costs that APS incurs in providing supplemental service to Electrical District No. 3 of the County of Pinal and State of Arizona ("ED-3") and Electric District No. 1 of the County of Pinal and State of Arizona ("ED-1") (collectively referred to herein as the "EDs").

APS requests that the revised rates be accepted for filing 60 days following the date of filing, to be effective on the first day of the month following the final order of the

Commission.[1] APS respectfully requests waiver by the Commission of any requirements of the Commission's rules and regulations, as well as any authorization as may be necessary or required, to permit the revised rates to be accepted by the Commission and made effective in the manner proposed herein.

I. COMMUNICATIONS

Communications regarding this filing should be sent to the following individuals:

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II. BACKGROUND AND GENERAL DESCRIPTION OF THE FILING

A. APS

APS, a wholly-owned subsidiary of Pinnacle West Capital Corporation, is a public utility incorporated in the state of Arizona. APS engages in the generation, transmission, distribution and sale of electricity in interstate commerce, and owns facilities used for the sale and transmission of electric energy in interstate commerce.

1 Under the Lease Power Agreements, APS may modify the rates under the just and reasonable standard, but the rates become effective only prospectively, upon "approval" of the rates by the Commission. *See Arizona Public Service Co.*, 1 FERC ¶ 63,042 (1977); *aff'd*, 4 FERC ¶ 61,101 (1978).

APS is the second fastest growing utility in the country. Presently, APS provides retail electric services to more than one million customers in a service territory comprising 34,645 square miles in the Phoenix metropolitan area and throughout the state of Arizona.

B. ED-3 and ED-1

ED-3 is an Electrical District in Pinal County, Arizona and is considered a municipal corporation. Since 1960, both APS and ED-3 have served customers located within ED-3's service territory. APS has primarily served the area's residential, commercial and industrial load, while ED-3 has historically served the area's irrigation pumping loads. As explained in the affidavit of Mr. Justin H. Thompson, ED-3 and APS own electrical systems in overlapping Arizona service territories. Within their respective service territories, ED-3 and APS have an intertwined distribution network. Generally, customers in the region may choose to take service from either APS or ED-3. In fact, APS has certain retail customers that it serves by use of the ED-3 distribution network and ED-3 has certain retail customers that it serves by use of the APS distribution network. From 1961 through October 8, 2001, ED-3 leased its transmission and distribution system to APS pursuant to a Lease Agreement between the parties. The Lease Agreement, combined with the Lease Power Agreement between APS and ED-3, provided for APS to operate the leased ED-3 system to serve both ED-3's customers and APS's own customers. The Lease Agreement expired on October 8, 2001.[2] Thereafter, APS and ED-3 entered into a settlement agreement that provided for certain interim

2 The Commission accepted APS's notice of termination of the ED-3 Lease Agreement on December 5, 2001. *Arizona Public Service Co.*, Letter Order in Docket No. ER02-65-000 (Dec. 5, 2001).

services, including service under a Lease Power Agreement (APS Rate Schedule FERC No. 12) that was approved on July 5, 2002, to be in effect until the Arizona Corporation Commission approved APS's sale of certain facilities to ED-3.[3] As discussed below, that approval has not yet been obtained. APS is experiencing a severe underrecovery of the costs of providing the interim service to ED-3 which must be rectified.

ED-1, a sister entity of ED-3, is also a municipal corporation. ED-3 and ED-1 were consolidated on January 14, 1989, for all purposes relevant to this filing. While there are separate Lease Power Agreements for ED-1 and ED-3, the business arrangements were largely identical. In fact, the corporate identity of, and APS's interactions with, ED-1 and ED-3 are essentially indistinguishable with respect to these agreements. ED-1 is also served on an interim basis under an almost identical Lease Power Agreement (APS Rate Schedule FERC No. 68) that was also approved on July 5, 2002, as part of the same settlement agreement referenced above. The proposed changes in rates apply equally to ED-1's Lease Power Agreement and, hereafter, for convenience any subsequent references to ED-3 apply equally to ED-1 unless specifically noted otherwise.

C. The Lease Power Agreements

As discussed above, APS currently serves the EDs through the amended Lease Power Agreements. Under the agreements, APS provides pre-OATT grandfathered transmission service to ED-3 for the wheeling of hydro power that ED-3 purchases from

3 *See Arizona Public Service Co.*, Letter Order in Docket No. ER02-1761 (Jul. 5, 2002) (waiving prior notice of termination requirements to permit cancellation of the Lease Power Agreement to become effective "upon the sale of certain distribution facilities.").

Morgan Lewis
COUNSELORS AT LAW

the United States Bureau of Reclamation. APS also provides supplemental power to ED-3 for certain loads that are not covered by the allotment of hydro power.[4] Amendments to these agreements were accepted by the Commission as the result of a settlement agreement between APS and ED-3.[5] The settlement agreement resolved all issues among APS, ED-3, and Pinnacle West Capital Corporation with respect to the parties' provision of transmission service and the ownership of certain facilities. Those issues included the transfer to ED-3 of certain facilities owned by APS; the amendment and deferred cancellation of certain transmission service and power sales agreements between APS and ED-3 on file with the Commission; the cancellation of other APS rate schedules for service to ED-3; and the provision of transmission service over the ED-3 system. Under a key provision of the settlement agreement, APS and ED-3 agreed to terminate the Lease Power Agreements effective upon the purchase by ED-3 of APS's Sexton Substation.[6] At the time these amendments were proposed, all parties involved

4 The amendments to the Lease Power Agreements also eliminated a previous service restriction that limited ED-3 to serving irrigation pumping loads. However, the provision of the Lease Power Agreement obligating APS to provide supplemental power and energy was unchanged and applies only to ED-3's pumping loads. Therefore, APS is free under the Agreements to provide supplemental power and energy to all loads, but is obligated to do so only with respect to irrigation pumping loads. APS has in the past supplied ED-3 for loads other than pumping loads, largely as an interim measure in expectation of the timely termination of the Lease Power Agreements. Because the Agreements have continued much longer than anticipated, APS no longer anticipates being able to serve ED-3 loads other than irrigation pumping loads under the Lease Power Agreements. APS is willing to discuss with ED-3 other avenues for meeting those loads, and of course, ED-3 is free under the Agreements to procure such power and energy from any other source.

5 *See Arizona Public Service Co.*, Letter Order in Docket No. ER02-1761 (Jul. 5, 2002).

6 *Id.* The Sexton Substation is a 69/12 kV substation located at Highway 84 and Anderson Road, adjacent to APS and ED-3 service areas.

expected that the sale of Sexton and the resulting termination of the Lease Power Agreements would occur within a short time frame.[7]

However, the necessary ACC approvals have been delayed, and with the length of time that has transpired in the interim, the revenues APS receives for this supplemental power are no longer just and reasonable.[8] Under the current rates, as shown in the affidavit of Ralph L. Luciani, APS earns a negative return on the services it provides ED-3. APS therefore proposes that the revised rates submitted with this filing become effective at the earliest possible date consistent with the terms of the Lease Power Agreements, with billing at the new rates to begin on the first of the month following approval by the Commission.

III. PROPOSED RATE METHODOLGY

APS bases the rates on a "units most likely to serve" rate methodology that is consistent with methodologies previously approved by the Commission.[9] As described in the affidavit of Mr. Ralph L. Luciani, this methodology derives a demand charge of

7 As further explained in the affidavit of Mr. Justin H. Thompson, the current Lease Power Agreements accepted on July 5, 2002, were meant as a short term fix, with these Agreements terminating after APS's Sexton substation was sold to ED-3. *Arizona Public Service Co.*, Letter Order in Docket No. ER02-1761-000 (Jul. 5, 2002). An application to transfer the Sexton substation was filed with the ACC on April 15, 2002. After discussions with the ACC staff and with the concurrence of ED-3, APS on June 18, 2007, withdrew that application and is currently preparing a revised application for submission to the ACC in the near future.

8 The current demand charge for ED-3 was accepted on July 28, 1994 in Docket No. ER94-1413. The current demand charge for ED-1 and the current energy charge for both ED-3 and ED-1 were accepted on September 19, 1990 in Docket No. ER89-265.

9 The Lease Power Agreements are short-term arrangements for the provision of supplemental power and energy to ED-3. ED-3 has no obligation to purchase supplemental power and energy from APS and is free to choose any other supplier. Moreover, due to provisions of the Agreements that permit it to offset its demands with preference power, ED-3 effectively can avoid placing any billing demands on the APS system. As a result, its choice of taking service from APS is simply an economic one, and the service is fundamentally a coordination service.

$6,901 per MW-month and an energy charge of $82.86 per MWh. These new rates provide recovery of APS's actual cost to serve ED-3, as opposed to the current rates, which as shown by Mr. Luciani, result in a $14,746,703 deficit in cost recovery by APS. As permitted by the terms of the Agreements, APS therefore proposes to change the demand and energy charges included in the Lease Power Agreements.[10] As also permitted by the Agreements, APS also proposes to delete the fuel adjustment clause in the Agreements and replace it with a fixed energy charge consistent with the units most likely methodology.

As required by Order No. 888, APS is unbundling the rates under these agreements to specifically delineate energy, demand and applicable transmission charges.[11] As noted above, the Agreements contain a grandfathered wheeling charge for deliveries of preference power to ED-3. The Agreements do not permit a change in that charge, and therefore the unbundled transmission charges will apply only to deliveries of supplemental power and energy under the Agreements.

As noted, APS proposes to delete the existing fuel adjustment clause, included in both Lease Power Agreements as Exhibit I(A), to be consistent with the underlying rate methodology. APS notes that the fuel clauses in the Lease Power Agreements were modified in 2000 as part of APS and its affiliates' request for waiver of code of conduct

10 *See* Rate Schedule FERC No. 12, Article XVIII; Rate Schedule FERC No. 68, Article 20.

11 Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888, 1991-1996 FERC Stats. & Regs., Regs. Preambles ¶ 31,036, 31,654 (1996), order on reh'g, *Order No. 888-A, 1996-2000 FERC Stats. & Regs., Regs. Preambles ¶ 31,048, order on reh'g, Order No.* 888-B, 81 FERC ¶ 61,248 (1997), reh'g denied, Order No. 888-C, 82 FERC ¶ 61,046 (1998), aff'd in part and remanded in part sub nom. Transmission Access Policy Study Group v. FERC, 225 F.3d 667 (D.C. Cir. 2000), aff'd sub nom. New York v. FERC, 535 U.S. 1 (2002).

restrictions in connection with approval of market-based rates. *See Pinnacle West Capital Corp.*, 91 FERC ¶ 61,290, 61,998-99 (2000); *Pinnacle West Capital Corp.*, Letter Order in Docket Nos. ER00-2268-001, *et al.*, (Aug. 25, 2000) (accepting compliance filing).[12] Because the fuel clause permitted an adjustment based on actual fuel and purchased power costs, which could have been affected by inter-affiliate transactions or communications, APS added two rate capping mechanisms to the fuel adjustment clauses. As a result, the monthly fuel adjustment calculation is capped at a level that is the lowest of: (a) the actual fuel adjustment factor as normally calculated, including inter-affiliate transactions; (b) the average of the actual corrected fuel adjustment factor for the same month for 1998 and 1999; or (c) recalculation of the actual fuel adjustment factor to reflect: (i) for sales APS makes to an affiliate, the FAC calculation shall substitute revenues from each such transaction based on the current Palo Verde Index price for a similar duration sale; and (ii) for sales an affiliate makes to APS, the FAC calculation shall substitute charges from each such transaction based on the current Palo Verde Index price for a similar duration transaction. Again, these caps in the fuel adjustment clause were necessitated by the fuel clause itself and its inclusion of adjustments for actual fuel and purchased power costs. Absent a fuel adjustment clause, there is no need for the capping mechanisms.

12 When APS proposed a fuel-clause cap as part of its affiliate sales application, there were several customers identified that purchased from APS under contracts with fuel clauses. Of those customers, the only one that continues to purchase from APS under a contract with a fuel clause and cap is ED-3. APS also capped the fuel component of the rate under its Coordination Tariff; however, APS serves no customers under that tariff.

It should also be noted that in any event, the EDs are not captive customers within the meaning of Order No. 697.[13] They are completely free under the Lease Power Agreements to procure supply from any party, and indeed, they and APS have already filed for termination of the Lease Power Agreements and the parties continue to expect the Agreements to terminate in the near future.[14]

APS therefore also requests that as part of its acceptance of the proposed rates, the Commission confirm that the modifications do not interfere with the existing waiver of code of conduct restrictions on APS and its affiliates.[15]

IV. CONTENTS OF FILING

This filing consists of the following documents:

- This Transmittal Letter
- Affidavit of Mr. Justin H. Thompson;
- Affidavit of Mr. Ralph L. Luciani;
- Exhibit APS-1 Units Most Likely Methodology;
- Exhibit APS-2 Red-lined APS Rate Schedule FERC No. 12 Sheets;
- Exhibit APS-3 Red-lined APS Rate Schedule FERC No. 68 Sheets;

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13 *See Market-Based Rates For Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, Order No. 697, FERC Stats. & Regs. ¶ 31,252 (2007); *order on clarification*, 121 FERC ¶ 61,260 (2007).

14 APS acknowledges that the parties expected that the Agreements would have terminated some time ago. However, to the extent the required ACC approval necessary for such termination is not received in the near future, the Agreements do provide renegotiation of the earlier settlement agreement in order to reach the same economic result. APS believes that termination of the Lease Power Agreements is required to accomplish that result.

15 APS notes for information purposes that its need for waiver of code of conduct restrictions may be eliminated later this year, due to anticipated changes in affiliate businesses. APS's wholesale marketing affiliate, Pinnacle West Marketing & Trading Co. LLC, is winding down operations, and APS Energy Services, Inc., APS's retail marketing arm, is transitioning away from any wholesale operations.

- Exhibit APS-4 Clean APS Rate Schedule FERC No. 12 Sheets;
- Exhibit APS-5 Clean APS Rate Schedule FERC No. 68 Sheets

V. EFFECTIVE DATE AND APPROVAL

APS requests that the proposed rates be accepted for filing and the new rates made effective on the first day of the month following Commission approval in a final order on the rates. APS's proposed rates follow a methodology that has been approved in the past filings of other entities. APS has followed this approach in order to facilitate the Commission's review of its filing and to enable the Commission to accept the filing without further proceedings. APS is also using an ROE for its rates that is the same as that accepted for filing in Docket No. ER07-23,[16] and believes the ROE proposed falls well with in the range of reasonableness.

VI. REQUESTS FOR WAIVER

APS respectfully requests the Commission to waive any requirements necessary to allow the change in rates to take effect as requested herein. In addition, due to unforeseen, intervening circumstances, APS requests that it be granted waiver to supplement this filing in the coming days with the completed signature page of the Ralph Luciani affidavit.

VII. SERVICE

APS is serving a copy of this filing on ED-1 and ED-3. In addition, APS representatives have met with representatives of the EDs and discussed this proposed filing prior to submitting this filing. APS is also serving a copy of this filing on the ACC.

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16 *See Arizona Public Service Co.*, Letter Order in Docket No. ER07-23 (Dec. 6, 2006).

Morgan Lewis
COUNSELORS AT LAW

VIII. STATEMENT ON EXPENSES OR COSTS

No expenses or costs included in this filing have been alleged or judged in any administrative or judicial proceeding to be illegal, duplicative or unnecessary costs that are demonstrably the product of discriminatory employment practices.

IX. CONCLUSION

APS respectfully requests that the Commission accept these proposed rates and make them effective upon issuance of the Commission's final order, with billing at the new rates to commence on the first day of the month following such order.

Should additional information be required, please contact the undersigned.

Respectfully submitted,

John D. McGrane / S.L.

John D. McGrane
Morgan, Lewis & Bockius, LLP

Suzanne K. McBride
Pinnacle West Capital Corporation

Attorneys for
Arizona Public Service Company

Enclosures

cc: Ernest G. Johnson, Director, Utilities Division, Arizona Corporation Commission
Chris Kempley, Chief Legal Counsel, Arizona Corporation Commission
Grant Ward, General Manager, ED-1 and ED-3
Kenneth Saline, K.R. Saline and Associates

Affidavit of
Mr. Justin H. Thompson

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Arizona Public Service Company ER08-

AFFIDAVIT OF
JUSTIN H. THOMPSON

My name is Justin H. Thompson. I am Director of Commercial Operations for Arizona Public Service Company (APS). I have a B.S. in Nuclear Engineering from the University of Arizona and an MBA from Keller Graduate School of Management. I have over 22 years of experience in the areas of power plant operations and development, engineering, security, Federal and State Regulation and power marketing. My business address is 400 N. Fifth Street, Phoenix, AZ 85004.

The purpose of this affidavit is to give background information related to Electrical District No. 3 (ED-3) and explain the reasons for our filing. APS currently serves ED-3 under a Lease Power Agreement (Rate Schedule FERC No. 12) that was approved on July 5, 2002. APS also serves ED-1 under an almost identical Lease Power Agreement (Rate Schedule FERC No. 68) that was also approved on July 5, 2002. (ED-3 and ED-1 were consolidated in 1988 for all purposes relevant to this filing. The proposed changes in rates apply equally to their existing Lease Power Agreements and hereafter any references to ED-3 apply equally to ED-1 unless specifically noted.) The agreements were the result of a 2002 Settlement Agreement between Pinnacle West Capital Corporation (PWCC), APS, and ED-3 that resolved all issues with respect to the parties' provision of services to each other.

ED-3 is an Electrical District in Pinal County, Arizona and is considered a municipal corporation. ED-3 and APS own electrical systems in overlapping service territories in the Pinal County of Arizona. Between 1961 and October 8, 2001, ED-3 leased its electric transmission and distribution system to APS under a Lease Agreement between ED-3 and APS. The Lease Agreement expired on October 8, 2001, but APS still had numerous retail customers connected to the ED-3 system that are served using that system. On October 9, 2001, PWCC filed an application under Section 211 of the FPA for an order requiring ED-3 to provide network transmission service over the ED-3 system for the delivery of electric power and energy to APS meters serving retail customer located on and within the ED-3 system. The Federal Energy Regulatory Commission (Commission) issued a proposed order directing ED-3 to provide the requested service and gave the parties time to engage in settlement discussions to resolve the rates, terms and conditions of service. On April 15, 2002, PWCC, APS, and ED-3 entered into a Settlement Agreement.

Under the Settlement Agreement, APS was to transfer certain facilities to ED-3 including distribution lines and APS' Sexton Substation and ED-3 was to provide transmission to APS. APS was to continue providing transmission service under the Lease Power Agreements to ED-3 for the wheeling of hydro power from the United States Bureau of Reclamation and supplemental power for certain loads of ED-3 not covered by their allotment of hydro power. The Settlement Agreement and the Lease Power Agreements were meant as a short-term fix, with the Lease Power Agreements terminating upon the transfer of the Sexton Substation to ED-3. Once terminated, ED-3 was planning to obtain transmission and supplemental service from other sources or negotiate a new contract with APS. After the Commission approved the amendments to the Lease Power Agreements, APS and ED-3 filed with the Arizona Corporation Commission (ACC) a request to approve the transfer of distribution lines and the Sexton Substation. The ACC has yet to act on the parties' request, leaving the Lease Power Agreements in effect much longer than anyone anticipated. APS and ED-3 are currently working on a supplement filing to the ACC in an effort to resolve the remaining issues of the case.

When APS agreed to the amended Lease Power Agreements approved on July 5, 2002, APS believed the rates in the Agreements would only be in effect for a short time and that ED-3 would most probably purchase supplemental power from another source knowing that we would need a substantial rate increase to continue providing power. Under the current rates, as shown in the affidavit of Ralph L. Luciani, APS is losing money through the Agreements. Given the circumstances, APS requests that the new rates be accepted for filing and become effective upon Commission approval, in accordance with the terms of the Lease Power Agreements.

Under the Lease Power Agreements, APS provides supplemental power to ED-3 to serve certain loads not covered by their allotment of hydro power from the United States Bureau of Reclamation. The current rates in the Lease Power Agreements can be found in Exhibit I of the agreements and is composed of a wheeling charge, a customer charge, a demand charge and an energy charge. The energy charge is further adjusted each month by a fuel cost adjustment clause. ED-3 is the only customer of APS that continues to have a fuel adjustment clause in its contract. The current demand rates were proposed and made effective in 1994, Docket No. ER94-1413, when sales to ED-3 were minimal. The current demand rates for ED-1 were actually made effective on July 23, 1989, in Docket No. ER89-265. The energy charge was last changed for ED-1 and ED-3 in Docket No. ER89-265 as well. Over the years, the deliveries of supplemental power from APS under the Agreements has increased dramatically, which, combined with increased costs, requires APS to propose the new demand and energy charges, and to eliminate the fuel adjustment clause. By changing these rates APS is also required to unbundle the current rates. Thus, APS is also proposing a pass through of the charges for Network Integration Transmission Service under the Company's Open Access Transmission Tariff that is applicable for the delivery of supplemental power and energy. The new rates are derived using the units most likely to serve methodology as explained in the affidavit of Mr. Ralph L. Luciani.

For review, attached to this filing as Exhibit APS-1 is the proposed units most likely methodology. Exhibit APS-2 through 5 are clean and redlined versions of Exhibit I of the Lease Power Agreements that shows new demand and energy rates and addresses how ED-1 and ED-3 will be billed for transmission service. The Commission's acceptance of the notice of cancellation of the Lease Power Agreements upon the purchase by ED-3 of APS's Sexton Substation will remain effective. APS will notify the Commission when the transfer of the Sexton Substation is completed and the Lease Power Agreements are thereby terminated.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Arizona Public Service Company ER08-

AFFIDAVIT OF
JUSTIN H. THOMPSON

I, Justin H. Thompson, being duly sworn, depose and state that the contents of the foregoing Affidavit are true, correct and complete to the best of my knowledge, information and belief.

Justin H. Thompson

Subscribed and sworn to before me this 31st day of January, 2008.

Notary Public
State of Arizona
Maricopa County

ISABEL C. CABRERA
Notary Public, State of Arizona
Maricopa County
My Commission Expires
September 16, 2008

Affidavit of
Mr. Ralph L. Luciani

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Arizona Public Service Company ER08-

AFFIDAVIT OF
RALPH L.LUCIANI

My name is Ralph L. Luciani. I am a Vice President of CRA International, Inc. (formerly, Charles River Associates, Inc.) My business address is 1201 F St., NW, Washington, DC 20004. I have more than 20 years of consulting experience analyzing economic and financial issues affecting the electricity industry, including those related to costing, ratemaking, generation planning, environmental compliance, fuel supply, competitive restructuring, stranded cost, asset valuation, wholesale power solicitations, power marketing, and Regional Transmission Organization costs and benefits.

Prior to joining CRA, I was a Senior Vice President at PHB Hagler Bailly, and a Director at Putnam, Hayes and Bartlett, Inc. I hold a B.S. in Electrical Engineering and Economics from Carnegie Mellon University, and a M.S. from the Graduate School of Industrial Administration at Carnegie Mellon University. I have previously testified before the FERC, the Arkansas, Maryland, Kansas, Louisiana, Maryland, Missouri, Ohio and Pennsylvania state regulatory commissions, and the Ontario Energy Board.

I was asked by the applicants to compute demand and energy charges based on the Commission's units most likely methodology. The results of my calculation are included in Exhibit APS-1 to the application, and this statement explains the methodology used to derive the demand and energy charges.

Exhibit APS-1 provides cost support for the proposed demand and energy charges under Exhibit I of the Lease Power Agreements with Electrical District Number Three of the County of Pinal and State of Arizona ("ED-3") (Rate Schedule FERC Nos. 12 and 68). The cost-supported rates are derived from the weighted demand cost of a group of the Arizona Public Service Company ("APS") generation resources that are likely to be used to provide service under the Lease Power Agreements.

This group of resources was selected under FERC's "stacking" method, under which APS's generating facilities are stacked in increasing order of fuel cost per kWh. The resources located in the stack between the minimum and maximum monthly APS peak loads are selected as the "likely resources". For purposes of this analysis, the minimum monthly APS native peak load was used as the minimum monthly peak. The maximum monthly peak was calculated as the sum of the maximum monthly APS native peak load and the maximum monthly ED-3 load.

The annualized demand charge for each of the likely resources is estimated, and these annualized charges are weighted by the amount of available capacity of each resource to arrive at the total demand charge. The available capacity of each likely resource is the difference between the resource's capacity factor and its availability, multiplied by the resource's capacity.

Page 4 of Exhibit APS-1 shows the individual APS resources, sorted (from lowest to highest) by 2006 fuel costs per KWh of net generation. The long-standing 480 MW exchange purchase with PacifiCorp is shown at the bottom of the stack. The minimum monthly peak load in 2006 was 3,550 MW, and the maximum was 7,236 MW. The next to last column entitled "Likely to Participate Unit?" indicates with a "1" those resources that are in the stack between the 3,550 MW minimum and the 7,236 MW maximum. These are the likely resources for APS. The plant factor, or capacity factor, for each of these resources is shown in the last column on page 4.

Page 5 of Exhibit APS-1 shows the calculation of O&M charges per kW for each of the likely resources, using 2006 FERC Form 1 data. The O&M charges listed for the Salt River Project purchase are the 2006 demand charges associated with this purchase. For purposes of this analysis, both demand-related O&M ($/kW) and variable O&M ($/MWh) was derived. FERC Form 1 page 402 and 403 non-fuel production expense items not treated as demand-related were treated as variable in this calculation.

Pages 6-8 of Exhibit APS-1 provide the calculation of the 14.45% fixed charge rate applicable to the gross book value (installed cost) of each of the likely resources. The fixed charge rate includes components for depreciation, income taxes, return, deferred income taxes, working capital, and an allocation of general plant. O&M expenses are excluded from the fixed charge rate because these are included separately. Nearly all of the data entered into the calculation of the fixed charge rate comes from the 2006 APS FERC Form 1, including the data used to derive the capital structure of 47% debt and 53% equity. A return on equity of 11.50% is applied based on the recommendation of William Avera in his recent testimony on behalf of APS in the APS retail rate case in Arizona,[1] and the Commission recently accepted a similar return on equity for APS in Docket No. ER07-23.[2]

Finally as shown on page 3 of Exhibit APS-1, APS calculated the maximum demand charge by weighting the annual costs of each likely resource based on its "available capacity" [Column2] compared to the total available capacity of all the participating generating resources used in the calculation.

The available capacity was determined by subtracting the resource's capacity factor [page 4, column labeled "Plant Factor"] from its equivalent availability factor [page 3, column 1], and multiplying that amount by the resource's nameplate capacity [Page 4, column labeled "Nameplate Capacity"]. The weighted annual costs for each participating resource was determined by multiplying the resource's total annual cost per installed kW[3] by the resource's expected participation,[4] and then dividing by the resource's equivalent availability factor.[5] This cost, in $/kW, was converted to $/MW by multiplying by 1,000.

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[1] *See* Testimony of Dr. William Avera, Arizona Corporation Commission, Docket No. E-01345A-05-0816, Nov. 4, 2005)

[2] *See Arizona Public Service Co.*, Letter Order in Docket No. ER07-23 (Dec. 6, 2006).

[3] Calculated as the resource's installed cost per kW multiplied by the fixed charge rate, plus the resource's O&M per kW.

[4] Calculated as the resource's available capacity as a share of the available capacity of all of the likely resources.

[5] The equivalent availability factor ("EAF") was obtained from the most recently available NERC Generating Unit Statistical Brochure, based on the type and size of the resource. If units of various size and type comprise the

The individual resource weighted annual costs were added together to derive the overall weighted annual cost of $75,183 per MW, before losses. An adder for demand losses was then applied based on the loss factor listed in the Lease Power Agreements. As shown on page 3, the total weighted annual cost is $82,817 per MW-year. Based on this annual demand charge, the monthly demand charge is $6,901 per MW-month.

FERC Form No. 1 data was also used to determine an energy charge. As shown on Page 3 a variable O&M expense and a fuel expense per MWh was derived for each participating unit. Weighted annual fuel and variable O&M costs were derived by multiplying the MWh expenses by the resource's expected participation. An adder for energy losses was then applied based on the contractual loss factor listed in the Lease Power Agreements. As shown on page 3, this resulted in a $78.95 per MWh charge for fuel and a $3.91 per MWh charge for variable O&M, for a total charge of $82.86 per MWh.

Page 2 of Exhibit APS-1 lists ED3's monthly 2006 demand and energy takes, the actual 2006 revenue paid, and the revenue that would have been paid under the cost-of-service charges discussed above. Page 1 of Exhibit APS-1 compares the actual 2006 revenue with the cost-of-service charges.

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resource, a weighted average EAF for the resource was calculated based on the capacity of each of the underlying units.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Arizona Public Service Company ER08-

AFFIDAVIT OF
RALPH L.LUCIANI

I, Ralph L. Luciani, being duly sworn, depose and state that the contents of the foregoing Affidavit are true, correct and complete to the best of my knowledge, information and belief.

____
Ralph L. Luciani

Subscribed and sworn to before me this 31st day of January, 2008.

____
Notary Public

Exhibit APS-1
Units Most Likely Calculation

Comparison of Actual Revenue from Customer and Revenue at Cost of Service

Cost of Service based on Most Likely Resouces Analysis using 2006 APS FERC Form 1 Data
Wheeling revenues and costs excluded.

Line	Item	Rate	Amount	Source
	Customer Data (2006)			*Source*
1	Average Net Monthly Billing Demand (MW)		2.7	*Monthly Customer Data sheet*
2	Annual Net Energy (MWh)		245,902	*Monthly Customer Data sheet*
3 (+)	Actual Annual Revenue ($)		5,678,586	*Monthly Customer Data sheet*
	Annual Customer Charges at Cost of Service ($)			
	Energy Charge	$/MWh		
4	Fuel	78.95	19,413,761	*Demand Charge sheet; Rate * L2*
5	Variable O&M	3.91	960,912	*Demand Charge sheet; Rate * L2*
6			20,374,673	*L4 + L5*
	Demand Charge	$/MW-mo		
7	Demand Related O&M	1,543	50,616	*Demand Charge sheet; Rate * L1 *12*
8	Fixed Charge Rate	14.45%		*Fixed Charge Worksheet*
9	Investment Cost/MW	37,074	175,799	*Demand Charge sheet; Cost/MW-mo * L1* L9 *12*
10			226,415	*L7 + L9*
11 (-)	Total Annual Charges at Cost of Service ($)		20,601,088	*L6 + L10*
12 (=)	**Over(Under)-recovery of Annual Cost of Service ($)**		**(14,922,502)**	*L3 - L11*
13	Over(Under)-recovery net of O&M and Fuel at Cost		(14,746,703)	*L3 - L4 - L5 - L7*
14	Fixed Charge Rate Recovery on Investment Cost		-1212.42%	*L13 / (L1 * L9 Cost/MW-mo * 12)*
15	Earned ROE for Service to Customer		**Less than 0%**	*From table in Fixed Charge Worksheet*

Monthly 2006 Customer Data for ED3

								Actual 2006 Revenue		2006 Revenue at Proposed Rates	
										Demand Charge ($/kW-mo)	6,901 (a)
										Energy Charge ($/MWh)	82.86 (a)
Year	Mo	Peak (MW)	Preference Power (MW)	Net Peak (MW)	Energy (MWh)	Preference Power (MWh)	Net Sales (MWh)	Power Revenue ($)	Wheel Revenue ($)	Power Revenue ($)	Wheel Revenue ($)
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
2006	01	61.2	61.2	0.0	15,714	6,888	8,826	231,575	15,499	731,278	15,499
2006	02	57.6	56.4	1.2	19,563	7,408	12,155	165,671	16,667	1,015,226	16,667
2006	03	41.8	41.8	0.0	20,622	9,923	10,700	192,681	22,326	886,536	22,326
2006	04	58.3	58.2	0.1	25,016	13,160	11,856	589,485	31,577	982,991	31,577
2006	05	86.9	83.8	3.1	38,422	12,816	25,605	507,466	28,837	2,143,313	28,837
2006	06	99.5	83.7	15.9	47,491	10,434	37,058	830,240	23,476	3,180,056	23,476
2006	07	105.7	101.9	3.8	51,683	12,962	38,721	1,317,736	29,164	3,234,369	29,164
2006	08	93.3	89.6	3.7	44,211	10,669	33,542	749,253	24,006	2,804,823	24,006
2006	09	86.7	86.7	0.0	34,187	11,143	23,045	-64,388	25,071	1,909,405	25,071
2006	10	74.0	69.1	4.9	26,016	8,482	17,534	398,837	19,085	1,486,261	19,085
2006	11	41.8	41.6	0.2	19,811	6,901	12,910	629,831	15,528	1,070,885	15,528
2006	12	41.1	41.1	0.0	20,523	6,572	13,951	130,199	14,788	1,155,944	14,788
Total					363,260	117,359	245,902	5,678,586	266,024	20,601,088	266,024
Average				2.7							
Minimum				0.0			Total:	5,944,611		20,867,112	
Maximum				15.9							

Loss Factors in Customer Rate Schedule:

Demand	9.218%	*as a % of total before losses*
Energy	6.230%	*as a % of total before losses*

Source:
c1 thru c8: APS billing records, preference power is adjusted for losses per customer rate schedule
*c9: (Demand Charge *c3 + Energy Charge *c6)*
c10: equal to c8
(a): from Demand Charge sheet

Arizona Public Service Company, Calculation of Demand Charge Rate, AEP Methodology

Resource	Likely Unit?	EAF	Available Capacity	Cumulative Avail. Cap. (kW)	Expected Ptcp.	Installed Cost/kW	Operation and Maintenance	Fixed Charge Rate	Weighted Annual Cost $/MW	Weighted Demand-Related O&M only ($/MW)	Weighted Installed Cost/kW only	Fuel ($/MWh)	Weighted Annual Fuel Cost $/MWh	Variable O&M ($/MWh)	Weighted Annual Non-Demand O&M Cost $/MWh
						Demand Charges						Variable Charges			
See Page 4		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Cholla 1-3	0		0	0											
Four Corners 1-3	1	0.8531	58,328	58,328	0.0245	$563.07	$33.15	14.45%	$3,286	$951	$16	16.5	$0.40	$5.61	$0.14
Red Hawk 1-2 CC	1	0.8838	442,847	501,175	0.1859	$400.65	$10.47	14.45%	$14,379	$2,201	$84	63.0	$11.70	$1.77	$0.33
West Phoenix 4-5 CC	1	0.8838	422,863	924,038	0.1775	$458.44	$8.44	14.45%	$15,001	$1,695	$92	63.9	$11.34	$4.32	$0.77
Saguaro	1	0.8578	208,594	1,132,631	0.0875	$195.51	$7.42	14.45%	$3,641	$758	$20	72.2	$6.32	$3.90	$0.34
Ocotillo	1	0.8578	179,686	1,312,318	0.0754	$230.23	$15.47	14.45%	$4,286	$1,360	$20	74.0	$5.58	$6.11	$0.46
Salt River Project	1	0.9779	297,982	1,610,299	0.1251	$0.00	$62.44	14.45%	$7,986	$7,986	$0	78.2	$9.77	$0.00	$0.00
Sundance CT	1	0.8820	385,142	1,995,441	0.1616	$609.47	$6.05	14.45%	$17,251	$1,108	$112	84.3	$13.63	$2.04	$0.33
West Phoenix CC	1	0.8838	315,989	2,311,431	0.1326	$317.24	$4.57	14.45%	$7,566	$686	$48	92.1	$12.21	$4.28	$0.57
Saguaro 3 CT	1	0.9261	71,353	2,382,784	0.0299	$369.07	$1.93	14.45%	$1,787	$62	$12	102.7	$3.08	$24.41	$0.73
West Phoenix CT	0		0	2,382,784											
Yucca CT	0		0	2,382,784											
Ocotillo CT	0		0	2,382,784											
Saguaro CT	0		0	2,382,784											
Douglas CT	0		0	2,382,784											
								Subtotal	**$75,183**	$16,807	$404		**$74.03**		**$3.66**
								Losses (a)	**$7,634**	$1,707	$41		**$4.92**		**$0.24**
								Total	**$82,817**	$18,514	$445		**$78.95**		**$3.91**
														$82.86	
								Monthly Cost	**$6,901**	$1,543	$37				
								Weekly Cost	$1,593						
								Daily Cost (w/ Weekly Cap)	$319						
								Hourly Cost (w/ Weekly and Daily Cap)	$19.91						

Sources
c1. NERC Generating Unit Statistical Brochure for type and size of unit. Plant level EAF is weighted average of units based on
c2. Available Capacity = (EAF - PF)*Name Plate Capacity for each unit. Set to 0 if PF > EAF.
c3: Cumulative sum of c2
c4. Weighted on Available Capacity for all units selected
c5. FERC Form 1.
c6. Demand Related Expenses Sheet
c7. Fixed Charge Worksheet
(a) Demand and energy loss factors taken from customer's rate schedule

c8. ((c5)*(c7) + (c6))*(c4)/(c1) * 1000
c9. ((c6))*(c4)/(c1) * 1000
c10. ((c5))*(c4)/(c1) * 1000
c11. From Plant Stack Sheet
c12. (c4) * (c11)
c13. Demand Related Expenses Sheet
c14. (c4) * (c13)

Stacking of Resources to Determine the Resources Likely to Participate in Short Term Power Sales

		APS System	APS Native	Wholesale Customer
Maximum Monthly Peak[1]	7,235,876	7,652,000	7,220,000	15,876
Minimum Monthly Peak[2]	3,550,000	3,772,000	3,550,000	0

Plant No.	Plant/Type	Fuel Expense	Generation	Fuel/Kwh	Name Plate Capacity (kW)	Accum. N.P Capacity	Production Inv/kW	Likely to Participate Resource?	Plant Factor
		(p.402-20)	(p.402-12)		(p.402-5)		(p.402-18)		
1	Pacificorp Exchange (a)			0.0000	480,000	480,000		0	
2	Solar Plants (b)	0	10,013	0.0000	5,720	485,720		0	
3	Palo Verde	45,619,493	6,987,559,019	0.0065	1,225,000	1,710,720	$2,087.10	0	65.1%
4	Navajo	36,347,308	2,403,573,998	0.0147	337,000	2,047,720	$743.90	0	81.4%
5	Four Corners 4-5	26,320,428	1,770,262,100	0.0149	245,000	2,292,720	$641.83	0	82.5%
6	Cholla 1-3	74,805,813	4,774,187,324	0.0157	715,000	3,007,720	$806.21	0	76.2%
7	Four Corners 1-3	69,864,610	4,227,245,205	0.0165	634,000	3,641,720	$563.07	1	76.1%
8	Red Hawk 1-2 CC	309,445,453	4,915,675,000	0.0630	1,136,000	4,777,720	$400.65	1	49.4%
9	West Phoenix 4-5 CC	112,058,879	1,753,895,000	0.0639	705,000	5,482,720	$458.44	1	28.4%
10	Saguaro	3,701,480	51,302,000	0.0722	250,000	5,732,720	$195.51	1	2.3%
11	Ocotillo	9,741,218	131,701,000	0.0740	227,000	5,959,720	$230.23	1	6.6%
12	Salt River Project	43,032,247	550,567,000	0.0782	369,000	6,328,720		1	17.0% (c)
13	Sundance CT	8,686,847	102,999,000	0.0843	450,000	6,778,720	$609.47	1	2.6%
14	West Phoenix CC	27,422,693	297,799,890	0.0921	396,000	7,174,720	$317.24	1	8.6%
15	Saguaro 3 CT	794,439	7,734,000	0.1027	78,000	7,252,720	$369.07	1	1.1%
16	West Phoenix CT	906,564	6,299,000	0.1439	106,000	7,358,720	$163.88	0	0.7%
17	Yucca CT	3,757,097	25,942,000	0.1448	152,000	7,510,720	$144.61	0	1.9%
18	Ocotillo CT	1,177,243	8,034,000	0.1465	106,000	7,616,720	$157.16	0	0.9%
19	Saguaro CT	271,647	1,796,000	0.1513	106,000	7,722,720	$164.91	0	0.2%
20	Douglas CT	11,135	59,000	0.1887	21,000	7,743,720	$106.85	0	0.0%

Notes:

(a) Exchange agreement for 571,181 MWh (FERC Form 1, pages 326-7)
(b) From FERC Form 1, page 410
(c) Salt River Project purchase capacity based on average billing demand (column d) on FERC Form 1, page 326-7. Generation is from column (g), energy charges from column (k).

Sources:

1 Sum of APS Native Load peak and peak of Wholesale Customer
2 APS Native Load peak

Demand Related Expenses For Participating Units

	Line No.	Four Corners 1-3	Cholla 1-3	Red Hawk 1 2 CC	West Phoenix 4-5 CC	West Phoenix CC	Douglas CT	Sundance CT	Saguaro 3 CT	Yucca CT	West Phoenix CT	Salt River Project	Ocotillo	Saguaro	Ocotillo CT	Saguaro CT
Plant Name Plate Capacity (kW)		634,000	715,000	1,136,000	705,000	396,000	21,000	450,000	78,000	152,000	106,000	369,000	227,000	250,000	106,000	106,000
FERC Form 1 Item																
Production Expenses: Oper, Supv & Engr	19	949,290	2,427,606	0	1,526,240	1,025,587	0	168,390	44,112	470,975	842,613		46,011	153,756	0	218,753
Coolants & Water (Nuclear Plants Only)	21	0	0	0	0	0	0	0	0	0	0		0	0	0	0
Steam Expenses	22	6,743,794	4,363,691	0	0	0	0	0	0	0	180		60,724	375,347	0	0
Electric Expenses	25	1,204,858	1,844,531	4,695,334	2,342,581	0	0	842,878	82,121	12,047	44,261		34,465	191,941	0	180,921
Misc. Steam (or Nuclear) Power Expenses	26	6,795,095	3,164,978	5,129,070	916,025	0	0	1,564,138	11,376	221,783	4,961		2,764,611	410,146	133,462	23,100
Rents	27	195,718	425,087	0	0	0	0	0	0	0	0		0	0	0	0
Maintenance of Structures	30	1,275,051	1,208,142	1,065,978	51,734	34,739	0	69,573	576	27,416	-16,940		85,738	24,513	0	1,403
Maint of Misc. Steam (or Nuclear) Plant	33	3,852,514	5,169,039	1,001,822	1,116,149	749,343	39,259	75,535	12,301	128,977	-114,532		530,837	700,096	44,347	85,709
Total Demand-Related O&M Expense		21,016,320	18,602,974	11,892,204	5,962,729	1,809,669	39,259	2,720,514	150,486	861,198	760,543	23,041,231	3,512,386	1,855,799	177,808	509,886
Portion of Year in FERC Form 1		100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
O&M Expense/Name Plate Capacity		$33.15	$26.02	$10.47	$8.44	$4.57	$1.87	$6.05	$1.93	$5.67	$7.17	$62.44	$15.47	$7.42	$1.68	$4.81
												(a)				

Additional O&M Items for Participating Units

FERC Form 1 Additional O&M Items	Line No.	Four Corners 1-3	Cholla 1-3	Red Hawk 1 2 CC	West Phoenix 4-5 CC	West Phoenix CC	Douglas CT	Sundance CT	Saguaro 3 CT	Yucca CT	West Phoenix CT	Salt River Project	Ocotillo	Saguaro	Ocotillo CT	Saguaro CT
Fuel Expense	20	69,864,610	74,805,813	309,445,453	112,058,879	27,422,693	11,135	8,686,847	794,439	3,757,097	906,564	43,032,247	9,741,218	3,701,480	1,177,243	271,647
Steam from Other Sources	23	0	0	0	0	0	0	0	0	0	0		0	0	0	0
Steam Transferred (Cr.)	24	0	0	0	0	0	0	0	0	0	0		0	0	0	0
Allowances	28	0	0	0	0	0	0	0	0	0	0		0	0	0	0
Maintenance Supervision and Engineering	29	1,503,284	4,062,867	204,017	109,353	108,593	449	0	0	624	2,243		55,465	16,562	0	0
Maintenance of Boiler (or reactor) Plant	31	16,997,192	11,590,692	0	0	0	0	0	0	0	718		403,493	105,304	0	0
Maintenance of Electric Plant	32	5,202,996	3,338,988	8,505,725	7,461,036	1,167,296	15,485	210,408	188,777	70,206	19,859		346,196	78,201	49,714	9,672
Total Production Expenses	34	114,584,402	112,401,334	330,047,399	125,581,997	30,508,251	66,328	11,617,769	1,133,702	4,689,125	1,689,927		14,058,758	5,757,346	1,404,766	791,205
		0	0	0	0	0	0	0	0	0	0		0	0	0	0
Variable O&M Expense (excl Fuel)		23,703,472	18,992,547	8,709,742	7,570,389	1,275,889	15,934	210,408	188,777	70,830	22,820	0	805,154	200,067	49,714	9,672
Generation (MWh)		4,227,245	4,774,187	4,915,675	1,753,895	297,800	59	102,999	7,734	25,942	6,299	550,567	131,701	51,302	8,034	1,796
Variable O&M ($/MWh)		5.61	3.98	1.77	4.32	4.28	270.07	2.04	24.41	2.73	3.62	0.00	6.11	3.90	6.19	5.39

Notes.
Line Number corresponds to pages 402 and 403 in FERC Form 1
(a) Demand charges for Salt River Project Purchase, pages 326-327, column j in FERC Form 1

Fixed Charge Worksheet

	Expense Component	Charge Component	
1	Production O & M Expense	0.00%	<-not used
2	Other Taxes Expense	1.31%	
3	A&G Expense	1.66%	
4	Depreciation Expense	0.73%	
5	Composite Income Expense	2.74%	
6	General Plant Expense	0.56%	
7	Rate of Return	8.58%	
8	Cash Working Capital Expense	0.06%	
9	Accumulated Deferred Income Tax Adjustment	-1.19%	
10	Annual Fixed Charge Rate	14.45%	

Fixed Charge Rates as a Function of ROE

	ROE	Fixed Charge Rate	ROE
Input Cell	11.5%	14.45%	11.5%
	0.0%	6.67%	0.0%
	0.5%	6.99%	0.5%
	1.0%	7.32%	1.0%
	1.5%	7.65%	1.5%
	2.0%	7.99%	2.0%
	2.5%	8.33%	2.5%
	3.0%	8.67%	3.0%
	3.5%	9.01%	3.5%
	4.0%	9.35%	4.0%
	4.5%	9.69%	4.5%
	5.0%	10.03%	5.0%
	5.5%	10.37%	5.5%
	6.0%	10.70%	6.0%
	6.5%	11.04%	6.5%
	7.0%	11.38%	7.0%
	7.5%	11.72%	7.5%
	8.0%	12.06%	8.0%
	8.5%	12.39%	8.5%
	9.0%	12.73%	9.0%
	9.5%	13.08%	9.5%
	10.0%	13.42%	10.0%
	10.5%	13.76%	10.5%
	11.0%	14.11%	11.0%
	11.5%	14.45%	11.5%
	12.0%	14.80%	12.0%
	12.5%	15.15%	12.5%
	13.0%	15.50%	13.0%
	13.5%	15.86%	13.5%
	14.0%	16.21%	14.0%
	14.5%	16.57%	14.5%
	15.0%	16.93%	15.0%
	15.5%	17.28%	15.5%
	16.0%	17.65%	16.0%
	16.5%	18.01%	16.5%
	17.0%	18.37%	17.0%
	17.5%	18.74%	17.5%
	18.0%	19.11%	18.0%
	18.5%	19.48%	18.5%
	19.0%	19.85%	19.0%
	19.5%	20.22%	19.5%
	20.0%	20.59%	20.0%

Preliminary Draft

Fixed Charge Worksheet

Source: FERC Form 1 (FF1)

Expense Component	Expense Component	Fixed Charge Component	Source	Page	Line No.	Other	Calculation
1 Production O&M Expense							
A Total Production Expenses	$1,794,155,971		FF1	321	80	Column (b)	
B Total Variable O&M Expenses	$1,574,275,642		FF1	320 - 321	5,7,8,12,15,17,18,25,35,37,38,56,63,76	Column (b)	
C Total Production Plant Investment - End of Year	$5,326,592,670		FF1	207	46	Column (g)	
D Production O&M Expense Factor		4.1280%					([1.A] - [1.B])/[1.C]
2 Other Taxes Expenses							
A Other Taxes (Electric Only)	$148,914,371		FF1	115	14	Column (g)	
B Electric Plant in Service - End of Year	$11,381,939,769		FF1	207	104	Column (g)	
C Other Taxes Expense Factor		1.3083%					[2.A]/[2.B]
3 A&G Expense							
A Production Wages Expense	$127,878,412		FF1	354	20	Column (b)	
B A&G Wages Expense	$58,904,656		FF1	354	27	Column (b)	
C Total Wages Expense	$288,417,425		FF1	354	28	Column (b)	
D Total A&G Related O&M Expense	$158,970,724		FF1	323	197	Column (b)	
E Total Production Plant Investment	$5,326,592,670		FF1	207	46	Column (g)	
F Production A&G Factor		1.6629%					[3.A]/([3.C] - [3.B]) * ([3.D]/[3.E])
4 Depreciation Expense							
A Production Depreciation Expense	$172,616,885		FF1	336	2-6	Column (b)	
B Total Production Plant Investment	$5,326,592,670		FF1	207	46	Column (g)	
C Production Depreciation Expense Factor							
I Straight-Line Method (SLD)		3.2407%					[4.A]/[4.B]
II Sinking-Fund Method (SFD)		0.7347%					[9.B.IX]/(1 + [9.B.IX])**([4.C.III] - 1)
III Life of Production Plant	30.86						1/[4.C.I]
5 Composite Income Tax Expense (CIT)							
A State Tax	6.23%						
B Production CIT Expense Factor		2.7441%					(35/65 + [5.A])*([9.B.IX] + [4.C.II] - [4.C.I])*(1 - Wtd. LTD/[9.B.IX])/(1 - [5.A])
6 General Plant Expense							
A General Plant	$436,787,645		FF1	207	99	Column (g)	
B Production General Plant Expense Factor		0.5563%					[6.A]*[3.A]*([9.B.IX] + [5.B] + [2.C] +[4.C.II] + [8.D])/([3.C] - [3.B])/[3.E]
7 Cash Working Capital Expense							
Cash Working Capital Expense Factor		0.0584%					([1.A] - [1.B])*([9.B.IX] + [5.B])*0.125/[1.C]
8 Accumulated Deferred Income Tax Deduction							
A ADIT - Account 282	$1,501,386,000		FF1	275	2	Column (k)	
B ADIT - Account 283	$541,296,000		FF1	277	9	Column (k)	
C ADIT - Account 190	$846,040,204		FF1	234	8	Column (c)	
D Accumulated Deferred Income Tax (ADIT) Expense Factor		-1.1905%					(-[8.A] - [8.B] + [8.C])*([5.B] + [9.B.IX])/[2.B]
9 Rate of Return Worksheet							

Fixed Charge Worksheet

Source: FERC Form 1 (FF1)

Expense Component	Expense Component	Fixed Charge Component	Source	Page	Line No.	Other	Calculation
A Common Stock Calculation							
I Proprietary Capital	$3,207,473,373		FF1	112	16	Column (c)	
II Less: Preferred Stock	$0		FF1	112	3	Column (c)	
III Less: Account No. 216.1	$7,746		FF1	112	12	Column (c)	
IV Common Stock (COM)	$3,207,465,627						[9.A.I] - [9.A.II] - [9.A.III]
B Rate of Return Calculation							
I Long Term Debt (LTD)	$2,889,039,691		FF1	112	24	Column (c)	
II Preferred Stock (PF)	$0		FF1	112	3	Column (c)	
III Common Stock (COM)	$3,207,465,627						[9.A.IV]
IV Total Capital (CAP)	$6,096,505,318						[9.B.I] + [9.B.II] + [9.B.III]
V LTD Interest (I)	$154,179,764		FF1	117	62 - 66	Column (c)	
VI Preferred Dividends (PFD)			FF1	118	29	Column (c)	
VII Rate of Return on Common Equity	11.50%						
VIII Rate of Return Calculation:							

	Percent of Capital (1)	Annual Cost (2)	Percent Embedded Cost (3)	Percent Weighted Cost (4)
Long Term Debt (LTD)	47.39%	$154,179,764	5.34%	2.5290%
Preferred Stock (PF)	0.00%	$0	0.00%	0.0000%
Common Stock (COM)	52.61%		11.50%	6.0503%
Total Capital (CAP)	100.00%	$154,179,764		8.5793%

Percent of Capital	Annual Cost	Percent Embedded Cost	Percent Weighted Cost
[9.B.I]/[9.B.IV]	[9.B.V]	[9.B.V]/[9.B.I]	(1)*(3)
[9.B.II]/[9.B.IV]	[9.B.VI]	[9.B.VI]/[9.B.II]	(1)*(3)
[9.B.III]/[9.B.IV]		[9.B.VII]	(1)*(3)

Expense Component	Fixed Charge Component
IX Overall Rate of Return (ROR) Factor	8.5793%

APS Native Load, Monthly 2006

	Year	Month	Peak(MW)
	2006	1	3,954
	2006	2	3,665
	2006	3	3,550
	2006	4	3,901
	2006	5	5,440
	2006	6	6,306
	2006	7	7,220
	2006	8	6,518
	2006	9	6,222
	2006	10	5,022
	2006	11	3,908
	2006	12	4,226
Maximum			7,220
Minimum			3,550

EAF Calculations

Plant	Unit No.	Prime Mover[1]	Energy Source 1[1]	Name Plate Capacity[1]	Ownership Share[2]	Owned Name Plate Capacity	Name Plate Capacity from FF1	EAF[3]	Weighted EAF	Comments
Red Hawk	CT1A	CT	NG	182	100.0%	182				
Red Hawk	CT1B	CT	NG	182	100.0%	182				
Red Hawk	CT2A	CT	NG	182	100.0%	182				
Red Hawk	CT2B	CT	NG	182	100.0%	182				
Red Hawk	ST1	CA	NG	204	100.0%	204				
Red Hawk	ST2	CA	NG	204	100.0%	204				
Red Hawk 1-2 CC				1,136		1,136	1,136	88.38	88.38	
West Phoenix	C4-1	CT	NG	91	100.0%	91				
West Phoenix	C4-2	CA	NG	45	100.0%	45				
West Phoenix	C5-1	CT	NG	184	100.0%	184				
West Phoenix	C5-2	CT	NG	184	100.0%	184				
West Phoenix	C5-3	CA	NG	201	100.0%	201				
West Phoenix 4-5 CC				705		705	705	88.38	88.38	
West Phoenix	1B	CS	NG	132	100.0%	132				
West Phoenix	2B	CS	NG	132	100.0%	132				
West Phoenix	3B	CS	NG	132	100.0%	132				
West Phoenix CC				396		396	396	88.38	88.38	
Sundance	CT1	GT	NG	45	100.0%	45		88.20	8.82	
Sundance	CT2	GT	NG	45	100.0%	45		88.20	8.82	
Sundance	CT3	GT	NG	45	100.0%	45		88.20	8.82	
Sundance	CT4	GT	NG	45	100.0%	45		88.20	8.82	
Sundance	CT5	GT	NG	45	100.0%	45		88.20	8.82	
Sundance	CT6	GT	NG	45	100.0%	45		88.20	8.82	
Sundance	CT7	GT	NG	45	100.0%	45		88.20	8.82	
Sundance	CT8	GT	NG	45	100.0%	45		88.20	8.82	
Sundance	CT9	GT	NG	45	100.0%	45		88.20	8.82	
Sundance	CT10	GT	NG	45	100.0%	45		88.20	8.82	
Sundance CT				450		450	450		88.2	
Saguaro	GE1	GT	NG	78	100.0%	78		92.61	92.61	
Saguaro 3 CT				78		78	78		92.61	
Yucca	GT1	GT	NG	20	100.0%	20		88.20	11.39	
Yucca	GT2	GT	NG	20	100.0%	20		88.20	11.39	
Yucca	GT3	GT	NG	56	100.0%	56		92.61	34.35	
Yucca	GT4	GT	DFO	56	100.0%	56		92.61	34.35	
Yucca CT				152		152	152		91.47	
West Phoenix	GT1	GT	NG	53	100.0%	53		92.61	46.31	
West Phoenix	GT2	GT	NG	53	100.0%	53		92.61	46.31	
West Phoenix CT				106		106	106		92.61	
Douglas	1	GT	DFO	21	100.0%	21		88.20	88.20	
Douglas CT				21		21	21		88.20	
Cholla	1	ST	SUB	114	100.0%	114		85.49	13.59	
Cholla	2	ST	SUB	289	100.0%	289		85.05	34.37	
Cholla	3	ST	SUB	312	100.0%	312		86.26	37.89	
Cholla 1-3				715		715	715		85.65	
Four Corners	1	ST	SUB	190	100.0%	190		85.49	25.64	
Four Corners	2	ST	SUB	190	100.0%	190		85.49	25.64	
Four Corners	3	ST	SUB	253.4	100.0%	253		85.05	34.03	
Four Corners 1-3						633	634		85.31	
Salt River Purchase										
Base Portion						318		100	83.68	
Navajo 1		ST	BIT	803.1		16		88.39	3.61	
Agua Fria 1		ST	NG	113.6		16		85.78	3.50	
Agua Fria 2		ST	NG	113.6		16		85.78	3.50	
Agua Fria 3		ST	NG	163.2		16		85.78	3.50	
Salt River Project						380	369		97.79	
Ocotillo	1	ST	NG	113.6	100.0%	114		85.78	42.89	
Ocotillo	2	ST	NG	113.6	100.0%	114		85.78	42.89	
Ocotillo						227	227		85.78	
Saguaro	1	ST	NG	125.0	100.0%	125		85.78	42.89	
Saguaro	2	ST	NG	125.0	100.0%	125		85.78	42.89	
Saguaro						250	250		85.78	
Ocotillo CT	1	GT	NG	53.1	100.0%	53		92.61	46.31	
Ocotillo CT	2	GT	NG	53.1	100.0%	53		92.61	46.31	
Ocotillo CT						106	106		92.61	
Saguaro CT	1	GT	NG	53.1	100.0%	53		92.61	46.31	
Saguaro CT	2	GT	NG	53.1	100.0%	53		92.61	46.31	
Saguaro CT						106	106		92.61	

Sources:
1 EIA 860 Database (2004)
2 2005 Company 10K
3 NERC Generating Unit Statistical Brochure (2006)

Solar Plants
Source: FERC Form 1, page 410

Plant	Nameplate Rating (MW)	Nameplate Rating (kW)	Net Generation
Flagstaff	0.08	80	164
Star	0.45	450	1,355
Tempe			
Glendale Airport	0.17	170	287
Gilbert	0.12	120	257
Scottsdale Covered Parking	0.34	340	119
Municipal Rooftops	0.01	10	
Yuma	0.28	280	418
Prescott EARU	0.20	200	457
Prescott Airport	3.06	3,060	6,538
Red Rock	1.00	1,000	401
Phoenix	0.01	10	17
Total Solar Plants	**5.72**	**5,720**	**10,013**

2006 Generating Unit Statistical Brochure -- All Units Reporting

NOTE: This brochure contains data on all units, whether they reported event records or not. For a review of statistics containing only those units that reported events, see the brochure "2006 Generating Unit Statistical Brochure -- Units Reporting Events"

(The differences between statistics with or w/o events will appear in equations needing derating information such as EAF, EFOR, and other equations. The equations are more accurate if events are reported.)

Unit Type	MW Tnb/Gen Nameplate	# of Units	Unit-Years	ART	SR	NCF	NOF	SF	AF	EAF	FOR	EFOR	EFORd	SOF	FOF	UOF	EUOF	EUOR	POF	MOF	WSF	WAF	WEAF	WFOR	WEFOR	WSOF	WFOF
FOSSIL	All Sizes	1 292	1289.33	288.69	87 89	57 58	79 97	65.97	88.81	85.56	5.49	7.59	6 88	9 19	3.80	5.78	7.61	10.61	6 21	1.96	72.81	87.36	85.07	5 09	7.51	8.76	3.86
All Fuel Types	1-99	289	287 00	177.92	95 14	35 27	68.45	49.32	89.84	87.46	5.79	8.43	6.96	7 32	3 03	5.28	6.86	12.46	5 97	2 25	51.37	89.65	87 31	5 63	8.56	7.38	3.07
	100-199	336	335.75	284.99	97 34	48.96	72 24	65.59	88.13	85.11	5 78	8.30	7.14	7 77	4.09	6.49	8.88	12 06	5 37	2 41	67.77	87.97	84.97	5 68	8.12	7.89	4.07
	200-299	165	164.50	324.13	98 54	54 32	77 67	72.87	84.79	84.12	6.96	8.68	7 93	7 76	5.44	7.22	9.06	11.34	5 97	1.79	72.52	86.49	83.97	7 06	8.72	7.64	5.51
	300-399	122	122.00	330.65	91.47	49 54	74 80	58 26	86.81	86.06	3.82	5.47	4.83	8 69	2.49	4.81	5.60	7.75	7 17	1 52	67.61	88.79	86 84	3 50	5 47	8.75	2.49
	400-599	216	215 08	366.03	87.33	56 40	80 83	72 98	86.81	84.63	4.92	7.16	6 50	9 11	1.77	3.46	7.30	9.60	7 62	1 68	73.49	87.04	84.69	4 81	6 99	8 22	3 73
	600-799	116	116 00	543.71	95 45	65 15	85 43	76 70	86.40	83.98	5.36	7 24	6 42	9 23	4.35	5.67	7.60	9.23	7 91	1.33	76.27	86.20	83.75	5 51	7.41	8.76	4 45
	800-999	36	36.00	717.14	87 46	61 90	84 81	72 39	89.03	88.19	3 65	3.03	2 85	9 81	1 97	3.35	3.70	5.60	7 42	1 29	72.89	89.14	88.50	2 53	2.98	8.97	1 89
	1000 Plus	13	13 00	765.06	89.31	71 05	87 15	62 63	86.20	82.91	6.36	8.88	7 89	8.25	5.62	7.39	9.99	11.12	6 49	1 78	83.07	86.93	82.86	6 18	7.77	8 51	5 47
Coal Primary	All Sizes	817	825 08	516.36	94 71	71 61	85 53	83 22	88.50	85.56	4.43	6.50	6.26	7.55	3.96	5.61	7.90	8.89	5 80	1.75	86.07	87.87	85.29	4 43	6.17	8.12	3 99
	1-99	141	140.67	253 78	98 42	52 30	72.73	78.61	88 81	86.60	6.34	7.26	6.35	6 77	3.21	5.22	7.32	9.91	4.76	2.91	71.63	89.75	86.65	4 46	7.35	6 89	3.34
	100-199	223	223 00	636.87	95.65	65 21	77.13	81.64	88.31	85.43	4.41	6.91	4.43	6.75	2.33	6.41	8.08	9.42	4 67	3.08	84.86	89.20	85.49	6 53	6.49	6.00	3 98
	200-299	116	115 50	458.75	98 63	72 34	83 48	86 48	88.27	83.05	4.60	4.13	8.04	7.64	4.27	5.86	8.86	9.70	5 67	1 77	86.42	88.16	85.04	4.54	6 08	7.71	4 21
	300-399	72	72 75	676.16	97 87	72 46	81 59	88 49	89.04	86.36	3.47	5.53	5.52	7.76	3.19	4.76	6.97	7 46	6 17	1 57	88.81	89.16	86.38	3 39	6.64	7 70	3 12
	400-599	147	145.08	615.93	94.58	75 30	86.96	84 99	87.21	84.52	4.76	6.05	6.92	8 56	4 33	5.95	8.00	8.66	7 03	1.53	86.69	87.33	84.73	4 62	6 63	8.57	4 28
	600-799	51	51 08	744.93	94 17	76 39	88 24	84 57	87.28	84.94	4.08	6.30	6 26	8.34	4.35	5.54	7.39	8.02	7 18	1 18	86.44	87.14	84.84	4.87	6 33	8.65	4 39
	800-999	25	25 00	1050.39	97.38	81 32	91 55	89.20	89.38	88.64	2.13	2.51	3 52	8.60	1.93	2.91	3.46	3.75	7 78	0.93	89.36	89.46	88 71	2 07	2.47	8 66	1 85
	1000 Plus	12	12.00	768 61	88 55	77.76	81.58	86.84	86.43	82.46	6.68	8.95	8 03	8 46	6.88	7.87	10.23	11 02	6 67	1.79	86.91	85.46	82.40	6.43	7.75	8 68	5.82
Oil Primary	All Sizes	116	100.25	91.83	39 27	13 80	42 60	30.86	91.98	88.27	20.14	31.65	15.85	10 43	7.50	9.43	10.82	27.36	8.59	1.85	32.40	84.34	82.62	17 55	36.64	10.46	5.24
	1-99	34	32.42	54.54	39 70	21.42	60.26	30.79	90.86	88.21	41.39	32.70	13 85	10 79	8.38	11.73	12.35	29.05	7 46	1.35	34.24	91.02	81.11	18 28	19.66	10 08	6.11
	100-199	29	25.75	116.90	97.88	16 74	54 18	26 55	81.29	79.60	19.12	30.64	18.30	10.44	6.28	6.88	10.84	29.81	9.81	8 61	30.89	83.09	79.20	15 80	22.70	11.11	5 80
	200-299	10	8.25	70 36	100 00	9 28	54.64	14.95	58.86	57.15	65.75	70.21	56 11	6 57	34.47	35.76	36.04	71.07	5 37	1.30	13.24	57.98	56.09	72 56	73 07	6 81	35 19
	300-399	15	13 50	220.83	100 00	21.55	49 99	43 67	87.58	86.95	1.81	2 92	2 23	11.62	0 80	2.12	2.67	5.04	10 30	1.32	43.31	87.59	86.91	1 81	2.92	13.65	0.80
	400-599	11	9.37	200.62	99 31	35 08	39 32	34 45	87.81	86.10	5.88	9.24	6 71	9 69	2.59	4.06	5.31	12.08	8.14	1.35	39.35	86.03	84.24	6 77	8.99	9.12	2 84
	600-799	6	7 35	85.33	98 00	5 65	31 10	16.23	89.26	86.61	3.35	8.67	4.60	10.87	0.91	2.35	4.01	16.60	9 42	2.45	26.64	88.24	86.65	3 34	8 63	10.92	0 92
	800-999	4	2.92	206.13	100 00	4 60	32 46	15 75	86.69	84.56	0.06	0.96	0 27	15.16	0.01	0.34	0.19	2.76	15 08	0.21	14.35	86.89	84.75	0 05	0.97	15 11	0 01
Gas Primary	All Sizes	232	319.33	82.99	98 75	13.05	31 48	31 56	88.35	87.25	7.44	8.70	7 78	9 12	2 53	3 13	6.08	16 37	6 52	2.60	35.00	86.25	84.95	8 19	10.67	10.41	3 13
	1-99	93	80 72	38 57	99 41	8.32	42 18	17 09	92.71	91.67	3.69	7.12	4 29	6 48	0.69	3.00	3.67	17 41	4 28	2 31	19.69	92.23	90 87	3.32	7 46	7 03	0 68
	100-199	92	87 00	81.02	98 89	15 75	44 07	35 27	86.55	85.78	8.84	11.35	9.92	9 40	3 85	7.62	8.26	19.23	5 83	3.77	35.77	86.13	85.12	9 61	11 19	10 06	3 00
	200-299	39	37 75	80.65	98.40	17 14	49 65	41 40	88.44	86.74	7.21	9.73	7 60	9 32	3.36	6 25	6.59	14.03	6 31	2 01	42.15	88.35	86.78	7 23	9 87	9 19	3 30
	300-399	37	35 75	93.43	98 91	11 71	33 69	35 38	88.82	87.97	6.86	6.25	6 38	9.47	1.72	3.20	3.91	10 02	7 99	1 48	35.36	88.54	87.71	6.84	6 53	9.66	1.80
	400-599	52	50 83	67.67	98 63	13 52	39 01	37 40	85.50	84.15	4.67	3.58	7 39	11.83	1.67	5 00	6.22	14.68	9 49	2 31	35.65	85.50	84.24	7 15	9.36	11 15	2.75
	600-799	10	10 00	114 15	85 23	10 00	34 99	28 94	74.39	73.28	19.35	24.25	15 20	16 67	6 94	9.16	11.30	28.64	14 66	2 19	28.58	75.83	72.50	10.45	25.38	16 82	7.75
	800-999	9	8.08	253.02	97 47	15 21	44 13	41.07	89.43	89.99	6.38	6.82	5 31	7.74	2.00	5.84	6.88	12.80	4 72	3 04	43.45	89.66	89.31	5 89	6 61	7 74	2 59
Lignite Primary	All Sizes	11	10.00	767 87	98 36	83 07	92 77	89.58	89.58	86.70	3.35	5.93	5 93	7 35	3.10	1.96	4.44	4.88	6 46	0 86	89.56	89.94	86.63	3 77	6 39	6 94	2 51
NUCLEAR	All Sizes	109	109 00	3507.05	96 96	88 50	98 76	89.10	90.32	89.77	2.35	3 11	3.10	7 93	3.16	2.72	3.59	3 90	6 95	0 58	89.45	90.55	89 59	2.07	2 94	7 56	1 89
All Types	400-799	21	21 00	4149 24	97 80	87 01	98 15	88 32	88.44	86.51	6.79	5.92	5 79	7 33	4.43	4.53	5.50	6 03	7 43	0 30	88.45	89.04	87.10	4 45	5 41	8 03	4 33
	800-999	38	38.00	3219.12	95 66	90 17	99 28	90 80	90.93	89.80	1.86	2.53	2 43	7 46	1 71	2.23	2.96	3.19	6 95	0 52	90.82	90.85	89.57	1 86	2 54	7 43	1 72
	1000 Plus	49	49 00	3630.31	98 17	87 83	98 90	88 69	90.73	88.13	1.67	2.39	2 37	7 76	1.51	2.34	3.23	3.55	6.93	0 83	88.81	90.70	88.05	1 65	2.66	7 79	1 52
PWR	All Sizes	45	45 00	3327.47	96.12	88 29	99 54	89 80	89.94	88.69	1.72	2.36	2 36	6.48	1.58	2.40	3.10	3 36	7 44	0.82	89.60	89.76	88.39	1 93	2 51	5 53	1.46
	400-799	5	5 00	4733 09	93 92	90 77	100 38	90.83	91.23	90.39	1.27	1 44	1.43	7 63	1.34	1.37	1.60	1.75	7 40	0 21	90.52	91.42	90.59	1 35	1.53	7 36	1.34
	800-999	21	21 00	2882.47	93 46	90 52	100 91	90.51	90.54	89.62	2.36	1.79	2.79	8.21	1 25	1.92	2.42	2 62	7 54	0 47	90.62	90.83	89 62	1 34	1.76	8 74	1 23
	1000 Plus	13	21 00	3737.55	98 60	88 44	98 23	89.27	89.17	87.97	2.11	2.98	2 98	8 91	1.92	1.81	3.98	6.12	7 81	1 09	89.33	89.33	87.45	2.11	3 07	8.95	1.90
BWR	All Sizes	32	32 00	3458.73	98 72	88 68	98 68	93.83	92.06	91.19	1.18	1.94	1 82	5 08	1.08	1.36	2.26	2.45	4 82	0.26	90.28	93.72	91.39	1 36	1.90	5 32	1 08
	400-799	5	5.80	4744.67	100 00	95.07	98 35	97 48	97.69	96.11	0.56	1.41	1 41	3 54	0.94	1.00	1.73	3.76	2 51	0 35	97.48	97.48	96.08	0 97	1.42	1 57	0 95
	800-999	11	12 00	3050.76	100 00	90 36	98 19	91 94	92.02	89.50	1.67	3.65	3 02	6 35	1 75	2.10	3.35	3 94	5 07	0 27	92.02	92.98	89.91	1 91	3 07	6.12	1 75
	1000 Plus	16	16.00	3413.75	97.40	86.50	98 23	87 48	91.83	92.75	0.76	1.11	1 11	5 39	0 47	0.99	1.47	1.88	6 11	0 28	88.15	93.94	92.37	0 77	1 15	5 35	0 69
CANDU	All Sizes	11	11 00	3604 05	100 00	80 64	46 45	62.33	82.93	79.63	8.48	12.42	13 47	8 01	8.66	8.64	10.39	11 42	8 83	0 40	83.82	83.82	81.35	8.34	10 02	8 54	7 62
JET ENGINE**	All Sizes	149	146.37	4 03	97 99	4 46	74 40	4 43	93.69	90.89	33.16	46.66	14 48	4.16	3 03	5.45	7.43	41 39	2 10	2 16	3.86	92.11	87.37	30 76	44 37	4 46	3 41
	1-19	47	44 42	3.78	94 41	0 85	71 24	0 84	95.41	92.74	67.51	77.18	21 88	2 30	2.28	3.05	4.25	102 49	3 52	0 77	0.92	94.86	92.11	71 43	75 48	2.62	2 72
	20 Plus	102	101.79	4 04	98 40	4 67	74 43	5 17	92.06	88.29	31.37	42 62	16 52	4 75	3 18	5.76	7.92	41 45	2 19	2 61	4.27	91.36	87.00	29 94	41 69	4 59	3 44
GAS TURBINE**	All Sizes	710	922 25	6.12	97.86	2.86	62 44	3.19	91.27	90.32	46.93	49.84	12 25	3 71	3.02	6.36	4.71	60 55	2 36	1 34	4.63	94.59	92.05	37 66	38 34	3 44	1 94
	1-19	190	184.25	6.07	96 86	0 46	70 24	1 25	90 95	86.08	82.17	82 86	35 25	4 27	5.75	7.49	7.83	83 38	2 46	1 74	1.22	90.93	86 48	81 74	82 86	3 63	5.48
	20-49	206	206 00	5.17	97.38	1 74	59 18	2 17	87.46	88.20	67.08	76.88	11 96	3 19	4 81	5.63	6.34	89 62	1 84	1 27	2.38	92.20	87.94	57 26	67 01	1 79	3 99
	50 Plus	314	542 00	6.34	98 42	3 12	4 93	4 24	94.78	92.61	24.72	27 71	7 77	1 77	1 52	2.78	3.00	40.52	1 55	1 24	5.05	94.99	92.07	20 62	21 08	3 45	1 37
COMB CYCLE (Units reporting Block data only)	All Sizes	40	90 00	43.50	99.25	28 92	71 13	39 40	92.01	88.28	2.95	9.43	6 32	5 57	1 61	5.58	6.45	11 19	3 94	1 59	39 40	93.72	89.94	1 43	5 19	5 44	0 57
HYDRO	All Sizes	934	991 83	46.22	95 59	42 82	71 42	57 54	89.12	87.69	1.72	3.33	3 13	9 15	2 53	3.71	3.86	5 58	8 17	1 18	59.32	87.48	87.18	2 16	2 57	10 89	1 61
	1-29	462	461 83	141.23	95.85	46 44	72 17	58 84	91.92	87.56	4.25	4.94	4 89	9 07	1.93	4.53	4.76	4.56	7.55	1 52	56.05	87.83	87.55	4 06	4 31	8 19	2 48
	30 Plus	532	532 00	44.71	95 39	41 93	71 93	56 42	88.29	88.18	3.22	3.16	2 82	9 59	2 11	3.08	3.89	4 66	8 79	6.53	58.53	87.44	87 37	2 31	2 40	11 06	1 82
PUMPED STORAGE	All Sizes	110	107 67	7 62	93 64	12 25	58 06	28 18	88.57	88.56	3.83	3.84	2 33	9 84	1.53	2.06	2.80	6.96	8 63	2 21	21.11	85.11	85.07	5 24	5 78	12 60	2 29
MULTI-BOILER/ MULTI-TURBINE	All Sizes	31	31.00	639.17	100.00	57 11	70 87	80 99	91.53	89.27	2.22	5.43	4 92	4 60	1.96	4.92	7.26	8 52	2 40	2 20	80.59	89.28	86.14	3 06	6 28	8 16	2 53
GEOTHERMAL	All Sizes	****	****	****	****	****	****	****	****	****	****	****	****	****	****	****	****	****	****	****	****	****	****	****	****	****	****
DIESEL**	All Sizes	116	112.67	16.37	99.11	3 13	54 16	4.35	95.76	94.75	40.86	42 95	8 59	1.22	1.80	3.76	3.86	47.48	0 49	0 74	5.71	96.08	95 33	38 42	36 77	1 41	2.43

**Caution: EFOR and WEFOR values may be low since deratings during reserve shutdown periods may not have been reported for a large number of these units.

*** The two methods for calculating combined cycle units is not available at this time

**** Only two generating companies are reporting this type of unit. To retain confidentiality of the data, no data is reported here.

Exhibit APS -2
FPC Rate Schedule No. 12
Red-lined Sheets

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ARIZONA PUBLIC SERVICE COMPANY

LEASE POWER AGREEMENT
WITH
ELECTRICAL DISTRICT NO. 3

FPC Rate Schedule No. 12

EXHIBIT I

The following charges and provisions shall be applicable to District.

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1.0 The District shall pay the Company monthly for electric power and energy supplied by the Company and delivered by the Company for the District, in accordance with Article II of the Lease Power Agreement, and in accordance with the following rate provisions effective October 1, 1994. The energy charge and any applicable discount will be applied to the kilowatthours used monthly by each pump served for the District, whether privately owned and operated or operated by the district, and the total amount thus obtained will be divided by the total kilowatthours used that month by all of said pumps to determine the average energy charge per kilowatthour. The average energy charge so determined each month will be multiplied by the number of kilowatthours supplied and delivered that month by the Company to and/or for the District, as determined in accordance with this Exhibit I to the Lease Power Agreement, to determine the monthly energy charge billing.

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2.0 Base Monthly Rate:

Customer Charge: $11.00 per connected pump, plus

Demand Charge: $6.901 per kW, plus

Deleted: Charge shall be that $/kW of Billing Demand as set forth in the "Schedule of Demand Charges" below,

Energy Charge: $0.08286 per kWh*

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* Less, where applicable, .05 cents/kWh discount for service rendered through the customer's own secondary voltage line transformer.

In addition to the above charges in this Section 2.0, the Customer will be billed a pass through of the charges for Network Integration Transmission Service under the Company's Open Access Transmission Tariff that is applicable for the delivery of supplemental power and energy from the Company.

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Issued by: David A. Hansen
Vice-President Power Marketing/Trading
Issued on: January 31, 2008

Effective Date: April 1, 2008

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10/01/94
thru
12/31/94
$16.50

3.0 [Reserved]

4.0 Base Monthly Minimum:

Customer Charge, plus

Demand Charge

Deleted: The Base Monthly Rate shall be adjusted in accordance with Exhibit I(A) attached hereto and made a part hereof.

5.0 Determination of Billing Demand kW and Billing Energy kWh:

(a)(i) The kilowatts supplied at the pumps by the Company and to be billed monthly under the rate provided above shall be determined as follows:

$$Dc = Dp - Dh$$

Where: Dc Effective during the period October 1, 1994 through December 31, 1994, Dc is the number of kilowatts billed by the Company during the month at the pumps.

Dp is the maximum monthly kilowatt load at the pumps as determined in Paragraphs (b)(i) and (b)(ii) hereof.

$$Dh = Dd \times (1 - Ld)$$

Dd is the monthly kilowatts from the Authority and/or from other sources utilized at the substation by the District during the billing month.

Ld shall equal actual losses computed and billed by the Company; the revised loss factor shall equal 9.218% (which is representative of the annual average Company system kilowatt loss factor for the month as determined in Paragraph (b) hereof).

(ii) The kilowatthours supplied and delivered by the Company to the pumps to be billed monthly under the rate provided above shall be determined as follows:

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Issued by: David A. Hansen — Effective Date: April 1, 2008
Vice-President Power Marketing/Trading
Issued on: January 31, 2008

INDEMNITY REGARDING THE NON-APPLICATION OF THE TAX CHARGE

1. Electrical District No. Three ("District") and Arizona Public Service Company ("Company") entered into a Lease Power Agreement, dated July 7, 1961 ("Agreement") which provides for a Tax Charge ". . . to cover the 'Arizona Transaction Privilege (sales) Tax', (which Tax Charge may be) imposed upon all rates, charges and billings under this Agreement . . ." District and Company enter into this Indemnity in light of the following facts:

   1.1 A Tax Charge was included to cover the Arizona Transaction Privilege Tax ("Sales Tax") if it were to be imposed. However, since then the tax statutes have been amended exempting sales for resale from tax, which presumptively includes wheeling. Nevertheless, a new Tax Charge will be included to cover the Sales Tax and Pinal County Transportation Excise Tax for wheeling and administrative services under the Agreement.

   1.2 The new Tax Charge is included as an economic precaution based on prior experience despite the fact that the District and Company agree that A.R.S. Section 42-1301, et seq., exempts from application of a Sales Tax or other sales and/or use taxes or other similar impositions the wheeling and administrative services provided under the Agreement.

2. If such tax is applicable to Company, the Agreement makes such tax a part of District's rate, thereby placing the burden of such tax on District.

3. The Parties agree that no imposition of such Sales Tax or other sales and/or use taxes or other similar imposition should be made.

4. The Parties agree as follows:

   4.1 Company shall not charge the Tax Charge set forth in the Agreement unless and until the Arizona Department of Revenue ("State"), Arizona cities or other governmental units required the payment thereof by Company.

Issued by: David A. Hansen
Vice-President Power Marketing/Trading
Issued on: January 31, 2008

Effective Date: April 1, 2008

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¶
FUEL COST ADJUSTMENT CLAUSE¶
¶
(1). The billing[1] for service rendered during the billing month shall be increased or decreased by an adjustment amount per kilowatthour of sales (to the nearest 0.0001¢) equal to the difference between the fuel cost per kilowatthour of sales for that month and the base period, calculated as follows:¶
Adjustment Factor =

\- 1.2438 ¢/kWh¶
. Where: . "F" is the expense of fossil and nuclear fuel and certain purchased power costs in the current period and "S" is the kWh sales in the current period, as defined below.¶
¶
<#>The applicable corrected monthly fuel adjustment factor for any given month shall be capped at a level that is the lowest of:¶
<#>the actual fuel adjustment factor as normally calculated including inter-affiliate transactions;¶
<#>the average of the actual corrected fuel adjustment factor for the same month for 1998 and 1999; or¶
<#>recalculation of the actual fuel adjustment factor so as to reflect:¶
<#>for sales APS makes to an affiliate, the FAC calculation shall substitute revenues from each such transaction based on the current Palo Verde Index price for a similar duration sale; and¶
<#>for sales an affiliate makes to APS, the FAC calculation shall substitute charges from each such transaction based on the current Palo Verde Index price for ... [1]

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EXHIBIT I(C)¶
Arizona Public Service Company¶
Fuel Cost Adjustment Clause "Hold" Harmless" Calculation¶ ... [2]

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Director, Pricing & Regulation¶
Issued on: October 1, 2000

Arizona Public Service Company
FERC Rate Schedule No. 12

Original Sheet No. 1

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EXHIBIT I(A)

FUEL COST ADJUSTMENT CLAUSE

(1) The billing[1/] for service rendered during the billing month shall be increased or decreased by an adjustment amount per kilowatthour of sales (to the nearest 0.0001¢) equal to the difference between the fuel cost per kilowatthour of sales for that month and the base period, calculated as follows:

Adjustment Factor = $\boxed{\quad\quad\quad}$ - 1.2438 ¢/kWh

Where: "F" is the expense of fossil and nuclear fuel and certain purchased power costs in the current period and "S" is the kWh sales in the current period, as defined below.

The applicable corrected monthly fuel adjustment factor for any given month shall be capped at a level that is the lowest of:

the actual fuel adjustment factor as normally calculated including inter-affiliate transactions;

the average of the actual corrected fuel adjustment factor for the same month for 1998 and 1999; or

recalculation of the actual fuel adjustment factor so as to reflect:

for sales APS makes to an affiliate, the FAC calculation shall substitute revenues from each such transaction based on the current Palo Verde Index price for a similar duration sale; and

for sales an affiliate makes to APS, the FAC calculation shall substitute charges from each such transaction based on the current Palo Verde Index price for a similar duration transaction.

The calculation of the applicable monthly "Hold Harmless" corrected fuel adjustment factor shall be performed in accordance with Exhibit IV(C).

(2) Fuel and purchased power costs (F) shall be the cost of:

(i) Fossil and nuclear fuel consumed in the Company's own plants, and the Company's share of fossil and nuclear fuel consumed in jointly owned or leased plants; plus

(ii) the actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in paragraph (2)(iii) below; plus

[1/] Billing under this clause will preliminarily be based on the billing month's sales multiplied by the adjustment factor determined from the second preceding month. The billing thus determined will be corrected to the adjustment factor determined for the billing month. Such correction will be made two months after the preliminary billing.

Issued by: Alan Propper
Director, Pricing & Regulation
Issued on: July 10, 2001

Effective Date: August 25, 2000

(iii) the net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transactions) when such energy is purchased on an economic dispatch basis. Included therein may be such costs as

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the charges for economy energy purchases and the charges as a result of scheduled outage, all such kinds of energy being purchased by the Company to substitute for its own higher cost energy; and less

(iv) the cost of fossil and nuclear fuel recovered through all inter-system sales and specific deliveries[2/]; plus

(v) a credit to allowable fuel and purchase power costs which passes to jurisdictional customers 75% of the benefits of sales transactions made under the aegis of the Conformed Western Systems Power Pool Agreement. Such credit shall be calculated in accordance with Exhibit IV(B).

(3) Sales (S) shall be all kWh's sold, excluding inter-system sales and specific deliveries. Where for any reason, billed system sales cannot be coordinated with fuel costs for the billing period, sales may be equated to the sum of (i) generation, (ii) firm purchases, (iii) economy purchases, less (iv) energy associated with pumped storage operations, less (v) inter-system sales referred to in paragraph (2)(iv) above, less (vi) total system losses.

(4) The adjustment factor developed according to this procedure shall be modified to properly allow for losses (estimated if necessary) associated only with wholesale sales for resale.

(5) The adjustment factor developed according to this procedure may be further modified to allow the recovery of gross receipts and other similar revenue based tax charges occasioned by the fuel adjustment revenues.

(6) (a) The cost of fossil fuel shall include those items listed in Account 151 of the Commission's Uniform System of Accounts for Public Utilities and Licenses. The cost of nuclear fuel shall be that as shown in Account 518, except that if Account 518 also contains any expense for fossil fuel which has already been included in the cost of fossil fuel, it shall be deducted from this account. (Paragraph C of Account 518 includes the cost of other fuels used for ancillary steam facilities.)

(b) The cost of both fossil fuel and nuclear fuel shall also reflect all refunds and credits (including any applicable interest) not in excess of $25,000 for the FERC jurisdictional allocation of any single refund/credit received from fuel suppliers/vendors applicable to previous period (non-current) payments made to such suppliers/vendors for fuel or other related allowable expenses. If such refunds/credits are not passed through and credited to applicable fuel accounts for

[2/] Specific deliveries are intended to include transactions for which the rate is tied to fuel costs of specific plants or units.

more than one billing cycle after the Company's receipt of such refunds/credits, the Company shall include an appropriate interest credit computed in accordance with 18 C.F.R. §35.19(a).

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(7) Notwithstanding the specified aforementioned treatment of fuel and purchased power costs for purposes of inclusion in determining the Company's monthly Fuel Cost Adjustment Clause (FAC) factor, the following specific credits/debits to Account 518 (nuclear fuel expenses) related to Spent Nuclear Fuel Disposal Cost refunds received from the United States Department of Energy covering the period October, 1986 through January, 1994 shall be allowed for inclusion in computing applicable monthly FAC factors:

10/86	($2,232)	07/91	($80,234)
07/88	($5,526)	08/81	($69,045)
10/88	($15,534)	09/91	($64,688)
10/89	($18,970)	10/91	($59,390)
12/90	($2,175,153)	11/91	($39,207)
01/91	($63,884)	12/91	$550,519
02/91	($59,363)	02/92	($147,600)
03/91	($63,981)	06/92	$11,136
04/91	($52,520)	07/92	($543,312)
05/91	($54,089)	01/94	$381,252
06/91	($69,544)		

(8) Additionally, credits to Accounts 501, 547, and 555 related to refunds received from El Paso Natural Gas Company as a result of FERC Docket Nos. RP90-81-000, RP91-26-000, RP91-188-000, and RP92-60-000 shall be allowed for inclusion in computing applicable monthly FAC factors. In the aggregate, such credits covering the period March 1990 through July 1994 are in the amount of ($1,168,468).

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EXHIBIT I(B)

SAMPLE
COMPUTATION OF WSPP CREDIT
FOR INCLUSION IN FERC FUEL ADJUSTMENT

MONTH OF: ____________

Economy Sales/
Unit Commitment Sales/
System Capacity Sales:

I. <u>Actual Revenue & Costs for Affilate Transactions</u>

(1) *(2)* *(3)* *(4)*

Customer	Total Sales Revenue ($)	Fuel Cost ($)	Wheeling Cost[1] ($)	Markup Col (1) - Col (2) - Col (3)
LADWP	23,150	17,703	106	5,341
NPC	4,250	3,213	65	972
SCE	217,914	161,272	1,047	55,595
SDG&E	45,788	29,351	250	16,187
SMUD	126,338	88,257	678	37,403
PWCC	35,000	22,000	100	12,900
TOTAL SALES				128,398
				X 75%
A. Amount to be compared for possible credit to Fuel Adjustment				$96,299

II. Revenue Based on Palo Verde Index Affilate Transactions

Customer	(1) Total Sales Revenue ($)	(2) Fuel Cost ($)	(3) Wheeling Cost[1] ($)	(4) Markup Col (1) - Col (2) - Col (3)
LADWP	23,150	17,703	106	5,341
NPC	4,250	3,213	65	972
SCE	217,914	161,272	1,047	55,595
SDG&E	45,788	29,351	250	16,187
SMUD	126,338	88,257	678	37,403
PWCC	38,000	22,000	100	15,900
TOTAL SALES				131,398
				X 75%
B. Amount to be compared for possible credit to Fuel Adjustment				$98,549

Amount to be Credited to Fuel Adjustor (Higher Dollar Amount of A or B) = **$98,549**

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/1/ Reflects only those wheeling costs incurred by APS.

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EXHIBIT I(C)

Arizona Public Service Company
Fuel Cost Adjustment Clause "Hold" Harmless" Calculation

Table 1
Calculation of APS' "Hold Harmless" Factor

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	S
(1)	Actual Corrected 1998 FAC Factor	(0.4090)	(0.5606)	(0.4802)	(0.2277)	(0.2914)	(0.2663)	(0.0289)	(0.1022)	(0.1
(2)	Actual Corrected 1999 FAC Factor	(0.2159)	(0.2674)	(0.3523)	(0.1837)	(0.2863)	(0.1521)	(0.1858)	(0.1515)	(0.2
(3)	Average (Row1 + Row2)	**(0.3125)**	**(0.4140)**	**(0.4163)**	**(0.2057)**	**(0.2889)**	**(0.2092)**	**(0.1074)**	**(0.1269)**	**(0.2**

Table 2
Examples Showing Determination of the Applicable Monthly Corrected FAC Factor
(January 2000)
These are Hypothetical Numbers Intended for Illustrative Purposes Only

Example A: (Example showing treatment assuming negative fuel adjustment factors)

Calculations Incl. Actual Rev/Costs from Affiliate Transactions			Calculations Using PV Index Rev. for Affiliate Transactions[3]				
(1) Preliminary FAC Factor	(2) Calculated Correction FAC Factor	(3) Actual Corrected FAC Factor Col (1) + Col (2)	(4) Preliminary FAC Factor	(5) Calculated Correction FAC Factor	(6) Actual Corrected FAC Factor Col (1) + Col (2)	(7) "Hold Harmless" Factor From Table 1	(8) Applicable FAC Factor[4]
(0.1948)	(0.2970)	(0.4918)	(0.1949)	(0.2971)	(0.4920)	(0.3125)	**(0.4920)**

Example B: (Example showing treatment assuming positive fuel adjustment factors)

Calculations Incl. Actual Rev/Costs from Affiliate Transactions			Calculations Using PV Index Rev. for Affiliate Transactions[5]				
(1) Preliminary FAC Factor	(2) Calculated Correction FAC Factor	(3) Actual Corrected FAC Factor Col (1) + Col (2)	(4) Preliminary FAC Factor	(5) Calculated Correction FAC Factor	(6) Actual Corrected FAC Factor Col (1) + Col (2)	(7) "Hold Harmless" Factor From Table 1	(8) Applicable FAC Factor[6]
0.0246	0.1002	0.1248	0.0240	0.0995	0.1235	(0.3125)	**(0.3125)**

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Exhibit I(D)
Palo Verde Index - Simulated Market Price for Affiliate Transactions

Description of Daily and Weekly Transactions:
The Dow Jones Palo Verde ("DJ PV") daily market[7] for on-peak and off-peak prices will be utilized for any inter-affiliate transactions that are for a duration of less than one month. The daily on-peak load in MWh will be multiplied by the DJ PV daily on-peak price for that day, and the daily off-peak load in MWh will be multiplied by the DJ PV daily off-peak price for that day to determine the cost of the affiliate transaction. If the transaction were longer than one day, this process would be repeated for each day of the transaction.

Example: 50 MW Transaction

[3] See Exhibit I(D)
[4] This Applicable FAC factor shall always be the lesser of the value in either Column 3, Column 6 or Column 7.
[5] See Exhibit I(D)
[6] This Applicable FAC factor shall always be the lesser of the value in either Column 3, Column 6 or Column 7.
[7] The DJ PV Daily On and Off-peak Index information is available from Dow Jones and a number of websites including http://www.energyonline.com/Restructuring/energydb/estathme.html

Daily Transaction: 01/31/02	MWh	Price ($/MWh)	Transaction Cost
On-peak	800	$24.73 / MWh	$19,784
Off-peak	400	$18.60 / MWh	$7,440
Total	1,200		$27,224

Note: for illustrative purposes only

Description of Monthly Transactions:

The DJ PV Daily market for on-peak and off-peak prices[7] will be utilized for any inter-affiliate transactions of one month or greater. The monthly average of the daily DJ PV on-peak price and off-peak price will be multiplied by the respective total monthly on-peak and off-peak consumption to derive the monthly on and off-peak costs for purposes of determining applicable affiliate transaction costs to be used in determination of the monthly FAC factor.

Example: 50 MW Transaction

Monthly Transaction	MWh	Price ($/MWh)	Transaction Cost
January 2002			
On-peak	21,600	$19.42 / MWh[8]	$419,472
Off-peak	11,600	$14.04 / MWh[9]	$162,864
Total	33,200		$582,336

Note: for illustrative purposes only

[8] Assumes that $19.42/MWh is what the average DJ PV Daily on-peak price was for January 2002.
[9] Assumes that $14.04/MWh is what the average DJ PV Daily off-peak price was for January 2002.

Exhibit APS-3
FERC Rate Schedule No. 68
Red-lined Sheets

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and after 1/1/95)

ARIZONA PUBLIC SERVICE COMPANY
LEASE POWER AGREEMENT
WITH
ELECTRICAL DISTRICT NO. 1

FPC Rate Schedule No. 68

EXHIBIT I

The following charges and provisions shall be applicable to District.

1.0 District shall pay Company monthly for electric power and energy supplied by Company and delivered by Company for District, in accordance with Article 5 of the Lease Power Agreement, and in accordance with the following rate provisions effective September 1, 1991. The energy charge and any applicable discount will be applied to the kilowatthours used monthly by each pump served for the District, whether privately owned and operated or operated by the district, and the total amount thus obtained will be divided by the total kilowatthours used that month by all said pumps to determine the average energy charge per kilowatthour. The average energy charge so determined each month will be multiplied by the number of kilowatthours supplied and delivered that month by the Company to District, as determined in accordance with this Exhibit I to the Lease Power Agreement, to determine the monthly energy charge billing.

2.0 Base Monthly Rate:

Customer Charge: $11.00 per connected pump, plus

Demand Charge: $6.901 per kW, plus

Energy Charge: $0.08286 per kWh*

* Less, where applicable, .05 cents/kWh discount for service rendered through the customer's own secondary voltage line transformer.

In addition to the above charges in this Section 2.0, the Customer will be billed a pass through of the charges for Network Integration Transmission Service under the Company's Open Access Transmission Tariff that is applicable for the delivery of supplemental electric power and energy from the Company.

Deleted: Charge shall be that $/kW of Billing Demand as set forth in the "Schedule of Demand Charges" below

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Deleted: Schedule of Demand Charges ($/kW of Billing Demand):

9/1/91 . 10/1/91 . 10/1/92 . 10/1/93 . On and
thru . thru . thru . thru . after
9/30/91 . 9/30/92 . 9/30/93 . 9/30/94 . 10/1/94
$13.00 . $14.00 . $15.00 . $15.50 . $16.50

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Deleted: October 1, 2000

Issued by: David A. Hansen
Vice-President Power Marketing/Trading
Issued on: January 31, 2008

Effective Date: April 1, 2008

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3.0 [Reserved]

Deleted: The Base Monthly Rate shall be adjusted in accordance with Exhibit I(A) attached hereto and made a part hereof.

4.0 Determination of Billing Demand kW and Billing Energy kWh:

(a)(i) The kilowatts supplied at the pumps by the Company and to be billed monthly under the rate provided above shall be determined as follows:

Dc = Dp - Dh

Where: Dc is the number of kilowatts billed by the Company during the month at the pumps; provided that, effective January 1, 1997, Dc is the number of kilowatts billed by the Company at the pumps, but not less than the highest number of such kilowatts supplied and delivered during the months of June, July, August, or September of the 12 months ending with the current month, but which 12 months begin no earlier than January 1, 1997 provided, however, nothing contained in this Amendment shall be construed as affecting in any way the right of Company to unilaterally make application to the FERC for a change in rates, charges, classification or terms and conditions of service, or any rule or regulation related thereto, under Section 205 of the Federal Power Act or any successor statute and pursuant to the FERC's Rules and Regulations promulgated thereunder. Nothing contained in this Amendment shall be construed as affecting in any way the right of District to exercise its rights under the Federal Power Act, including Section 206, or any successor statute and pursuant to the FERC's Rules and Regulations promulgated thereunder.

Dp is the maximum monthly kilowatt load at the pumps as determined in Paragraphs (b)(i) and (b)(ii) hereof.

Dh = Dd x (1 – Ld)

Dd is the monthly kilowatts from the Authority and/or from other sources utilized at the substation by the District during the billing month.

Ld shall equal actual losses computed and billed by the Company; the revised loss factor shall equal 9.218% (which is representative of the annual average Company system kilowatt loss factor for the month as determined in Paragraph (b) hereof), effective beginning with the first bills rendered after execution of the Stipulation and Agreement, dated May 7, 1990 ("Stipulation").

(ii) The kilowatthours supplied and delivered by the Company to the pumps to be billed monthly under the rate provided above shall be determined as follows:

Deleted: Issued by: Alan Propper . Effective Date: January 1, 1995
Director, Pricing & Regulation
Issued on: October 1, 2000

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FUEL COST ADJUSTMENT CLAUSE

(1) The billing[1/] for service rendered during the billing month shall be increased or decreased by an adjustment amount per kilowatthour of sales (to the nearest 0.0001¢) equal to the difference between the fuel cost per kilowatthour of sales for that month and the base period, calculated as follows:

Adjustment Factor = - 1.2438 ¢/kWh

. Where: . "F" is the expense of fossil and nuclear fuel and certain purchased power costs in the current period and "S" is the kWh sales in the current period, as defined below.

<#>The applicable corrected monthly fuel adjustment factor for any given month shall be capped at a level that is the lowest of:

<#>the actual fuel adjustment factor as normally calculated including inter-affiliate transactions;

<#>the average of the actual corrected fuel adjustment factor for the same month for 1998 and 1999; or

<#>recalculation of the actual fuel adjustment factor so as to reflect:

<#>for sales APS makes to an affiliate, the FAC calculation shall substitute revenues from each such transaction based on the current Palo Verde Index price for a similar duration sale; and

<#>for sales an affiliate makes to APS, the FAC calculation shall substitute charges from each such transaction based on the current Palo Verde Index price for a similar duration transaction.

The calculation of the applicable monthly "Hold Harmless" corrected fuel adjustment factor shall be performed in accordance with Exhibit I(C).

(2) Fuel and purchased power costs (F) shall be the cost of:

(i) . Fossil and nuclear fuel consumed in the Company's own plants, and the Company's share of fossil and nuclear fuel consumed in jointly owned or leased plants; plus ... [1]

Deleted: Issued by: Alan Propper . . Effective Date: August 25, 2000
Director, Pricing & Regulation
Issued on: October 1, 2000

AGREEMENT

AGREEMENT, dated as of March 29, 1977, by and between ARIZONA PUBLIC SERVICE COMPANY ("Company"), an Arizona corporation, and ELECTRICAL DISTRICT NUMBER ONE OF THE COUNTY OF PINAL AND STATE OF ARIZONA ("District"), an electrical district duly organized and existing under the laws of the State of Arizona.

WITNESSETH:

WHEREAS, pursuant to a Power Agreement dated as of July 2, 1975, ("Power Agreement"), the Company is supplying power and energy to the District in accordance with the terms of that agreement for irrigation service to customers of the District, and

WHEREAS, the parties have entered into a Purchase Agreement dated as of July 2, 1975 pursuant to which the Company has conveyed, by Bill of Sale of even date, certain electric distribution facilities ("Electric Facilities") to the District, and

WHEREAS, the parties have entered into a Lease Power Agreement ("Lease Power Agreement") and Lease Agreement of even date herewith pursuant to which the Company will lease back the Electric Facilities sold to the District in accordance with the terms of the Lease

Page 26: [1] Deleted **MCGR7621** **1/30/2008 11:06:00 AM**

EXHIBIT I(A)

FUEL COST ADJUSTMENT CLAUSE

(1) The billing[1/] for service rendered during the billing month shall be increased or decreased by an adjustment amount per kilowatthour of sales (to the nearest 0.0001¢) equal to the difference between the fuel cost per kilowatthour of sales for that month and the base period, calculated as follows:

Adjustment Factor = $\boxed{\quad\quad}$ - 1.2438 ¢/kWh

Where: "F" is the expense of fossil and nuclear fuel and certain purchased power costs in the current period and "S" is the kWh sales in the current period, as defined below.

The applicable corrected monthly fuel adjustment factor for any given month shall be capped at a level that is the lowest of:

the actual fuel adjustment factor as normally calculated including inter-affiliate transactions;

the average of the actual corrected fuel adjustment factor for the same month for 1998 and 1999; or

recalculation of the actual fuel adjustment factor so as to reflect:

for sales APS makes to an affiliate, the FAC calculation shall substitute revenues from each such transaction based on the current Palo Verde Index price for a similar duration sale; and

for sales an affiliate makes to APS, the FAC calculation shall substitute charges from each such transaction based on the current Palo Verde Index price for a similar duration transaction.

The calculation of the applicable monthly "Hold Harmless" corrected fuel adjustment factor shall be performed in accordance with Exhibit I(C).

(2) Fuel and purchased power costs (F) shall be the cost of:

(i) Fossil and nuclear fuel consumed in the Company's own plants, and the Company's share of fossil and nuclear fuel consumed in jointly owned or leased plants; plus

[1/] Billing under this clause will preliminarily be based on the billing month's sales multiplied by the adjustment factor determined from the second preceding month. The billing thus determined will be corrected to the adjustment factor determined for the billing month. Such correction will be made two months after the preliminary billing.

(ii) the actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in paragraph (2)(iii) below; plus

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(iii) the net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transactions) when such energy is purchased on an economic dispatch basis. Included therein may be such costs as the charges for economy energy purchases and the charges as a result of scheduled outage, all such kinds of energy being purchased by the Company to substitute for its own higher cost energy; and less

(iv) the cost of fossil and nuclear fuel recovered through all inter-system sales and specific deliveries[2/]; plus

(v) a credit to allowable fuel and purchase power costs which passes to jurisdictional customers 75% of the benefits of sales transactions made under the aegis of the Conformed Western Systems Power Pool Agreement. Such credit shall be calculated in accordance with Exhibit I(B).

(3) Sales (S) shall be all kWh's sold, excluding inter-system sales and specific deliveries. Where for any reason, billed system sales cannot be coordinated with fuel costs for the billing period, sales may be equated to the sum of (i) generation, (ii) firm purchases, (iii) economy purchases, less (iv) energy associated with pumped storage operations, less (v) inter-system sales referred to in paragraph (2)(iv) above, less (vi) total system losses.

(4) The adjustment factor developed according to this procedure shall be modified to properly allow for losses (estimated if necessary) associated only with wholesale sales for resale.

(5) The adjustment factor developed according to this procedure may be further modified to allow the recovery of gross receipts and other similar revenue based tax charges occasioned by the fuel adjustment revenues.

(6) (a) The cost of fossil fuel shall include those items listed in Account 151 of the Commission's Uniform System of Accounts for Public Utilities and Licenses. The cost of nuclear fuel shall be that as shown in Account 518, except that if Account 518 also contains any expense for fossil fuel which has already been included in the cost of fossil fuel, it shall be deducted from this account. (Paragraph C of Account 518 includes the cost of other fuels used for ancillary steam facilities.)

(b) The cost of both fossil fuel and nuclear fuel shall also reflect all refunds and credits (including any applicable interest) not in excess of $25,000 for the FERC

[2/] Specific deliveries are intended to include transactions for which the rate is tied to fuel costs of specific plants or units.

jurisdictional allocation of any single refund/credit received from fuel suppliers/vendors applicable to previous period (non-current) payments made to

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such suppliers/vendors for fuel or other related allowable expenses. If such refunds/credits are not passed through and credited to applicable fuel accounts for more than one billing cycle after the Company's receipt of such refunds/credits, the Company shall include an appropriate interest credit computed in accordance with 18 C.F.R. §35.19(a).

(7) Notwithstanding the specified aforementioned treatment of fuel and purchased power costs for purposes of inclusion in determining the Company's monthly Fuel Cost Adjustment Clause (FAC) factor, the following specific credits/debits to Account 518 (nuclear fuel expenses) related to Spent Nuclear Fuel Disposal Cost refunds received from the United States Department of Energy covering the period October, 1986 through January, 1994 shall be allowed for inclusion in computing applicable monthly FAC factors:

10/86	($2,232)	07/91	($80,234)
07/88	($5,526)	08/81	($69,045)
10/88	($15,534)	09/91	($64,688)
10/89	($18,970)	10/91	($59,390)
12/90	($2,175,153)	11/91	($39,207)
01/91	($63,884)	12/91	$550,519
02/91	($59,363)	02/92	($147,600)
03/91	($63,981)	06/92	$11,136
04/91	($52,520)	07/92	($543,312)
05/91	($54,089)	01/94	$381,252
06/91	($69,544)		

(8) Additionally, credits to Accounts 501, 547, and 555 related to refunds received from El Paso Natural Gas Company as a result of FERC Docket Nos. RP90-81-000, RP91-26-000, RP91-188-000, and RP92-60-000 shall be allowed for inclusion in computing applicable monthly FAC factors. In the aggregate, such credits covering the period March 1990 through July 1994 are in the amount of ($1,168,468).

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EXHIBIT I(B)

SAMPLE
COMPUTATION OF WSPP CREDIT
FOR INCLUSION IN FERC FUEL ADJUSTMENT

MONTH OF: ____________

Economy Sales/
Unit Commitment Sales/

Arizona Public Service Company
FPC Rate Schedule First Revised Volume No. 68
System Capacity Sales:

Original Sheet No. 4

I. Actual Revenue & Costs for Affilate Transactions

Customer	(1) Total Sales Revenue ($)	(2) Fuel Cost ($)	(3) Wheeling Cost[1] ($)	(4) Markup Col (1) - Col (2) - Col (3)
LADWP	23,150	17,703	106	5,341
NPC	4,250	3,213	65	972
SCE	217,914	161,272	1,047	55,595
SDG&E	45,788	29,351	250	16,187
SMUD	126,338	88,257	678	37,403
PWCC	35,000	22,000	100	12,900
TOTAL SALES				128,398
				X 75%
A. Amount to be compared for possible credit to Fuel Adjustment				$96,299

II. Revenue Based on Palo Verde Index Affilate Transactions

Customer	(1) Total Sales Revenue ($)	(2) Fuel Cost ($)	(3) Wheeling Cost[1] ($)	(4) Markup Col (1) - Col (2) - Col (3)
LADWP	23,150	17,703	106	5,341
NPC	4,250	3,213	65	972
SCE	217,914	161,272	1,047	55,595
SDG&E	45,788	29,351	250	16,187
SMUD	126,338	88,257	678	37,403
PWCC	38,000	22,000	100	15,900
TOTAL SALES				131,398
				X 75%
B. Amount to be compared for possible credit to Fuel Adjustment				$98,549

Amount to be Credited to Fuel Adjustor (Higher Dollar Amount of A or B) = **$98,549**

/1/ Reflects only those wheeling costs incurred by APS.

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Issued by: Alan Propper
Director, Pricing & Regulation
Issued on: October 1, 2000

Effective Date: August 25, 2000

EXHIBIT I(C)
Arizona Public Service Company
Fuel Cost Adjustment Clause "Hold" Harmless" Calculation

Table 1
Calculation of APS' "Hold Harmless" Factor

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
(1)	Actual Corrected 1998 FAC Factor	(0.4090)	(0.5606)	(0.4802)	(0.2277)	(0.2914)	(0.2663)	(0.0289)	(0.1022)	(0.1908)	(0.3143)	(0.3190)	(0.1623)
(2)	Actual Corrected 1999 FAC Factor	(0.2159)	(0.2674)	(0.3523)	(0.1837)	(0.2863)	(0.1521)	(0.1858)	(0.1515)	(0.2356)	0.0436	(0.1472)	(0.1342)
(3)	Average (Row1 + Row2)	**(0.3125)**	**(0.4140)**	**(0.4163)**	**(0.2057)**	**(0.2889)**	**(0.2092)**	**(0.1074)**	**(0.1269)**	**(0.2132)**	**(0.1354)**	**(0.2331)**	**(0.1483)**

Table 2
Examples Showing Determination of the Applicable Monthly Corrected FAC Factor
(January 2000)
These are Hypothetical Numbers Intended for Illustrative Purposes Only

Example A: (Example showing treatment assuming negative fuel adjustment factors)

Calculations Incl. Actual Rev/Costs from Affiliate Transactions			Calculations Using PV Index Rev. for Affiliate Transactions[3]				
(1) Preliminary FAC Factor	(2) Calculated Correction FAC Factor	(3) Actual Corrected FAC Factor Col (1) + Col (2)	(4) Preliminary FAC Factor	(5) Calculated Correction FAC Factor	(6) Actual Corrected FAC Factor Col (1) + Col (2)	(7) "Hold Harmless" Factor From Table 1	(8) Applicable FAC Factor[4]
(0.1948)	(0.2970)	(0.4918)	(0.1949)	(0.2971)	(0.4920)	(0.3125)	**(0.4920)**

Example B: (Example showing treatment assuming positive fuel adjustment factors)

Calculations Incl. Actual Rev/Costs from Affiliate Transactions			Calculations Using PV Index Rev. for Affiliate Transactions[5]				
(1) Preliminary FAC Factor	(2) Calculated Correction FAC Factor	(3) Actual Corrected FAC Factor Col (1) + Col (2)	(4) Preliminary FAC Factor	(5) Calculated Correction FAC Factor	(6) Actual Corrected FAC Factor Col (1) + Col (2)	(7) "Hold Harmless" Factor From Table 1	(8) Applicable FAC Factor[6]
0.0246	0.1002	0.1248	0.0240	0.0995	0.1235	(0.3125)	**(0.3125)**

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[3] See Exhibit I(D)
[4] This Applicable FAC factor shall always be the lesser of the value in either Column 3, Column 6 or Column 7.
[5] See Exhibit I(D)
[6] This Applicable FAC factor shall always be the lesser of the value in either Column 3, Column 6 or Column 7.

Exhibit I(D)

Palo Verde Index - Simulated Market Price for Affiliate Transactions

Description of Daily and Weekly Transactions:
The Dow Jones Palo Verde ("DJ PV") daily market[7] for on-peak and off-peak prices will be utilized for any inter-affiliate transactions that are for a duration of less than one month. The daily on-peak load in MWh will be multiplied by the DJ PV daily on-peak price for that day, and the daily off-peak load in MWh will be multiplied by the DJ PV daily off-peak price for that day to determine the cost of the affiliate transaction. If the transaction were longer than one day, this process would be repeated for each day of the transaction.

Example: 50 MW Transaction

Daily Transaction: 01/31/02	MWh	Price ($/MWh)	Transaction Cost
On-peak	800	$24.73 / MWh	$19,784
Off-peak	400	$18.60 / MWh	$7,440
Total	1,200		$27,224

Note: for illustrative purposes only

Description of Monthly Transactions:

The DJ PV Daily Market for on-peak and off-peak prices[7] will be utilized for any inter-affiliate transactions of one month or greater. The monthly average of the daily DJ PV on-peak price and off-peak price will be multiplied by the respective total monthly on-peak and off-peak consumption to derive the monthly on and off-peak costs for purposes of determining applicable affiliate transaction costs to be used in determination of the monthly FAC factor.

Example: 50 MW Transaction

Monthly Transaction	MWh	Price ($/MWh)	Transaction Cost
January 2002			
On-peak	21,600	$19.42 / MWh[8]	$419,472
Off-peak	11,600	$14.04 / MWh[9]	$162,864
Total	33,200		$582,336

Note: for illustrative purposes only

Section Break (Next Page)

[7]The DJ PV Daily On and Off-peak Index information is available from Dow Jones and a number of websites including http://www.energyonline.com/Restructuring/energydb/estathme.html
[8] Assumes that $19.42/MWh is what the average DJ PV Daily on-peak price was for January 2002.
[9] Assumes that $14.04/MWh is what the average DJ PV Daily off-peak price was for January 2002.

Exhibit APS-4
FPC Rate Schedule No. 12
Clean Sheets

ARIZONA PUBLIC SERVICE COMPANY

LEASE POWER AGREEMENT
WITH
ELECTRICAL DISTRICT NO. 3

FPC Rate Schedule No. 12

EXHIBIT I

The following charges and provisions shall be applicable to District.

1.0 The District shall pay the Company monthly for electric power and energy supplied by the Company and delivered by the Company for the District, in accordance with Article II of the Lease Power Agreement, and in accordance with the following rate provisions effective October 1, 1994. The energy charge and any applicable discount will be applied to the kilowatthours used monthly by each pump served for the District, whether privately owned and operated or operated by the district, and the total amount thus obtained will be divided by the total kilowatthours used that month by all of said pumps to determine the average energy charge per kilowatthour. The average energy charge so determined each month will be multiplied by the number of kilowatthours supplied and delivered that month by the Company to and/or for the District, as determined in accordance with this Exhibit I to the Lease Power Agreement, to determine the monthly energy charge billing.

2.0 Base Monthly Rate:

Customer Charge: $11.00 per connected pump, plus

Demand Charge: S6.901 per kW, plus

Energy Charge: $0.08286 per kWh*

* Less, where applicable, .05 cents/kWh discount for service rendered through the customer's own secondary voltage line transformer.

In addition to the above charges in this Section 2.0, the Customer will be billed a pass through of the charges for Network Integration Transmission Service under the Company's Open Access Transmission Tariff that is applicable for the delivery of supplemental power and energy from the Company.

3.0 [Reserved]

4.0 Base Monthly Minimum:

Customer Charge, plus

Demand Charge

5.0 Determination of Billing Demand kW and Billing Energy kWh:

(a)(i) The kilowatts supplied at the pumps by the Company and to be billed monthly under the rate provided above shall be determined as follows:

$$Dc = Dp - Dh$$

Where: Dc Effective during the period October 1, 1994 through December 31, 1994, Dc is the number of kilowatts billed by the Company during the month at the pumps.

Dp is the maximum monthly kilowatt load at the pumps as determined in Paragraphs (b)(i) and (b)(ii) hereof.

$Dh = Dd \times (1 - Ld)$

Dd is the monthly kilowatts from the Authority and/or from other sources utilized at the substation by the District during the billing month.

Ld shall equal actual losses computed and billed by the Company; the revised loss factor shall equal 9.218% (which is representative of the annual average Company system kilowatt loss factor for the month as determined in Paragraph (b) hereof).

(ii) The kilowatthours supplied and delivered by the Company to the pumps to be billed monthly under the rate provided above shall be determined as follows:

INDEMNITY REGARDING THE NON-APPLICATION OF THE TAX CHARGE

1. Electrical District No. Three ("District") and Arizona Public Service Company ("Company") entered into a Lease Power Agreement, dated July 7, 1961 ("Agreement") which provides for a Tax Charge ". . . to cover the 'Arizona Transaction Privilege (sales) Tax', (which Tax Charge may be) imposed upon all rates, charges and billings under this Agreement . . ." District and Company enter into this Indemnity in light of the following facts:

   1.1 A Tax Charge was included to cover the Arizona Transaction Privilege Tax ("Sales Tax") if it were to be imposed. However, since then the tax statutes have been amended exempting sales for resale from tax, which presumptively includes wheeling. Nevertheless, a new Tax Charge will be included to cover the Sales Tax and Pinal County Transportation Excise Tax for wheeling and administrative services under the Agreement.

   1.2 The new Tax Charge is included as an economic precaution based on prior experience despite the fact that the District and Company agree that A.R.S. Section 42-1301, et seq., exempts from application of a Sales Tax or other sales and/or use taxes or other similar impositions the wheeling and administrative services provided under the Agreement.

2. If such tax is applicable to Company, the Agreement makes such tax a part of District's rate, thereby placing the burden of such tax on District.

3. The Parties agree that no imposition of such Sales Tax or other sales and/or use taxes or other similar imposition should be made.

4. The Parties agree as follows:

   4.1 Company shall not charge the Tax Charge set forth in the Agreement unless and until the Arizona Department of Revenue ("State"), Arizona cities or other governmental units required the payment thereof by Company.

   4.2 When and if the State, Arizona cities or other governmental units so require payment of said Sales Tax or other sales and/or use taxes or other similar impositions, Company will bill the District for such tax whether prospectively or retroactively, and the District agrees to pay the same to Company and Company will make such payments to the State, Arizona cities or other governmental units under protest on behalf of the District and Company, as their interest may appear.

   4.3 The District shall pursue its legal remedies to the extent it desires, at its own cost and expense and with counsel and other personnel of its own choosing. In so

Exhibit APS-5
FERC Rate Schedule No. 68
Clean Sheets

ARIZONA PUBLIC SERVICE COMPANY
LEASE POWER AGREEMENT
WITH
ELECTRICAL DISTRICT NO. 1

FPC Rate Schedule No. 68

EXHIBIT I

The following charges and provisions shall be applicable to District.

1.0 District shall pay Company monthly for electric power and energy supplied by Company and delivered by Company for District, in accordance with Article 5 of the Lease Power Agreement, and in accordance with the following rate provisions effective September 1, 1991. The energy charge and any applicable discount will be applied to the kilowatthours used monthly by each pump served for the District, whether privately owned and operated or operated by the district, and the total amount thus obtained will be divided by the total kilowatthours used that month by all said pumps to determine the average energy charge per kilowatthour. The average energy charge so determined each month will be multiplied by the number of kilowatthours supplied and delivered that month by the Company to District, as determined in accordance with this Exhibit I to the Lease Power Agreement, to determine the monthly energy charge billing.

2.0 Base Monthly Rate:

Customer Charge: $11.00 per connected pump, plus

Demand Charge: $6.901 per kW, plus

Energy Charge: $0.08286 per kWh*

* Less, where applicable, .05 cents/kWh discount for service rendered through the customer's own secondary voltage line transformer.

In addition to the above charges in this Section 2.0, the Customer will be billed a pass through of the charges for Network Integration Transmission Service under the Company's Open Access Transmission Tariff that is applicable for the delivery of supplemental electric power and energy from the Company.

3.0 [Reserved]

4.0 Determination of Billing Demand kW and Billing Energy kWh:

(a)(i) The kilowatts supplied at the pumps by the Company and to be billed monthly under the rate provided above shall be determined as follows:

$$Dc = Dp - Dh$$

Where: Dc is the number of kilowatts billed by the Company during the month at the pumps; provided that, effective January 1, 1997, Dc is the number of kilowatts billed by the Company at the pumps, but not less than the highest number of such kilowatts supplied and delivered during the months of June, July, August, or September of the 12 months ending with the current month, but which 12 months begin no earlier than January 1, 1997 provided, however, nothing contained in this Amendment shall be construed as affecting in any way the right of Company to unilaterally make application to the FERC for a change in rates, charges, classification or terms and conditions of service, or any rule or regulation related thereto, under Section 205 of the Federal Power Act or any successor statute and pursuant to the FERC's Rules and Regulations promulgated thereunder. Nothing contained in this Amendment shall be construed as affecting in any way the right of District to exercise its rights under the Federal Power Act, including Section 206, or any successor statute and pursuant to the FERC's Rules and Regulations promulgated thereunder.

Dp is the maximum monthly kilowatt load at the pumps as determined in Paragraphs (b)(i) and (b)(ii) hereof.

$$Dh = Dd \times (1 - Ld)$$

Dd is the monthly kilowatts from the Authority and/or from other sources utilized at the substation by the District during the billing month.

Ld shall equal actual losses computed and billed by the Company; the revised loss factor shall equal 9.218% (which is representative of the annual average Company system kilowatt loss factor for the month as determined in Paragraph (b) hereof), effective beginning with the first bills rendered after execution of the Stipulation and Agreement, dated May 7, 1990 ("Stipulation").

(ii) The kilowatthours supplied and delivered by the Company to the pumps to be billed monthly under the rate provided above shall be determined as follows:

AGREEMENT

AGREEMENT, dated as of March 29, 1977, by and between ARIZONA PUBLIC SERVICE COMPANY ("Company"), an Arizona corporation, and ELECTRICAL DISTRICT NUMBER ONE OF THE COUNTY OF PINAL AND STATE OF ARIZONA ("District"), an electrical district duly organized and existing under the laws of the State of Arizona.

W I T N E S S E T H:

WHEREAS, pursuant to a Power Agreement dated as of July 2, 1975, ("Power Agreement"), the Company is supplying power and energy to the District in accordance with the terms of that agreement for irrigation service to customers of the District, and

WHEREAS, the parties have entered into a Purchase Agreement dated as of July 2, 1975 pursuant to which the Company has conveyed, by Bill of Sale of even date, certain electric distribution facilities ("Electric Facilities") to the District, and

WHEREAS, the parties have entered into a Lease Power Agreement ("Lease Power Agreement") and Lease Agreement of even date herewith pursuant to which the Company will lease back the Electric Facilities sold to the District in accordance with the terms of the Lease Agreement and will provide power and energy to the District upon the terms set forth in the Lease Power Agreement, and

WHEREAS, subsequent to the effectiveness of the Power Agreement, the Company made a wholesale rate increase filing with the Federal Power Commission in Docket No. ER76-530, which proceeding is now pending before that Commission with the District participating as an Intervenor, and

Contract No. 89695

APS

The following terms and conditions shall govern this transaction made on **February 26, 2008**, between **Arizona Public Service Company** ("APS" or "Seller") and **Electrical District No. 3 of Pinal County** ("Counterparty" or "Purchaser" or "ED-3"), whereby APS agreed to sell and deliver energy and Counterparty agreed to purchase and receive energy. In this Confirmation, the Seller and the Purchaser may be individually referred to as a "Party" and collectively as "Parties". This transaction replaces certain Lease Power Agreements ("LPAs") between APS and ED-3 and Electrical District No. 1 of Pinal County, Arizona, designated as APS First Revised Rate Schedule No. 12 and APS First Revised Rate Schedule No. 68, respectively. The Parties shall request termination of the LPAs, effective midnight, February 29, 2008.

This Confirmation supplements, forms part of, and is subject to the Power Sale Agreement ("Agreement") dated, **February 26, 2008**, between Seller and Purchaser. All provisions contained in the Agreement govern this Confirmation. In the event of a conflict between this Confirmation and the Agreement, this Confirmation shall govern. Terms used but not defined herein shall have the meanings set forth in the Agreement.

In consideration of the premises and the agreements contained herein, the Parties agree as follows:

Seller: **Arizona Public Service Company**	**Purchaser:** **Electrical District No. 3 of Pinal County**
Confirm Administrator: Michele Yanik Deken (602) 250-2341 (phone) (602) 371-5256 (facsimile)	**Confirm Administrator:** K.R. Saline & Associates (480) 610-8741 (phone) (480)610-8796 (facsimile)
Preschedule: (602) 250-4371 **Real Time:** (602) 250-4470	**Preschedule:** (480) 610-8741 **Real Time:** (480) 610-8741/(602) 321-9086
Quantity (MW/hr.): **As per the attached Power Block Tables (Exhibits 1- 10)**	**Quantity (MWh):** 2,041,840 MWh* **Subject to change per Section 1hereto.*
Contract Price ($/MWh): Base Rate / Adjusted Rate Mar 2008 – Feb 2009: 75.00 / 73.50 Mar 2009 – Feb 2010: 77.50 / 76.00 Mar 2010 – Feb 2011: 80.00 / 80.00 Mar 2011 – Feb 2012: 80.00 / 80.00 Mar 2012 – Feb 2013: 82.50 / 82.50	**Product Type:** Firm Capacity and/or Energy sale pursuant to the Agreement
Start Date: March 1, 2008	**End Date:** February 28, 2013
Day(s) of week: **As per the attached Power Block Tables (Exhibits 1- 10)**	**Hours:** **As per the attached Power Block Tables (Exhibits 1-10)**

Attached Exhibits:

Exhibits 1–5:	Power Block Tables for years 1 through 5. Excludes APS Retail Block.
Exhibits 6–10:	Power Block Tables for years 1 through 5. Includes APS Retail Block.
Exhibit 11:	Contract Payment Example Calculations
Exhibit 12:	Definitions

Delivery Points: Santa Rosa 230/69 kV Substation (Delivery requiring use of APS Transmission System)
Test Track 230/69 kV Substation (Delivery not requiring use of APS Transmission System)
Future Delivery Points upon mutual agreement.

Special Terms and Conditions

The Contract Prices shown on page 1 include both base rates and adjusted rates. In this Confirmation, the Contract Price may be referred to as either a "Base Rate" or an "Adjusted Rate."

APS is committed to supply Firm Capacity and/or Energy, as shown on Power Block Tables (Exhibits 1 through 5). ED-3 is obligated to purchase these same quantities at the Adjusted Rates.

1. Obligations Regarding Transfer of Retail Customers

The Power Block Tables (Exhibits 1 through 5) represent the Take-or-Pay power block demand obligations of both Parties, prior to and irrespective of the potential transfer of APS Retail Block to ED-3

The Parties agree that if and when the transfer of the APS Retail Block to ED-3 is authorized by the Arizona Corporation Commission ("ACC"), the total supply obligations of the Parties under this transaction will be as shown in Power Block Tables (Exhibits 6 through 10). If this transfer of APS Retail Block occurs over a period of time, the Parties agree to develop a transition plan to move the APS Firm Capacity and/or Energy obligation from the quantities in Exhibits 1 through 5 to the quantities in Exhibits 6 through 10. The Adjusted Rates shown above apply to whichever power block demand/energy APS is obligated to provide and ED-3 is obligated to take.

Until such transfer of APS Retail Block occurs, ED-3 agrees that for new customers locating within the ED-3 service area, who want APS service, ED-3 will provide all extensions and APS will provide the meter.

2. Reimbursement Payment

Beginning March 1st of year three (3) and over the following twenty-four (24) months, ED-3 will reimburse APS the total dollar difference between what would have been invoiced to ED-3 for the APS Power Block Energy if the Base Rates had been applied, and the actual invoiced Power Block Energy dollars using the Adjusted Rates during the first two (2) years of this transaction ("Reimbursement Payment"). This Reimbursement Payment will also include interest at a rate of 0.4167% compounded monthly. (5.0% / 12 months = 0.4167%)

The monthly Reimbursement Payment (RP) shall be calculated as follows:

$RP_{m+24} =$ $PBE_m * \Delta R * MI$

Where,

$RP =$ Monthly reimbursement to APS (dollars)

$PBE =$ Power Block Energy (in MWh) obtained by using the appropriate Month's Power Block Tables.

$m =$ months 1 through 24 in subject two-year period

For example:
m = 1 is March 2008
m = 6 is August 2008

$\Delta R =$ Difference between Base Rate and Adjusted Rate over the first 24 months of the Term and shall be \$1.50/MWh.

$MI =$ Interest compounded monthly and shall equal to $(1.004167)^{24} = 1.10495$

For example, when repayment begins in month 25, the payment for power delivered when m=1, month=March, 2008, and the following calculation would apply:

$$\begin{aligned} RP_{25} &= (23{,}312\ \text{MWh}) * (\$1.50/\text{MWh}) * 1.10495 \\ &= \$34{,}968 * 1.10495 \\ &= \$38{,}638 \quad \text{payment due APS March 2010} \end{aligned}$$

A total of 24 monthly payments will be made to APS during the March 2010 to February 2012 period. However, ED3 may prepay based upon calculation of the above formula, including a proration of the interest accrued up to the time of the pre-payment.

3. *Purchase of Additional Power and Scheduling*

Since the APS supplied power, as shown in Exhibits 1 through 10, may supply only a portion of the ED-3 total load, the following process will be followed to secure additional resources when necessary and for purposes of developing the monthly invoice.

Prior to the start of any month, ED-3 will estimate the total hourly ED-3 load for the upcoming month. ED-3 will establish and transmit to APS an hourly pre-schedule of all resources available for the month, including their Schedule of Purchase Preference Resources and including all other existing purchase power contracts. ED-3 may change hourly schedules during the month with a minimum of two (2) days advance notice and adherence to industry practice for weekends and holidays scheduling. APS may schedule the ED-3 preference power for the benefit of the integrated APS loads and resources, but shall use the ED-3 pre-schedule developed above for the after-the-fact billing.

At any time, ED-3 has the right to purchase additional power or authorize APS to purchase additional power to meet ED-3's future loads. Scheduling of such power must be done with a minimum of two (2) days notice to APS and adherence to industry practice for weekends and holidays scheduling. For any proposed purchase by ED-3 from a third party of one (1) month or longer, APS has a right to match the lowest offer given to ED-3 for not less than half of the proposed purchase. The foregoing sentence does not apply to resources with a term of ten (10) years or longer. ED-3 must provide APS with details of any purchase as soon as possible and with adequate time for APS scheduling and administration purposes.

Additional power from third party resources which is specified and requested by ED-3 to be purchased by APS will be delivered to ED-3 under this Confirmation and all associated costs will be passed through including a $2/MWh adder. The cost of these additional deliveries to ED-3 will be included in the invoice developed pursuant to this Confirmation and the Agreement.

4. Transmission Service

APS has arranged for network transmission service under the APS Open Access Transmission Tariff ("OATT"), by application dated February 21, 2008, a copy of which is attached to this Confirmation (Exhibit 14). This service will cover the APS supplied power including any other purchases made by APS or ED-3 that require use of the APS transmission system to get to the Santa/Rosa 230/69 kV Substation Delivery Point. APS will pass through to ED-3, with no mark-up, any and all costs associated with provision of these transmission services. These costs will include any and all required study costs (if any), facilities costs (if any) or other costs (if any) tied to the request for service and/or the provision of service. APS Marketing and Trading will not oppose efforts by ED-3 to obtain network service for its loads at the End Date of this Confirmation, including arguments by ED-3 that it has rollover rights associated with pre-existing service on the APS system to such loads, provided however, that any such determination shall be made by APS Transmission and all communications by ED-3, with respect to such efforts, shall be to and with APS Transmission.

Any of the other purchases authorized by ED-3, as well as Purchaser Preference Resources, which are delivered by a third party supplier or ED-3 directly to the Test Track 230/69 kV Substation over a third party's transmission, without use of the APS Transmission System, will not be included in the OATT pass through transmission charge.

ED-3 currently charges APS $15.00/MWh for wheeling of APS energy to APS loads served off the ED-3 system, per the existing Transmission Service Agreement (TSA) between ED-3 and APS dated, May 2002. Pursuant to this TSA, ED-3 must file any proposed adjustment to this rate with the Federal Energy Regulatory Commission ("FERC") for approval. APS is willing to pay the proposed rate starting thirty (30) days after ED-3 has made such a filing with such rates being subject to refund based on the final FERC Order. APS reserves the right to intervene and/or protest such rates in the proceedings at FERC.

5. <u>Changes In Performance Assurance Requirements</u>

Transactions entered into by APS, on behalf of ED-3 and pursuant to this Confirmation, will be placed in separate accounts. ED-3 will be responsible for any and all credit impacts APS incurs with respect to purchases made on behalf of ED3 under this Agreement and booked to such separate accounts by APS, including such increased demands for performance assurance (if any) as may be made against APS with respect to such purchase(s) made on behalf of ED3. ED3 may discharge its responsibility under this Section 5 for increases in performance assurance requirements imposed on APS by third party sellers as the direct and proximate result of APS having made a purchase on behalf of ED3 under this Agreement, by (a) providing cash, with respect to the transaction(s) triggering the demand for increased performance assurance on APS, sufficient to avoid such impacts on APS with respect to purchases undertaken on behalf of ED-3. ED-3 authorizes APS to use the cash to satisfy these demands and APS agrees to return such cash, including interest if applicable, to ED-3 when it is no longer required of APS by third party sellers or (b) assuming responsibility for such purchase on its own account, subject to approval of the third party, in which case the purchase will cease any performance assurance requirements associated with such transaction will be eliminated. ED3 shall have the option of selecting the mode of mitigating APS's exposure to enhanced performance assurance requirements with respect to purchases made on behalf of ED3 in the manner least costly to ED3, as determined in its sole and absolute discretion.

For purposes of third party transactions, APS will enter into such transactions pursuant to the same master agreements utilized when purchasing for APS native load

If the counterparty from which purchases were made by or on behalf of ED-3, does not perform in accordance with the terms of such purchase(s), ED-3 will be liable for ED3's proportionate share of costs associated with the failure to perform, including but not limited to replacement costs and any penalties imposed on APS. In such event, APS assigns to ED3, without the need for further documentation, all of its rights and remedies against such non-performing counterparty, including without limitation, the right to damages, specific performance or any other form of remedy whatsoever.

For purposes of implementing this Section 5, APS will provide ED3 access to any information necessary to validate the collateral requirements or other information which may be useful or necessary to the effectuation of ED3's rights under this Section 5.

6. Pricing

The following pricing shall be applicable to ED-3 for the energy sold to ED-3 pursuant to this transaction. The methodology for calculating such contract payments shall be fixed for the period 12:01 A.M. on March 1, 2008 through 12:00 A.M. on February 28, 2013.

6.1 Monthly Calculation of Contract Payment:

Monthly billing contract payment formula: P = PBA + RP + S + PPC +TRAN+ IS + VIA

Where:

P = Monthly contract payment (in dollars)

PBA = Power Block Amounts (in dollars) obtained by using the appropriate Month's Power Block Energy shown in the Power Block Tables times the Adjusted Rate. This is a "Take or Pay" obligation to Purchaser per month.

RP = Reimbursement Payment identified in Section 2 of this Confirmation.

S = Surcharge (in dollars), when applicable, as specified in Section 8 of this Confirmation..

PPC = the total cost (in dollars) of any additional power purchased and delivered to ED-3 by APS under this Confirmation.

TRAN = Pass-through transmission charges identified in Section 4 of this Confirmation.

IS = Monthly contract payment in dollars due APS for ED-3 not providing the minimum instantaneous interruptible load as specified in Section 8.

VIA = Volume Imbalance Adjustment (in dollars) determined as follows:

In the case where Purchaser's Total Load Requirements at the Delivery Points less Purchaser Preference Resources and less other purchase power exceed the On-Peak Hourly Demand or Off-Peak Hourly Demand, whichever is applicable, for any hour in the billing month, Seller shall obtain the shortfall from the APS system and/or energy market. Purchaser shall be responsible for paying Seller on its' monthly bill for the purchase of this shortfall based on the Volume Imbalance Adjustment calculation set forth below.

In the case where Purchaser's Total Load Requirements less Purchaser Preference Resources and less other purchased power are below the On-Peak Hourly Demand or Off-Peak Hourly Demand, whichever is applicable, for any hour of the Billing Month, Seller shall absorb or sell the excess to the energy market. Purchaser shall receive a credit for the sale of this excess energy based on the Volume Imbalance Adjustment calculation set forth below. For billing purposes, the amount sold any hour cannot exceed PBD.

$$VIA = \sum[(PTLR-PREF-PBD-OP)(HI\pm IAF)]$$

Where for each hour:

PTLR = Purchaser's Total Load Requirement (in MW) as measured by the Meters at the Delivery Points and adjusted for APS and Ak-Chin retail load. PTLR for any Delivery Point for any hour shall not be less than zero.

PREF = The Energy (MW) pre-scheduled by ED-3 from Purchaser's Preference Resources at Delivery Point which corresponds to the same PTLR hour during the billing month.

PBD = Power Block Demand (In MW) is the On-Peak Hourly Demand or Off-Peak Hourly Demand which corresponds to the same PTLR Hour in the billing month.

OP = Any other purchased power (MW) which had been authorized and approved by ED-3 during the same hour.

HI = Hourly Index: The Dow Jones Palo Verde Hourly Index Price in (dollars per MWh) for each corresponding Hour. (See Exhibit 13 attached). If the index no longer exists or becomes unreliable, the parties agree to work together to establish a substitute index which provides the same economic impacts.

IAF = Index Adjustment Factor: The IAF shall be either 1) or 2) below:

1) If PTLR-PREF-PBD-OP≥0 for any hour, IAF for such hour shall be equal to +$2/MWh.

2) If PTLR-PREF-PBD-OP<0 for any hour, IAF for such hour shall be equal to -$2/MWh.

Σ = The aggregate of the items specified after this sign. In this case, it sums each hourly MWh calculation shown above for the entire billing month.

An example of the calculation of monthly contract payment is attached as Exhibit 11.

7. Calculating the Purchaser's Total Load Requirement

For invoicing purposes, the actual hourly ED-3 PTLR will be determined as follows:

The hourly metered data for the month, at the Delivery Points, will be adjusted downward by (1) the hourly loads of the Ak-Chin Electric Service, and (2) the hourly loads of the APS customers being served off of the ED-3 system. APS will estimate the total monthly energy for APS customers where hourly metering data does not readily exist. These Ak-Chin and APS hourly loads will be grossed up by 8% losses to reflect load at the Delivery Points. For calculating thePTLR, the net total Delivery Points metered hourly loads, after subtraction of the Ak-Chin hourly loads, will be further reduced by the proportion of APS monthly energy divided by the sum of ED3's and APS's monthly metered energy. For example: If APS' total monthly estimated energy is 8,000 MWh and the total monthly metered energy of APS and ED3 is 73,000 MWh, then each Hourly Load will be reduced by the ratio of 8000/73000 or 11.0%.

Any adjustment to the APS estimated loads for prior months' usage will be included in APS customer loads for in the then current month.

If during the term of this Confirmation, the configuration of the APS / ED-3 system changes, such that amendments must be made to these calculations to accurately account for the Parties' loads, the Parties agree to amend the calculations as needed in a timely manner.

8. Reserves

APS is providing "firm" capacity for the energy Power Blocks provided to ED-3, which require APS to carry reserves sufficient to support such firmness. The Parties agree that to help compensate APS for this service, ED-3 agrees to provide the services indicated in Section 8.1, 8.2 and 8.3.

8.1 ED-3 will use best efforts to provide 140 MW/months per year of instantaneously interruptible load as described below, metered to and controlled by APS, by June 1, 2009 for five (5) years thereafter. To fulfill the 5 year commitment, APS control of this interruptible load shall extend beyond termination of this Confirmation. The Parties acknowledge that the technical/engineering feasibility of accomplishing the above has not been fully vetted. The Parties shall implement this provision in accordance with WECC standards and criteria. The Parties further agree to jointly use best efforts to accomplish the desired interruptibility in a timely fashion. If it is determined that such interruptibility cannot be fully implemented for 140 MW/months per year with a minimum of 20 MW per month for June, July and August with a monthly schedule due February 15 of each year for the seven month period March through September APS will charge for any shortfall, in the amount of $14.30/kW-month. Each party shall be responsible for its respective share of implementation costs. ED-3 reserves the right, with reasonable advance notice, to suspend the interruptibility and compensate APS at the rate stated herein for any given billing month.

8.2 During the period between the execution of the Agreement and February 28, 2017, ED-3 will provide APS with up to three opportunities to participate in ED-3's share of future generation then in development by ED-3. Each opportunity shall be structured to conform to the following criteria:

- The participation made available to APS will be consistent with maintaining the eligibility of ED-3 and the particular generating project for tax-exempt financing under the Internal Revenue Code and implementing regulations;
- The participation made available to APS will be subject to, and consistent with, the agreements for the development of the relevant generating project;
- The participation made available to APS shall be subject to, and consistent with, regulatory requirements then incumbent upon APS, including rules established by the Arizona Corporation Commission for competitive procurement;
- The participation made available to APS shall cease to be available after the 120th day prior to the commercial operation date of the generating project;
- The participation made available to APS shall be assignable, provided that the creditworthiness of a proposed assignee of APS must be acceptable to ED-3, with the consent of ED-3, which shall not be unreasonably withheld, and any proposed assignee shall be subject to same limitations and restrictions as APS.

8.3 ED-3 will pay a surcharge for any hour that purchases are made by APS to serve APS native load that exceed $300/MWh. This surcharge will be calculated on a load ratio share basis using the power block as the basis for ED-3 load share.

For example:

Assume: APS Load 5200 MW
ED-3 Block Load 90 MW, Base Rate $80/MWh
APS Purchasing 500MW at $400/MWh + $0/kW-mth

Surcharge: [500MW * (400-80) +0/kW] * 90/5290
= $2,722

9. Curtailments

During emergency conditions which require load shedding ED-3 will reduce its load at the Delivery Points on a pro-rata basis with APS retail load up to the amount of load served by the APS Power Blocks. All other ED-3 loads, except that portion of the ED-3 load served out of Test Track 230/69 Delivery Point, will be curtailed prior to APS retail load provided, however, this Section 9 shall not be used to allow interruptions of such other ED-3 loads for reasons other than reliability of service to APS native load.

Notwithstanding any provisions of this Confirmation or the Agreement, ED-3 will not be entitled to any damages, as provided in Section 13.3 of the Agreement, incurred from curtailment of any power not provided for in the Power Block Tables of this Confirmation.

10. Notifications

APS will make reasonable efforts to notify ED-3, in accordance with Section 6.3 of the Agreement, as soon as is practicable, if APS anticipates that a load shedding emergency is imminent, per Section 9 of this Confirmation, or when and for what duration APS anticipates purchasing power to serve APS native load at a cost above $300/MWh. Upon notification, ED-3 may attempt to mitigate these events within the terms of this Confirmation.

11. Continuing Relationship

The Parties acknowledge a desire for a continuing relationship beyond the End Date of this Confirmation and are committed to negotiating in good faith, addressing longer term power supply needs.

Because ED-3 is not obligated to continue to purchase power from APS and APS is not obligated to continue to sell to ED-3 beyond the termination date of this Agreement on February 28, 2013, both Parties understand that APS will not plan and procure capacity and energy to meet the expected future needs of ED-3 beyond February 28, 2013. Unless and until ED-3 enters into an agreement with APS for service beyond February 28, 2013, all obligations under this Confirmation will cease, except as provided in Section 8, instantaneous interruptible load and the option to participate in ED-3's future resource.

Counterparty's execution of this Confirmation shall acknowledge its agreement to these terms and conditions. Please return a copy via facsimile to (602) 371-5256 attention the APS Confirm Administrator listed above.

ARIZONA PUBLIC SERVICE COMPANY	**Electrical District No. 3 of Pinal County**
Signature:	Signature:
Printed Name: David Hansen	Printed Name: Dan Thelander
Title: Vice President	Title: Chairman of the Board
Date: 02/26/08	Date: 02/26/08

APSMT
Contracts
Department
By. SM 02/26/08

EXHIBIT 1
ARIZONA PUBLIC SERVICE CORPORATION
AND
ED 3

POWER BLOCK TABLES

TABLE YEAR 1

Excludes APS Retail Block

March 1, 2008 through February 28, 2009

The following Power Block Table is to be used in conjunction with calculating the Monthly Power Supply Billing Amount.

Billing Month	On-Peak 7x16 Hourly Demand (MW)	Off-Peak 7x8 Hourly Demand (MW)	Power Block Energy (MWh)
Mar-08	35	24	23,312
Apr-08	48	24	28,800
May-08	70	28	41,664
Jun-08	90	38	52,320
Jul-08	90	38	54,064
Aug-08	90	38	54,064
Sep-08	70	28	40,320
Oct-08	48	24	29,760
Nov-08	33	24	21,600
Dec-08	35	20	22,320
Jan-09	30	20	19,840
Feb-09	33	24	20,160
		Total Block Energy	408,224

EXHIBIT 2
ARIZONA PUBLIC SERVICE CORPORATION
AND
ED 3

POWER BLOCK TABLES

TABLE YEAR 2

Excludes APS Retail Block

March 1, 2009 through February 28, 2010

The following Power Block Table is to be used in conjunction with calculating the Monthly Power Supply Billing Amount.

Billing Month	On-Peak 7x16 Hourly Demand (MW)	Off-Peak 7x8 Hourly Demand (MW)	Power Block Energy (MWh)
Mar-09	35	24	23,312
Apr-09	48	24	28,800
May-09	70	28	41,664
Jun-09	90	38	52,320
Jul-09	90	38	54,064
Aug-09	90	38	54,064
Sep-09	70	28	40,320
Oct-09	48	24	29,760
Nov-09	33	24	21,600
Dec-09	35	20	22,320
Jan-10	30	20	19,840
Feb-10	33	24	20,160
		Total Block Energy	408,224

EXHIBIT 3
ARIZONA PUBLIC SERVICE CORPORATION
AND
ED 3

POWER BLOCK TABLES

TABLE YEAR 3

Excludes APS Retail Block

March 1, 2010 through February 28, 2011

The following Power Block Table is to be used in conjunction with calculating the Monthly Power Supply Billing Amount.

Billing Month	On-Peak 7x16 Hourly Demand (MW)	Off-Peak 7x8 Hourly Demand (MW)	Power Block Energy (MWh)
Mar-10	35	24	23,312
Apr-10	48	24	28,800
May-10	70	28	41,664
Jun-10	90	38	52,320
Jul-10	90	38	54,064
Aug-10	90	38	54,064
Sep-10	70	28	40,320
Oct-10	48	24	29,760
Nov-10	33	24	21,600
Dec-10	35	20	22,320
Jan-11	30	20	19,840
Feb-11	33	24	20,160
		Total Block Energy	408,224

EXHIBIT 4
ARIZONA PUBLIC SERVICE CORPORATION
AND
ED 3

POWER BLOCK TABLES

TABLE YEAR 4

Excludes APS Retail Block

March 1, 2011 through February 29, 2012

The following Power Block Table is to be used in conjunction with calculating the Monthly Power Supply Billing Amount.

Billing Month	On-Peak 7x16 Hourly Demand (MW)	Off-Peak 7x8 Hourly Demand (MW)	Power Block Energy (MWh)
Mar-11	35	24	23,312
Apr-11	48	24	28,800
May-11	70	28	41,664
Jun-11	90	38	52,320
Jul-11	90	38	54,064
Aug-11	90	38	54,064
Sep-11	70	28	40,320
Oct-11	48	24	29,760
Nov-11	33	24	21,600
Dec-11	35	20	22,320
Jan-12	30	20	19,840
Feb-12	33	24	20,880
		Total Block Energy	408,944

EXHIBIT 5
ARIZONA PUBLIC SERVICE CORPORATION
AND
ED 3

POWER BLOCK TABLES

TABLE YEAR 5

Excludes APS Retail Block

March 1, 2012 through February 28, 2013

The following Power Block Table is to be used in conjunction with calculating the Monthly Power Supply Billing Amount.

Billing Month	On-Peak 7x16 Hourly Demand (MW)	Off-Peak 7x8 Hourly Demand (MW)	Power Block Energy (MWh)
Mar-12	35	24	23,312
Apr-12	48	24	28,800
May-12	70	28	41,664
Jun-12	90	38	52,320
Jul-12	90	38	54,064
Aug-12	90	38	54,064
Sep-12	70	28	40,320
Oct-12	48	24	29,760
Nov-12	33	24	21,600
Dec-12	35	20	22,320
Jan-13	30	20	19,840
Feb-13	33	24	20,160
		Total Block Energy	408,224

EXHIBIT 6
ARIZONA PUBLIC SERVICE CORPORATION
AND
ED 3

POWER BLOCK TABLES

TABLE YEAR 1

Includes APS Retail Block

March 1, 2008 through February 28, 2009

The following Power Block Table is to be used in conjunction with calculating the Monthly Power Supply Billing Amount.

Billing Month	On-Peak 7x16 Hourly Demand (MW)	Off-Peak 7x8 Hourly Demand (MW)	Power Block Energy (MWh)
Mar-08	48	27	30,504
Apr-08	61	27	35,760
May-08	85	27	48,856
Jun-08	110	41	62,640
Jul-08	110	41	64,728
Aug-08	110	41	64,728
Sep-08	85	27	47,280
Oct-08	61	27	36,952
Nov-08	46	27	28,560
Dec-08	40	25	26,040
Jan-09	35	25	23,560
Feb-09	46	27	26,656
		Total Block Energy	496,264

EXHIBIT 7
ARIZONA PUBLIC SERVICE CORPORATION
AND
ED 3

POWER BLOCK TABLES

TABLE YEAR 2

Includes APS Retail Block

March 1, 2009 through February 28, 2010

The following Power Block Table is to be used in conjunction with calculating the Monthly Power Supply Billing Amount.

Billing Month	On-Peak 7x16 Hourly Demand (MW)	Off-Peak 7x8 Hourly Demand (MW)	Power Block Energy (MWh)
Mar-09	48	27	30,504
Apr-09	61	27	35,760
May-09	85	27	48,856
Jun-09	110	41	62,640
Jul-09	110	41	64,728
Aug-09	110	41	64,728
Sep-09	85	27	47,280
Oct-09	61	27	36,952
Nov-09	46	27	28,560
Dec-09	40	25	26,040
Jan-10	35	25	23,560
Feb-10	46	27	26,656
		Total Block Energy	496,264

EXHIBIT 8
ARIZONA PUBLIC SERVICE CORPORATION
AND
ED 3

POWER BLOCK TABLES

TABLE YEAR 3

Includes APS Retail Block

March 1, 2010 through February 28, 2011

The following Power Block Table is to be used in conjunction with calculating the Monthly Power Supply Billing Amount.

Billing Month	On-Peak 7x16 Hourly Demand (MW)	Off-Peak 7x8 Hourly Demand (MW)	Power Block Energy (MWh)
Mar-10	48	27	30,504
Apr-10	61	27	35,760
May-10	85	27	48,856
Jun-10	110	41	62,640
Jul-10	110	41	64,728
Aug-10	110	41	64,728
Sep-10	85	27	47,280
Oct-10	61	27	36,952
Nov-10	46	27	28,560
Dec-10	40	25	26,040
Jan-11	35	25	23,560
Feb-11	46	27	26,656
		Total Block Energy	496,264

EXHIBIT 9
ARIZONA PUBLIC SERVICE CORPORATION
AND
ED 3

POWER BLOCK TABLES

TABLE YEAR 4

Includes APS Retail Block

March 1, 2011 through February 29, 2012

The following Power Block Table is to be used in conjunction with calculating the Monthly Power Supply Billing Amount.

Billing Month	On-Peak 7x16 Hourly Demand (MW)	Off-Peak 7x8 Hourly Demand (MW)	Power Block Energy (MWh)
Mar-11	48	27	30,504
Apr-11	61	27	35,760
May-11	85	27	48,856
Jun-11	110	41	62,640
Jul-11	110	41	64,728
Aug-11	110	41	64,728
Sep-11	85	27	47,280
Oct-11	61	27	36,952
Nov-11	46	27	28,560
Dec-11	40	25	26,040
Jan-12	35	25	23,560
Feb-12	46	27	27,608
		Total Block Energy	497,216

EXHIBIT 10
ARIZONA PUBLIC SERVICE CORPORATION
AND
ED 3

POWER BLOCK TABLES

TABLE YEAR 5

Includes APS Retail Block

March 1, 2012 through February 28, 2013

The following Power Block Table is to be used in conjunction with calculating the Monthly Power Supply Billing Amount.

Billing Month	On-Peak 7x16 Hourly Demand (MW)	Off-Peak 7x8 Hourly Demand (MW)	Power Block Energy (MWh)
Mar-12	48	27	30,504
Apr-12	61	27	35,760
May-12	85	27	48,856
Jun-12	110	41	62,640
Jul-12	110	41	64,728
Aug-12	110	41	64,728
Sep-12	85	27	47,280
Oct-12	61	27	36,952
Nov-12	46	27	28,560
Dec-12	40	25	26,040
Jan-13	35	25	23,560
Feb-13	46	27	26,656
		Total Block Energy	496,264

EXHIBIT 11

Contract Payment Example Calculations

For the month of June, 2008 the calculation of the monthly billing contract payment would be:
P = PBA + RP + S + PPC +TRAN+ IS + VIA

PBA for June, 2008 = 52,320 MWh * $73.50/MW = $3,845,520

VIA = $\sum$[(PTLR – PREF – PBD – OP) (HI ± IAF)]

Assume:	**For June 5, 2008, HE 0500:**	**For June 20, 2008, HE 1700:**
PTLR (MW) =	70	130
PREF (MW) =	25	40
PBD (MW) =	38	90
OP (MW) =	0	10
DJ Hourly Index ($/MWh)	45.00	71.00
R & S & PPC & IS	0	0

Day	**Hour Ending**	**PREF + OP (MW)**	**PBD (MW)**	**PTLR – PREF – PBD – OP (MW)**	**Dow Jones Hourly Index ± IAF ($/MWh)**	**Volume Imbalance Hourly (Sale) / Purchase ($)**
06/05/08	5:00	25	38	7 IAF = +$2/MWh	47.00	47.00 * 7 = 329.00
06/20/08	17:00	50	90	(10) IAF = -$2/MWh	69.00	69.00 * (10) = (690.00)

For simplicity in this example, the values in the column titled "Volume Imbalance Hourly" above are assumed to be "$0" for each hour in this month, except for the two (2) hours shown above. Therefore, VIA for all hours of the month of June, 2008 would be ($361.00). The Contract Payment: P=$3,845,520+TRAN and VIA= ($361.00) for a total monthly bill of $3,845,159+TRAN, assuming no surcharge or PPC.

EXHIBIT 12

Definitions

As used in this Confirmation to which this is Exhibit "12," and in all other Exhibits to this Confirmation, the following defined terms have the meanings set forth below:

"APS Retail Block" The 3800 ± customers which are subject to transfer pursuant to other negotiations between ED-3 and APS and upon Arizona Corporation Commission ("ACC") approval.

"Capacity" means the electric generating capability, expressed in megawatts (MW).

"On-Peak Hour(s)" means hour ending 0700 to 2200 PPT Monday through Sunday including NERC Holidays.

"On-Peak Hourly Demand" means the demand (MW) to be used for any On-Peak Hour during the applicable billing month, as set forth in the calculation of VIA.

"Off-Peak Hour(s)" means all hours that are not On-Peak hours.

"Off-Peak Hourly Demand" means the demand (MW) to be used for any Off-Peak Hour during the applicable billing month, as set forth in the calculation of VIA.

"Power Block Energy" means the minimum energy Purchaser must Take-or-Pay for each billing month as shown in column 4 for the month that corresponds to the billing month in Exhibits 1 through 10.

"Power Block Tables" means those tables set forth in Exhibit 1 through 10 to this Agreement used in calculation of the Contract Payment.

"Purchaser Preference Resources" are limited to resources purchased by District from the Western Area Power Administration ("Western") and from the Arizona Power Authority ("APA"), including (a) Salt Lake City Area Integrated Project firm entitlements, including Western Replacement Power, Customer Displacement Power and any redistribution under the integrated Scheduling Agreement and the Integrated Federal Resource and Power Transaction Contract; (b) Boulder Canyon Project ("Hoover") Power, including layoffs and exchanges of power under the APA Resource Exchange Program, Boulder Canyon Project firming power and APA firming power sold pursuant to Section 6(b) of the APA Power Sales Contract between the District and APA, and Firming Energy, as that term is defined in, and provided by Contract No. DE-MS65-86WP39574 between Western and APA, and adjustments to APA power arising from APA's scheduling entity arrangements; and (c) Parker Davis and/or Navajo power, that may be obtained by the District; but Purchaser Preference Resources do not include third-party supplemental power.

"Take-or-Pay" means Purchaser shall pay Seller the Power Block Amount for the appropriate billing month as a minimum cost per month whether Seller takes any Energy Product that month or not.

EXHIBIT 13

DOWJONES

Palo Verde Hourly Index

Power Delivery Date: 02/22/08

	Price	Volume	High	Low
Hour 1	$52.00	25	52	52
Hour 2	$51.31	72	52	50
Hour 3	$48.22	185	52	40
Hour 4	$53.13	213	56	50
Hour 5	$60.93	233	65	52
Hour 6	$88.16	310	90	88
Hour 7	$87.67	225	88	85
Hour 8	$90.00	300	90	90
Hour 9	$86.60	265	90	78
Hour 10	$91.23	462	98	78
Hour 11	$83.04	228	98	78
Hour 12	$78.00	133	78	78
Hour 13	$72.00	25	72	72
Hour 14	$80.57	175	88	70
Hour 15*	$83.00	0	89	78
Hour 16*	$85.00	0	90	80
Hour 17*	$88.00	0	94	83
Hour 18	$90.00	30	90	90
Hour 19	$98.00	260	98	78
Hour 20	$98.00	260	98	98
Hour 21	$96.00	120	96	96
Hour 22	$87.00	200	87	87
Hour 23	$76.32	269	87	70
Hour 24	$68.00	65	70	68

EXHIBIT 14

APS

Arizona Public Service Company

February 21, 2008

Mark Hackney
Arizona Public Service Company
PO Box 53999
Station 2260
Phoenix, AZ 85072-3999

Re: ED3 Network Contract

Dear Mr. Hackney,

Arizona Public Service Co. has recently negotiated a power supply agreement with the Electrical District 3 (ED 3) to continue serving them similar to their current contract. APS currently serves this load as an embedded network load in its own system and has in the past included that load in the total APS Network load in each of the 10 year load forecasts.

ED 3 has preference hydro power entitlements which are delivered at the Test Track 230/69 kV substation and APS M&T supplies the load following and covers any energy needs on top of their preference hydro entitlements. APS M&T has been serving this customer for many years as an extension of its own APS Native Load Customers and uses power purchases and APS generating resources as needed. **This extended supply arrangement is projected to start March 1, 2008 and will be in place for 5 years with the expiration date being February 28, 2013.**

Rather than keeping the ED 3 load included in the total APS Native Load we are requesting that their load be added to APS Marketing and Trading's existing Network Integration Transmission Service Contract **(52013)** that is used to serve the TOUA, Majority Districts and the City of Wickenburg. APS M&T believes that partitioning this load away from the APS Native Load and adding it to Transmission Service Contract **52013** will allow APS M&T to allocate each billing component that belongs to each of the separate customers under contract **52013**. APS M&T asks for confirmation from APS Transmission Operations that adding ED 3 will not impair our ability to bill each of the customers with their appropriate transmission related charges as we are able to do presently.

Please respond as quickly as possible if you see any problems with shifting the ED 3 network load to the existing Service Contract 52013 and serving them similarly to the other loads associated with this contract.

Since this request is a continuation of service to the ED 3 and the ED 3 load has been a Network Load on the APS system for years we don't expect that any studies are necessary in order to transfer the load to Service Contract 52013.

In accordance with section 29.2 of the APS open access transmission tariff, APS Marketing & Trading Department submits the following application to modify its network integration transmission service arrangement, which it uses to make deliveries to its wholesale customers known as the TOUA, Majority Districts, and the City of Wickenburg:

29.2.1 The identity, address, telephone number and facsimile number of the party requesting service;

Arizona Public Service Company Marketing & Trading Department
(602) 250-3936
(602) 250-3719 (facsimile)

29.2.2 A statement that the party requesting service is, or will be upon commencement of service, an Eligible Customer under the Tariff;

Arizona Public Service Company Marketing & Trading Department is an Eligible Customer under the APS OATT.

29.2.3 A description of the Network Load at each delivery point. This description should separately identify and provide the Eligible Customer's best estimate of the total loads to be served at each transmission voltage level, and the loads to be served from each Transmission Provider substation at the same transmission voltage level. The description should include a ten (10) year forecast of summer and winter load and resource requirements beginning with the first year after the service is scheduled to commence;

<u>*See*</u> *Exhibit A.*

29.2.4 The amount and location of any interruptible loads included in the Network Load. This shall include the summer and winter capacity requirements for each interruptible load (had such load not been interruptible), that portion of the load subject to interruption, the conditions under which an interruption can be implemented and any limitations on the amount and frequency of interruptions. An Eligible Customer should identify the amount of interruptible customer load (if any) included in the 10 year load forecast provided in response to 29.2.3 above;

Not applicable.

29.2.5 A description of Network Resources (current and 10-year projection), which shall include, for each Network Resource:

- Unit size and amount of capacity from that unit to be designated as Network Resource
- VAR capability (both leading and lagging) of all generators
- Operating restrictions
- Any periods of restricted operations throughout the year
- Maintenance schedules
- Minimum loading level of unit
- Normal operating level of unit

- Any must-run unit designations required for system reliability or contract reasons
- Approximate variable generating cost ($/MWh) for redispatch computations
- Arrangements governing sale and delivery of power to third parties from generating facilities located in APS Control Area, where only a portion of unit output is designated as a Network Resource
- Description of purchased power designated as a Network Resource including source of supply, Control Area location, transmission arrangements and delivery point(s) to APS' Transmission System;

See Exhibit A.

29.2.6 Description of Eligible Customer's transmission system:

- Load flow and stability data, such as real and reactive parts of the load, lines, transformers, reactive devices and load type, including normal and emergency ratings of all transmission equipment in a load flow format compatible with that used by APS
- Operating restrictions needed for reliability
- Operating guides employed by system operators
- Contractual restrictions or committed uses of the Eligible Customer's transmission system, other than the Eligible Customer's Network Loads and Resources
- Location of Network Resources described in subsection (v) above
- year projection of system expansions or upgrades
- Transmission System maps that include any proposed expansions or upgrades
- Thermal ratings of Eligible Customer's Control Area ties with other Control Areas; and

Not applicable.

29.2.7 Service Commencement Date and the term of the requested Network Integration Transmission Service. The minimum term for Network Integration Transmission Service is one year.

Requested service is existing Network Load to be transferred to APS' Network Integration Service Contract #52013. The ED 3 Load will be served by APS M&T for five years (see Exhibit A).

If you determine after reviewing this submittal that you need more information, contact either **Dennis Beals at 81-3101** or me at **81-3936**.

Sincerely,

Randy A. Young
Commodity Consultant
APS M&T
(602) 250-3936

ED 3 Yearly Network Load Forecast

Year >	2008	2009	2010	2011	2012	2013*
Load in MW Load is served off the Santa Rosa 230/69 kV sub	179	197	212	222	232	170

* Contract ends Feb 28, 2013 at Midnight.

ED 3 Network Resources

Year >	2008	2009	2010	2011	2012	2013
Primary Resources						
Preference Power (MW) (delivered at Test Track 230/69 kV sub)	89	97	102	105	107	70
Power Purchase Contracts (MW) (delivered at Palo Verde/Hassayampa 500 kV sub)	90	100	110	117	125	100

Secondary Resources

Could include any of the APS Generating Plants and any of the APS Purchased Power Contracts that have been designated as a Network Resource.

ED 3 Monthly Peak Loads in MW

MONTH	2008	2009	2010
January	110	122	132
February	124	138	148
March	114	126	136
April	109	121	130
May	165	182	196
June	173	191	205
July	179	197	212
August	171	188	201
September	136	148	159
October	117	127	136
November	114	124	132
December	127	137	146

Contract Execution Cover Sheet

Power Sale Agreement and Confirmation

Contract No.: 89694 & 89695

Between

Arizona Public Service Company

and

Electrical District No. 3 of Pinal County

Credit:

Daniel Sarti
Credit Risk Manager

Legal:

Tim Bolden
Associate General Counsel

Marketing:

Dennis Beals
Director, Marketing & Origination

Contracts:

Steve McAdams
Contracts Manager

Contracts:

Michele Yanik Deken
Sr. Contract Development Analyst